DISCUSSION PAPER

January 2012; revised February 2012 ■ RFF DP 11-43-REV

Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act

Joshua Linn, Erin Mastrangelo, and Dallas Burtraw

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act

Joshua Linn, Erin Mastrangelo, and Dallas Burtraw

Abstract

The Clean Air Act has assumed the central role in U.S. climate policy, directing the Environmental Protection Agency to develop regulations governing the emissions of greenhouse gases from existing coal-fired power plants. The cost and environmental effectiveness of policy options depend on abatement costs, the magnitude of emissions reduction opportunities, and the sensitivity of plant utilization. This paper examines the operation of electricity-generating units over 25 years to estimate the marginal costs and potential magnitude of emissions reductions that could result from improvements in their efficiency. We find that a 10 percent increase in coal prices causes a 0.2 to 0.5 percent heat rate reduction, broadly consistent with engineering assessments of abatement costs and opportunities. We also find that coal prices have a significant effect on utilization, but that effect will vary depending on the policy design. The results are used to compare cost-effectiveness of alternative policies.

Key Words: efficiency, regulation, greenhouse gas, carbon dioxide, coal, performance standards

JEL Classification Numbers: L94, Q54

Contents

Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act

Joshua Linn, Erin Mastrangelo, and Dallas Burtraw*

1 Introduction

There has been considerable debate over the costs and effectiveness of energy efficiency investments, such as improving fuel economy of passenger vehicles or retrofitting buildings with better-insulated windows. On the one hand, many estimates suggest that low-cost and even negative cost opportunities exist across the economy, where the market value of the energy savings outweighs the investment cost. On the other hand, many analysts are skeptical of these assertions, arguing that if such opportunities were available, firms and consumers would take advantage of them.

Many of the optimistic estimates are based on case studies or engineering assessments of particular technologies. Previous analysis has identified several reasons why such assessments may be incomplete. First, there may be costs that the analyst does not observe and that hinder adoption. Second, technologies, particularly new ones, may be less effective than expected or not used as expected. Third, missing data on the extent to which the technologies have already entered the market may cause an overestimate of available efficiency opportunities. Fourth, there may be a rebound effect, in which adopting energy-efficient technology reduces its cost of operation and increases its use. Underestimating the rebound effect could lead to an overestimate of emissions reductions caused by technology adoption. For the most part, however, there is little direct evidence on these possibilities, and the controversy remains.

Recent policy developments heighten this debate. Since a legislative approach to climate policy stalled in the U.S. Congress, the Clean Air Act (CAA) has assumed the central role in the development of regulations that will reduce greenhouse gas (GHG) emissions. The

* Linn is a Fellow and Burtraw is a Senior Fellow and Darius Gaskins Chair at Resources for the Future. Erin Mastrangelo is an analyst at the Federal Energy Regulatory Commission, and previously at Resources for the Future where she conducted most of her research. We thank participants at the USAEE, APPAM, and InfraDay conferences along with David A. Evans, Alex Marten, Stephen Puller and Margaret Taylor for helpful comments, and Louis Preonas for outstanding research assistance. The authors received funding from the Bechtel Foundation and the U.S. Environmental Protection Agency's National Center for Environmental Economics.

Environmental Protection Agency (EPA) has been developing performance standards—often, emissions rate standards—for many sectors of the economy, such as passenger vehicles and industrial sources. EPA is introducing performance standards for existing stationary sources, such as electricity generators and industrial facilities—an approach that is nearly unprecedented. Such standards raise the possibility of achieving carbon dioxide (CO_2) emissions reductions rapidly, which is particularly important given the U.S. commitment to reduce emissions under the 2009 Copenhagen Accord. Coal-fired electricity generators account for about one-third of annual U.S. CO_2 emissions. EPA estimates that 2 to 5 percent efficiency improvements may be achieved on average,[1] comparable to the annual emissions reductions expected from new efficiency standards for passenger vehicles sold from 2012 through 2016.[2] The novelty and potential of these electricity sector standards raise two questions: (1) what are the available abatement opportunities; and (2) what are the costs of reducing emissions? Answering these questions requires addressing each of the issues above: estimating technological potential, costs, and the rebound effect.

This paper focuses on existing coal-fired electricity generation units. We analyze the actual efficiency of the entire fleet of coal units in the United States, where efficiency is measured as electricity generated per unit of heat input. We assess abatement opportunities and costs by observing how market and regulatory incentives affect the energy efficiency of coal plants. We use the results to compare the cost-effectiveness of alternative energy efficiency policies.

Previous approaches to these questions have used the case study or engineering approach, and this paper differs in two important ways. First, abatement costs and opportunities are estimated from observed behavior. Other studies, for example Metcalf and Hassett (1999) and Linn (2008), have analyzed the effect of fuel prices on energy efficiency in other sectors, but this

---

[1] EPA (2008), p. 16. With no change in utilization, a 5 percent efficiency improvement would produce emissions reductions of 90 million tons per year, about 1.6 percent of total U.S. emissions in 2009. Drawing on estimates from Sargent & Lundy, L.L.C. (2009) that we discuss below, these reductions could be achieved at a cost of $10.74 to $63.91 per ton CO_2 before accounting for the value of saved energy.

[2] This estimate is calculated by taking the 992 million tons in cummulative emissions reductions expected from pasenger vehicles introduced between 2012 and 2016 (http://environment.about.com/od/environmentallawpolicy/a/obama-sets-new-fuel-efficiency-standards.htm) and dividing by the expected 13 year lifetime of passenger vehicles in the United States resulting in average emissions reductions of 76 million tons per year. The calculation does not consider the effect of CAFE on the ownership and operation of existing passenger vehicles.

is the first study on the electricity sector. Second, as we explain next, heterogeneous abatement costs and opportunities across generators play an important role in the policy comparisons, and we incorporate this heterogeneity in a manner that is internally consistent with the empirical analysis.

We first assess abatement opportunities from efficiency improvements by examining heterogeneity in the efficiency of existing coal units. The analysis is performed using a unique panel data set of coal-fired generation units for the years 1985–2009. The data include monthly fuel input, generation, and coal prices by generation unit for nearly all U.S. coal plants, and the units in the sample account for 95 to 98 percent of total coal generation in each year. We use a generation unit's heat rate (the ratio of heat input to electricity generated) to measure efficiency; heat rate is approximately proportional to the rate of CO_2 emissions per unit of electricity generation.

We show that there is considerable heterogeneity and a substantial right-hand (positive) tail in the heat rate distribution. Specific technical factors help explain heterogeneity across units, including boiler design, size, and vintage, and features such as pollution control equipment and cogeneration. After controlling for these factors, we find that fleetwide emissions rate reductions of up to 5 percent may be technically feasible without changing the amount of electricity generated with coal. This estimate does not account for costs, and we consider it an upper bound, given current technology.

To provide the basis for comparing the costs of alternative policies, we next estimate the cost of improving efficiency and the rebound effect. In principle, several types of policies could be used to incentivize heat rate improvements, and the costs may vary across the alternatives. We compare the costs of four policy alternatives: a traditional (inflexible) performance standard, a flexible performance standard, and two types of emissions taxes. To make this comparison we observe that (1) cost-effectiveness depends largely on abatement costs and the rebound effect; and (2) coal prices mimic the incentives created by a CO_2 emissions price (i.e., an emissions cap or tax) or some types of performance standards. Demonstrating the first point requires a brief description of the policies. A traditional emissions rate standard sets a particular emissions rate per unit of generation (or per unit of heat input) for each generator to meet. Units that decrease heat rates to meet the standard also experience a rebound effect because the lower heat rate reduces the cost of generating electricity.[3]

A flexible emissions rate standard sets a benchmark emissions rate and allows firms to overcomply and sell credits to firms that undercomply. The standard creates incentives to adopt energy efficiency technology and has two effects on generation: it imposes an opportunity cost on heat rates by effectively adding to the cost of fuel, and it provides an output subsidy through the allocation of credits based on generation. The opportunity cost provides a disincentive for generation while the output subsidy provides an incentive to increase generation. Hence, like the traditional standard, the flexible standard creates incentives to adopt energy efficiency technology, but unlike the traditional standard the effect of the flexible standard on generation is ambiguous.

A CO_2 emissions or fuel tax raises the cost of using fuel, thereby creating an incentive to adopt energy efficiency technology. This also creates an incentive for firms to reduce generation. The emissions or fuel tax raises the cost of using fuel and therefore creates the smallest rebound effect; the emissions or fuel tax would require the smallest overall reduction in heat rates to achieve a given emissions target. In short, the relative cost-effectiveness of the policies depends on the cost of improving heat rates and the magnitude of the rebound effect.

Because data on energy efficiency technology adoption are not available, we focus on the response of heat rates to changes in coal prices. As we argue below, conditional on the utilization of the unit, there is a one-to-one correspondence between the level of energy efficiency technology and the unit's heat rate. A simple model demonstrates that we can estimate the cost of adopting technology by examining the empirical relationship between coal prices and heat rates. Similarly to the CO_2 policies, an increase in the price of coal increases the opportunity cost for heat rates, conditional on utilization. Using the same panel data set as for the analysis of abatement opportunities, we find that a 10 percent coal price increase, corresponding to a tax on CO_2 emissions of about \$1.64 per ton, reduces heat rates by 0.2 to 0.5 percent, depending on the estimation procedure. A change in coal prices commensurate with a \$10 per ton tax on CO_2 emissions would stimulate a 1 to 3 percent heat rate reduction (holding fixed utilization). This range of estimates encompasses the estimates suggested in the engineering literature but includes the possibility of somewhat lower costs than have been estimated. We note that the overall

[3] The analysis in this paper focuses on the short run and does not consider retirements. Consistent with this focus, in the policy analyis we consider relatively small efficiency improvements of 1-2 percent.

efficiency improvements of 2 to 5 percent discussed in the engineering literature correspond to the change in heat rate resulting from an increase in coal prices of more than two standard deviations—that is, out of sample. We also obtain a significant relationship between coal prices and utilization. A 10 percent increase in coal prices reduces utilization by 2 to 4 percent.

