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When Does Regulation Distort Costs? Lessons from Fuel Procurement in US Electricity Generation

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Abstract

Under what conditions does cost-of-service regulation lead firms to distort costs? This paper analyzes changes in fuel procurement practices by coal- and natural gas-fired electricity generating plants in the United States following state-level legislation that ended cost-of-service regulation among investor-owned electric utilities in the late 1990s. I construct a detailed dataset that links confidential, shipment-level data on the price of virtually all of the fuel delivered to coal- and gas-fired electricity plants in the United States from 1990-2009, with plant-level data on operations and regulatory status. Using a matched difference-in-difference estimation strategy to account for confounding shipping costs, I find the price of coal drops by 12% at deregulated plants relative to matched plants that were not subject to any regulatory change, whereas there was no relative drop in the price of gas. Deregulated plants disproportionately switch to burning low-sulfur coal rather than install capital-intensive abatement equipment to comply with environmental regulations, and expand imports from out of state by 25% if they were initially burning in-state coal. I show how these results lend support to theories of asymmetric information between generators and regulators, regulatory capture, and capital-bias as important sources of distortion under cost-of-service regulation. I then show that the drop in the price of coal is associated with a reallocation of purchases to more productive mines, rather than simply a transfer of regulatory rents from coal producers to electricity generators. Although only one quarter of U.S. coal-fired capacity has been deregulated, the end of cost-of-service regulation has reduced the price of fuel by about one billion dollars per year for these plants.

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1 Introduction

What determines whether government policy intended to correct a market failure improves social welfare, or ultimately causes more harm than the problem it was intended to ameliorate? In this paper I identify three leading potential mechanisms from the theoretical literature seeking to answer this question, and measure their importance in contributing to distortions in fuel procurement arising from cost-of-service regulation of U.S. electricity generation.

To do so, I develop a model of a regulated monopolist who may reduce the price paid for fuel by exerting costly effort (more intensive search, negotiation, etc.) that is not directly observed by the regulator. The regulator has discretion to allow "prudently incurred" costs to be recovered, and the fixed cost of effort is covered by receiving a rate of return on the capital value of the plant that exceeds the cost of capital. The "Averch-Johnson Effect" (Averch and Johnson (1962)) predicts that this compensation scheme leads firms to adopt economically inefficient production techniques that are capital-biased. It also becomes impossible to induce efficient cost-reducing effort when the regulator is unable to observe both effort and the cost of this effort (Laffont and Tirole (1986, 1993)). Finally, fuel prices are predicted to exceed those prevailing under competition when special interest groups (such as coal producers) influence the regulator's decision on which costs to allow (Stigler (1971); Peltzman (1976); Grossman and Helpman (2002)).

I compare the importance of the mechanisms hypothesized by these theories at natural gas- and coal-fired electricity generating facilities following the end of cost-of-service regulation in states that passed electricity industry restructuring legislation. By virtue of the need to transmit via public thoroughfares, the production and sale of electricity has historically been regulated by state or municipal governments in the United States (Stigler and Friedland (1962); Jarrell (1978)). When not owned by the government, electricity providers have typically taken the form of vertically-integrated Investor-Owned Utilities ("Utilities" or IOUs). IOUs own the generating plants, the transmission network, and exclusive licenses to sell electricity in their respective service areas. In the mid to late 1990's, state-level initiatives sought to restructure the electricity industry by transforming the rate-regulated IOUs in to participants in a competitive market guided by private investment, procurement, and production decisions. This required breaking up utilities so that owners of the transmission network could not favor their own plants in the face of lower-cost competition. This was often accomplished through divestiture, in which IOUs sold off their generating assets or transferred them to unregulated affiliates. Once divested, power plant operators' costs are no longer subject to oversight by the state Public Utility Commission. Although all states had at least held hearings to consider restructuring reforms by 2000, the California energy crisis put a halt to any legislation that had not already passed. As a result, the regulation of electricity generators varies dramatically across states, with over half of states virtually untouched by any reform.

To measure changes induced by this deregulation, I construct a panel on the operations, fuel costs, and regulatory status of all gas- and coal-fired electricity generating facilities in the lower 48 states, responsible for roughly two-thirds of U.S. electricity generation.[1] Although many plants initially ceased reporting costs following divestiture–as is standard when cost-of-service rules end–the Department of Energy's Energy Information Administration asserted its jurisdiction to collect data on fuel prices at deregulated plants beginning in 2002. This is the first study to evaluate the impact of deregulation on costs using detailed, restricted-access data from the post-divestiture period in U.S. electricity generation.

I employ a matched Differences-in-Differences (DID) estimator in the spirit of Heckman, Ichimura, Smith, and Todd (1998) to compare fuel prices and sulfur regulation compliance strategies at similar divested and non-divested plants in close geographical proximity. The estimation strategy relies on the assumption that fuel purchasing opportunities are identical between "treatment" and "control" facilities. Close proximity is therefore a critical element of the estimation strategy because coal transportation costs are substantial, and have changed over time. I find that divested plants reduce the price paid for coal by 12% relative to a counterfactual scenario in

[1]"Gas" and "Natural Gas" both refer to a gaseous mixture of hydrocarbons (mostly methane) extracted from underground deposits, are used interchangeably.

which their operations had continued under cost-of-service regulation.

A small fraction of this gain may attributed to the fact that divested generating units have been far more likely to have switched to cheaper, low-sulfur sub-bituminous coal.[2] The opposite is true of regulated generating units, which have disproportionately installed "scrubbers" as a means of compliance with sulfur emission regulations. Since scrubbers are enormously expensive pieces of equipment (∼$400/kW of capacity), the fact that rate-regulated units would opt for more capital-intensive methods to achieve compliance with environmental regulations is consistent with the hypothesis of Averch and Johnson (1962).

The drop in the cost of coal following divestiture does not reflect the universal inefficiency of regulation. Instead, I find that divestiture had no impact on the price of fuel paid by gas-fired generators. These plants were commonly owned with coal-fired units by monopolistic IOUs, and were subject to the same change in regulatory oversight. Differences in the markets for natural gas and coal lend support to agency-based theories that emphasize the role of asymmetric information between firms and regulators as a source of distortion under regulation. While gas is a homogeneous commodity traded in regional markets with transparent prices, the market for coal is dominated by confidential bilateral contracts. In addition, shipping from mines is costly and plants must be specifically tuned to the heterogeneous characteristics of the coal being burned. Regulators therefore have less information on a coal-fired plant's purchasing opportunities, and operators may justify expenses based on idiosyncrasies of their location and equipment. It is clear, however, that these justifications become less important when generators become the residual claimants of cost savings through divestiture.

To evaluate the importance of regulatory capture on distorting procurement decisions, I confine my analysis to the set of plants that were burning coal sourced in-state during the pre-divestiture period. Coal producers are hypothesized to have

[2]Coal is classified by 'rank', which refers to the purity of energy concentrated over millions of years of exposure to heat and pressure. In decreasing order of energy content, they are: Anthracite (mostly in PA), Bituminous (Central Appalachia), Sub-bituminous (WY, CO, UT), and Lignite (TX). About 90% of coal burned for electricity generation in the United States is Bituminous or Sub-bituminous.

greater influence over regulators in the states in which their mines (and jobs) are located. I find that divested facilities in these areas increase their out-of-state purchases by about 25% relative to matched non-divested facilities in coal-producing states, suggesting that regulation was an impediment to efficient procurement. I also find evidence suggesting that local coal has had some success in protecting their operations, as price reductions in these areas are mostly confined to plants that switched to burning low-sulfur coal.

I then connect my data on coal purchases to detailed data on mining cost determinants in the counties of origin. This allows me to decompose the extent to which these changes are driven by a reallocation of rents between mines and utilities, as opposed to real social welfare gains. I find that divested plants buy coal from mines with substantially lower extraction cost profiles: the mined coal seams are about 30% thicker and 50% closer to the surface than coal purchased by matched facilities. In total, divested plants purchase coal that requires $\sim 25\%$ less labor to extract from the ground at mines that pay 5% higher wages.

Aside from any conclusions that may be drawn regarding the wider debates on the merits of government intervention in the economy,[3] the sheer scale of the coal-fired electricity sector makes these results of independent interest. Over 40% of electricity in the United States is derived from coal, and fuel accounts for about 80% of variable costs (Fabrizio, Rose, and Wolfram (2007)). A 12% reduction in fuel prices at the coal-fired facilities that have already been divested amounts to about one billion dollars per year. These facilities account for roughly one quarter of U.S. coal-fired generating capacity; the remaining facilities have not undergone any major changes in regulatory structure.

The structure of the paper is as follows: in the next section I describe the process of divestiture in the United States, and the institutional details that will facilitate

[3]A form of cost-of-service has recently been implemented in health care under the "80/20 rule" of the Affordable Care Act. This rule requires that insurance companies reimburse their customers for any revenues exceeding a set percentage above medical expenditures. As opposed to regulation in the electricity sector, in which variable costs are simply passed through, this rule means that insurance companies can only raise their profits by spending more on medical care. My results suggest the notorious opacity of costs and political activity in this sector does not bode well for the anticipated cost-savings from recent health care reform legislation.

estimation. The third section frames the potential sources of regulatory inefficiency with a model of regulatory oversight that captures the hypothesized mechanisms in a unified framework. The fourth section details the estimation strategy, and the fifth section describes the data that I will bring to bear on the question. The sixth and seventh sections discuss the results and the associated welfare gains. The final section concludes.

2 Background on the U.S. Electricity Industry

Operations under Cost of Service Regulation

The market for electricity was chaotic and competitive in its early years due to duplicative, non-exclusive franchises granted by municipalities (Jarrell (1978)). At the turn of the 20^{th} century, improvements in economies of scale of generation and transmission led to widespread consolidation in the industry. State governments responded to this consolidation by asserting themselves over municipalities to regulate the operations of electricity companies in their respective states. Under the subsequent form of regulation, utilities have been granted exclusive licenses to sell electricity in their service territories in exchange for being subject to oversight of their operations and the rates they are permitted to charge customers. IOUs are guaranteed recovery of 'prudent' costs incurred, as well as a pre-determined rate of return on the value of the utility's capital base. All major investments (such as building new generation assets or installing major abatement equipment for use with existing units) can only be undertaken with the approval of the state's Public Utility Commission. The prices an IOU is permitted to charge are determined during 'rate hearings'. These costly, politically charged affairs entail an intensive audit of the utility's costs, operations, and demand projections in order to justify a change in the pricing formula for electricity. Rate hearings may be requested by the utility, or may be automatically triggered when profits exceed a predetermined threshold.

Kahn (1971) argues that the regulatory lag induced by a rate hearing leads many utilities to reduce costs between adjustments so as to reap profits during periods of fixed output price. After oil price spikes in the 1970's, many state commissions allowed IOUs to implement automatic pass-through clauses for fuel costs since intermittent rate cases could not keep up with the rise in the IOU outlays.[4] Once the adjustment formula is set, IOUs are guaranteed recovery of their fuel costs without further oversight. Since IOUs operate exclusively in their service territory, it is not possible for consumers to punish inferior procurement practices by switching to a lower cost producer.

There are two additional types of facilities that deserve mention. An early effort to reduce the cost of electricity during the Carter Administration led to the Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA made it easier for non-utility generating facilities to sell power to regulated entities in an attempt to remove barriers to entry in the industry. This was followed by the Energy Policy Act of 1992, which sought to remove some of the obstacles non-utilities faced when seeking transmission service from the IOUs who owned the wires. These reforms stimulated limited entry from non-utility generators, mostly co-generating facilities that also provided steam for industrial purposes (Joskow (2005)).[5]

The final class of operators are federal, municipal, and cooperative organizations. These organizations produce about 20% of the nation's electricity (mostly in rural areas), and have made up about 20% of U.S. coal-fired capacity since at least 1990. Public Utility Commissions do not have jurisdiction to regulate these entities since they are owned either by the government or their members. Facilities owned by either non-utilities or not-for-profits were not subject to divestiture, and therefore do not experience operational or regulatory changes during the period of study.

[4] Gollop and Karlson (1978), and Baron and Bondt (1979) provided early theoretical analysis on how these changes are likely to distort IOU procurement decisions by reducing the incentive to lower costs, as well as make utilities less likely to switch to lower cost fuels when switching costs require commission approval, but continuing to burn uneconomical fuel is costless to the utility. Kaserman and Tepel (1982) find evidence in favor of these hypotheses.

[5] Less than 2% of coal-fired capacity belong to this class of power plants. The mid-2000's saw more substantial entry in the form of gas-fired non-utility generators.

Restructuring and Divestiture

In spite of the successful deregulation of U.S. telecommunications (Olley and Pakes (1996)), airlines (Kahn (1987, 1988); Ng and Seabright (2001)), railroads (McFarland (1989); Ellig (2002)), and trucking (Rose (1987)), electricity was thought to be different. The fact that vertically integrated utilities owned both the generation assets and the wires meant that a deregulated firm would be able to shut out competition from other producers. Markets in electricity could also be vulnerable to the exercise of market power since electricity production must match demand in every moment in time–the impossibility of storage means that a firm can unilaterally withhold capacity to drive up prices with impunity in a free market with high fixed costs of entry.

Joskow and Schmalensee (1988) was groundbreaking in that their evaluation of the electricity industry confronted these challenges directly, and suggested a set of policy options that would facilitate the transition to a restructured market. Among these policies was that vertically-integrated IOUs divest their generation assets to prevent owners of transmission networks from favoring their own plants. Instead, generators would be required to bid their capacity in day-ahead and real-time auctions, and would only be dispatched if their bid was below that of the marginal unit required to meet demand. This change transferred control of transmission networks to independent system operators in order to become participants in regional markets. Once divested, plant operators bear the full cost of their procurement decisions. Units that purchase relatively expensive fuel would be forced to raise their bids to break even in wholesale markets, and therefore become less likely to be called upon to operate.

Figure 1 shows the geographic distribution of these reforms with respect to coal-fired electricity stations in the United States that report fuel deliveries between 1990 and 2009.[6] Although divestitures were required of all IOU generating assets in

[6] States that restructured, but do not have coal-fired generating assets reporting cost data include California, Washington, DC, Maine, and Rhode Island. New Hampshire introduced retail choice, but did not require divestiture of generating assets. A more detailed discussion of the state-by-state history of divestitures can be found in the Data Appendix.

states passing legislation, it is clear that neither coal-fired plants nor restructuring reforms were randomly spread across the country. Almost all coal production and consumption occurs to the east of the Rocky Mountains. At the time many coal-fired plants were built, most coal consumed by electric facilities in the United States was the high-sulfur, bituminous variety from the central Appalachian mountains and Illinois basin. In spite of the high cost of shipping coal relative to transmitting the derived power by wire, the establishment of exclusive service areas by IOUs ensured local utilities would not be competed out of the market by producers in the Ohio River Valley. This is one source of the price differential in electricity across areas that motivated restructuring legislation. Another major driver of restructuring legislation was the gap between retail and industrial electricity prices (White (1996) and Joskow (1996)). States with larger gaps were more likely to restructure due to the perception that retail consumers were getting a raw deal relative to industrial buyers.

Restructuring legislation was first passed in the Northeastern states and California in the mid-1990s. The movement had gained sufficient momentum by 1998 that every state in the union had at least held hearings on the prospective gains from deregulation (Fabrizio, Rose, and Wolfram (2007)). This momentum dissipated quickly in the wake of the California electricity crisis of 2000-2001, leading several states who had made significant progress in the direction of restructuring to delay or cancel planned reforms (Joskow (2005)). No state has passed restructuring legislation since this time: fairly or not, restructuring is popularly associated with the spectacular failure in California, and a lack of significant offsetting benefits to consumers (Kwoka (2008)).[7] As noted by Joskow (2006), "Even the Cato Institute has lost patience with competitive reforms in electricity and appears to see merit in returning to the good old days of regulated vertically integrated utilities (Van Doren and Taylor (2004))."

[7]Borenstein, Bushnell, and Wolak (2002) find that the price of electricity would have tripled between 1998 and 2000 based on rising input costs alone. Although there were a number of factors that contributed to the crisis (including the exercise of market power), it was most certainly exacerbated by the fact that retail prices were fixed while wholesale prices were skyrocketing. This led generators to withhold capacity due to doubts of receiving compensation, not the exercise of market power. See Joskow (2001) for a detailed discussion of the history of the California electricity crisis.

That said, the states that had already restructured before the California crisis have not returned to the model of vertically-integrated IOUs. The perils of liberalized electricity markets have received significant scrutiny in the wake of the California electricity crisis (Borenstein, Bushnell, and Wolak (2002); Borenstein (2002); Bushnell, Mansur, and Savaria (2007); Mansur (2001, 2008)), and adjustments have been made to promote wholesale electricity markets that function reasonably well (Mansur and White (2009)). Recent work has also shown that restructuring is associated with more productive nuclear generating facilities (Davis and Wolfram (2012)), and declines in labor and non-fuel costs (Fabrizio, Rose, and Wolfram (2007)).[8] The market for electricity in the United States is therefore characterized by a patchwork of regulatory structures that are separated by state borders and/or historical service area boundaries.

3 Sources of Regulatory Imperfection

To explore the possible mechanisms that can explain changes in the price of inputs following deregulation, it is helpful to consider the main hypotheses posed in the theoretical literature on regulatory imperfection. To do so I consider a setting in which a firm can reduce the price paid for inputs by exerting cost-reducing effort. After deriving the optimal behavior in the absence of regulation, I introduce standard rate-of-return (or "cost-plus") regulation, in which the regulator has discretion to approve capital investments and "prudent" variable costs. In a key departure from the agency literature, I leave the regulator's objective function unspecified. Rather than derive the optimal policy for the regulator, I am instead interested with how regulation affects the set of *feasible* policies. The reason for this approach is two-fold: it is sufficiently flexible to allow for consideration of different theories of regulatory inefficiency in a common framework, and it results in a set of hypotheses that can

[8]Fabrizio, Rose, and Wolfram (2007) as well as concurrent work by Chan, Fell, Lange, and Li (2012) define treatment as the time between law passage and divestiture because post-divestiture data on costs has not been utilized prior to this study. For work on incentives to invest in new capacity in restructured markets, see Bushnell and Ishii (2007), Ishii and Yan (2004), and Ishii and Yan (2007).

be taken to the data on firm behavior without having already assumed the nature of the regulator's objective.

Suppose generating facilities produce electricity by combining fuel (F) and capital (K) according to the quasiconcave production function $G(F, K)$–labor is a small share of generation costs and is ignored. Let p denote the per-unit compensation received by plant operators, whose determination will depend upon the regulatory environment. Given this price, plants face the inverse demand function $p = p[G(F, K)]$. For simplicity, assume a constant elasticity of demand, and denote the inverse price elasticity of demand $\eta = -\frac{G(F,K)}{p[G(F,K)]}\frac{dp}{dG}$, with $0 \leq \eta < 1$.[9] Suppose plants must exert managerial effort to solicit bids, negotiate contracts, etc. and that this effort reduces the price paid for coal according to $c = \beta - e$ where $e \in [0, \beta]$. Effort is itself costly, and reduces profits according to a convex function $\psi(e)$, $\psi'(e) > 0$, $\psi''(e) > 0$.

First, consider the behavior of the plant in the absence of regulation. Let $R = p[G(F, K)]G(F, K)$ denote total revenues when the manager considers the effect of output on price. The plant manager takes the rental rate of capital, r as given, and chooses effort and inputs to maximize

$$\max_{e,F,K} R - (\beta - e)F - rK - \psi(e) \tag{1}$$

Assuming that price is sufficiently high to cover the fixed costs of effort, we have the standard first order conditions

$$\begin{aligned}
[e]: &\quad \psi'(e) &&= F \\
[F]: &\quad (1-\eta)pG_F &&= (\beta - e) \\
[K]: &\quad (1-\eta)pG_K &&= r
\end{aligned}$$

The optimal effort equates the marginal cost of effort to the marginal benefit: a reduction in the cost of every unit of coal purchased. When the plant takes price as given, marginal revenue is equal to price (i.e. $\eta = 0$ from the firm's perspective), and

[9]Sufficient conditions for a maximum will hold so long as the demand function is not so convex as to reverse the quasiconcavity of revenues with respect to inputs.

standard optimality conditions for inputs equate marginal cost to value marginal product. It is worth noting the effect that market power has on input costs in this scenario. Since a monopolist will restrict output to raise price, the reduced demand for inputs implies less effort will be exerted to reduce input costs than in a competitive market.[10] Input costs in a deregulated market therefore depend on the ability of firms to exert market power. Let the triple (e^*, F^*, K^*) denote the effort and input demand in a competitive, deregulated market.

Next, suppose the firm is regulated on a cost-of-service basis known as "cost-plus." This does not imply that firms are (directly) rewarded for higher coal prices. Instead, variable costs are reimbursed only if the regulator deems them "prudent" and the plant receives a rate of return $s > r$ on its capital stock, or "rate base" that exceeds the cost of capital. The regulator is unable to directly observe cost-reducing effort, and instead decides whether or not to allow fuel expenditures based only on the reported price, c. Let $\theta(\beta - e)$ denote the probability that the regulator allows recovery of costs c. The firm therefore maximizes profits subject to the constraint that revenues are no greater than allowed costs:[11]

$$R \leq \theta(\beta - e)[\beta - e]F + sK$$

Thus the term "cost-plus": the revenues the firm can raise are equal to its prudently incurred variable costs, plus a guaranteed "fair rate of return" paid to capital. To focus attention on cost reduction, it is assumed that the regulator is perfectly able to observe and dictate quantities conditional upon costs.[12] This yields the La-

[10]Following Hicks (1935), the tendency for monopolists to have costs that exceed those prevailing under competition has been referred to as "the quiet life of the monopolist."

[11]Joskow (1974) argues that while regulators may use this constraint for setting nominal prices at formal rate hearings, firms are actually able to earn any rate of return so long as prices are not rising during intermediate periods. Jha (2012) extends this intuition in a model in which excess profits are confiscated, but imprudent expenditures are punished, inducing a form of risk aversion among regulated utilities. The widespread adoption of automatic fuel adjustment clauses in the late 1970's effectively re-coupled revenues and costs in the manner implied by the rate of return constraint. Imprudent costs may be rejected in the spirit of Jha (2012) through $\theta(\beta - e)$.

[12]This is equivalent to defining the analogous probabilities of approval for fuel and capital as unity at the quantities desired by the regulator, and zero otherwise.

grangian and first order conditions

$$\mathcal{L} = \max_{e,F,K} R - (\beta - e)F - rK - \psi(e) + \lambda\{\theta(\beta - e)[\beta - e]F + sK - R\} \quad (2)$$

$$\begin{aligned}
[e]: \quad & \psi'(e) && = F\{1 - \lambda[\theta(\beta - e) + [\beta - e]\theta'(\beta - e)\} \\
[F]: \quad & (1-\eta)pG_F && = \frac{[1 - \lambda\theta(\beta - e)]}{(1-\lambda)}(\beta - e) \\
[K]: \quad & (1-\eta)pG_K && = r - \frac{\lambda}{(1-\lambda)}[s - r]
\end{aligned}$$

The binding revenue constraint and sufficient second order condition for a maximum imply $0 < \lambda < 1$.[13] Capital-bias is expressed clearly by assuming for a moment that the regulator approves all variables costs ($\theta(c) = 1 \, \forall \, c$). Instead of equating the relative marginal product of capital to the relative price, cost-plus recovery implies

$$\frac{G_K}{G_F} = \frac{r}{(\beta - e)} - \frac{\lambda}{(1-\lambda)}\frac{s-r}{\beta - e} < \frac{r}{(\beta - e)}$$

This is the seminal hypothesis of Averch and Johnson (1962): cost-plus regulation leads to economically inefficient capital-biased production, also called "gold-plating" and "rate-base padding"[14]. When cost recovery is guaranteed regardless of c, it is also clear that fuel prices are inefficiently high. This is because allowed revenues are directly tied to costs through the revenue constraint. While the plant bears the full cost of search effort, it only reaps benefits at rate $(1 - \lambda)$.[15] One strategy is to decouple revenues from costs via "yardstick competition" (Shleifer (1985)). Under yardstick competition, the allowed output price is tied to the realized costs of *other*

[13] The determinant of the bordered Hessian of (2) is positive when $\lambda < 1$ and revenues are not too concave.

[14] See Baumol and Klevorick (1970) for a more complete treatment, and Berg and Tschirhart (1988) (chapter 9) for a discussion of the subsequent literature on the "Averch-Johnson effect."

[15] If we instead assumed that the regulator could fully compensate the firm for effort, effort would be efficient conditional upon quantities, but quantity would still inefficiently low because the plant anticipates the effect of output on price.

producers–thereby effectively setting λ and η to zero.

In the agency-theoretic approach, the regulator removes the unconditional guarantee of recovered costs in order to induce the plant to undertake the desired level of cost reduction effort and production. This is a relatively straightforward task when there is no uncertainty on intrinsic costs, β (i.e. the cost of fuel when no effort is exerted): the regulator approves the costs that maximize her objective function, and denies compensation otherwise.[16] The plant's best response is to comply with the regulator's wishes so long as the resulting profits are non-negative.

Of course, potential costs are often unobserved by the regulator, who makes decisions in the context of political pressure. Thus the interaction between regulators and firms has become a key area of interest in principal-agent theory (Baron and Myerson (1982); Laffont and Tirole (1986) and meticulously detailed in Laffont and Tirole (1993)). The workhorse model of modern political economy (Grossman and Helpman (2002)) adopts the principal-agent framework, and considers the influence of special interest groups as an argument in the regulator's objective function. From the plant's perspective, the common theme of these models is that the probability of recovering expenses depends in some way on reported costs. In choosing a profit-maximizing level of effort, the firm trades off the direct reduction of allowed revenue due to lower costs, and the increased probability of having costs allowed.

In the case of asymmetric information, the regulator must adopt a strategy of approving costs without observing effort or intrinsic costs. Suppose β can take on any value on the interval $[\underline{\beta}, \overline{\beta}]$ with some positive probability. Let $\underline{c}$ denote the costs realized when firms with intrinsic costs $\underline{\beta}$ exert optimal effort $e^*(\underline{\beta})$, and similarly for $\overline{c}$. While it is possible for the regulator to induce efficient outcomes over some range of β, this becomes infeasible as the unobserved heterogeneity grows sufficiently large so that it is no longer possible to punish higher costs while preserving solvency.

To see this, first note that the efficient level of effort in the first-best world

[16] If we consider only differentiable strategies, the first best outcomes of (1) are achieved when the regulator approves effort e^* with certainty, and the probability of cost allowance at the optimum changes according to $\theta'(\beta - e^*) = -\frac{\theta(\beta - e^*)}{(\beta - e^*)}$. This neutralizes the effect of the rate of return constraint by increasing the probability of allowed costs one-for-one with cost-reducing effort–a zero net revenue effect.

is decreasing in intrinsic costs, that is $\frac{de^*}{d\beta} < 0$.[17] As a result, optimal costs are increasing with intrinsic costs, $\frac{dc^*}{d\beta} > 0$. This makes sense, for otherwise we would have the perverse scenario in which firms with higher costs are producing more than those with lower costs. Similarly, applying the envelope theorem to (2) when differentiating profits with respect to β implies that profits of an operating plant are strictly declining as intrinsic costs rise.

Suppose the regulator approves $\theta(c) = 1$ for $c \leq \underline{c}$, with $\theta'(c) = -\frac{\theta(c)}{c}$ for $c \geq \underline{c}$. This is a feasible strategy to induce efficient search so long as profits remain non-negative. However, for fixed $\underline{\beta}$, as $\overline{\beta}$ grows large, there will eventually be a region of β in which the optimal policy does not allow the plant to cover its costs, and is forced to shut down. It is important to note that this is due to the variance of unobserved heterogeneity, not the levels of costs. When intrinsic costs are high, but observed, it is perfectly possible for the regulator to approve costs at the efficient level of effort. This is a classic result in principal-agent theory, typically proven in circumstances in which the regulator aims to maximize the sum of consumer surplus and profits. The point here is that efficient effort is impossible to induce under *any* regulator objective function when unobserved heterogeneity is sufficiently large.

The inefficiency associated with regulatory capture is also straightforward to demonstrate. Suppose the local coal mines exert some influence over the regulator's decision-making. In this case, the regulator approves fuel costs according to $\theta(c, b)$ where b represents the influence of the mines, perhaps via campaign contributions as in Grossman and Helpman (2002). In this case we can express the effect of this influence on allowed costs as $\frac{\partial\theta}{\partial b} > 0$; $\frac{\partial^2\theta}{\partial b\partial c} \geq 0$ – contributions raise the probability of allowing high fuel costs, and reduce the punishment for marginally reducing effort.[18]

[17] This is shown by differentiating the first order conditions of (1) with respect to β while noting input demand is a function of fuel price. The input demand conditions yields the standard $\frac{\partial F}{\partial c} = \frac{R_{KK}}{R_{KK}R_{FF} - R_{FK}^2} < 0$, by the assumed quasiconcavity of revenue. Differentiating the optimal effort condition yields $\frac{de^*}{d\beta} = \frac{\frac{\partial F}{\partial c}}{\frac{\partial F}{\partial c} + \psi''(e^*)}$. This implies optimal effort is decreasing in intrinsic costs so long as the convexity of the effort function is greater than the drop in fuel demand arising from higher fuel prices. This follows from the assumption that the revenue function is not too concave in order for the solution to (1) to be a maximum.

[18] In fact, the necessary assumption is that $\frac{\partial^2\theta}{\partial b\partial c}$ not be so negative as to reverse the direct effect

To show how increased mining influence affects the cost-minimizing effort exerted by plants, suppose the regulator is initially inducing optimal effort with $\frac{\partial\theta}{\partial c} = -\frac{\theta(\beta - e^*, b)}{(\beta - e^*)}$ and consider the effect of a marginal rise in influence on search effort. Accounting for political influence via $\theta(c, b)$ in (2), differentiation of the analogous first order condition for effort with respect to b and substituting in for the initial policy yields

$$\frac{de^*}{db} = -\frac{F\lambda[\frac{\partial\theta}{\partial b} + (\beta - e^*)\frac{\partial^2\theta}{\partial c\partial b}]}{\psi''(e^*) + \frac{\partial F}{\partial c}}$$

The denominator is positive by the same condition that implies $\frac{de^*}{d\beta} < 0$. Thus an increase in political influence leads to a decrease in cost-reducing effort, and higher fuel prices.

We have therefore derived a core set of predictions to test against the data. The price of fuel is expected to remain constant after divestiture when determinants of cost are readily observable by the regulator–who is operating relatively freely of political constraints imposed by fuel suppliers. Conversely, both opacity of the procurement process and political influence tend to raise input prices above levels observed by plants operating in a competitive market. Finally, divested plants are anticipated to favor less capital-intensive production methods than when they are compensated based on their capital stock.

4 Estimation Strategy

To estimate the impact of plant divestiture on coal procurement practices, one would ideally like to randomly assign treatment (divestiture) to observationally equivalent plants in close proximity. The control plants would continue operating under cost-of-service. With random assignment, these plants would serve as a clean counterfactual for the operations of the divested plants, allowing causal inference to be made. Forced divestitures triggered by state-level restructuring legislation has ensured that probability of treatment *within* state is uncorrelated with potential confounders. Complete

of $\frac{\partial\theta}{\partial b}$.

divestiture of all generating assets guaranteed regulated utilities were not left operating the least desirable plants in their portfolio, for example. However, it is clear from Figure 1 that restructuring legislation was not randomly assigned *across* states.

With a panel of data on costs and plant characteristics, one could potentially account for the differences between treatment and control groups with a Differences-In-Differences estimator (DID, Ashenfelter (1978) and Ashenfelter and Card (1985)). This is the approach taken by Bushnell and Wolfram (2005), Davis and Wolfram (2012), and Chan, Fell, Lange, and Li (2012) when studying the effect of divestiture on plant efficiency. A DID framework with plant-level fixed effects assumes that once permanent, plant-specific determinants of cost have been removed, coal prices at control facilities track the counterfactual prices at treatment facilities. This assumption is problematic in settings where unobserved or endogenous time-varying determinants of the outcome variable differ between treatment and control groups. In the case of coal procurement, the combination of substantial shipping costs and wide geographic dispersion of plants between treatment and control groups suggests that a straightforward DID estimation would be inappropriate. For example, Figure 2 shows the estimated relationship between plant distance from mine and shipping costs during three of the past twenty years (1997 is year before divestitures begin).[19] Fluctuations in the price of oil, and their subsequent effect on freight rates will disproportionately influence prices at facilities farther from their supplier because shipping rates are tightly connected to oil prices. However, simply controlling for distance from the mine is unsatisfactory—part of the goal of this paper is to test whether firms differentially respond to cost shocks. If a divested firm is more likely to change their supplier in response to cost spikes, the savings from the change itself will be lost when limiting to estimation conditional upon distance.

Another possible approach would be to use the synthetic control group approach of Abadie and Gardeazabal (2003) and Abadie, Diamond, and Hainmueller (2010), who match on pre-treatment outcome variables. Again, the potential confounders

[19] While shipping is charged per ton of coal, not per unit of heat, all coal data in this paper is denominated in Millions of British Thermal Units (MMBTU). This is because heat energy is fundamentally what is being converted to electricity, and the heat content per ton of coal varies.

in this setting render such an approach problematic. This is because in the pre-treatment years, a facility in Chicago may be matched with a facility in Atlanta that receives its coal from West Virginia, roughly equal distance between the two. The plant in Atlanta, however, is a poor counterfactual for the relative prices of coal ranks in Chicago, which is much closer to the Powder River Basin in Wyoming. They may have identical prices at baseline, but face different choice sets unrelated to treatment status.