We use a stylized model of the electricity sector to simulate the effects of four energy efficiency policies: a traditional emissions rate standard, a flexible standard, a coal Btu tax (roughly equivalent to a coal emissions tax), and a fossil fuel emissions tax. We find that because of the narrower focus of the performance standards and the greater rebound effect, more investment in heat rate technology is required under the performance standards than the taxes to achieve a given emissions reduction. This raises the relative costs of the standards, but overall, the costs approximate the engineering estimates and are low compared with other abatement opportunities in the electricity sector.

This paper is organized as follows. Section 2 provides a brief background on the regulation of existing coal units under the CAA. Section 3 discusses the operation of coal-fired units in the U.S. electricity system. Section 4 describes the data and summarizes heterogeneity in the heat rates across individual units. We identify some of the factors that might influence efficiency and quantify abatement opportunities. Section 5 describes the empirical strategy for estimating the effects of coal prices on heat rates and utilization, and Section 6 presents the estimation results. Section 7 uses the estimation results to compare cost-effectiveness across policies, and Section 8 concludes.

2 The Clean Air Act

The modern CAA was passed in 1970 and conveys broad authority to EPA to develop regulations to mitigate harm from air pollution. In 2007 the Supreme Court affirmed this authority with respect to the regulation of GHGs *(Massachusetts v. EPA)*.[4] Subsequently, the agency made a formal, science-based determination that GHGs are dangerous to human health and the environment. This "endangerment finding" compelled the agency to mitigate that harm.

[4] 549 U.S. 497 (2007).

In 2011 EPA implemented regulations affecting CO_2 emissions from passenger vehicles, medium-duty trucks, and heavy-duty trucks.[5] The agency also implemented regulations for construction permitting (New Source Review, NSR) for major new and modified sources, such as power plants and industrial facilities.[6] The third anticipated EPA regulatory action is the development of performance standards for GHGs affecting the *operation* of stationary facilities.[7] EPA has a long history of setting performance standards for new sources, but performance standards for existing sources are nearly unprecedented.[8] The first standards, expected in 2012, will target steam boilers at power plants fueled with coal, oil, and natural gas, along with petroleum refineries. These sources represent more than one-third of GHG emissions in the United States (EIA 2011).

In principle, power plants and refineries could reduce emissions in many ways, including fuel switching, making incremental changes to efficiency, or adopting new, energy-efficient technology. Indications from EPA (2008) are that the regulations will encourage improvements in the efficiency of power plants and refineries without requiring large-scale substitution among fuels or technologies. The efficiency of facilities varies substantially, possibly indicating potential opportunities for improvements at the least efficient facilities. EPA suggested that average efficiency might be improved by 2 to 5 percent at moderate cost.[9] However, one might conjecture that incentives already exist to reduce costs at these facilities, and the presence of heterogeneity across plants might reflect variation in technological, geographic, and economic factors that make operational improvements more expensive in some situations. To date, there has been no comprehensive examination of the actual opportunities for efficiency improvements, or the magnitude and cost of potential emissions reductions.

---

[5] Beginning with model year 2012, average fuel economy of cars and light trucks improves by 5 percent per year to a fleet average of 35.5 miles per gallon (mpg) in 2016. New regulations are expected to extend this target to 54.5 mpg by 2025.

[6] Implementing regulations including the definition of best available control technology are in development.

[7] Standards under §111(b) of the CAA apply to new sources (these are termed New Source Performance Standards), and those under §111(d) apply to existing sources.

[8] Existing sources regulated under other provisions of the CAA are not eligible for regulation under §111(d) (Richardson et al. 2011).

[9] Equivalent additional reductions could be achieved if facilities were allowed to co-fire with biomass under the assumption that waste biomass was used and its combustion led was carbon neutral.

3 Coal Plant Operations

At a simplified level, a coal-fired power plant consists of one or many boilers that burn pulverized coal to produce steam from water. The boilers are connected to one or many generation turbines, which spin from the pressure of the steam to produce electricity. A condensing and cooling system collects and recycles the steam.

3.1 Determinants of Efficiency

Efficiency is often measured by the heat rate—the amount of heat input, in million British thermal units (mmBtu), required to generate one megawatt-hour (MWh) of electricity. A lower heat rate represents a more efficient unit. A generating unit can improve efficiency by reducing the amount of fuel required for a specific level of generation. A percentage improvement in heat rate is nearly equivalent to an equal percentage improvement in the emissions rate in terms of the change in CO_2 emissions.[10] The difference stems from the small variation in carbon per Btu across varieties of coal.

The heterogeneity in heat rates across coal-fired generation units can partly be explained by technical characteristics determined at the time of plant construction that cannot be changed without a major overhaul. This category includes size, age, firing type, and the technology employed. Higher efficiency is generally associated with plants that are used more heavily because efficient units are less costly to operate.

A second factor is how the boiler is used. The relationship between the heat rate and utilization is nonlinear, as efficiency tends to be lower at very low and very high levels of utilization. Routine decisions regarding plant operations affect efficiency, and many of these decisions result from constraints or factors that weigh against efficiency concerns (e.g., variation in demand, voltage regulation, or system reliability). Units with lower utilization may be ramped up and down more frequently, which requires additional fuel input as temperature in the boiler fluctuates. The result could involve efficiency losses at least partly outside the control of plant decisionmakers.

[10] The product of the rate of emissions per mmBtu and the heat rate gives the rate of emissions per MWh. For example, combustion of Powder River Basin low-sulfur subbituminous coal emits about 212.7 lb CO_2 per mmBtu of heat content. A plant with a heat rate of 10 mmBtu/MWh has a CO_2 emission rate of about 2,127 lb CO_2/MWh (212.7 * 10).

Plant managers control several other factors that affect heat rates. Techniques, management, or technology may improve the efficiency of the plant by targeting the major components of the coal combustion process: oxygen, temperature, and pressure. Excessive deviations in any of these areas may decrease efficiency through waste or shortfalls. For example, Beer (2007) and Rosen and Dincer (2003) explain that enhanced coal-feeding systems or grinding the coal more finely can reduce excess air in the boiler and increase efficiency by reducing heat loss. Maintenance and performance testing are also critical for identifying and preventing losses.

Although technical adjustments can be made to improve heat rate, a firm's institutions, such as training or commitment to goals, are also important. Industry experts identify as potential barriers weak support from management and a lack of expertise or onsite engineers dedicated to heat rate improvement (DOE/NETL 2009).

Regulations can also affect a firm's heat rate. Some measures that improve efficiency may trigger New Source Review, under which the firm must demonstrate that the efficiency improvement would not create or exacerbate air quality violations. NSR can raise the cost of improving efficiency if the firm has to install pollution abatement equipment. In addition, the market environment may influence investment and operational behavior of firms. Firms subject to greater competition in wholesale power markets may have greater awareness of and incentive to minimize costs (Fabrizio et al. 2007). Firms may vary in their ability to access capital when investment opportunities exist.

Table 1 describes factors that affect heat rates and hypotheses from the literature on how the factors affect heat rates. Appendix 1 includes a more complete literature review.

3.2 Engineering Estimates of Costs and Heat Rate Improvements

According to an engineering analysis prepared for EPA, the cost of reducing heat rates varies widely across options (Sargent & Lundy 2009). In one example, for a 200-MW unit, cleaning the condenser improves heat rates up to 0.07 mmBtu/MWh and costs a modest \$30,000 per year.[11] Accounting for utilization and coal prices, this would be profitable for a typical 200-MW unit in 2008. Other improvements may be less cost-effective, however. A new fan system to

[11] The range of identified reductions could be achieved at a cost of \$10.74-\$63.91 per ton of CO_2 before accounting for the value of reduced fuel expenditures.

control air flow in the flue gas system can cost $6 million in capital investment plus $50,000 per year in operating and maintenance costs for heat rate reductions up to 0.05 Btu/kWh for a 200-MW unit.

Each potential measure at a typical plant improves the heat rate between 0.01 and 0.1 mmBtu/MWh (compared with an average heat rate of about 11 mmBtu/MWh) and improvements may be additive. Importantly, significant analysis and expertise are required to find the optimal combination of upgrades and techniques, if any, for each specific plant. There are no comprehensive data, however, on the extent to which such technologies are already in use.

4 Data and Summary Statistics

To study the efficiency of coal-fired power plants, we assemble a comprehensive annual panel data set of coal-fired generating units in the United States from 1985 through 2009. The dataset combines several public sources and contains a uniquely detailed set of characteristics and efficiency of coal-fired units over time. Because of data limitations, 2006 and 2007 are excluded from the panel. Appendix 2 provides further information about data sources.

The annual heat rate is calculated from reported monthly heat input and generation at a boiler and corresponding generator. Because some units fire multiple fuels, heat input from fuels other than coal is included in the calculation of heat rate; however, close to 99 percent of total annual heat input is from coal in any given year in the panel. Each year contains about 1,000 units, although the sample size is somewhat larger after 2001 because of changes in the reporting requirements of the primary data source. The sample contains about 340 gigawatts (GW) of capacity and accounts for 97 percent of U.S. coal-fired electricity generation and emissions in 2009.

Although we do not observe heat rate investments in the data, the data set includes other variables that influence heat rate. Characteristics of the plant, such as vintage, size, boiler firing type, and cogeneration capacity, help determine the unit's physical ability to achieve a particular level of efficiency. We also include variables that describe how the plant is used and managed. These include utilization rates, the presence of pollution controls, choice of fuel including coal type, regulatory environment, and ownership structure. Finally, we merge plant-by-year prices of the delivered price of coal. Note that the coal price is the annual average price of coal because it is calculated by dividing expenditure by heat content of the delivered coal. Most of the analysis uses the overall price of coal, including contract and spot market purchases, and some of the analysis includes contract and spot market prices separately.

Table 2 and Figures 1–3 summarize the data. Table 2 aggregates the data to five-year time periods and reports means of several variables with standard deviations in parentheses. Figure 1 shows the distribution of heat rates in 2008. The horizontal axis is the average annual heat rate and the vertical axis is the heat input, which maps into the unit's electricity generation. The figure displays a right-hand tail, indicating that many of the least efficient units have relatively little electricity generation. Figure 2 disaggregates the data and illustrates differences in heat rates across three prominent firing types. Figure 3 reports the distribution of heat rates after controlling for several characteristics, including firing type, cogeneration, capacity and fuel type. More specifically, the figure plots the residuals of a regression of the unit's heat rate on the indicated control variables; the variables are added sequentially to generate the different plots (in each case, the sample mean heat rate is added to the residuals before plotting). Even after accounting for these characteristics, one observes substantial heterogeneity, which is the focus of our analysis.

We use the observed heat rate heterogeneity to place an upper bound on the available abatement opportunities. For this calculation, we put aside abatement costs and consider what levels of abatement—that is, percentage emissions reductions—would be possible under alternative traditional performance standards. We first consider a uniform standard equal to the 90th percentile of efficiency (corresponding to the 10th percentile of heat rates) and calculate the percentage emissions reduction across all units in the sample. This calculation implicitly assumes that it is technically feasible for all units to achieve a heat rate equivalent to the most efficient 10th percentile, but this may not be possible for some units whose inherent features, such as firing type, size, or other characteristics, are inflexible. Therefore, we also analyze traditional standards that are set according to the firing type or other attributes of the generation unit that cannot be changed.

Table 3 reports the results of these calculations. Each column reports a different performance standard that is determined according to the generator attributes in the column heading. In Panel A we assume that the standard does not affect utilization, and in Panel B we assume a 20 percent rebound effect (as estimated below). We find that the percentage emissions reduction is about 5 to 6 percent assuming no rebound effect, and 5 percent assuming a 20 percent rebound effect. Somewhat surprisingly, the reductions are fairly insensitive across the different columns.

5 Strategy for Estimating the Effects of Coal Prices on Heat Rates and Utilization

5.1 A Firm's Choice of Heat Rate

The cost of fuel input creates an incentive for firms to adopt heat rate-improving technology. Most technology options involve capital cost expenditures, such as an economizer and/or acid dew point control to transfer heat from exhaust gases, but there are also variable cost opportunities, such as cleaning the condenser. Ideally, we could estimate the cost of adopting such technology by investigating empirically the relationship between coal prices and technology adoption. However, because data on technology adoption are not available, we instead focus on the effect of coal prices on heat rates, which are expected to change with technology adoption. This presents the challenge that heat rates are not fixed for a given heat rate technology, and in fact heat rates depend on utilization, as discussed above. However, if we condition the analysis on utilization, there is a direct relationship between heat rate technology and heat rate. That is, if two units have the same utilization but different heat rates (and are otherwise identical), they have a different heat rate technology; we refer to the unit with the lower heat rate as having a "better" heat rate technology. Figure 4 plots heat rates against the utilization for two levels of heat rate technology, T. The figure shows that if the units have the same utilization, the unit with the lower heat rate has the better technology. Therefore, we proceed with a model in which the firm chooses heat rates and characterize the effect of coal prices on heat rates, conditional on utilization. Subsequently, we allow utilization to vary, which introduces a rebound effect.

To begin, we argue that abatement costs can be estimated from the relationship between coal prices and heat rates. We assume a facility operator makes a decision about heat rate to maximize profit. We posit a reduced-form relationship between utilization (electricity generation per unit of capacity) and operating costs: $u = u(p^f h, \theta)$, where p^f is the price of fuel ($/mmBtu), h is the heat rate (mmBtu/MWh), θ is the unit's type, $u_1 < 0$, and $u_2 > 0$. The term $p^f h$ is the fuel cost per unit of electricity generation. A lower heat rate reduces fuel costs and raises utilization. The unit's type captures factors that affect generation other than fuel costs, such as managerial quality, as well as the unit's idiosyncratic economic value due to its location in the transmission system; higher type is associated with greater utilization. We use the reduced-form utilization function to focus the analysis on the firm's choice of heat rate. Alternatively, we could embed the coal unit in a competitive wholesale electricity market, where we would conclude similarly that utilization is a function of type and fuel costs.

The profit maximization problem is

$$\max_h \pi = [p - m - p^f h]u(p^f h, \theta)K - c(h)K \tag{1}$$

where:

p= price of electricity ($/MWh)

m = operation and maintenance costs ($/MWh)

K = capacity (MW)

$c(h)$= cost of heat rate technology ($/MW); $c' < 0, c'' > 0$

The term in brackets is the difference between the electricity price and operating costs, which include operations and maintenance costs as well as fuel costs.[12] The function $c(h)$ is the capital cost of choosing heat rate h; a lower heat rate is more costly.[13] The capital cost scales linearly with the unit's capacity.

The first-order conditions for the facility's problem can be represented as

$$\frac{\partial u(p^f h, \theta)}{\partial h}[p - m - p^f h] - p^f u - c'(h) = 0 \tag{2}$$

We interpret $c'(h)$ as the marginal cost of reducing the heat rate. Equation (2) shows that, conditional on utilization ($\partial u / \partial h = 0$), high coal prices are associated with low heat rates.

5.2 Estimating the Effect of Coal Prices on Heat Rates

We are interested in two relationships: (1) the effect of coal prices on investment in efficiency improvements and efficiency; and (2) the effect of coal prices on utilization. We begin by focusing on the average effect of coal prices on efficiency. We use the full panel data set and a linear regression model in which heat rate is the dependent variable that measures efficiency, and the major independent variables are coal prices and unit characteristics.

Ideally, to estimate the effect of coal prices on efficiency investments and efficiency, we would have data on specific improvements made at individual plants. Because such data are not

[12] For simplicity, the utilization function does not include natural gas prices and operations and maintenance costs. These assumptions are relaxed in the empirical work.

[13] The large majority of opportunities to reduce heat rates at coal plants are capital cost related (Sargent & Lundy 2009).

available, we introduce further structure by assuming that the first term in equation (2) is small compared with the other terms (this assumption is supported by empirical estimates of the derivative of utilization to the heat rate, below, which do not depend on this assumption). Taking logs of equation (2) yields the following relationship between the heat rate of unit i in time t and the price of coal:

$$\ln h_{it} = \alpha \ln p_{it}^{f} + X_{it}\gamma + \epsilon_{it} \quad (3)$$

where X_{it} is a vector of characteristics including state and time fixed effects, utilization, and a large number of unit-specific variables. The coefficients α and γ are to be estimated, and ϵ_{it} is a random error term.

Because equation (3) uses a log-linear relationship between coal prices and efficiency, we can interpret α as the elasticity of the heat rate to the coal price. Based on equation (2), we expect that high coal prices increase the incentive to adopt technology that improves efficiency and reduces heat rates, so α should be negative. Importantly for the policy comparison below, equation (2) suggests that α is inversely proportional to the marginal cost of reducing the heat rate.

The extent to which this predicted relationship will be observed at individual units depends on unit-specific characteristics and other factors, including the assumption that the firm minimizes costs. If the firm does not minimize costs perfectly, the data should reveal a relatively weaker relationship between heat rates and fuel price for generating units owned by that firm. Hence, the economic relationship observed in the data may underestimate how firms would respond to regulations requiring an improvement in emissions rates or heat rates.

The theoretical model and discussion of the data and power plant characteristics illustrate three major challenges to estimating equation (3): reducing measurement error in heat rates, controlling for utilization, and controlling for the unit's type (θ_{it}). The measured heat rates are quite noisy, occasionally falling outside engineering bounds (see Appendix 1 for more details).

To reduce measurement error for heat rates we aggregate observations to five-year periods. Each unit is observed a maximum of five time periods over the sample 1985–2009.[14]

An increase in coal prices decreases utilization because it makes the relative cost of operating coal plants more expensive. The decreased utilization raises heat rates, for reasons discussed earlier. Failing to control for utilization would bias the estimate of α toward zero; that is, a simple regression of heat rates on coal prices would combine the positive effect of a change in utilization with the negative effect of a change in efficiency. Since we are interested in the latter, it is important that we control for the effect of coal prices on heat rates due to utilization.

Equation (3) includes an extensive set of controls for utilization. The relationship between coal prices and utilization may be nonlinear; that is, including a linear measure of utilization would imperfectly control for utilization and would bias other estimated coefficients. Therefore, we include a linear control for utilization, as well as a large set of variables that account for the potentially nonlinear relationship between utilization and efficiency, particularly at low levels of utilization. Utilization controls in X_{it} include the unit's utilization rate (generation divided by the maximum generation over the time period if the unit operates at full capacity). We also include a set of fixed effects for the number of months in the five-year period that the unit operated below 10 percent or below 30 percent of rated capacity. These control variables were selected based on an analysis of hourly data, in which we concluded that these monthly utilization variables predicted heat rates nearly as well as hourly utilization variables. The results are unaffected if we use high-order polynomials in utilization rather than the utilization fixed effects.

Note that aggregating to five-year periods also helps control for the effect of coal prices on heat rates due to utilization. It takes time for firms to implement heat rate improvements in response to higher coal prices. For example, they may have to hire engineering consultants or approve and implement capital projects. Using five-year intervals rather than annual observations

[14] There may also be measurement error in the independent variables such as utilization or coal prices. If generation is measured with error, the estimates would be biased because generation is used to construct the unit's heat rate and utilization. This does not appear to be a significant concern, however, because the results are similar if we use the unit's fuel input as the dependent variable rather than the heat rate. In principle, we could address potential measurement error in coal prices using an instrumental variables approach, but as noted below, we are not able to identify suitable instruments for the unit's coal price.

allows us to more plausibly capture the effect of coal prices on heat rate improvements, rather than the effect of coal prices on heat rates due to changes in utilization.[15]

In Section 5.1 we assumed that utilization depends on fuel prices and heat rate. In practice, other variables affect utilization and therefore heat rates, particularly natural gas prices. However, controlling for utilization in equation (3) avoids the need to include other variables that affect heat rates via utilization; below we show that the results are similar if we control for natural gas prices and other determinants of utilization.[16]

The final empirical challenge is the relevance of the unobserved type (θ_i). We assume a unit with a higher type would have a higher efficiency, independent of its other unit-specific characteristics (X_{it}), the coal price, or its utilization. For example, the plant or firm may have better managers, or the unit may operate with less variation in its utilization rate. Thus, the unit's type may contain a fixed and time-varying component. This introduces a significant challenge because the unit's type is not directly observed in the data.

Perhaps the simplest approach to controlling for fixed unit type would be to include unit fixed effects in equation (3). However, as we show below, this absorbs much of the coal price variation and makes it difficult to identify α. Below, we show results that control for fixed unit characteristics by including the variables for the technical characteristics that were analyzed earlier: state, rated capacity, firing type, primary fuel type, and whether the unit is a cogenerator.[17] As an alternative specification, we include fixed effects for each generating unit.