Instead, I compare facilities in close proximity that burned the same rank of coal in 1997, before divestitures began.[20] More formally, suppose we have N plants indexed $i \in \{1, ..., N\}$ so that plants $i \in \{1, ..., N_0\}$, $N_0 < N$ are never divested, but those with $i \in \{N_0 + 1, ..., N\}$ eventually are. There are T time periods indexed $t \in \{1, ..., T\}$, and T_0 pre-treatment time periods with $1 < T_0 < T$. Using the 'Potential Outcomes' framework of Fisher (1935), Roy (1951), and Rubin (1974), let $Y_{it}(0)$ denote the price of coal per MMBTU paid by a non-divested facility i in period t. Similarly, let $Y_{it}(1)$ denote a facility that has been divested. Suppose fuel costs at non-divested facilities are

$$Y_{it}(0) = \gamma_i + \delta_t + c_t(X_i, 0) + \nu_{it}$$

where $c_t(X_i, 0)$ represents a time-varying procurement cost function that depends on facility i's location X_i (a richer set of pre-treatment covariates is possible), and regulatory status. Suppose that divestiture induces procurement cost $c_t(X_i, 1)$, but that time invariant costs γ_i are unaffected by regulatory status (an example would be "last mile" costs that are idiosyncratic to the plant). Then coal prices at divested facilities can be written as

$$\begin{aligned} Y_{it}(1) &= Y_{it}(0) + [c_t(X_i, 1) - c_t(X_i, 0)] \\ &= Y_{it}(0) + \tau_t(X_i) \end{aligned}$$

[20]The variance in heat, sulfur, and ash content across rank is much greater than within rank, so switching across ranks requires more costly adjustments than the tuning needed to switch suppliers within rank. The procurement options available to two plants in close proximity are likely to overlap when they burn the same rank of coal.

where $\tau_t(X_i)$ represents the relative procurement cost between being divested and regulated at location X_i in period t. The observed fuel price at plant i in period t is therefore

$$Y_{it} = Y_{it}(0) + \tau_t(X_i)D_{it}$$

where

$$D_{it} = \begin{cases} 1 & \text{if } i > N_0 \text{and } t > T_0 \\ 0 & \text{otherwise.} \end{cases}$$

The difficulty in estimation is that only control facilities in close proximity to X_i are suitable to serve as counterfactuals for the price $Y_{it}(0)$, and only after permanent facility-specific differences and common transitory shocks have been taken into account. The estimation strategy employed is similar to the conditional DID estimator of Heckman, Ichimura, Smith, and Todd (1998), but matches on geographic proximity and binary baseline characteristics (rank of coal burned), rather than the propensity score.

As in the matching literature (Abadie and Imbens (2006); Dehejia and Wahba (1999); Heckman, Ichimura, and Todd (1997)), let $1\{\}$ denote an indicator function that evaluates to one if the statement in braces is true, and let $D_i \equiv max\{D_{it}\}$ denote treatment group, and $l_m(i)$ be the index of facilities with $D_l \neq D_i$ and

$$\sum_{j|D_j \neq D_i} 1\{\|X_j - X_i\| \leqslant \|X_l - X_i\|\} = m \tag{3}$$

Equation (3) identifies the m closest facilities of the opposite treatment group according to the norm metric $\| \centerdot \|$. I match exactly on the most common rank of coal (bituminous, sub-bituminous, or other) burned at baseline, then based on geographic proximity. An alternative approach is to match all facilities j with a caliper on distance, $\|X_j - X_i\| < d$, rather than based on a fixed number of matches. Results will be shown to be robust to the choice of matching metric. With a (possibly unbalanced) panel, it is possible to estimate $\tau_t(X_i)$ with a DID estimator applied to facilities i and the m facilities whose distance from X_i satisfies (3):

$$Y_{it} = \gamma_i + \delta_t + \tau_t(X_i)D_{it} + \varepsilon_{it}$$

The average treatment effect on the treated, $\tau = E[\tau_t(X_i)|D = 1]$ can be estimated by taking the average over the divested facilities of the derived $\hat{\tau}_t(X_i)$, or more efficiently, by pooling the data of the divested facilities and their nearest neighbors in a single fixed-effects DID estimation (Angrist and Krueger (2000)), that weighs each matched control facility by the inverse of the number of matches to facility i in period t, then clusters standard errors at the facility level.

Figure 3 shows the distribution of distance between divested and matched facilities under three potential thresholds. All facilities are matched exactly on the predominant rank of coal burned at the facility in 1997, the final common pre-divestiture year. All facilities but one have at least a single match within 200 miles. All results based on matching the m closest non-divested facilities constrain the search radius to 200 miles–beyond this point diminishes the quality of the counterfactual without much gain in terms of broadening the sample. Estimates based on various search radii show that the results are not particularly sensitive to this choice of cut-off. Constraining the sample to these matches yields the set of facilities shown in Figure 4. It is clear that this estimation strategy is not well suited to estimating an average treatment effect for all U.S. plants, as the facilities in South-East, Upper Mid-West, and South-West are all hundreds of miles from the nearest divested facility. It is therefore not possible to estimate a credible counterfactual of how these non-divested plants would have operated if they had been subject to divestiture with this framework.

5 Data

This study utilizes a detailed and comprehensive panel dataset I have constructed from a combination of publicly-available and restricted-access data on the operations of the U.S. electricity sector from 1990-2009. Data on fuel expenditures, generating unit configurations, plant operations and regulatory status are from the Department of Energy's Energy Information Administration (EIA), and the Federal Energy Regulatory Commission. Data on the mines from which coal is sourced is from the Mine Safety and Health Administration (MSHA), the U.S. Geological Survey (USGS), and the Bureau of Labor Statistics (BLS). The Data Appendix describes each of the constituent elements in greater detail. Instead, this section focuses on describing the data in the context of potential threats to the validity of the proposed estimation strategy.

Plant-Level Characteristics

Table 1 presents summary statistics of plant characteristics by treatment group.[21] Panel A includes all facilities that report coal receipts in 1997, the common baseline year before divestitures begin. While divested plants are a few years older, the only substantial difference between the two groups is the likelihood of being subject to an Incentive Regulation program, a common precursor to restructuring. Panel B weights the data from non-divested plants in proportion to the number of divested plants matched for $m = 10$, subject to the constraint that plants be within 200 miles. Matching removes two-thirds of the non-divested plants from the sample, but only one divested facility is without any matches meeting this criteria. The high degree of balance between the two groups is consistent with the history of power plant construction. Generating capacity is closely related to economic activity, which is spatially correlated. It therefore makes sense that areas that grew together in the middle of the 20^{th} century made similar decisions to expand their generation capacity. Again, the exception is exposure to Incentive Regulation, which is consistent with the relationship with eventual restructuring. The fact that divested plants were disproportionately already attempting to reduce costs suggest findings may be somewhat biased against subsequent cost reductions.

It is important to note that entry and attrition of coal-fired plants was rare during the sample period, and are unlikely to be sources of bias. Stringent environmental

[21] The data series upon which this table is based is described in the Data Appendix.

regulations on new boilers combined with high capital costs have made new coal plant construction largely uneconomical. In total, 96% of coal heat in 2009 was delivered to plants reporting in 1990 (slightly more after accounting for the non-reporting of permanent non-utilities prior to 2002). As a fraction of plants, 92% of plants reporting in 2009 also reported in 1990. For attrition, the combination of high entry costs with the high option value from operating during periods of peak demand justifies maintenance costs at most aging facilities. 94% of plants operating in 1990 continued to report fuel deliveries in 2009. The plants that closed tended to be small and rarely used–as a group they accounted for less than 2% of the heat delivered in 1990.

Data on The Cost and Quality of Coal

Figure 5 shows how nominal delivered and mine-mouth prices of bituminous and sub-bituminous coal have evolved over time. This figure again emphasizes the importance of shipping costs, as the price of bituminous coal is nearly 50% higher upon delivery than at the mine, and sub-bituminous prices more than double. This figure also shows a reason for the increasing popularity of sub-bituminous coal, as the average delivered price has fallen below the mine-mouth price for bituminous. While the delivered price depends on the spatial distribution of selected plants, the crossing in the early 2000's means that for plants that switched, sub-bituminous was cheaper on average than bituminous coal, even for plants located at a bituminous mine-mouth. After flat or declining prices through much of the nineties, the delivered price of coal has roughly doubled for bituminous and increased by about 50% for sub-bituminous coal over the last decade. Increases in mine-mouth prices only account for about half of the rise in sub-bituminous prices, the rest is due to increased shipping costs (both in terms of shipping rates and expanded delivery areas). Increases in bituminous prices since 2003 are largely due to increased mining costs and international demand.[22] All told, expenditures on coal for generating electricity averaged about $23B through

[22] Crippling weather events in Chinese and Australian coal fields in 2007 led to a spike in demand for U.S. bituminous coal, causing the price to rise nearly 50% (intra-year spikes were even higher).

most of the nineties, and has increased rapidly since 2002 to about \$40B in 2009 (see Figure A.1b). Expenditures among divested facilities since reporting commenced in 2002 is about \$8B per year on average.

Figure 6 breaks down average delivered coal prices by regulatory category. The vertical lines in the figure denote the year that divestitures began (1998), and the year that the EIA began collecting data from non-utility plants (2002). There is therefore a gap in reporting for any plant that was divested prior to 2002. It should be kept in mind that between these lines there are compositional changes in the data.[23] Prior to 1998, the facilities that were ultimately divested operated as IOUs, and had somewhat higher prices than IOUs that did not face restructuring. Divested plants are at parity with their IOU counterparts shortly after reporting commences, and by the end of the sample period they have reduced the average cost paid for coal to the levels achieved by Gov/Muni/Coop plants.

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 6 provides informal evidence of its validity: IOU and Gov/Muni/Coop price paths are parallel throughout the period of study. Figure 7 tests this hypothesis more formally 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. Since some facilities are not within 200 miles of 10 members of the opposite group, matched observations are weighted by $\frac{1}{m_j}$, the number of matches for facility j within 200 miles. The matched data is then pooled, and regressed against a set of group-month dummies, with 95% confidence intervals formed by clustering standard errors at the facility level. Once this re-weighting is performed, 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

[23]See the Data Appendix for a detailed discussion.

as IOU facilities to estimate the counterfactual prices that would have prevailed in the absence of divestiture.

Table 2 presents summary statistics on the characteristics of coal deliveries reported to FERC/EIA in 1997, the final year before divestitures began. As detailed in Joskow (1985, 1987, 1988), the market for coal is largely conducted through long-term bilateral contracts, with supplemental demand procured on the "spot market," which are short-term bilateral contracts in practice.[24]

At baseline there are substantial differences in the characteristics of coal delivered, though quantities are similar. Divested facilities pay substantially more for coal, both through contracts and on the spot market. They buy 12% more of their coal from within their home state, and are 13 percentage points more likely to be burning bituminous coal. Differences in sulfur content stem from the bias toward bituminous coal among divested facilities. Divested facilities tended to have about two and a half fewer years remaining on their coal purchasing contracts in 1997.

Many of the differences in the characteristics of coal purchases between divested and non-divested facilities are due to geographical dispersion, and are eliminated through matching. In fact, there are no statistically significant differences between coal delivered to divested plants and their matched counterparts.

Since the estimation strategy relies on comparing changes over time, it is also important to ensure that pre-existing trends are not responsible for the subsequent differences between treatment and control units. This does not appear to be the case using the complete, unweighted sample in Figure 6. Figure 8 examines the common pre-treatment period employing the methodology described above to compare non-divested IOU and Gov/Muni/Coop in Figure 7. It provides encouraging evidence that both treatment and control groups were following parallel paths throughout the '90s.[25] It appears that the 12 cent premium paid in 1997 by IOU facilities that would later be divested was a relatively constant feature of coal deliveries. It would

[24]These contracts typically take the form of "base plus escalation": initial prices are set to reflect current market conditions, and the price subsequently rises or falls based on a producer price index for coal production.

[25]If one squints, there might be a slight narrowing of the gap around 1993, perhaps due to the introduction of incentive regulation programs.

be difficult to attribute the decline in prices paid by divested facilities in subsequent periods to mean-reversion, as there is no evidence that prices were moving in different directions before divestiture.

Unit-Level Characteristics

Although coal deliveries are reported at the facility level, the decision to switch the rank of coal burned or install a scrubber is unit-specific (a coal-fired "unit" typically consists of a boiler connected to a generator, cooling and pollution abatement equipment). On average, there are two to three coal-fired units operating per facility.

Table 3 presents summary statistics on coal-fired unit characteristics, both nationwide and in the matched sample. The number of facilities here and those in the plant-level analysis are slightly different due to reporting requirements at the unit-level. In addition, the matching criteria at the unit-level also includes the presence of a scrubber. This is important when estimating the differential probability of adding a scrubber after divestiture. This additional matching requirement eliminates a handful of divested facilities, and about 25% of non-divested facilities. As with the plant-level data, matching removes any statistically-significant differences between divested and non-divested units.

6 Results

This section evaluates the conditions under which divestiture led to a change in behavior by power plant operators, and relates these results to the hypotheses of theories of regulatory inefficiency. I begin with coal prices, and show the robustness of the estimation strategy to various assumptions and specifications. I then contrast the results for coal with those of natural gas as evidence of the importance of asymmetric information in distorting procurement decisions under regulation. I then look at sulfur regulation compliance decisions in the context of capital-bias hypotheses, and show that the disproportionate switch to low-sulfur coal among divested plants does not explain much of the observed drop in relative price. Finally, I constrain my analysis to plants that were initially burning in-state coal, and relate their change in procurement behavior to theories of regulatory capture by politically-active coal mines.

Deregulation and the Price of Coal

Table 4 shows the percent change in price associated with plant divestiture using the matched DID estimator. To evaluate the robustness of the estimates to matching criteria, the first three columns use a caliper on distance, while the last three vary the number of matches. One shortcoming of the distance caliper approach is that the number of divested facilities with *any* matches within the specified distance drops off as the criteria becomes more stringent. Thus the composition of divested plants changes between columns (1) and (3). This caveat aside, all matching specifications show large and statistically significant drops in the relative price paid for coal following divestiture. The results using a fixed number of matches rather than a distance threshold are stable and significant regardless of the number of matches included. Taken together, these estimates show a 12-13% drop in the price that divested facilities have paid for coal relative to nearby generation stations that were similar both on the characteristics of the facility, coal, and trends before divestiture occurred. When using levels rather than logs, this is about 25 cents per MMBTU of coal heat delivered. Based on the post-divestiture period average annual coal expenditure at divested facilities (about eight billion dollars per year), the treatment on the treated estimate amounts to one billion fewer dollars per year being spent on coal, holding quantities constant.

One can see the effect that the weighting scheme employed by the matched DID estimator has by comparing the results from Table 4 with those of Table 5, which uses a standard difference-in-difference estimator. Panel A is based on the full sample of coal plants in the United States. Consistent with the mean price trends in Figure 6, divested plants as a group buy coal that is about 14% more expensive pre-treatment. The first two specifications rely on the assumption that divested and non-divested facilities would have followed parallel paths in the absence of restructuring–there are no time-varying differences between the two groups. Under this assumption, divestiture is associated with a modest, but statistically insignificant drop in purchased coal price.

The third specification of Panel A relaxes the common-trend assumption by allowing the price of coal to vary by census division-year. As a result, the post-divestiture coefficient measures the percent change in coal prices at divested facilities compared to non-divested facilities within the same census division, which has a similar flavor to the approach proposed in Section 4. The drop in prices paid by divested coal plants is quite close to those of Table 4 using this specification.

Panel B of Table 5 is also based on a standard difference-in-difference estimator, but it limits the sample based on proximity to divested plants. This is an unweighted analog to columns (1)–(3) of Table 4, except that baseline rank of coal is not considered. Panel B shows that while estimates of the effect on coal prices remain negative, the magnitude is sensitive to the threshold distance for inclusion in the sample. At 100 miles, the coefficient is 7% and is only marginally statistically significant. However, the loss in precision from limiting the sample to closer facilities is more than offset by the substantial increase in the coefficient estimates for the other specifications. The weighting procedure used in Table 4 puts greater emphasis on non-divested plants in close proximity to multiple divested plants, and therefore stabilizes estimates somewhat in comparison to the unweighted approach.

To evaluate the time path of the effect of divestiture, I interact an indicator variable for treatment facilities with a dummies indicating the time relative to year of divestiture in Figure 9. The omitted coefficient is the year prior to divestiture. Figure 9a is analogous to the average effect in column (2) of Table 4, and Figure 9b breaks out the results of column (4). Both panels show a flat relative price profile prior to divestiture that is close to, and statistically indistinguishable from zero. The corresponding figures at different thresholds share this characteristic (not shown). It appears that any changes that occurred after divestiture are not part of a continuation of a pre-existing trend. Again, one unfortunate characteristic of the data is plants divested prior to 2002 drop out of the data immediately following sale. Since it took until 2002 for EIA to re-establish this reporting requirement under their authority, there is a gap in reporting for most facilities of the first couple years operating without utility commission oversight. The vertical line in year three represents the point where the majority of divested facilities resume reporting. If divestiture lead to an immediate change in operations, there would be a jump in the first year after sale. Instead, it appears the gains achieved by divested plants took a few years to settle in to a new, permanent level. This may be due to staggered expiration of contracts written before divestiture, but again it is difficult to draw conclusions based on the handful of plants for which data is available for the first two years after sale. The pattern of reductions for the other specifications are nearly indistinguishable from those in Figure9: a relatively stable period starting at year 3 at over 10% less than their regulated counterparts.