We take several approaches to controlling for time-varying components of the unit's type. The utilization variables control for type to the extent that high-type units have higher utilization rates because they are more efficient; that is, there is a monotonic relationship between type and utilization (Olley and Pakes 1996). Several other included variables are likely to be correlated with type: age, percentage of coal in total heat input (to account for units that use

[15] Alternatively to aggregating to five-year time periods, we could use annual data and include the moving average of the coal price rather than the current coal price. The results are unaffected if we take this approach; we prefer aggregation because of the concerns about measurement error discussed above.

[16] There may be an interaction between natural gas prices and coal prices. A coal plant that faces high coal prices and low natural gas prices would have an even greater incentive to reduce its heat rate than if natural gas prices were higher. We find evidence for this mechanism during the sample period.

[17] More specifically, the control variables include a set of fixed effects for the unit's firing type and fuel type. Deciles are computed for rated capacity across the units in the sample, and equation (3) includes fixed effects for each decile.

a small amount of natural gas or biomass), ownership type, and whether the unit has selective catalytic reduction (for nitrogen oxides) or flue gas desulfurization (for sulfur dioxide).[18] The ownership type fixed effects control for the fact that different ownership types may have different incentives to improve heat rates. We also report results from a specification that includes parent company by time period fixed effects, which control for changes over time in management quality at the parent company level.

Given the control variables included in equation (3), the main remaining concern is that coal prices may be correlated with omitted, particularly time-varying, unit characteristics, even after conditioning the analysis on utilization. In particular, coal markets are not perfectly competitive (Busse and Keohane 2004), and certain owners of coal plants may be able to negotiate more favorable prices. This could result in a negative correlation between the unobserved type and the observed coal price. In the estimation we take several approaches to address this possibility, such as including parent company fixed effects.[19]

5.3 Estimating the Effect of Coal Prices on Utilization

To estimate the rebound effect stemming from an improvement in heat rate, we assume that a 1 percent decrease in coal prices has the same effect on utilization as a 1 percent decrease in heat rate. Because marginal generation costs depend on the product of the coal price and the heat rate, this is a reasonable assumption, given the importance of marginal generation costs in determining utilization. Therefore, we are interested in the effect of coal prices on utilization, holding heat rates constant. We estimate the reduced-form utilization function by assuming a log-linear relationship between utilization and the price of coal:

$$\ln u_{it} = \beta \ln p_{it}^{f} + X_{it}\gamma + \epsilon_{it} \tag{4}$$

The dependent variable is the log of utilization, and the independent variables are the same as in equation (3), except that we omit the utilization controls. The main challenge to estimating equation (4) is that utilization and heat rate are jointly determined; that is, changes in coal prices affect both heat rates and utilization rates. Ideally, we would add heat rate to equation (4) and

[18] Equation (3) includes a set of age fixed effects, for 6-10 years, 11-20 years, 21-30 years, 31-40 years, 41-50 years, 51-60 years and above 60 years, where 0-5 years is the omitted category.

[19] In principle, one could instrument for the price of coal using variables that are correlated with coal prices but not with the error term in equation (3). We have considered a number of potential instruments, for example, coal prices observed at neighboring plants owned by other firms, but we have not found variables that meet both requirements.

jointly estimate equations (3) and (4), but appropriate instrumental variables are not available. Instead, we use annual observations rather than five-year intervals to reflect the short-term nature of variable costs and system operation. We note that the estimate of β in equation (4) may be biased if heat rates respond to coal prices within one year. However, the magnitude of the bias is likely to be small in practice because coal prices have a small effect on heat rates: the elasticity of heat rates to coal prices turns out to be about –0.05. This suggests we may underestimate the the effect of coal prices on utilization, but probably not by a large amount. Below, we further assess the potential bias by using different length time periods.

6 Estimation Results

This section first presents the estimated effects of coal prices on heat rates and utilization. We discuss the magnitude and robustness of the estimates, as well as interactions between New Source Review and coal prices. We then discuss the abatement costs of efficiency improvements that the estimates imply. The section concludes by reporting the estimated rebound effect.

6.1 Effect of Coal Prices on Heat Rates

6.1.1 Main Results

Table 4 reports estimates of equation (3), where the dependent variable is the unit's log heat rate over the five-year time period. Panel A does not include unit fixed effects, and Panel B includes unit fixed effects. The main coefficient of interest is α, which is the coefficient on the log price of coal and is interpreted as the elasticity of the heat rate to the price of coal.[20] The regression includes a large number of other control variables for technical characteristics and utilization, as well as state and time period fixed effects.

Column 1 shows the baseline specification. Without fixed effects, the estimate of α is -0.053 with standard error 0.008, which is significant at the 1 percent level. The point estimate can be interpreted as an elasticity; a one standard deviation increase in coal prices reduces heat rate by about 1.7 percent.

[20] The coal price variable reflects the cost of using coal. Therefore we add to the delivered coal price the associated sulfur dioxide emissions multiplied by the sulfur dioxide permit price for 1995-2009, adjusting for whether the unit is connected to a scrubber and whether the unit participated in the Acid Rain Program.

Adding unit fixed effects decreases the estimate to -0.016 with standard error 0.009, which is significant at the 10 percent level. A one standard deviation coal price increase causes a 0.5 percent heat rate reduction.[21] There are several possible explanations for the fact that adding unit fixed effects decreases the estimate by a substantial amount. First, the estimate with fixed effects could correspond to more of a short run estimate because it is estimated using within-unit variation; the estimate without fixed effects may reflect efficiency improvements that require major changes to capital equipment that are difficult to implement quickly but can be observed on a cross-sectional basis.[22] Because our primary focus is on efficiency improvements at existing coal units, we would interpret the estimates in Panel A and Panel B as upper and lower bounds to the effect of coal prices on efficiency improvements. However, there are two other explanations for the discrepancy that suggest caution with making this interpretation: the specification that does not include unit fixed effects may not fully control for time-invariant unit characteristics; and including unit fixed effects may absorb much of the coal price variation, making it difficult to precisely estimate the coefficient. Note that the bias for the latter two cases could be in either direction. It is difficult to distinguish among these hypotheses, and in the remaining analysis we report estimates with and without fixed effects.

We show that, overall, the results are robust to other specifications and functional form assumptions. Equation (3) imposes a log-linear relationship between coal prices and heat rates. Although this functional form approximates a more complicated relationship, it is somewhat arbitrary. The results are similar using other functional forms, for example, estimating the equation using the heat rate and coal price in levels rather than in logs. Figure 5 provides further confirmation that the log-linear approximation is reasonable. Residuals are constructed from a regression of log heat rate and log coal price on the same independent variables as column 1 in Panel A, except that log coal price is not included as an independent variable. The figure plots

[21] The calculation of the change in heat rate for a one standard deviation price increase uses the standard deviation of observed coal prices across the entire estimation sample. In Panel B, α is identified by within-unit coal price variation. Therefore, a more appropriate calculation may use the standard deviation of coal prices after removing unit-specific means. The standard deviation is smaller than for the full sample ($0.50/mmBtu instead of $0.62/mmBtu), and a one standard deviation increase corresponds to a 0.4 percent heat rate decrease.

[22] To investigate this interpretation further, we have restricted the sample to periods 1 and 5. The estimate of α could be interpreted as more of a long run estimate than the estimate reported in Table 4 because it would reflect changes in coal prices and efficiency over a 25 year time horizon. The point estimate (without or with unit fixed effects) is very close to the estimate in Table 4 which suggests that the estimates reported in the table may reflect long run responses to coal prices.

the residuals as well as the fitted values from a regression of the heat rate residuals on the coal price residuals (the slope of the fitted values equals α). The figure does not indicate the presence of a nonlinear relationship between the heat rate and coal price residuals, which supports the linearity assumption in equation (3).

Given the fixed costs and the importance of managerial quality in implementing heat rate improvements, heat rates at units owned by larger firms may be more responsive to coal prices than units owned by smaller firms. Columns 2 and 3 restrict the sample to the 10 largest and 20 largest firms, based on firms' total coal capacity in 2009.[23] The estimates are not statistically significantly different from the baseline in Panel A (without fixed effects), but the results with fixed effects suggest that most of the response occurs at units owned by smaller firms. Thus, we do not find strong evidence that units owned by larger firms respond more to coal prices.

6.1.2 Persistence

Ideally, we would estimate the long-run effect of coal prices on heat rates because this relationship would provide insight into the effects of potentially permanent CO_2 policies. Because the regressions include state and period fixed effects, we estimate α using deviations in coal prices from state averages and from the period averages. If such deviations were less than fully persistent, we would underestimate the long-run effect of coal prices on heat rates. We use several approaches to address this issue and find some evidence that the baseline estimates understate the long-run effect of coal prices on heat rates.

We begin by estimating the persistence of coal prices. Panel A of Table 5 reports a series of regressions in which the log price of coal is the dependent variable and independent variables include the one-period lag coal price, state fixed effects, and period fixed effects. Column 1 uses the overall price of coal based on total contract and spot market purchases, column 2 uses the contract price, and column 3 uses the spot price. The estimates are all much less than one, which suggests that all prices exhibit some mean reversion.

Panel B shows that the coefficients on lagged prices are much higher if the state fixed effects are removed. The same is not true if period fixed effects are removed (not reported), which suggests that if the estimates in Table 4 are less than long-run estimates, removing state fixed effects in the baseline regression would increase the estimated magnitude of α.

[23] A firm refers to a parent company; for example, Southern Company is a single firm, which owns Alabama Power, Georgia Power, and several other subsidiaries.

Column 1 in Table 6 repeats the specifications in column 1 of Table 4, except that the average coal price is separated into spot and contract prices. Given the relatively low persistence of these prices, we would expect these coefficients to be smaller in magnitude than the estimate for the overall price of coal. This pattern is observed, in fact, and the estimates on the spot and contract prices are small and are not statistically significant.