Before examining these results in the light of theories of regulatory inefficiency, it is important to rule out a rather simple hypothesis: that the relative change in price is due to changes in quantities demanded at coal-fired facilities. Figure 10 shows this is not the case: there has been no differential change in production between divested and non-divested plants. This may be explained by the fact that coal-fired units tend to be used for "baseload" generation–that is, they run at full capacity at all times except during maintenance periods.

Importance of Asymmetric Information: Comparison with Natural Gas

We have shown that coal burned for electricity is heterogeneous, and often sold via bilateral contracts. Furthermore, prices are location-specific due to high transportation costs. This makes it difficult for a regulator to know what purchasing opportunities are available to an operator, and whether the operator is exerting sufficient effort to keep costs low. By contrast, natural gas is a homogenous product (methane, mostly), traded on a transparent market.[26] Since it is delivered by a national network of pipelines that maintain pressure throughout the grid, transportation costs

[26] A set of year-month dummies explains half of the variation in gas prices, but only one quarter of the variation in the delivered price of coal.

are essentially zero. This is evidenced by the fact that the price of gas at the Henry Hub in Louisiana rarely deviates from the price in New York. Since IOUs typically own the complete portfolio of generating plants, gas- and coal-fired facilities were subject to an identical change in regulatory structure. The importance of the interaction of information asymmetry and local capture can therefore be demonstrated by comparing the results for coal prices with those of natural gas.

Figure 11 shows the analogous map of divested gas-fired plants in the United States as of 1997. It is important to use this baseline because the recent drop in natural gas has lead to a boom in gas-fired generating capacity, much of which was never owned by an IOU, and therefore only began reporting costs in 2002. The key distinction between geographic distributions of gas- and coal-fired plants is that we now include the divestitures of California, which relies primarily on gas and hydro-powered generators.

Figure 12 shows the pre-treatment trends of prices paid by matched divested and non-divested plants. While gas prices are clearly more volatile than coal prices, divested and non-divested prices co-move; there is no indication of a pre-existing differential trend between the groups.

Table 6 shows that divestiture has had essentially zero effect on the price generators pay for gas. This is true regardless of the matching criteria, and is relatively precisely estimated. In the case of gas, regulation was not distorting input price. It is important to point out that regulated IOUs operating coal-fired plants also tend to own gas-fired plants in order to meet changes in demand throughout the day. Thus the exact same operators whose coal prices changed substantially following divestiture were apparently making their gas procurement decisions efficiently. This implies that differences in the markets for coal and gas play a critical role in determining the potential for cost reductions following divestiture. The defining characteristics that differentiate these markets is price transparency and the room for discretion allowed by commodity heterogeneity, suggesting the importance of asymmetric information in creating the conditions that yield distortions under regulation.

Sulfur Emissions Compliance Decisions

Title IV of the Clean Air Act Amendments of 1990 capped the total emissions of sulfur oxides (which contribute to acid rain) allowed from major sources (i.e. coal-fired power plants), and created a market so that plants with high abatement costs could buy allowances instead of install abatement equipment. The market began in 1996 for the largest plants, with the remainder of coal-fired plants following soon after. Aside from buying allowances, plant operators had two main options to comply with the new regulations: buy a flue-gas desulfurization system (called a "scrubber"), or switch to burning low-sulfur coal, typically from the Powder River Basin (PRB) in Wyoming. The Averch-Johnson hypothesis predicts that regulated plants will prefer to install capital-intensive scrubbers, which will add to their rate base.

Since scrubber installation is a permanent, binary outcome, it does not make sense to employ the matched DID approach described above. The behavior of managers that already have a scrubber installed is also uninteresting. I therefore perform a straightforward matching of divested and non-divested facilities that burned a common rank of coal, but did not have scrubbers installed in 1997. In recent work, Fowlie (2010) finds evidence consistent with the Averch-Johnson hypothesis in the context of compliance decisions for regional nitrogen oxide markets using a random-coefficients logit model. By contrast, the approach taken here is nonparametric. The benefit of this approach is that the results are free of the distributional assumptions that may cost more complex estimators some credibility. The main cost is that the structural approach identifies behavioral parameters that can be used to make out-of-sample predictions.

With this caveat in mind, Table 7 compares compliance decisions among generating units that were burning high-sulfur coal in 1997 without a scrubber installed. While divested units are clearly less likely to install scrubber, the seven percentage point difference masks the magnitude of how big this effect really is. Instead consider Figure 13a, which shows the differential rate of scrubber adoption. It is quite striking that only 3 of roughly 200 divested units install a scrubber up to six years after divestiture. It is only at the end of the sample that scrubber installation begins to pick up at divested units, so that they are about half as likely to install a scrubber by the end of the sample period. This result is relatively consistent across threshold specifications, with the difference being slightly larger when using a distance caliper rather than number of matches.

Instead, divested plants disproportionately chose to comply with sulfur emissions regulations by switching to sub-bituminous coal, as shown in Figure 13b. Since sub-bituminous coal has become relatively cheap in the past decade,[27] it may be that Averch-Johnson-type motives are the source of the observed drop in the price of coal among divested plants. One method of accounting for the role of fuel switching in cost savings estimates is to allow the treatment effect to differ between facilities that have switched the rank of coal they burn, and those who are still burning the same rank of coal as at baseline. Panel A of Table 8 reproduces the baseline estimates of Table 4, allowing for this heterogeneous treatment effect. The overall average price difference among plants that eventually switch is absorbed in the plant fixed-effects. It shows that facilities do in fact realize larger gains after having switched fuels– the total effect among switchers is obtained by adding the coefficients–though the difference is not statistically significant. This is not due to compositional differences between switchers and non-switchers: all but three facilities report at least one month of post-divestiture fuel purchases using the same rank of coal that was burned in the baseline year 1997. These post-divestiture purchases contribute to the non-switching estimate until the actual switch is made. Perhaps most important is the fact that around 90% of the gains seen overall are from facilities that have not switched to low-sulfur coal. While switching yields a larger drop, it accounts for a relatively small fraction of the overall treatment effect. This means that divested facilities were able to find and negotiate for cheaper coal, regardless of any motives to use low-capital methods to comply with sulfur emission regulations. The cost reductions found here are largely not an ancillary benefit of more fundamental motives to distort abatement techniques to more capital-intensive options among regulated utilities.

[27] This may be surprising in light of the finding of Busse and Keohane (2007) that railroads exerted market power in the face of greater demand for low-sulfur coal. However, increases in productivity over this period have more than offset demand shocks and markups. See the Data Appendix for a discussion of these trends.

Regulatory Capture by Local Coal Producers

A distortion in the spirit of Stigler (1971) and Peltzman (1976) would exist if coal suppliers lobby the state regulator to force generators to buy from local coal mines. However, it is ambiguous *a priori* whether such a distortion would lead to larger or smaller gains in coal-producing states following divestiture. While there may be larger potential gains in these states, there is also likely to be greater resistance to keep them from being realized. Lile and Burtraw (1998), for example, document efforts undertaken by state legislatures to promote the purchase of local coal, ranging from subsidies to blatant mandates on the percent of coal that must come from within the state. While efforts to legislate such policies were voided by the courts under the Commerce Clause, it was still possible to make life for generators difficult via state oversight of environmental regulations. Panel B of Table 8 provides evidence suggesting that local coal may have been an impediment to fully realizing the potential gains from divestiture. It allows the effect of divestiture on $log(price)$ to vary between facilities that bought the majority of their coal from within their home state in 1997, and those who mostly imported. Although facilities that initially imported their coal consistently realized gains across specifications that are about 50% greater than plants that bought from within-state, the difference between the coefficients is not statistically significant. Furthermore, this can only be interpreted as suggestive evidence since geographic distance between these groups could also cause differences in realized cost reductions.

More definitive evidence of inefficient procurement practices under cost-of-service regulation in coal-producing states can be seen by examining changes in sourcing after divestiture. Recall that at baseline divested and non-divested plants are relatively balanced on the percent of coal sourced in-state. Table 9 limits the sample to divested and control plants that burned in-state coal in 1997. It measures the change in the fraction of coal sourced from in-state associated with divestiture. Since any plants that switch to sub-bituminous coal will mechanically increase their out-of-state purchases, it allows for heterogeneous effects between plants that switch, and those who do not. The goal here is to separate off switching motives from efforts to find lower cost producers that are not protected by state governments. If sourcing practices under regulation were efficient, one might see price drops as generators negotiated for larger fractions of the surplus, but there would be no reallocation of business to different mines. Table 9 shows this was not the case. Instead, divested facilities that initially sourced their coal in-state increased their out-of-state purchases, unconditional upon switching status.[28] While the biggest changes are among those who switch, there is also some evidence that plants in Pennsylvania, Ohio, and Illinois were able to find lower cost bituminous coal after divestiture (likely from Kentucky and West Virginia), although this effect is only statistically significant in one of the matching specifications.

Figure 14 breaks down the differential fraction of coal burned from in-state mines by year from divestiture. As with the price results, there is no evidence that the post-treatment coefficient is spuriously due to pre-existing trends. Instead, a flat pre-trend around zero is followed by a precipitous fall shortly after divestiture. In total, the relative fraction of coal sourced locally falls by about 25% during the post-divestiture period. While local coal lobbies may have prevented divested facilities from fully realizing the price reductions achieved in areas without coal deposits, they were not completely successful at mitigating the impact of divestiture on demand for their product.

Among the plants that switch to burning low-sulfur coal, it is not possible to distinguish between the importance of Averch-Johnson and regulatory capture with the current evidence: both theories predict that deregulated plants will be more likely to switch sub-bituminous coal, which is both lower in cost and capital-intensity. In fact, it is likely that the two forces are mutually-enforcing: eastern coal producers and regulated IOUs both stand to benefit from the installation of a scrubber. It is also not possible to identify the separate effects of asymmetric information and regulatory capture in coal-producing regions. However, the fact that there is no relative price drop for gas suggests that opacity in the market for coal creates the

[28] The coefficients are not minus one for switchers because this estimate is relative to the matched control facilities, who also switched ranks of coal, albeit at a lower rate.

room needed for special interests to exert influence.[29]

7 Transfers versus Efficiency Gains

The large drop in price observed at divested coal-fired plants says little about the social welfare gains derived from restructuring. Even the substantial reallocation to out-of-state mines is consistent with minimal mining cost reductions. Suppose, for example, that out-of-state mines are only marginally more productive than in-state mines, the latter of which have been receiving regulatory rents. Prices fall and output shifts following divestiture, but to little effect in terms of the resources required to produce electricity.[30]

Fortunately the EIA data on coal deliveries includes information on the supplier and county of origin. I have linked these deliveries to characteristics of the mines from which the coal is derived. This includes quarterly data on the labor hours per ton (converted to hours per MMBTU to preserve consistency) from the Mine Safety and Health Administration, the associated wage bill from the Bureau of Labor Statistics, and data on the depth and thickness of coal seams from the U.S. Geological Survey. Seam depth measures how many feet underground must be dug before reaching the coal, and seam thickness measures how much coal per foot of horizontal digging can be recovered once the seam has been reached.

Figure 15 shows the effect of divestiture on the mining labor embodied in coal purchases. The difference between divested and matched plants prior to divestiture is relatively flat and insignificantly different from zero in both panels. The hours of labor required to mine coal then drops by about 25% for coal that is subsequently sold to divested plants, and this persists throughout the post-divestiture period. While hours drop, wages rise by about 5%–suggesting relative labor productivity gains at mines that sell to divested plants. Results are similar when considering the characteristics of the mines from which the coal is being sourced. Figure 16 shows

[29]For a theoretical treatment along these lines, see Coate and Morris (1995).

[30]The success of special interest groups that advocate for transfers with minimal welfare costs is predicted by Becker (1983, 1985).

that coal delivered to divested plants comes from seams that are about 30% thicker, and nearly 50% closer to the surface following divestiture. These results indicate that the shift in procurement following divestiture lead to substantial reductions in the cost of mining coal for electricity generation.

8 Conclusion

This paper uses two decades of detailed procurement data at gas- and coal-fired power plants to characterize the major determinants of regulatory inefficiency in U.S. electricity generation. I find evidence that asymmetric information, regulatory capture, and capital-bias all lead to substantial distortions in procurement decisions. I find the price of coal drops by 12% at deregulated plants relative to similar, nearby coal-fired facilities that were not subject to any regulatory change. Deregulated plants disproportionately switch to burning low-sulfur coal rather than install a capital-intensive abatement equipment to comply with environmental regulations, and expand imports from out of state by 25% if they were initially burning in-state coal. In addition, I find that the reallocation of procurement following divestiture is toward mines that are substantially more productive than those who supply regulated facilities. In total, operators of divested coal-fired plants spend about $1B less per year on coal due to deregulation.[31] These plants make up only 25% of coal-fired capacity, while the rest have continued operating without any change in regulation.

My results do not imply the universal failure of regulators to induce efficient behavior in the regulated community: I find that generators pay the same price for natural gas regardless of their regulatory status. Instead, this indicates that regulation may work well when the regulated community is unable to shroud its inefficient behavior from oversight.

After thirty years of deregulation, the pendulum is swinging back toward greater government oversight in order to correct market failures in critical sectors of the American economy such as finance, banking, and health care. In addition, the

[31] This is calculated by subtracting observed post-divestiture expenditures from predicted expenditures based on the average treatment on the treated.

deregulatory momentum of the 1990's has stalled in the electricity sector following the 2000-2001 crisis in California. Although regulation may appear at first to be the solution to imperfect markets, as eloquently described by Bastiat (1850), this is not the end of the story.

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Figures

Figure 1: Coal-Fired Plants in The United States, 1990-2009

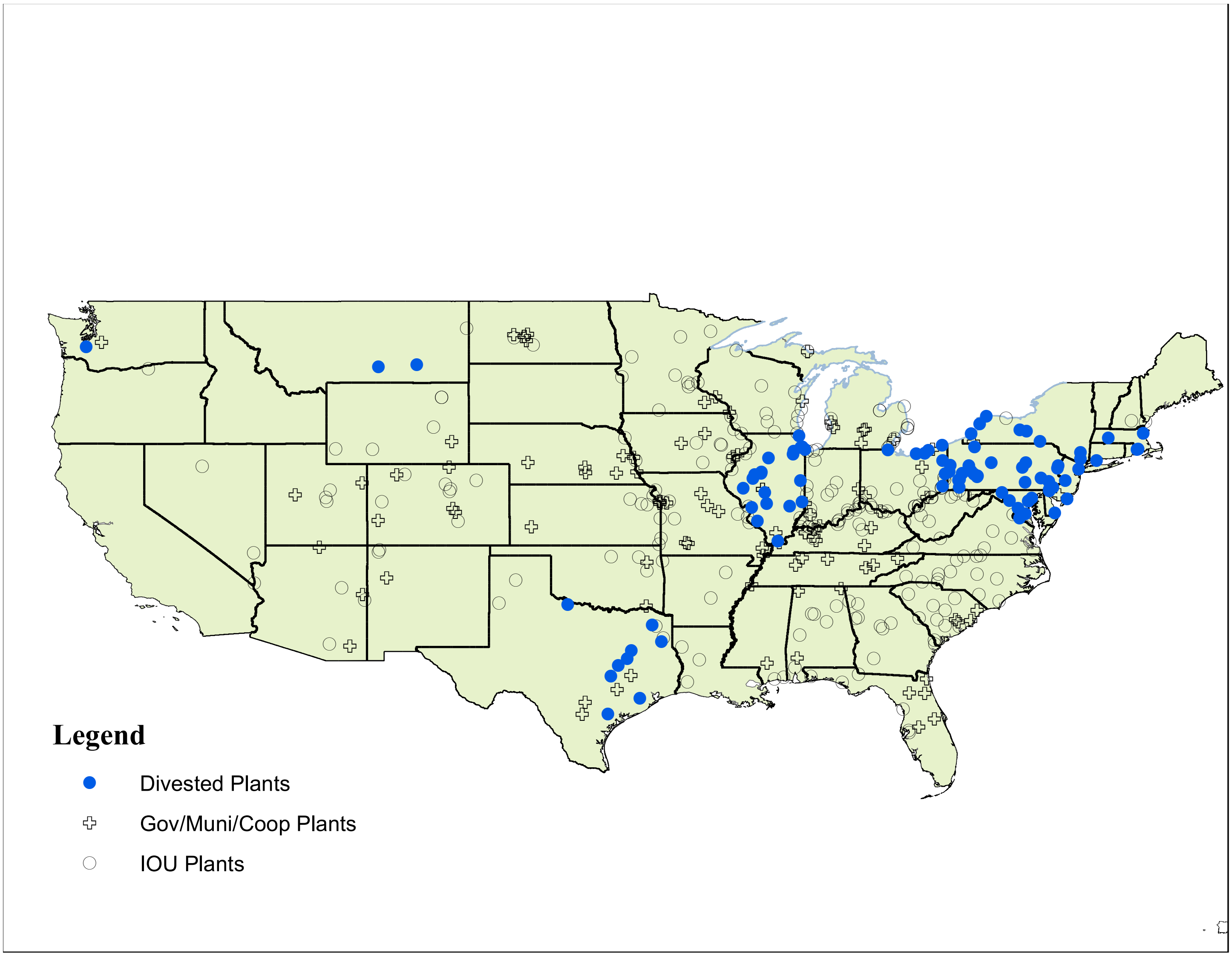
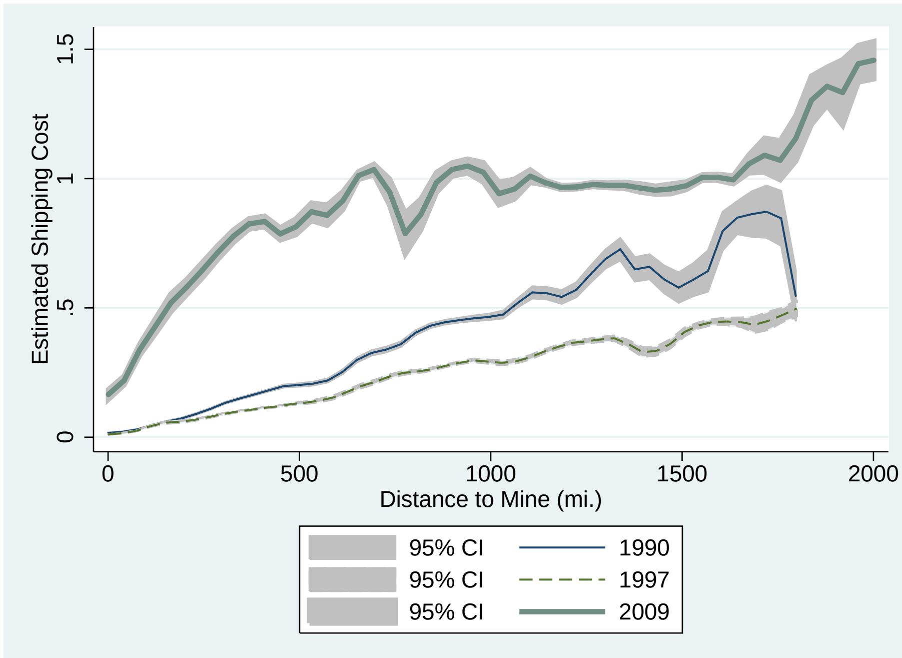


Figure 2: Estimated Shipping Costs per MMBTU of Coal



Note: Estimated shipping costs are derived from a regression of delivered costs on a polynomial of coal characteristics, distance to the mine, and dummies for time, place of origin, and site of delivery. The relationship between estimated shipping cost and distance is then fit with a local polynomial expansion of shipping distance.

Figure 3: Distance Between Divested and Matched Facilities

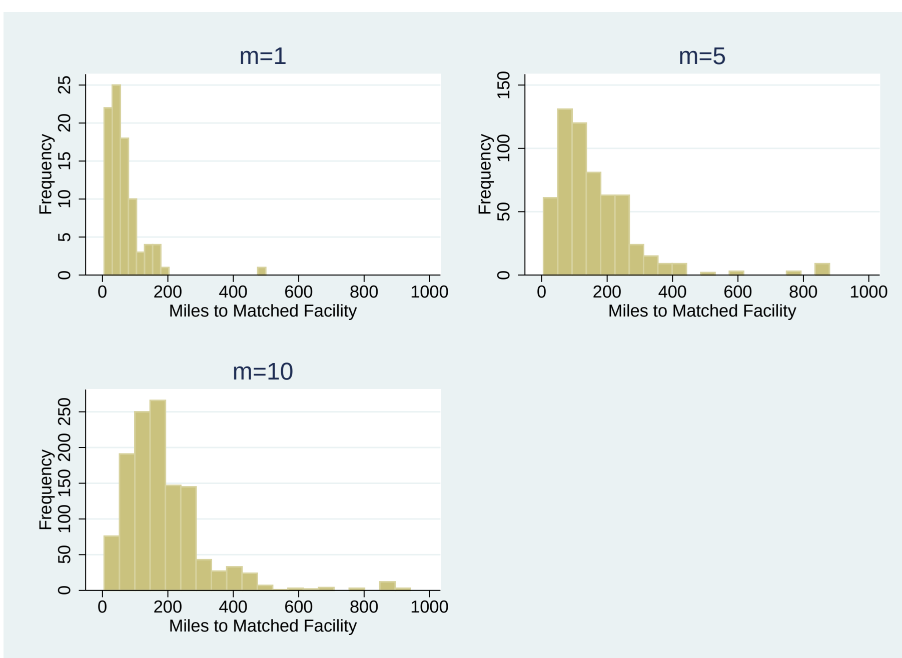


Figure 4: Divested and Control Coal-Fired Plants within 200 miles

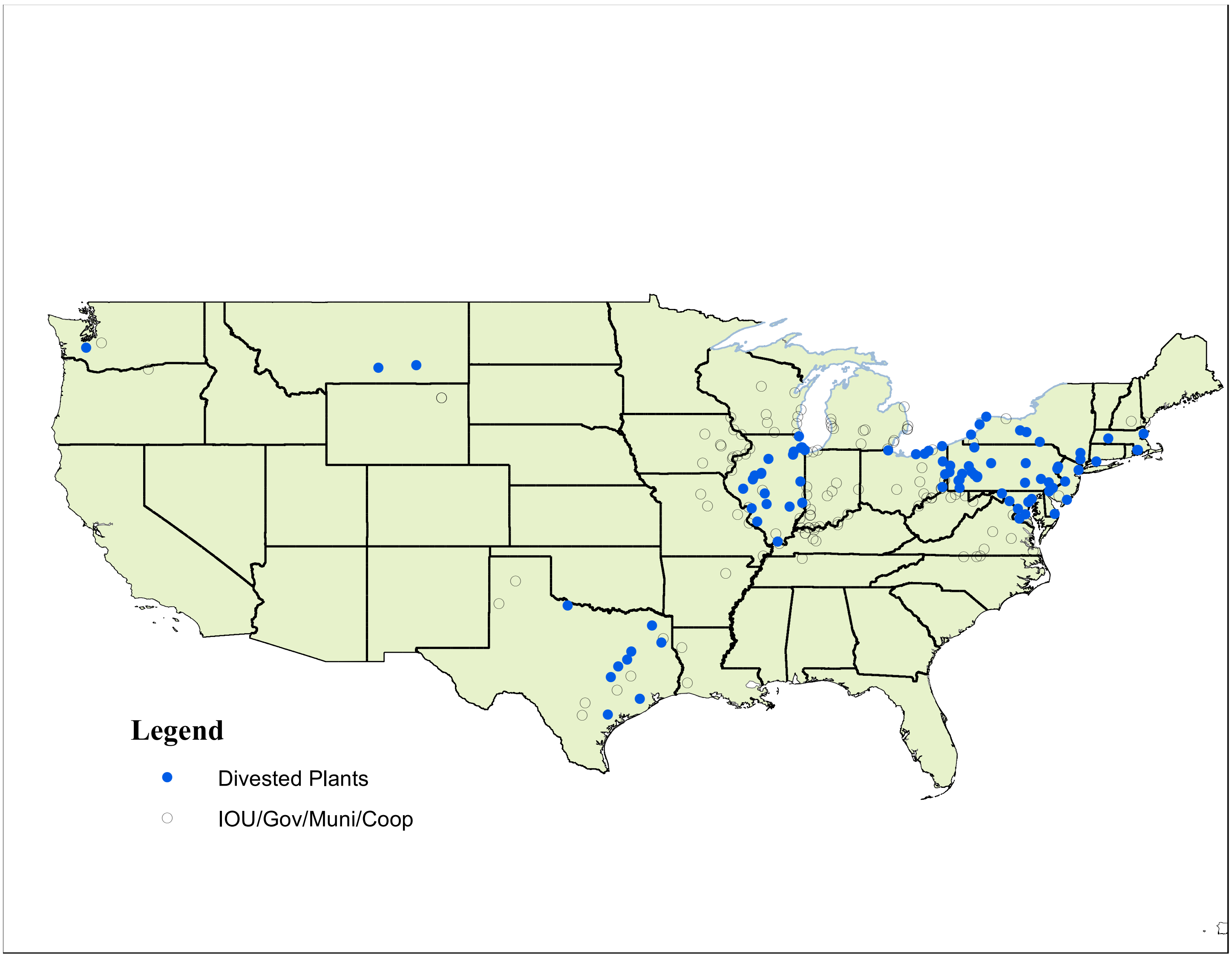
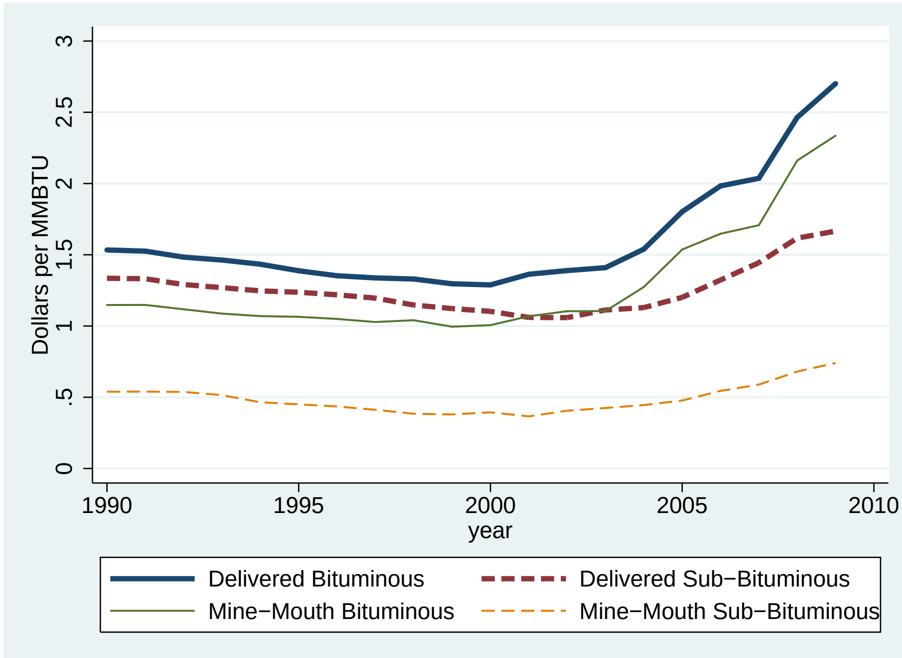
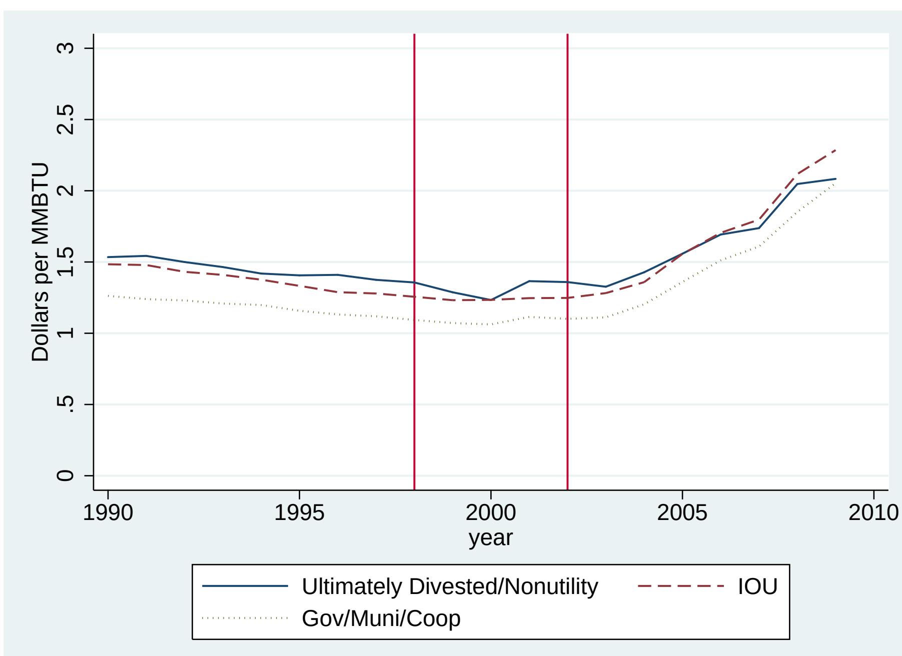


Figure 5: Price per MMBTU by Coal Type, 1990-2009



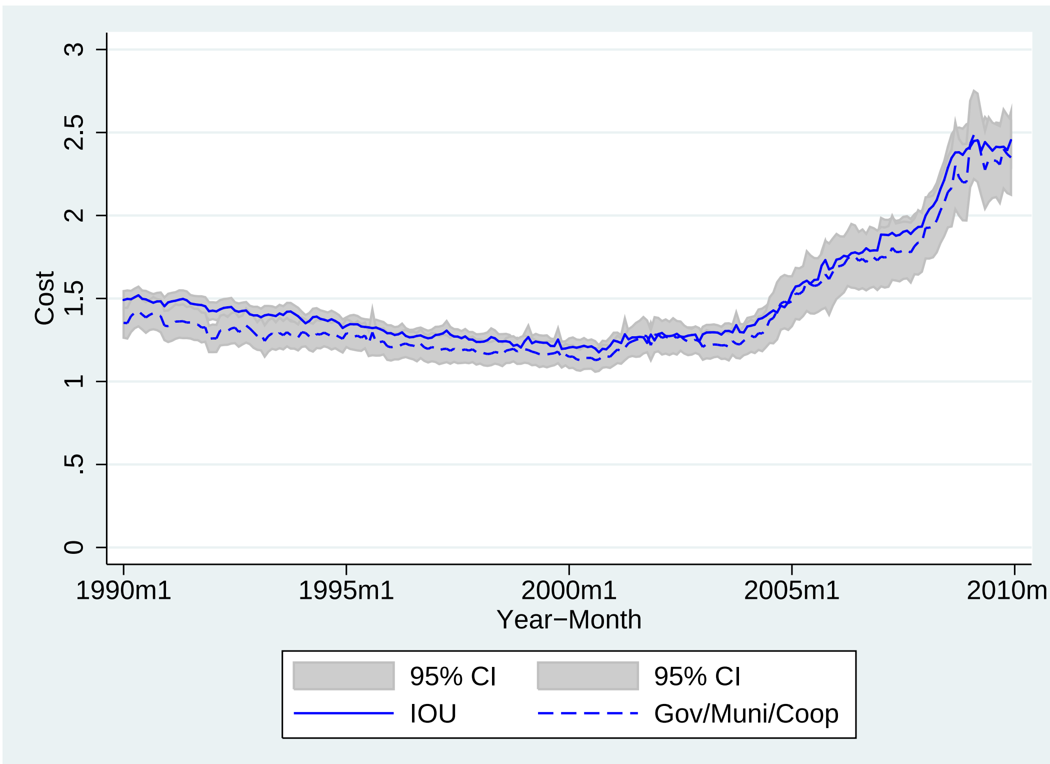
Note: Mine-mouth prices from EIA Annual Energy Review (2011), Table 7.9 and converted to heat units using average heat content by year and rank as reported in Forms EIA-423. EIA-923 and FERC-423.