The specifications in Panel B of Table 5 indicate that omitting state fixed effects from equation (3) should result in larger coefficients for the spot and contract prices, and to a lesser extent for the overall price. Columns 2 and 3 of Table 6 report the results of this exercise, which conform to expectations.[24]

Another approach to assessing whether we estimate long-run responses is to use the coal price in the first year of each period rather than the average price in each period. Suppose firms take several years to implement heat rate improvements. If coal prices happen to change late in the five-year periods in our sample, we would underestimate the effect of coal prices on heat rates over a five-year period. To investigate this possibility, column 4 replaces the average coal price over the time period with the price in the first year. The results are similar to the baseline, as is the case if we estimate equation (3) using the price in the third year of each time period (not reported). We would expect to estimate a smaller coefficient using the price in the final year of each period rather than the average price, which is the case (not reported).[25]

Finally, we attempt to incorporate persistence directly in equation (3). We estimate the same regression as column 1 of Table 5 separately for each region of the North American Electric Reliability Corporation (NERC), and we define a persistence variable as the coefficient on the lagged coal price. Column 5 of Table 6 adds to the baseline the interaction of the persistence variable with the coal price. The interaction coefficient would be negative if more persistent coal price shocks had a larger effect on heat rates. The estimate is negative, but it is small and not statistically significant; in short, there is not sufficient variation in persistence to

[24] Because of differences in the persistence of contract and spot prices, heat rates at units that use coal purchased under long term contracts may respond differently to coal prices than units that rely more on spot market purchases. In fact, the estimates are similar to the baseline if we restrict the sample to units that use coal mostly purchased under long term contracts, suggesting that this is not a significant concern.

[25] A related concern is that the five-year time periods are somewhat arbitrary. We obtain very similar results using 3-year, 4-year or 10-year time periods.

identify an effect. Taken together, Table 6 provides some evidence that we underestimate the effect of a permanent change in coal prices on heat rates.

6.1.3 Coal Price Endogeneity

As noted above, coal prices may be correlated with unobserved and time-varying generation unit attributes, such as managerial quality or negotiations over coal prices. Table 7 reports specifications that address this possibility. Overall, we find that the results are robust.

Unobserved unit characteristics are likely to be correlated with utilization. Column 1 restricts the sample to units with high utilization, or more specifically, units with a median utilization rate above 0.5 across the five time periods. The estimate of α is similar to the baseline.

Plant or generation unit entry and exit could be correlated with unobserved unit characteristics. Estimating equation (3) and omitting unit fixed effects would result in biased estimates in that case. Column 2 controls for entry and exit by restricting the sample to a balanced panel. The estimate of α is close to the baseline.

Unobserved unit characteristics are likely to be correlated at the firm level. Some firms may be more efficient than others because of ownership structure, regulatory environment, or other factors. Column 3 includes parent company fixed effects, and the estimate of α is similar to the baseline. Column 4 allows for time-varying unobserved firm characteristics by including parent company-period fixed effects. The results are again similar to the baseline. Column 5 adds unit fixed effects to column 4, which results in a similar estimate to the baseline in Panel B of Table 4.

The discussion has focused on unit, plant, or firm variables that vary over time and affect heat rates, but there may also be aggregate shocks that affect utilization in ways that we do not control for in equation (3). Column 6 includes several variables measured by state and year to proxy for such shocks: generation capacity, generation, gross state product, employment, and population. All variables are included in logs, and there are three separate variables for capacity and generation: total, coal, and natural gas. Because the capacity and generation variables are not available before 1990, the regressions do not include the first time period. Adding these variables to the baseline specification does not significantly affect the estimate. Column 7 adds unit fixed effects to column 6, however, which reduces the estimate compared with Panel B of Table 4. The results are not affected if we add natural gas prices to the baseline regression (not reported).

6.1.4 Regulatory and Market Incentives

Regulatory and market incentives may affect the relationship between coal prices and heat rates. We have noted that some measures that might improve efficiency may be considered a major modification to the plant and thereby trigger a permitting process for NSR. This process may impose additional costs on plant owners and may provide a formidable barrier to making investments to improve heat rates. To examine the influence of NSR, we divide our data into two time periods. Before 1998 there was little concern about NSR enforcement proceedings, but that year EPA initiated information requests that signaled a potentially more aggressive stance. Keohane et al. (2007) note that by October of that year, the electricity trade press began reporting the possibility of EPA enforcement, and a year later, in November 1999, the Department of Justice initiated the first of a series of enforcement actions. We consider the first regime through 1998 as one in which energy efficiency investments would be considered and implemented as part of routine maintenance and would not be expected to trigger an enforcement action. During the second regime (1999–2009) we assume that energy efficiency investments would be subject to scrutiny because they might increase utilization of a plant and its emissions, and hence would be likely to trigger NSR review.

We use the two regimes to assess the interactions between NSR and heat rates. We expect heat rates to respond more to coal prices in the first regime when heat rate improvements would not have been expected to trigger NSR. We could estimate a separate α for the two regimes, expecting the estimate for the first regime to be larger in magnitude. Many other regulatory and market changes occurred between the first and second regimes, however, which could confound the analysis. Instead, we use annual data and estimate a separate α for each year of the sample; otherwise the specification is identical to the baseline in Table 4. Figure 6 plots the coefficient estimates and 95 percent confidence intervals. The figure provides only suggestive evidence for an NSR effect because it reveals a positive trend in α (heat rates becoming less sensitive to coal prices) over most of the sample period; in other words, factors other than NSR may have caused the upward trend. We have also tried estimating the same equation but rather than estimating a separate α for each year, we estimate a separate α for each regime and allow α to follow a separate linear trend in each regime. If we do not include unit fixed effects, we estimate a statistically significant and much larger α in the first regime, and the time trends are small and not significant in both regimes. This provides some further evidence that NSR reduces the responsiveness of heat rates to coal prices, but without better data we cannot reach a stronger conclusion.[26]

Section 3 suggested that privately owned firms might respond more to economic incentives. We examine the influence of ownership structure with a dummy variable interacted with log coal price. The sign of the interaction coefficient is consistent with the hypothesis that privately owned firms are more responsive, separately considering investor-owned utilities and nonutility generators, but it is small and significant at only about the 10 percent level (not reported). Similarly, we do not observe large differences across federal, state, municipal, and co-op ownership types.

Beginning with the 1992 Energy Policy Act, competition began to affect the industry in a stronger way and different types of private ownership emerged. These changes suggest that privately owned units, and in particular nonregulated privately owned units, would respond more to coal prices after around 1995. For example, Fabrizio et al. (2007) find that the transition to market-oriented environments in this period had led to the greatest efficiency gains at investor-owned plants in states that restructured their electricity markets. Our results are not affected if we control for the effect of restructuring on average heat rates by adding to the baseline specification the interaction of a set of state dummies with a post-1995 dummy. We have estimated several specifications that allow for different responses to coal prices across ownership types and generally do not find significant differences, either for units in the same period that have a different ownership type or for units with a particular ownership type across periods. The pre- and post-1995 distinction is somewhat crude, however, and the interaction between regulatory environment and coal prices is a topic for future research.

6.2 Effect of a Carbon Tax on Heat Rates

The estimation results can be used to estimate abatement costs at existing coal units from improving heat rates. We use the baseline estimates in Table 4 to calculate the percentage reduction in heat rate from a $10 per ton of CO_2 tax on coal (i.e., assuming the tax is fully passed through to delivered coal prices and holding fixed utilization). We estimate heat rate reductions of 1 to 3 percent, where the lower estimate derives from the specification with fixed effects and

[26] Whether adding pollution abatement controls triggers NSR also varies over time. This suggests examining changes in heat rates after pollution equipment is added, but unfortunately, there are not enough units that add equipment in the different regimes to test this hypothesis.

the upper estimate from the specification without fixed effects. As the previous analysis showed, this range is quite robust to a variety of alternative specifications. The range overlaps engineering estimates, although the upper end of the range is higher than the engineering estimates. For many of the robustness checks, the effect of the coal price on heat rates was even larger than in the baseline specification, which suggests that the baseline estimate may, if anything, be biased toward zero.

6.3 Effect of Coal Prices on Utilization

We use equation (4) to estimate the effect of coal prices on utilization. The dependent variable is the log utilization rate by unit and year, and the independent variables are the same as in equation (3) except that the utilization controls are omitted.

Tables 8 and 9 report the estimation results. Columns 1–3 repeat the specifications from Table 4. The coefficient on the log price of coal is interpreted as the elasticity of the utilization rate to the coal price. Across specifications, the estimated elasticity is typically around –0.4, which suggests that a 10 percent price increase would cause a 4 percent reduction in the utilization rate (from a mean utilization rate of 0.61 across all years in the sample).

The remaining columns in Table 8 and all of Table 9 document the robustness of these results. Two specifications in Table 8 are particularly noteworthy. First, if a coal price increase causes firms to reduce heat rates, we would expect the effect of an increase in coal price on utilization to decrease over longer time horizons as firms make investments to reduce their heat rates. Column 4 of Table 8 reports results that are consistent with this hypothesis; the estimated elasticities are only somewhat smaller using five-year intervals instead of annual observations. This suggests that the bias from failing to control for heat rates in equation (4) may not be large.

Second, the effect of coal prices on utilization depends on other factor prices, particularly natural gas prices. If natural gas prices are high relative to coal, a coal price increase may have a small effect on coal unit utilization because the increase would not affect the competitiveness of coal units compared with gas units. In fact, we do observe a smaller effect of coal prices on coal unit utilization when natural gas prices are high. For example, column 5 of Table 8 uses observations from the years 2001–2009, when natural gas prices were higher than in the previous decade, and the reported elasticities are much smaller than in column 1, which uses the entire sample. The results suggest that the price of natural gas relative to the price of coal affects utilization, which is confirmed in other unreported specifications (e.g., replacing the coal price in equation (5) with the ratio of the coal to natural gas price); other factors could explain the results, of course, and we treat the results with some caution.

Table 9 reports a statistically significant effect of coal prices on utilization across specifications that parallel the heat rate specifications in Table 7. Overall, we estimate an elasticity of utilization to coal prices of about –0.2 to –0.4. Because of our interest in estimating the cost-effectiveness of future policies, we prefer the estimates from the most recent time period (i.e., the specification in column 5 of Table 8, which uses observations from 2001–2009).

7 The Cost-Effectiveness of Policy Alternatives

We use a simple model of the power sector to illustrate the policy implications of the empirical estimates. One paper (Burtraw et al. 2011b) has previously represented endogenous efficiency improvements at existing coal plants within a simulation model using engineering estimates of investment opportunities and costs. This section conducts similar analysis incorporating the econometric estimates into a simple model of the electricity sector to compare the cost-effectiveness of four policies for reducing CO_2 emissions from existing coal units. We consider two forms of a technology standard, a traditional heat rate standard and a flexible standard, plus a Btu tax on coal and an emissions tax on fossil fuel. We briefly summarize these policy alternatives, then we summarize the model and report the results; Appendix 3 contains details of the model.