Figure 6: Coal Price per MMBTU by Divestiture Class, 1990-2009



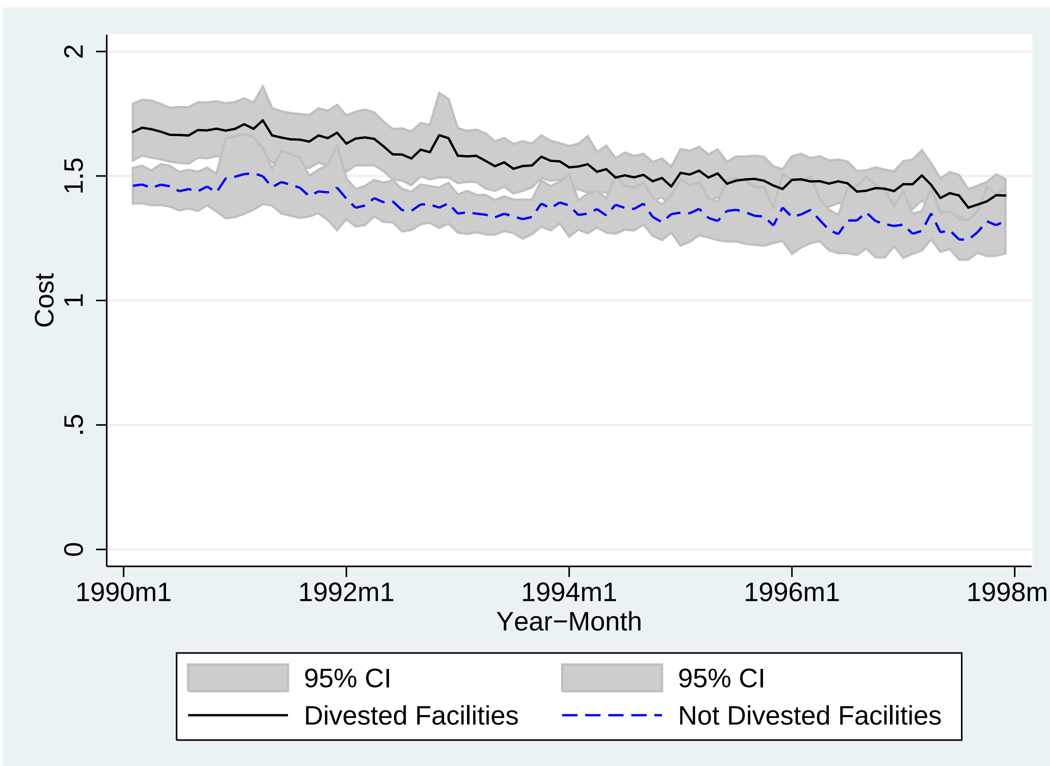
Note: Vertical lines denote the year in which divestitures begin (1998), and when reporting for non-utilities commences (2002). Source: Forms EIA-423,923 and FERC 423.

Figure 7: Matching Estimates of Delivered Coal Price at IOU and Gov/Muni/Coop Plants within 100 miles, 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.

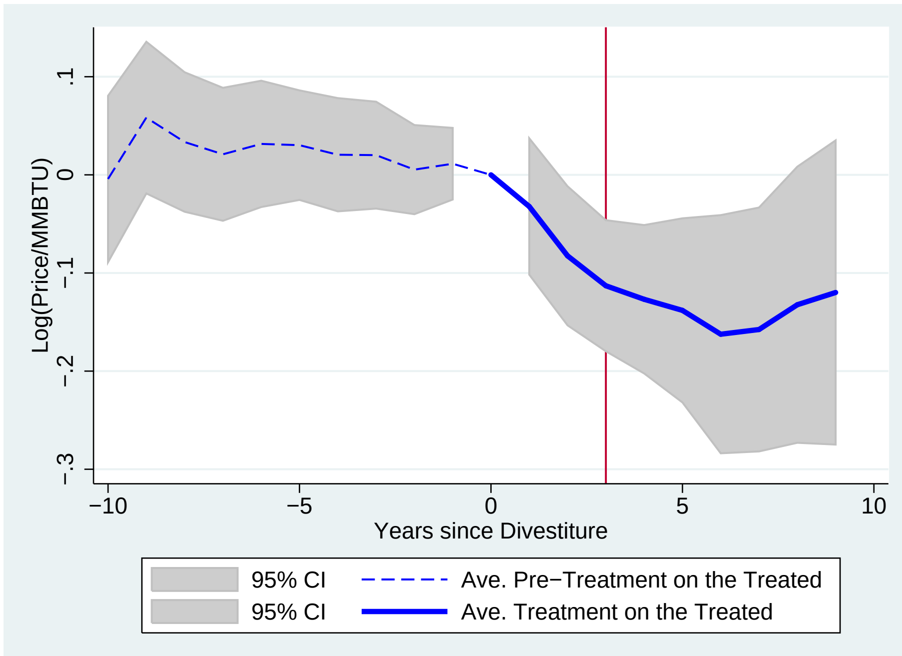
Figure 8: Pre-Trend Test: Matching Estimates of Delivered Coal Price, 1990-1997



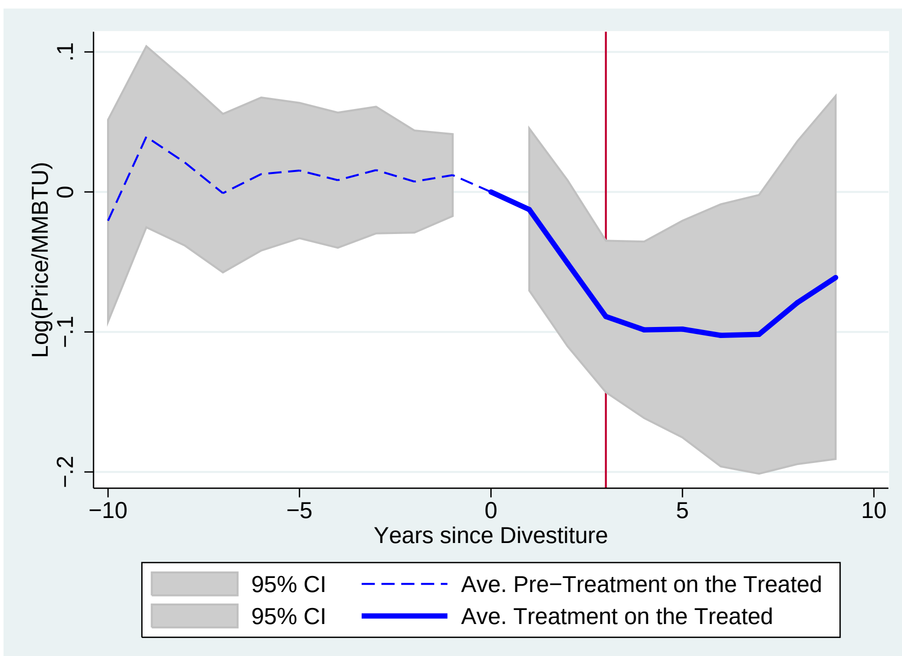
Note: Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

Figure 9: Matching by Year from Divestiture: $Log(Price)$

(a) Distance < 100 Miles

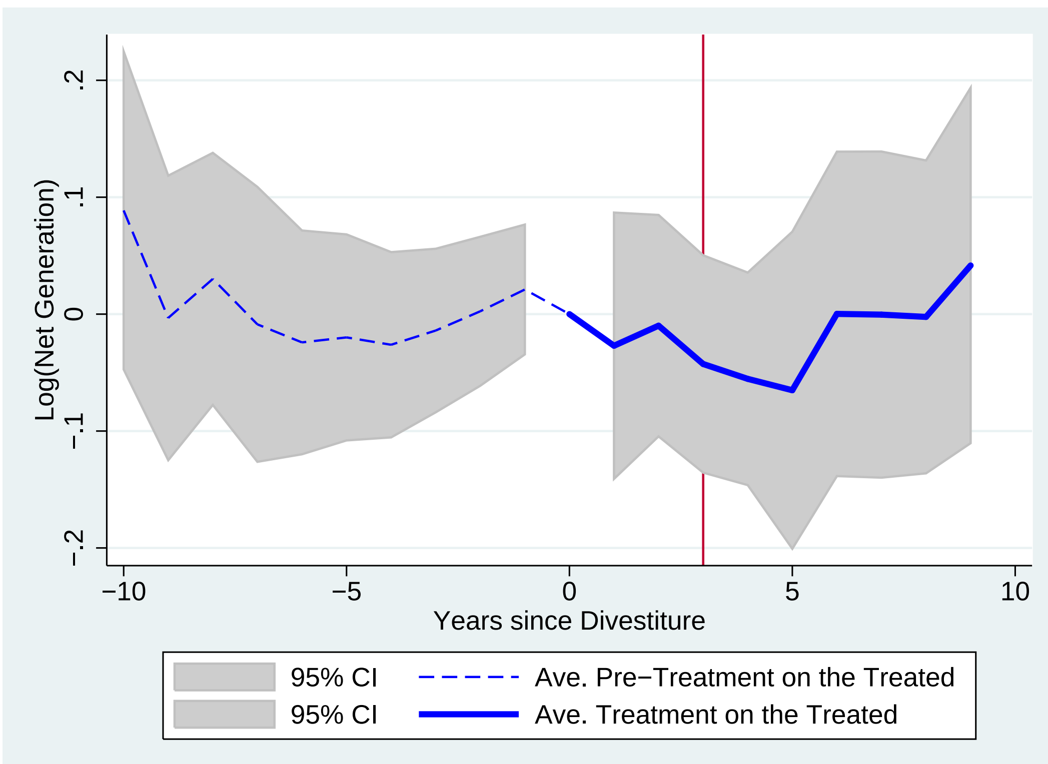


(b) 10 Nearest Neighbors



Note: Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j that satisfies the indicated criterion. 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.

Figure 10: Matching by Year from Divestiture: *Log*(*Net Generation*), 10 nearest neighbors



Note: Non-Divested 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.

Figure 11: Divested and Control Gas-Fired Plants, 1990-1997

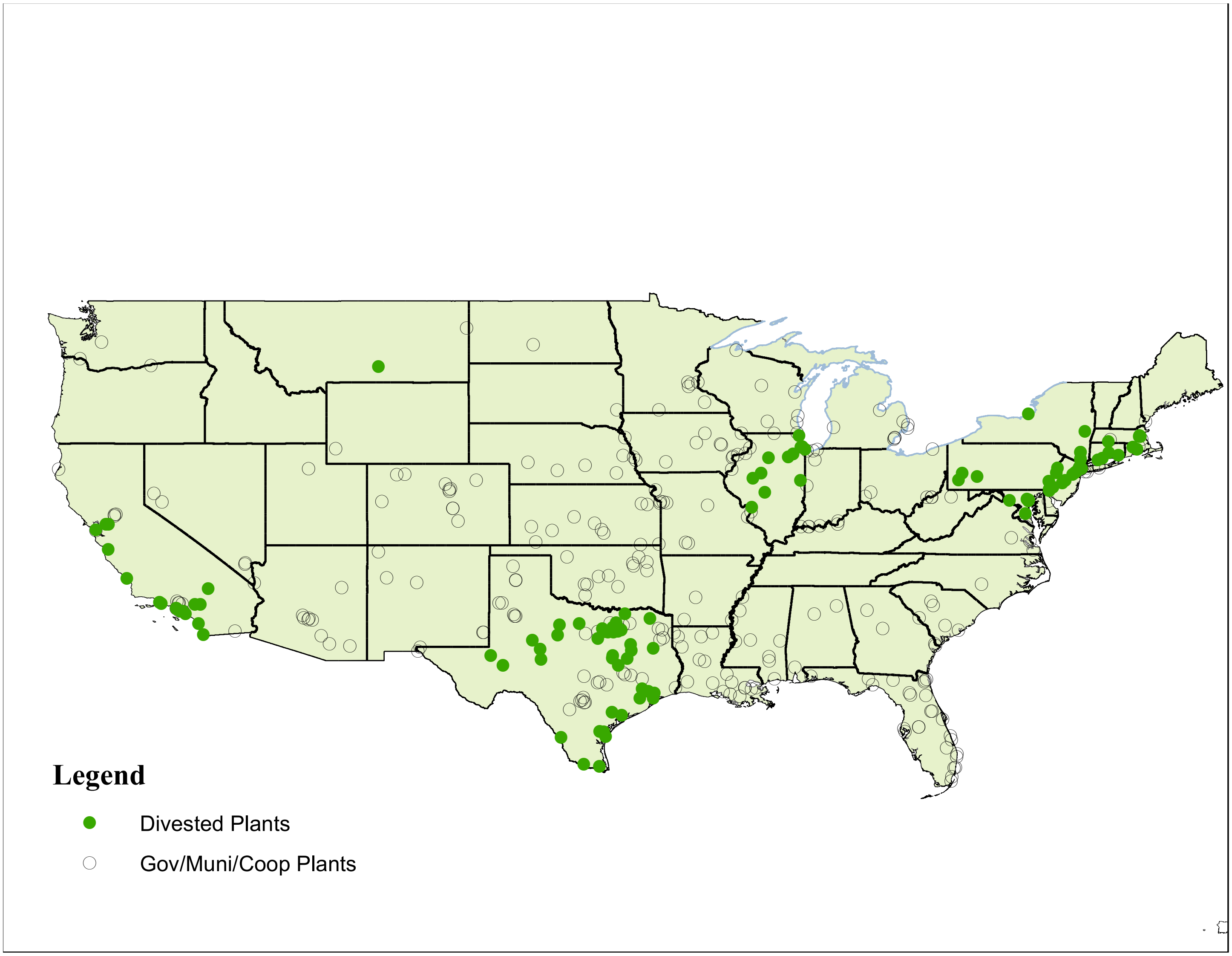
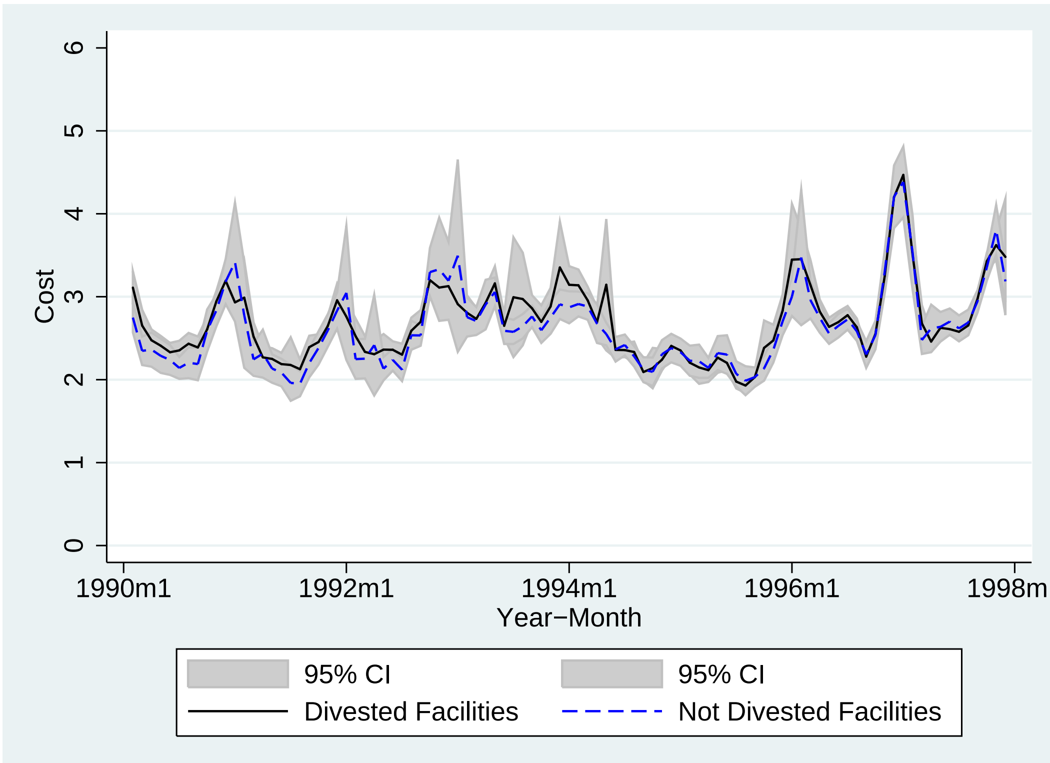


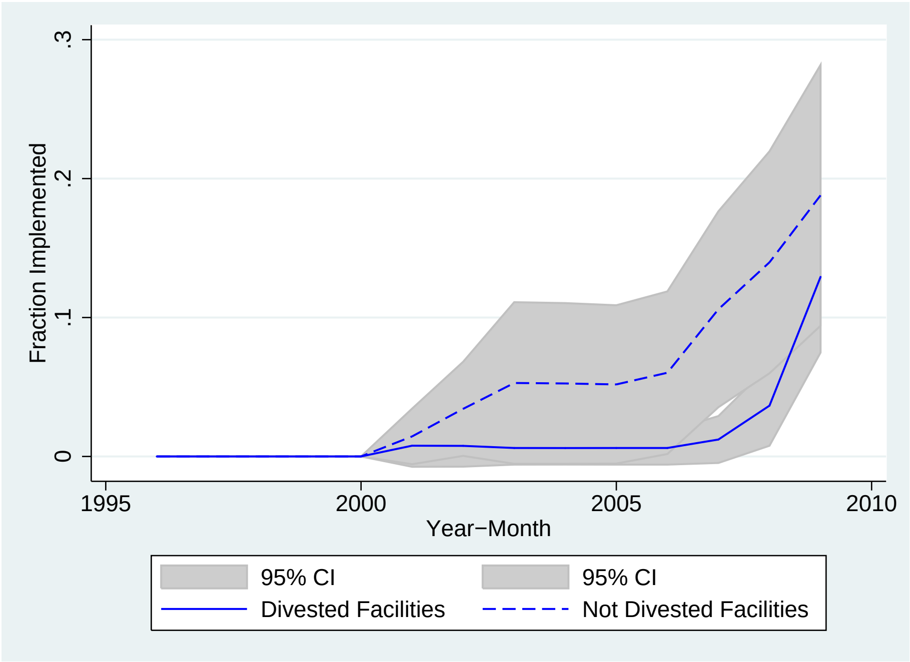
Figure 12: Pre-Trend Test: Matching Estimates of Delivered Gas Price, 1990-1997



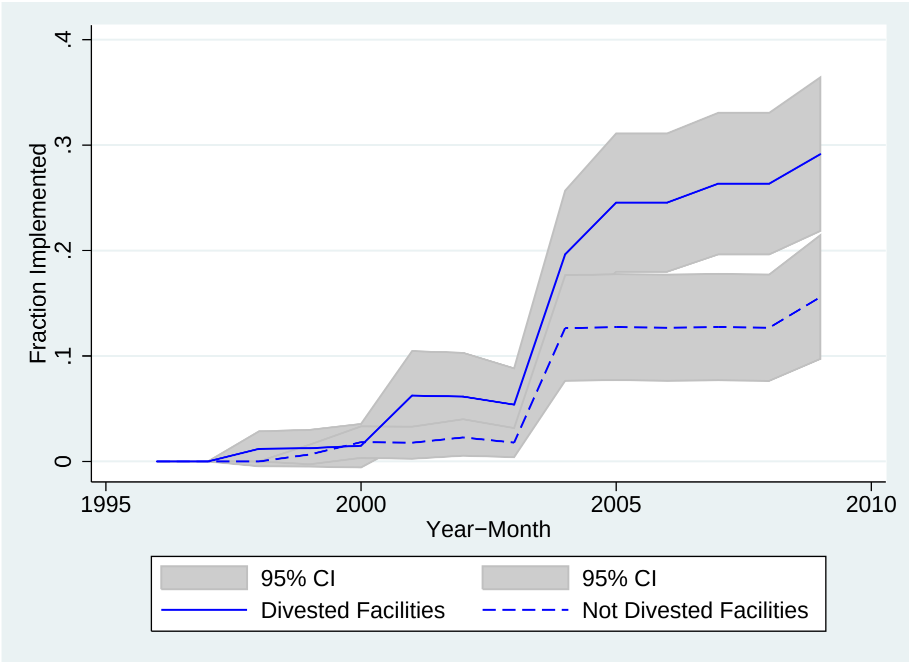
Note: Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

Figure 13: Matching by Year from Divestiture: Sulfur Compliance Strategies , 10 nearest neighbors

(a) $Pr(Add\ Scrubber)$

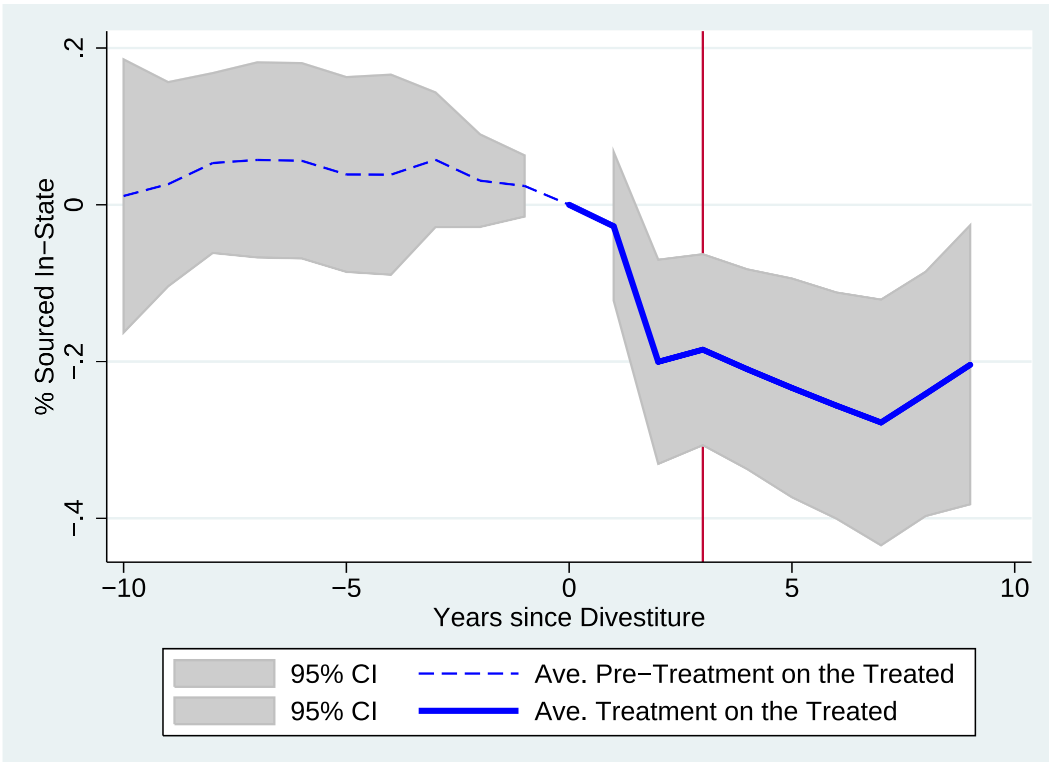


(b) $Pr(Switch\ Rank)$



Note: Sample is based on units that did not have a scrubber installed in 1997. Non-Divested 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.

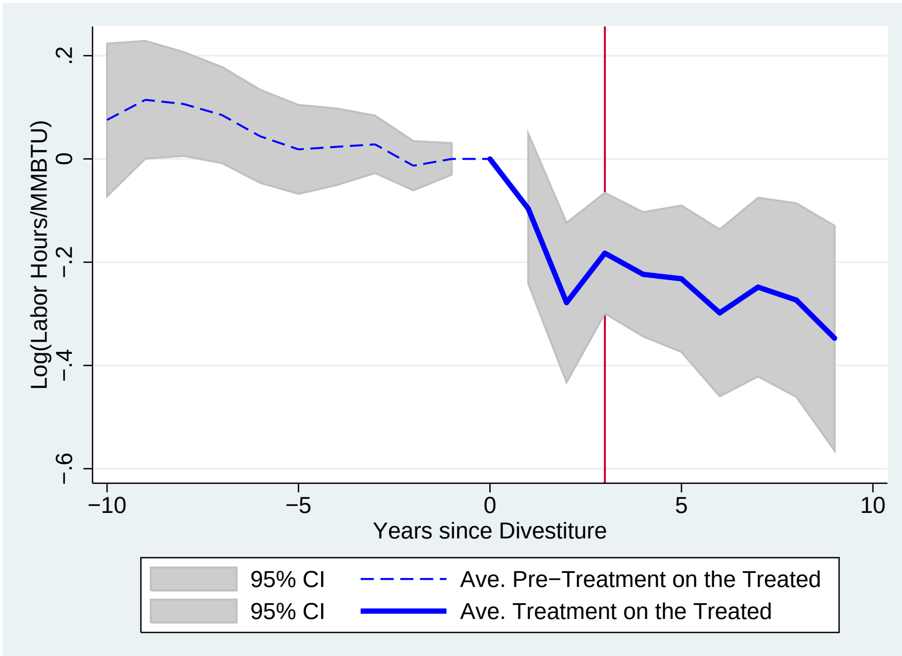
Figure 14: Matching by Year from Divestiture: Fraction of Coal Sourced In-State, 10 nearest neighbors



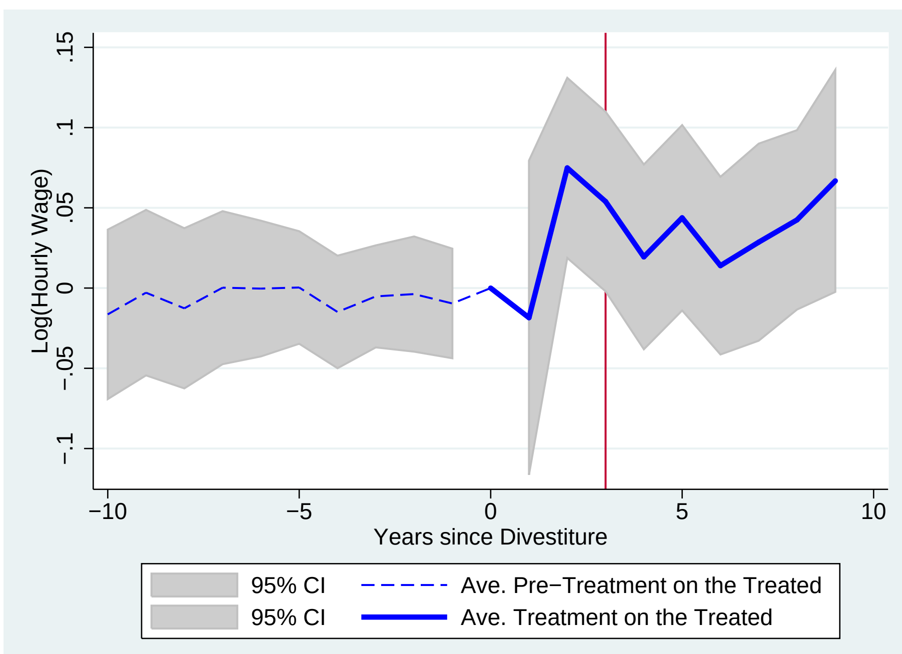
Note: Sample is based on plants that sourced the majority of their coal from in-state in 1997. Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

Figure 15: Matching by Year from Divestiture: Mine Labor, 10 nearest neighbors

(a) $Log(Hours\ per\ MMBTU)$



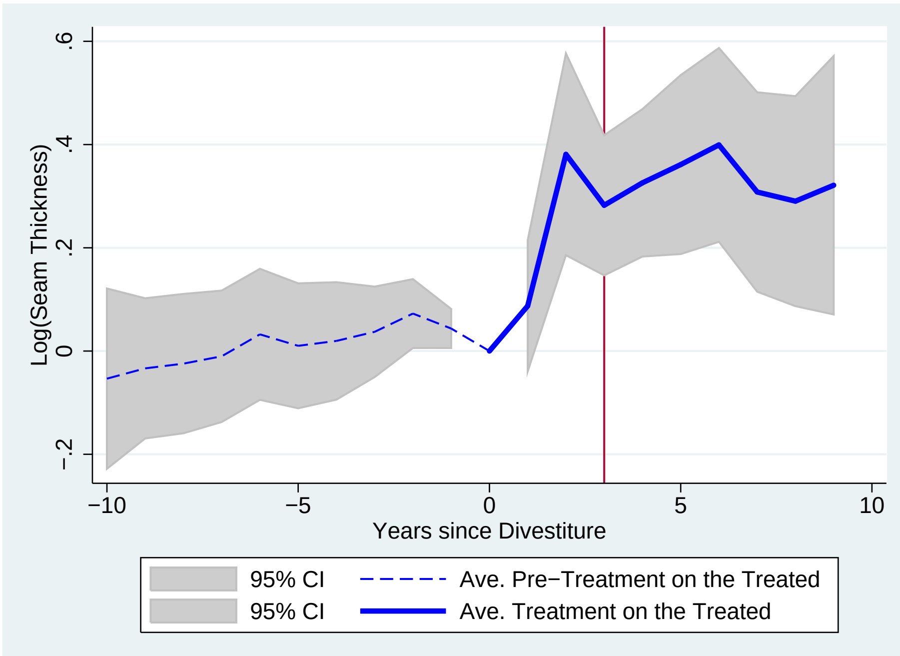
(b) $Log(Hourly\ Wage)$



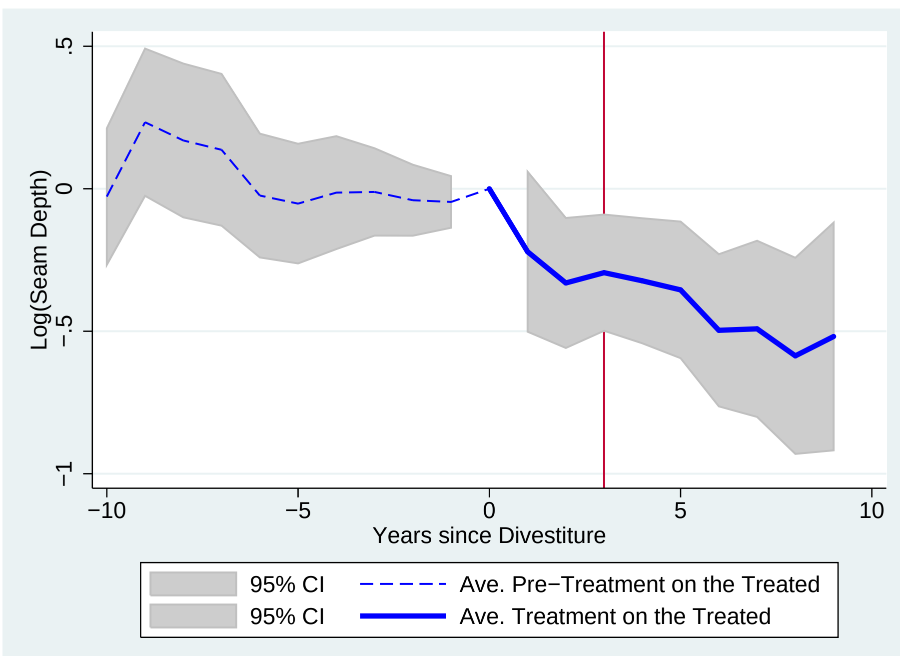
Note: $Log(Hours\ per\ MMBTU)$ is the number of hours of labor required to extract 1 worth of coal at the mines from which matched plants purchase coal. Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility. The vertical line denotes the third year post-divestiture, the point at which most divested facilities resumed reporting fuel costs.

Figure 16: Matching by Year from Divestiture: Source Mine Characteristics, 10 nearest neighbors

(a) *Log(Seam Thickness)*



(b) *Log(Seam Depth)*



Note: *Seam Thickness* is the thickness and *Seam Depth* is the estimated depth below the surface of coal seams at the mines from which matched plants purchase coal. Non-Divested 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. The vertical line denotes the third year post-divestiture, the point at which most divested facilities resumed reporting fuel costs.

Tables

Table 1: Characteristics of Divested and Non-Divested Plants in 1997

A. All Facilities

	Divested	Not Divested	Difference of Means
Capacity (MW)	799.79	797.48	2.32
	[671.86]	[730.74]	(82.63)
Annual Capacity	0.59	0.57	0.02
Factor	[0.19]	[0.18]	(0.02)
Plant Vintage	1961.99	1964.72	–2.73*
	[10.92]	[13.53]	(1.39)
% Scrubbers	0.25	0.32	–0.07
Installed	[0.44]	[0.47]	(0.05)
Incentive	0.44	0.15	0.29***
Regulation Util.	[0.50]	[0.36]	(0.06)
Facilities	88	309	397

B. Matched Facilities

	Divested	Not Divested	Difference of Means
Capacity (MW)	803.95	648.72	155.23
	[674.61]	[657.66]	(119.86)
Annual Capacity	0.59	0.55	0.04
Factor	[0.19]	[0.22]	(0.05)
Plant Vintage	1962.14	1962.91	–0.78
	[10.90]	[14.04]	(2.20)
% Scrubbers	0.25	0.26	–0.01
Installed	[0.44]	[0.44]	(0.08)
Incentive	0.45	0.07	0.38***
Regulation Util.	[0.50]	[0.25]	(0.06)
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

Table 2: Characteristics of Coal Deliveries to Divested and Non-Divested Plants in 1997

A. All Facilities

	Divested	Not Divested	Difference of Means
Millions MMBTU	44.76	44.18	0.58
Delivered	[42.78]	[43.01]	(5.16)
Price($/MMBTU)	1.42	1.20	0.21***
	[0.37]	[0.37]	(0.04)
% Spot Market	0.24	0.27	–0.03
	[0.29]	[0.32]	(0.04)
Yrs to Contract	5.37	7.95	–2.58***
Expiry	[6.19]	[7.21]	(0.88)
% Sourced	0.41	0.30	0.12**
In-State	[0.46]	[0.44]	(0.05)
% Bituminous	0.76	0.62	0.13**
	[0.42]	[0.46]	(0.05)
Sulfur Content	1.19	1.02	0.17*
(lbs/mmbtu)	[0.72]	[0.81]	(0.09)
Ash Content	8.67	8.03	0.64
(lbs/mmbtu)	[4.83]	[4.15]	(0.56)
Mine Distance	318.10	364.92	–46.82
(mi.)	[330.64]	[312.52]	(39.38)
Facilities	88	309	397

B. Matched Facilities

	Divested	Not Divested	Difference of Means
Millions MMBTU	44.93	37.36	7.57
Delivered	[43.00]	[37.48]	(7.19)
Price($/MMBTU)	1.42	1.30	0.12
	[0.37]	[0.34]	(0.08)
% Spot Market	0.23	0.27	–0.04
	[0.28]	[0.36]	(0.06)
Yrs to Contract	5.42	7.42	–2.00
Expiry	[6.23]	[7.92]	(1.28)
% Sourced	0.41	0.40	0.01
In-State	[0.46]	[0.45]	(0.08)
% Bituminous	0.76	0.76	–0.00
	[0.42]	[0.42]	(0.07)
Sulfur Content	1.19	1.34	–0.16
(lbs/mmbtu)	[0.73]	[0.87]	(0.14)
Ash Content	8.56	9.45	–0.89
(lbs/mmbtu)	[4.75]	[7.74]	(1.38)
Mine Distance	321.01	264.58	56.43
(mi.)	[331.42]	[299.16]	(47.52)
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