7.1 Policies

We characterize a traditional heat rate standard as imposing a maximum heat rate ceiling (mmBtu/MWh) requiring all facilities to achieve that standard or to retire. (The heat rate standard has a close analogue in an emissions rate standard in tons of CO_2/MWh.) Another approach might impose a requirement for a percentage improvement in heat rate in all or some portion of the fleet, or impose a different rate for different types of generators (e.g., based on firing type). Facing a traditional standard, a facility operator evaluates the net profit of the necessary improvements to enable continued operation, and α serves as a measure of the opportunity cost of those improvements. Improving heat rates would reduce fuel costs and increase utilization, as captured by β.

A flexible heat rate performance standard sets a benchmark (e.g., a uniform standard or one that varies by generator type) and allows firms that overcomply with the benchmark to transfer efficiency credits to those who fail to comply. Facilities with economic advantages make relatively greater investments and transfer efficiency credits to other facilities. Flexibility allows for equalization of the marginal opportunity costs of efficiency improvements, and greater total emissions reductions can be achieved for the same aggregate cost as under a traditional standard.

Introducing a market-determined opportunity cost for generation units is one feature a flexible performance standard has in common with a Btu tax on coal or an emissions price that might be introduced through either an emissions cap or a tax. However, a flexible performance standard is different from cap-and-trade in two important ways. First, a standard does not cap emissions. Overall emissions are able to grow with increased production, even as that production becomes more efficient. Second and following from the first, with the flexible performance standard the regulator does not explicitly allocate credits. Instead, the regulator sets a benchmark emissions rate for each unit. Credits are earned for electricity production at the benchmark rate; that is, the regulator implicitly allocates credits through the assignment of benchmark rates. Facilities surrender credits at their actual emissions rates. Facilities with emissions rates below the benchmark earn surplus credits with each unit of generation, while facilities with rates above the benchmark earn a deficit that would be filled with transfers from other facilities. Hence, the flexible performance standard can be understood to encompass two instruments in one policy: it imposes an opportunity cost on heat rate, providing an incentive for heat rate improvements, and it provides an output subsidy equivalent to the value of credits earned for each unit of electricity generation.[27] Thus, the flexible standard introduces a sort of rebound effect, in which units that overcomply have an incentive to increase output.

The consequence is that a flexible performance standard is likely to result in greater utilization of the regulated facilities than under a Btu tax, emissions cap-and-trade, or an emissions tax, and conceivably greater utilization than in the absence of regulation. Under a Btu tax or an emissions price, one way to reduce emissions is to reduce utilization, but this would not necessarily lead to a reduction in the heat rate, which is the target of a standard. Similarly, a reduction in utilization would not contribute to meeting a traditional (inflexible) performance standard. Further, the output subsidy implicit in the flexible performance standard provides an incentive to increase utilization and should lead to greater total utilization of the regulated facilities.

[27] One can view this as equivalent to an emissions trading program where the cap is determined endogenously as the product of the benchmark emissions rate and output, and allocation is performed on the basis of output.

We measure the rebound effect as the change in system level emissions due to the change in utilization that arises from heat rate improvements at the generating units. To estimate the change in emissions in the absence of the rebound effect we evaluate the new equilibrium with utilization determined by the baseline heat rates. See Appendix 4 for details.

7.2 Model

Our static model of the electricity market contains a representation of all coal-fired power plants in operation in 2009 organized into 22 regions. Each firm in the market owns a single unit, as indexed by i in equation (1), and sells electricity into a competitive wholesale market. There is perfect substitutability among facilities within a region but no transmission between regions. Each region has a backstop natural gas combined-cycle power plant that provides residual generation necessary to meet a fixed level of demand. The operating costs of the natural gas plants vary by region, based on empirical information about variable operations and maintenance costs, and the delivered cost of natural gas determines the price of wholesale power in the region and the revenue to coal plants. Hence, gas units do not earn profits. Profits for coal plants come from the difference between the wholesale power price and the sum of operating costs and fuel costs.

The analysis focuses on the optimal choice of heat rate conditional on the capacity and exogenous variables. In equation (1) the cost of choosing heat rate is $c(h_i)K_i$, and thus the heat rate cost scales linearly with the unit's capacity. The marginal cost of generating electricity includes fuel costs, which equal the average price of coal in each region multiplied by the heat rate ($p^f h$), plus average regional nonfuel operations and maintenance costs, m. To simplify the expressions, we normalize the CO_2 emissions rate to equal 0.1 ton of CO_2 per mmBtu of heat input, thereby making a heat rate standard equivalent to an emissions rate standard. We adopt constant elasticity of substitution functional forms for the cost of choosing heat rate and utilization, and set the elasticity parameters, $\alpha = -0.05$ and $\beta = -0.2$, based on the regression of heat rate and utilization on coal prices. We solve for the constant θ_i, describing each unit's type, based on its observed utilization rate. The profit function is modified appropriately for each policy, and we solve the model to estimate changes in heat rates, emissions, and profits (see Appendix 3).

7.3 Policy Effects on Efficiency Investments and Fuel Switching

The traditional standard is calibrated to achieve a 1 percent reduction in heat rate, and the other policies are calibrated to achieve the same emissions reductions. Under the traditional standard, each unit must achieve a heat rate of 10.78 mmBtu/MWh or reduce its heat rate by 10 percent, whichever results in a higher heat rate. By setting the average heat rate reduction to 1 percent and imposing a cap on heat rate reductions of 10 percent, the changes in heat rates that occur in the simulations are of similar magnitude to the changes observed in the data. In the baseline 22 percent of units have heat rates above this standard. Achieving the standard results in a 0.88 percent reduction in emissions across coal and gas units, illustrating that the rebound effect erodes 13 percent of the emissions reduction associated with efficiency improvements. Coal generation increases of 0.19 percent are concentrated entirely at facilities that have initial heat rates above the standard. These results are presented in Table 10.

To achieve a 0.88 percent reduction in emissions under the flexible standard requires an emissions rate benchmark of 10.26 mmBtu/MWh, and a price for a tradable performance standard credit of $0.42/mmBtu. The rebound effect due to the increase in utilization erodes 15.3 percent of emissions reductions that would otherwise result from the heat rate improvement, illustrating the important role of the output subsidy under a tradable performance standard. Heat rate improvements occur across the distribution of coal plants.

Under the taxes, the emissions reductions are achieved with an emissions tax of $1.126 per metric ton CO_2 and a coal Btu tax of $0.115 per mmBtu. As expected, the coal tax requires a higher tax rate (after converting to a common metric) than the more broadly based emissions tax. Under the taxes, the rebound effect is much smaller, about 2 percent in each case. However, it is noteworthy that the rebound is slightly greater under the emissions tax because it applies to natural gas as well as coal. Hence, the change in relative prices is less under the emissions tax than under the coal Btu tax.

Although calibrated to achieve comparable emissions reductions as the inflexible standard, the flexible standard also yields a nearly identical decline in heat rates. In contrast, the emissions tax yields a reduction in heat rates of 0.18 percent, and the carbon Btu tax yields a reduction of 0.16 percent. The standards lead to an order of magnitude greater annual investment in heat rate improvements than the taxes, with the inflexible standard resulting in about twice the investment of the flexible standard.[28] Consequently the standards result in an increase in coal generation whereas the taxes lead to an increase in natural gas generation. In sum, we find these policies are relatively most effective with respect to their specific targets. The relatively narrowly

[28] This result differs from Burtraw et al. (2011b), where retirement of existing facilities can occur.

focused performance standards lead to greater improvements in energy efficiency and less fuel switching. The price-based policies are effective across all eligible channels to achieve comparable emissions reductions.[29]

We have conducted sensitivity analysis using a larger utilization elasticity ($\beta = -0.4$ instead of -0.2) and for more stringent policies (using heat rate improvements of 2 or 3 percent as the benchmark instead of 1 percent). For the higher elasticity, to achieve a given emissions reduction with the standards there is more investment (compared to the low elasticity simulation) because of the larger rebound effect. The measures reported in Table 10 change roughly linearly with the stringency of the policies, although the rebound effect for the standards grows only modestly. Across the alternative simulations, the conclusions are qualitatively similar to those from the simulation reported in Table 10 (results are available upon request).

8 Conclusions

Currently, the Clean Air Act is the most important federal policy for addressing climate change. EPA is preparing to regulate greenhouse gas emissions from existing stationary sources, the most important of which are coal-fired electricity steam boilers. Engineering case studies have identified possible reductions in emissions through efficiency improvements at zero or moderate cost that could amount to 1.6 percent of total U.S. emissions in 2009. However, a substantial literature raises doubts that widespread and unrealized cost-effective efficiency opportunities exist. Heretofore, empirical information was lacking about the actual magnitude and cost of these potential efficiency improvements across the fleet of existing generating units. This information should be central to rulemakings under the CAA, which in this case will rely on technical estimates of potential opportunities as well as costs for the determination of a standard for these facilities. Furthermore, this information should be important to the characterization of other policy alternatives, such as legislative proposals for cap-and-trade or emissions taxes. For example, federal agency analysis of proposed cap-and-trade legislation (HR 2454) that passed the House of Representatives in 2009 had no information about potential efficiency

[29] Welfare comparisons across the policies are not strictly valid because we assume natural gas supply is perfectly elastic and consumer demand is perfectly inelastic. Electricity prices and consumer surplus are affected only under the emissions tax which is applied to natural gas as well as coal emissions. Within this framework, the inflexible standard is about three times more costly than the taxes. Firms optimize against the taxes and abate in ways that is more expensive under the flexible standard; the fuel switching that occurs under the taxes is very expensive because of the assumption that natural gas generators earn zero profits.

improvements at existing coal boilers, and consequently it may have overestimated the abatement cost for the economy as a whole (EIA 2009). Moreover, engineering estimates of potential improvements in other existing stationary sources suggest potential emissions reductions that add up to more than 6 percent of U.S. emissions, without accounting for fuel switching (Burtraw et al. 2011a). Analysis similar to the one in this paper could possibly verify or refute those potential opportunities.

We compile a unique data set covering about 97 percent of U.S. coal-fired units over 25 years of operation and use the data to estimate the opportunities to reduce emissions rates by improving the efficiency of these plants. We note that the introduction of a performance standard will impose opportunity costs similar to costs associated with fuel use; hence, the effective price of fuel will change in response to the regulation.

We find strong evidence that heat rates (a measure of efficiency and a proxy for emissions) respond to changes in fuel prices. For example, a change in coal prices commensurate with a $10 tax on CO_2 emissions would stimulate a 1 to 3 percent reduction in heat rates and emissions rates. This range of costs encompasses the estimates suggested in the engineering literature; indeed it includes the possibility of somewhat lower costs than have been suggested.

An important consideration in whether these efficiency improvements lead to emissions reductions is the degree to which generating units respond to improvements in heat rates by increasing their utilization. If they do, one would observe a rebound in emissions that would erode some of the emissions reductions that would otherwise occur. In fact, we find a significant effect of coal prices on utilization. A 10 percent coal price increase would decrease utilization 2-4 percent (holding fixed heat rates).

We evaluate these econometric estimates in a simulation model with inelastic demand and infinitely elastic fuel supply. Natural gas generation is used to meet residual demand, and we solve for changes in heat rate and utilization at coal facilities under a variety of policy scenarios. We find that a performance standard leads to substantially greater investment in efficiency improvements than taxes (or other policies that set an emissions price, such as cap-and-trade), which allow for broader compliance options, including fuel switching. This outcome is consistent with the theory that broad-based, incentive-based policies should be more efficient than performance standards, even after accounting for the opportunity for efficiency improvements. We also find the rebound effect to be 11 to 13 percent, which reduces the emissions savings by roughly the same percentage. The rebound effect under the taxes is an order of magnitude less than under the performance standards.

We have noted a few possible directions for future work. Because the econometric model is static, we do not allow for plant retirements in the simulations. Introducing dynamics would enable an evaluation of more aggressive performance standards than those considered here.

We have provided some suggestive evidence that the economic and regulatory environments affect the relationship between fuel prices and heat rates. Future work could investigate further the effect of competition, NSR, and other policies on the adoption of energy efficiency technology.

In conclusion, substantial long-term reductions in GHG emissions from the power sector will require greater use of nonemitting sources (renewables, nuclear), lower-emitting sources (natural gas), or postcombustion control of carbon. However, we find evidence that there exist opportunities to reduce emissions at existing facilities at low cost in the short run. These reductions could contribute importantly to meeting international commitments as articulated in the Copenhagen Accord.

References

Beer, J. M., 2007. High Efficiency Electric Power Generation: The Environmental Role. Progress in Energy and Combustion Science 33: 107-134.

Borenstein, S., J. B. Bushnell and F. A. Wolak, 2002. Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market. American Economic Review 92(5): 1376-1405.

Boyd, G. A. and J. D. McClelland, 1999. The Impact of Environmental Constraints on Productivity Improvement in Integrated Paper Plants. Journal of Environmental Economics and Management 38: 121–142.

Burtraw, D., A. Fraas and N. Richardson, 2011a. Greenhouse Gas Regulations under the Clean Air Act: A Guide for Economists. Review of Environmental Economics and Policy 5(2): 293-313.

Burtraw, D., M. Woerman and A. Paul, 2011b. Retail Electricity Price Savings from Compliance Flexibility in Greenhouse Standards for Stationary Sources. Energy Policy 10.1016/j.enpol.2011.11.036.

Bushnell, J. B. and C. Wolfram, 2005. Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants. Center for the Study of Energy Markets, University of California Energy Institute, UC Berkeley, CSEM WP 140.

Bushnell, J. and C. Wolfram, 2010. Enforcement of Vintage Differentiated Regulations: The Case of New Source Review. Iowa State University Department of Economics Working Paper No. 10027.

Bushnell, J. B., E. Mansur and C. Saravia, 2008. Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured US Electricity Markets. American Economic Review 98(1): 237-266.

Busse, M. R. and N. O. Keohane, 2004. Market Effects of Environmental Regulation: Coal, Railroads and the 1990 Clean Air Act. CSEM WP 137, Berkeley, CA, Center for the Study of Energy Markets, University of California Energy Institute, UC Berkeley.

Department of Energy (DOE) and National Energy Technololgy Laboratory (NETL), 2009. Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants. Techical Workshop Report, Rosemont, IL.

Department of Energy (DOE) and National Energy Technololgy Laboratory (NETL), 2010. Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States. Baltimore, MD.

Ellerman, A. D., 1998. Note on the Seemingly Indefinite Extension of Power Plant Lives, a Panel Contribution. Energy Journal 19(2): 129-132.

Energy Information Administration (EIA), 2009. Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009. SR/OIAF/2009-05, Washington, DC, Energy Information Administration.

Energy Information Administration (EIA), 2011. Annual Energy Outlook 2011. DIE.EUA-0383(2011), Washington DC.

Environmental Protection Agency (EPA), 2008. Technical Support Document for the Advance Notice of Proposed Rulemaning for Greenhouse Gases: Stationary Sources. Washington DC.

Fabrizio, K. R., N. L. Rose and C. D. Wolfram, 2007. Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency. American Economic Review 97(4): 1250-1277.

Fischlein, M., T. M. Smith and E. J. Wilson, 2009. Carbon Emissions and Management Scenarios for Consumer-Owned Utilities. Environmental Science and Policy 12: 778-790.

Fleishman, R., R. Alexander, S. Bretshneider and D. Popp, 2009. Does Regulation Stimulate Productivity: The Effect of Air Quality Policies on the Efficiency of US Power Plants. Energy Policy 37(11): 4574-4582.

Hendricks, W. E., 1975. The Effect of Regulation on Collective Bargaining in Electric Utilities. Bell Journal of Economics 6(2): 451-465.

Joskow, P. L., 1974. Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation. Journal of Law and Economics 17(2): 291-327.

Joskow, P. L., 1997. Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector. Journal of Economic Perspectives 11(3): 119-138.

Keohane, N., E. T. Mansur and A. Voynov, 2007. Averting Regulatory Enforcement: Evidence from New Source Review. NBER Working Paper Series. Working Paper 13512, Cambridge, MA, National Bureau of Economic Research.

Knittel, C. R., 2002. Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry. Review of Economics and Statistics 84: 530-540.

Linn, J., 2008. Energy Prices and the Adoption of Energy-Saving Technology. The Economic Journal 118: 1986-2012.

Metcalf, G. E. and K. A. Hassett, 1999. Measuring the Energy Savings From Home Improvement Investments: Evidence from Monthly Billing Data. Review of Economics and Statistics 81: 516-28.

Murty, M., S. Kumar and K. K. Dhavala, 2007. Measuring Environmental Efficiency of Industry: A Case Study of Thermal Power Generation in India. Environmental and Resource Economics 38(1): 31-50.

Olley, S. and A. Pakes, 1996. The Dynamics of Productivity in the Telecommunications Equipment Industry. Econometrica 64(6): 1263-1298.

Richardson, N., A. Fraas and D. Burtraw, 2011. Greenhouse Gas Regulation under the Clean Air Act: Structure, Effects, and Implications of a Knowable Pathway. Environmental Law Reporter 41: 10098-10120.

Rosen , M. A. and I. Dincer, 2003. Survey of Thermodynamic Methods to Improve the Efficiency of Coal-Fired Electricity Generation. Proceedings of the Institution of Mechanical Engineers, Part A: Journal of Power and Energy 217: 63-73.

Sargent & Lundy, L.L.C. 2009. Coal-Fired Power Plant Heat Rate Reductions.

Shadbegian, R. J. and W. B. Gray, 2006. Assessing Multidimensional Performance: Environmental and Economic Outcomes. Journal of Productivity Analysis 26: 213-234.

Stavins, R. N., 2006. Vintage-Differentiated Environmental Regulation. Stanford Environmental Law Journal 25(1): 29-63.

Appendix 1: Determinants of Heat Rates

This section provides a more detailed review of the literature on heat rates than is found in the main text.

Cogeneration

Cogenerators, or combined heat and power generators, are facilities that recycle heat to produce both electricity and useful thermal energy. The additional energy captured is typically used for manufacturing processes or central heating. Cogeneration is regarded as a highly efficient technology for many applications, yet traditional heat rate calculations are misleading because heat input per unit of generation does not account for the useful thermal output. Furthermore, the manager of a cogeneration facility can adjust the proportion of heat versus electricity based on the customers' needs, heating fuel and electricity prices, and regulation.

Utilization

As noted, more efficient plants typically are used more heavily. Moreover, higher utilization tends to reduce heat rates. Conversely, less efficient plants are available to be ramped up and down more frequently, which requires additional fuel input because the temperature in the boiler fluctuates, and which further amplifies their relatively high heat rates.

Pollution Controls

Because fossil fuel–fired electric power plants emit a variety of pollutants, they are subject to numerous environmental regulations at the local, state, and federal levels. Regulations exist for sulfur dioxide, nitrogen oxides, particulate matter, mercury, and acid gases. Reducing emissions to comply with these regulations can affect efficiency. Fleishman et al. (2009) found that implementing pollution controls may "crowd out" investment in productivity improvements if firms face capital constraints. On the other hand, several papers have studied the trade-offs between pollution controls and productivity of a plant in the power sector as well as other manufacturing industries that face similar environmental regulations. These studies conclude that inputs and pollution can be reduced without sacrificing productivity (Boyd and McClelland 1999; Shadbegian and Gray 2006; Murty et al. 2007).

Fuel Choice

Coal-fired power plants generally use one or a combination of three types of coal: bituminous, subbituminous, and lignite. The choice depends on relative prices and characteristics. Coal types vary in heat, ash, and sulfur per pound and are priced accordingly; higher heat content justifies a higher price. Because of regulations on emissions of sulfur dioxide, low-sulfur coal is also priced higher. Efficiency may also increase with low-sulfur coal as it negates the need for energy-intensive postcombustion pollution control (scrubbers). Transportation costs also have a large effect on delivered coal prices. Because certain coal types are more common to specific regions of the country, location may influence a plant's choice of fuel.