Table 3: Characteristics of Divested and Non-Divested Generating Units in 1997

A. All Units

	Divested	Not Divested	Difference of Means
Boiler Vintage	1962.97	1965.25	–2.28***
	[10.65]	[12.43]	(0.84)
Connected	328.53	290.81	37.73*
Nameplate (MW)	[265.07]	[268.24]	(20.27)
Capacity Factor	0.77	0.79	–0.02
	[0.22]	[0.19]	(0.02)
Bituminous	0.80	0.79	0.01
	[0.40]	[0.41]	(0.03)
Potential Sulfur	11.43	8.61	2.82***
Emissions (1000 tons/yr)	[14.26]	[13.55]	(1.08)
% Scrubbers	0.16	0.20	–0.04
	[0.37]	[0.40]	(0.03)
Facilities	88	310	398
Generating Units	215	849	1064

A. Matched Units

	Divested	Not Divested	Difference of Means
Boiler Vintage	1962.41	1963.95	–1.54
	[10.24]	[11.88]	(1.35)
Connected	325.91	281.13	44.78
Nameplate (MW)	[268.49]	[275.55]	(33.25)
Capacity Factor	0.77	0.76	0.01
	[0.22]	[0.25]	(0.04)
Bituminous	0.84	0.84	–0.00
	[0.37]	[0.37]	(0.04)
Potential Sulfur	11.35	11.54	–0.19
Emissions (1000 tons/yr)	[14.69]	[18.30]	(1.98)
% Scrubbers	0.13	0.13	0.00
	[0.34]	[0.34]	(0.04)
Facilities	79	76	155
Generating Units	197	197	394

Note: Non-Divested facilities in Panel B are weighted based on the number of divested facilities matched for $m = 10$ burning the same rank of coal and common scrubber status in 1997, subject to the constraint that distance be less than 200 miles. Standard errors clustered by unit in parentheses. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 4: Coal: Matched DID Estimates of $Log(Price)$ and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.124***	–0.188***	–0.152*	–0.124***	–0.128***	–0.136**
	(0.044)	(0.058)	(0.077)	(0.045)	(0.046)	(0.064)
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	0.721	0.712	0.668	0.723	0.726	0.738
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 5: Coal: Difference-in-Difference Estimates of *Log*(*Price*) and Divestiture

A. All Facilities:

	(1)	(2)	(3)
Post-Divest	–0.051	–0.054	–0.131***
	(0.035)	(0.035)	(0.041)
Divest	0.145***		
Facilities	(0.030)		
Year-Month FE	Yes	Yes	Yes
Facility FE		Yes	Yes
Division-Year FE			Yes
Divest States Only			
R^2	0.252	0.772	0.803
Facilities	397	397	397
Divested Facilities	88	88	88
Obs.	86225	86225	86225

B. By Distance:

	(1)	(2)	(3)
Post-Divest	–0.055	–0.069*	–0.137**
	(0.036)	(0.040)	(0.055)
Proximity Threshold (mi.)	200	100	50
Year-Month FE	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes
R^2	0.733	0.700	0.712
Facilities	333	221	123
Divested Facilities	88	78	47
Obs.	71569	47324	26483

Note: Dependent variable is *Log*(*Price*) of Coal per MMBTU, including shipping costs. Panel B contains all divested facilities, and any non-divested facilities within the specified distance of a divested plant. Standard errors clustered by facility in parentheses. * $p<0.1$, ** $p<0.05$, *** $p<0.01$

Table 6: Gas: Matched DID Estimates of $Log(Price)$ and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	0.012	0.027	0.010	0.012	0.005	0.038
	(0.026)	(0.029)	(0.036)	(0.027)	(0.027)	(0.038)
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	0.853	0.852	0.861	0.855	0.857	0.854
Facilities	276	198	111	254	224	165
Divested Facilities	109	99	59	109	109	109
Obs.	46828	33465	17631	41089	36727	26510

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

Table 7: Matching DID Estimates of Sulfur Compliance Strategy

	(1) Scrubber	(2) Low Sulfur	(3) Uncontrolled
Post-Divest	–0.072***	0.100***	–0.032
	(0.024)	(0.031)	(0.038)
Divested Unit	0.014	0.010	–0.023
	(0.040)	(0.034)	(0.047)
m Nearest Neighbors	10	10	10
R^2	0.017	0.049	0.056
Units	384	384	384
Divested Units	197	197	197
Obs.	7145	7145	7145

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

Table 8: Matching DID Estimates of $Log(Price)$ and Divestiture, by Coal Rank Switching and Import Status

A. By Low-Sulfur Switching:

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.109**	–0.176***	–0.166*	–0.109**	–0.114**	–0.121*
	(0.050)	(0.067)	(0.091)	(0.051)	(0.052)	(0.068)
Post-Divest x	–0.053	–0.038	0.046	–0.052	–0.052	–0.053
Switching Plant	(0.048)	(0.057)	(0.092)	(0.048)	(0.049)	(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
R^2	0.721	0.712	0.668	0.724	0.727	0.738
Facilities	230	146	69	198	166	121
Divested Facilities	87	74	39	87	87	87
Obs.	47024	28449	12682	37495	32958	23336

B. By Import Status in 1997:

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.157**	–0.244***	–0.250**	–0.157**	–0.161**	–0.169**
	(0.067)	(0.083)	(0.107)	(0.068)	(0.069)	(0.082)
Post-Divest x	0.066	0.115	0.210*	0.066	0.066	0.066
Initially In-State	(0.068)	(0.081)	(0.113)	(0.068)	(0.068)	(0.069)
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	0.722	0.715	0.679	0.724	0.727	0.739
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. The treatment indicator in Panel A is interacted with dummies indicating whether the facility changes the predominant rank of coal burned after 1997. The treatment indicator in Panel B is interacted with dummies indicating whether the facility sourced its coal from within its home state in 1997. Main effects are absorbed in plant-level fixed effects. 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 9: Matching DID Estimates of Percent of In-State Coal Among Plants Burning In-State Coal in 1997

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.093	–0.114	–0.111	–0.102	–0.107	–0.160***
	(0.058)	(0.073)	(0.072)	(0.065)	(0.065)	(0.055)
Post-Divest x	–0.374***	–0.351***	–0.342***	–0.374***	–0.373***	–0.377***
Switching Plant	(0.059)	(0.057)	(0.092)	(0.059)	(0.059)	(0.059)
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	0.687	0.667	0.689	0.682	0.679	0.718
Facilities	82	68	30	81	74	57
Divested Facilities	40	33	15	40	40	40
Obs.	17433	13745	5858	16802	14707	10820

Note: Dependent variable is % of Coal sourced from in-state. All plants in the sample sourced from in-state in 1997. 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

Data Appendix

Data on Divestitures

Data on divestitures is 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 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 approval 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). The data records 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 is redacted from public release for non-utilities, restricted-access data on prices was made available for this study under a non-disclosure agreement with EIA.

One critical caveat is that plants were no longer required to report to FERC upon divestiture, and EIA did not assert their authority under the Federal Energy Administration Act of 1974 to resume collection from non-utility plants until 2002.[32]

[32] When switching to Form 923 in 2008, the EIA began collecting monthly data from a sample of plants, and a census annually. Monthly data is 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.

Plants that were sold before 2002 therefore have a gap in reporting following divestiture. With most divestitures occurring between 1999 and 2001, this results in a two year gap on average. An exception 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 (typically produced $<$50MWh/month) facilities that were divested, but never report 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.[33] 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).

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

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.

Plant-Level Data

Data on generator nameplate capacity and vintage comes from Form EIA-860, "Annual Electric Generator Report," while data on installed abatement equipment is 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 FormEIA-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 and Pfeifenberger (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 is 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 was later compiled on Form EIA-923, "Power Plant Operations Report" after a gap in reporting for 2006.[34]

[34] 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.

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,[35] 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 Table 1, and the unit-level statistics in Table 3.[36] 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 is 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 has more than offset the decline of output elsewhere, so that there has been a modest increase in coal

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

[36] 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.

production overall. The shift in output has been accompanied with a sharp decline in mining employment, which has only rebounded slightly since 2005. The 1990's 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.[37] Wage rates are calculated at the county level by dividing the total county wage bill by total hours.

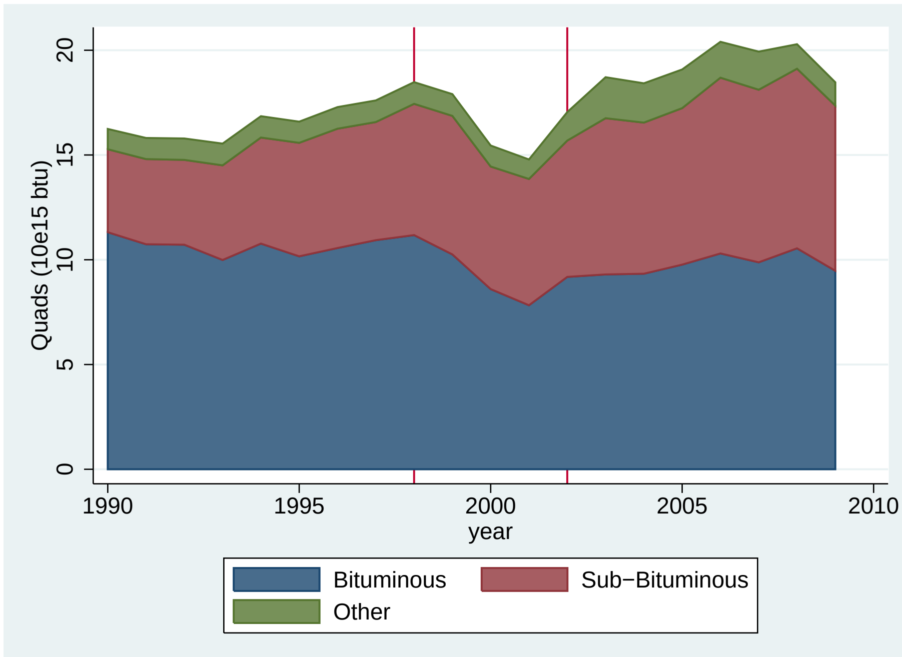
The thickness of coal seams is from MSHA's "Mine Dataset," which contains descriptive data on all mines under MSHA's jurisdiction since 1970. To calculate the depth of mine seams, I used a Perl script to collect the universe of stratigraphic data from the U.S. Geological Survey's "National Coal Resources 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.

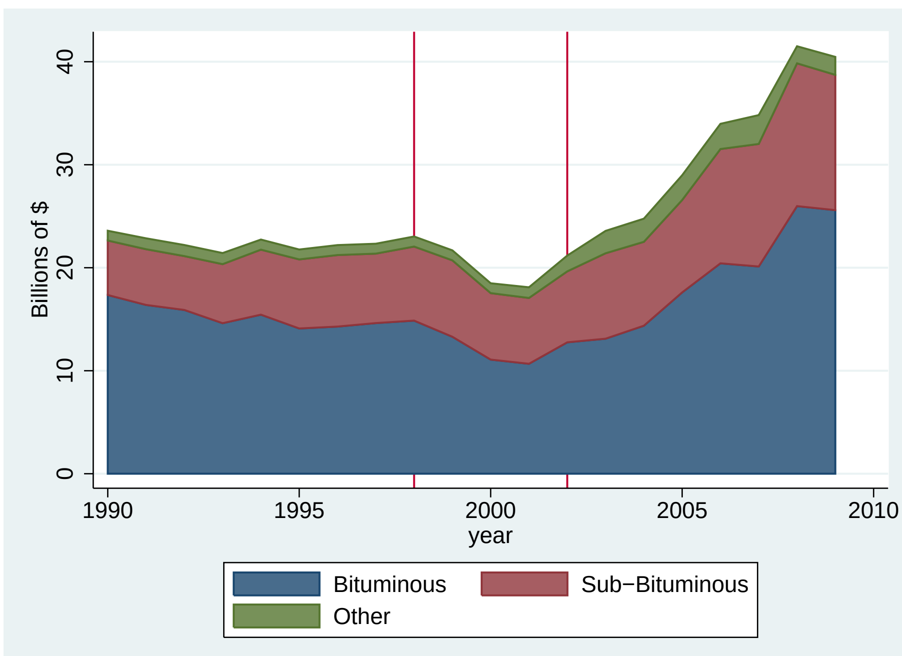
[37] Coal mining employment is reported under the four-digit NAICS code, "2121."

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

(a) Total Heat Content of Coal Deliveries



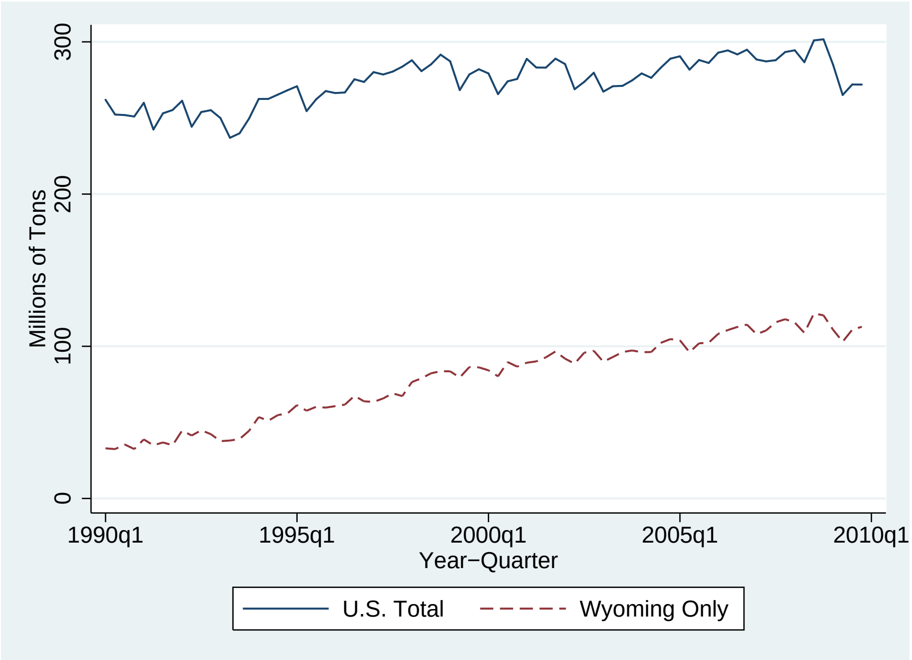
(b) Total Cost of Coal Deliveries



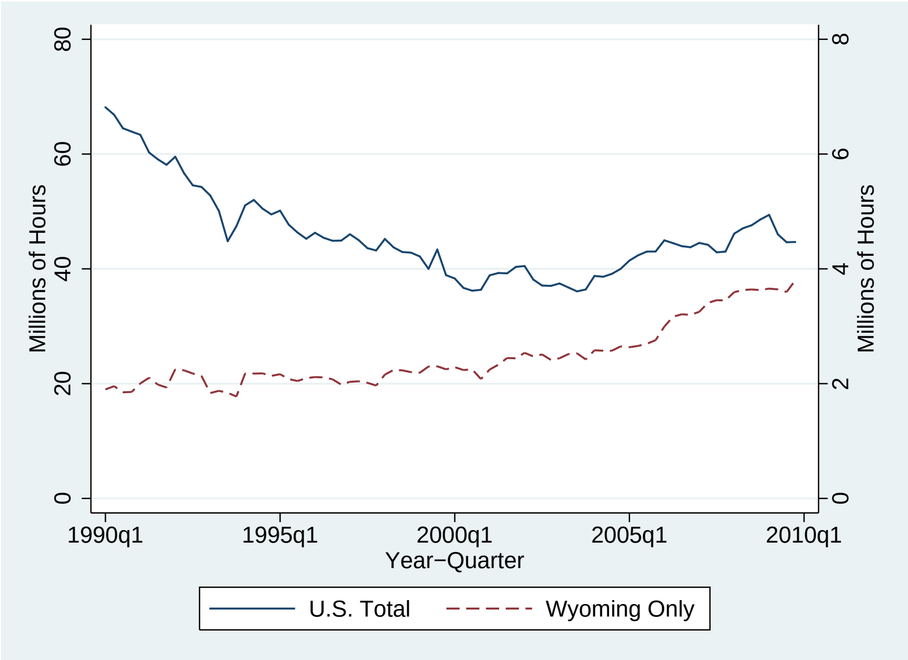
Note: Vertical lines denote the year in which divestitures begin (1998), and when reporting for non-utilities commences (2002). Source: Forms EIA-423,923 and FERC 423.

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.