Regulation and Incentives

Regulation may also affect efficiency. Coal-fired power plants have demonstrated useful lives that are much longer than many anticipated when they were originally constructed. Ellerman (1998) notes that these life extensions are due to new electronics in the boilers and other features that improve plant efficiency and longevity. However, some measures that might improve efficiency and reduce CO_2 emissions may be considered a major modification to the plant and thereby trigger New Source Review (NSR) for other pollutants under the Clean Air Act. Permitting under NSR requires a site-specific and technology-based review of the control technology proposed by the source and a demonstration that the plant will not create or exacerbate violations of air quality standards in the surrounding area (Richardson et al. 2011). Consequently, NSR can raise the cost of efficiency improvements by requiring the installation of pollution abatement equipment.

At least three papers have studied the effect of NSR on plant operations. Bushnell and Wolfram (2010) and Stavins (2006) found that NSR causes older plants—and therefore potentially less efficient plants—to operate more. Also, anecdotal evidence suggests that plant owners have deferred cost-effective improvements that might initiate a permitting process (Keohane et al. 2007).

Other regulatory practices may insulate plant operators from the cost of continuing the inefficient operation of existing plants. For example, state-level fuel cost adjustment clauses allow firms to pass fuel costs through to retail electricity ratepayers (DOE/NETL 2010). These provisions are common in regions of the country that operate under cost-of-service regulation, including regulated investor-owned utilities and publicly owned utilities. Such provisions are intended to remove from shareholders the risk from fluctuations in fuel prices. Depending on how they are structured, fuel cost pass-through provisions could reduce the incentive to make efficiency improvements if cost savings would be offset by lower retail prices.

Knittel (2002) examined various efficiency incentive programs run by electric utilities. Programs for generator efficiency modifications improve efficiency more than other types of programs. Automatic fuel cost pass-through, in which an increase in fuel cost passes directly to the consumer without a rate hearing, reduces plant efficiency.

Since 1978, the electricity sector has been restructured gradually so that electricity generators increasingly operate in competitive environments. Many studies have focused on the effects of electricity restructuring in the United States. Much of the literature has examined the effect of restructuring on electricity prices, market performance, or market power (Joskow 1997; Borenstein et al. 2002; Bushnell et al. 2008), but several have considered the relationship between regulation and technical efficiency. Joskow (1974) and Hendricks (1975) showed that regulatory structures can provide significant incentives for public utilities to reduce costs. As noted previously, Fabrizio et al. (2007) found that restructuring reduces employment and fuel consumption at firms throughout the affected wholesale power markets, including those that were not restructured.

Ownership

The firm's ownership structure may affect efficiency improvements. Ownership types include private utilities (investor owned or privately owned), public utilities (municipal, state, or federal), and cooperatives. Because of different objective functions, degrees of principal-agent conflicts, and exposure to market forces or other factors, different ownership types may not place the same emphasis on improving efficiency (all else equal).

Ownership structure is also closely related to the regulatory environment. Following deregulation in many states, privately owned utilities were required or encouraged to divest generation assets and act solely as transmitters and distributers of electricity. Publicly owned utilities were largely unaffected by this trend. States that remained under regulation tended to remain dominated by vertically integrated utilities, although nonutilities may still participate in the wholesale market. Bushnell and Wolfram (2005) report greater efficiency at units that were divested from utility to nonutility; however, similar improvements were observed at nondivested units that were subject to other efficiency incentives. Thus, restructuring or changing regulatory incentives can encourage efficiency investments. On the other hand, Fischlein et al. (2009) find large differences in the efficiency of investor-owned utilities as opposed to municipalities, rural cooperatives, or district power providers. A possible explanation is that publicly owned companies might be insulated from market-driven incentives to improve efficiency, but this is widely disputed, and publicly owned companies have broader performance criteria than do privately owned firms that may affect efficiency measures.

Appendix 2: Data

Data Sources

The main data source, which defines our universe of units, is the Energy Information Administration's form 767 (EIA-767) and successor forms. This government-mandated survey collects boiler- and generator-level information from fossil fuel–fired electric power plants with nameplate capacity greater than 10 megawatts (MW). All units that fire any coal during each year were included in the panel data set.

The EIA-767 provides most of the variables of interest, including monthly heat input, monthly generation, boiler vintage, boiler technology, nameplate capacity, location, and fuel type. Other data sources provide additional variables or fill in missing observations. EIA forms 860 and 861 provided information on ownership and generator characteristics. EPA's National Electric Energy Data System (NEEDS) includes variables for the existence and vintage of environmental controls at individual units.

Issues with the Data

Coverage

The panel data set covers the years 1985 through 2009. However, the sample does not include the years 2006 and 2007 because EIA discontinued form 767 after 2005 and did not collect unit-specific data on the successor forms until 2008.

Another issue that affects coverage is the change in reporting requirements for EIA-767 over time. Prior to 2001, only regulated plants with nameplate capacity greater than 10 MW were required to report. Between 2001 and 2003, the survey expanded to include unregulated plants, but they reported generation only if nameplate capacity exceeded 100 MW. After 2003, all plants greater than 10 MW—both regulated and unregulated—reported all variables.

Heat Rate Adjustments

Because the annual heat rates are calculated using sums of monthly data, measured annual heat rates can be highly influenced by missing data or unreasonably high or low heat rates in a single month. These "outlier" heat rates are not possible according to engineering estimates and usually arise because of a problem in the data, such as negative generation, missing heat input or generation, or reporting error.[30] Often, these outlier monthly heat rates contributed to a misleading figure for the annual heat rate.

To address this issue and avoid dropping full years of data, we adjust the annual heat rates by dropping months that contain negative generation, missing data, or outlier heat rates. We define an outlier monthly heat rate as being more than two standard deviations above or below the monthly mean across all years for the unit. This ensures that only heat rates outside normal engineering limits were dropped. The annual heat rates are calculated using the remaining months.

Boiler-to-Generator Correspondence

The last constraint on the data stems from the boiler-to-generator correspondence at individual plants. Heat input is measured at the boiler level, whereas generation is measured at the generator level. In most cases, a single boiler is connected to a single generator, and calculating heat rate is straightforward. When many boilers connect to a single generator, we aggregate heat input across boilers. Other characteristics of that group of boilers are aggregated or averaged. Similarly, when many generators are linked with a single boiler, we aggregate generation to a single generator. This technique allows us to calculate heat rates for the units in our sample that do not have a one-to-one boiler-to-generator correspondence. However, the trade-off is that for some units, the vintage, size, technology, and fuel represent an average or dominant characteristic of the group rather than an actual unit. In general, the configurations with multiple boilers or generators account for less than 4 percent of the observations.[31] Omitting these units in the estimation does not affect the results.

Appendix 3: Simulation Model

We use a model of coal unit operation to simulate the effects on profits and emissions of four policies: a traditional emissions rate standard, a flexible emissions rate standard, a coal

[30] Negative generation occurs when the plant generates electricity for use at the plant but does not supply any electricity to end users.

[31] The higher percentage in 2004 results from the different reporting requirements across years. Prior to 2004, smaller or unregulated units did not report generation and these units are less likely to have a one-to-one correspondence.

emissions tax (or equivalently a cap-and-trade program that introduces a comparable price on CO_2), and a fossil fuel emissions tax. The effects on profits and emissions depend on how the policies affect generator utilization and heat rates; we first illustrate these effects using the model's first-order conditions. Then, the model is calibrated using the empirical estimates from Section 6 and using the coal prices and heat rates observed in our sample in 2009.

Profit Maximization in the Absence of CO_2 Regulation

We begin with a static model of the electricity market that contains a large number of coal electricity generation units, each of which maximizes profits, taking prices as given. We first consider the case in which there is no CO_2 regulation. Each firm in the market owns a unit, which we index by i. The firm sells electricity into a competitive wholesale market in which there is a backstop natural gas generator that supplies electricity at a constant marginal cost. Let p_r equal the price of electricity in region r in dollars per MWh and p_r^f equal the delivered price of coal in dollars per mmBtu. The firm has already chosen the capacity of the unit, K_i, and the analysis focuses on the optimal choice of heat rate conditional on the capacity and exogenous variables.

The cost of choosing heat rate h_i is $c(h_i)K_i$, where $c' < 0$ and $c'' > 0$. Thus, the heat rate cost scales linearly with the unit's capacity.

The marginal cost of generating electricity includes fuel costs, which equal the price of coal multiplied by the heat rate $\left(p_r^f h_i\right)$, plus nonfuel operations and maintenance costs, m_r, which is the capacity-weighted average for coal units in the region.

The unit's generation output is equal to its capacity multiplied by the capacity utilization rate, u. The utilization rate is a function of fuel costs and unit type: $u_i = u\left(p_r^f h_i, \theta_i\right)$, where θ_i is a unit-specific constant. For simplicity we ignore operations and maintenance costs in the utilization decision. Utilization is decreasing in fuel costs because a unit with higher marginal costs is less competitive with other generation units in the market. Thus, a unit with a higher heat rate produces less electricity. The constant θ_i is proportional to the quality of the unit, and it may reflect unit-specific characteristics such as managerial quality or its idiosyncratic economic value, given its location in the transmission system. Units with a higher value of θ_i produce more electricity.

The firm maximizes profits by choosing the heat rate. The profit maximization problem is

$$\max_{h_i}\left(p_r - m_r - p_r^f h_i\right)u\left(p_r^f h_i, \theta_i\right)K_i - c(h_i)K_i \tag{A5}$$

The first-order condition for the heat rate is

$$\frac{\partial u\left(p_r^f h_i, \theta_i\right)}{\partial h}\left(p_r - m_r - p_r^f h_i\right) - p_r^f u\left(p_r^f h_i, \theta_i\right) - c'\left(h_i\right) = 0 \qquad \text{(A6)}$$

If utilization is relatively insensitive to heat rate and coal prices (consistent with the empirical evidence), an increase in the price of coal reduces heat rates. The net effect of the coal price increase on utilization is ambiguous, depending on whether the decrease in heat rate more than offsets the increase in the coal price.

Traditional Heat Rate Standard

Suppose the government mandates a heat rate ceiling such that all units have to achieve this standard through efficiency investments. In our model, units will respond in one of two ways. Units with an initial heat rate at or below the standard ($h_i \le \hat{h}_i$) will make no change (note that the standard could be unit-specific). Units with an initial heat rate above the standard ($h_i > \hat{h}_i$) will make investments to lower their heat rates to equal the standard. Units with an initial heat rate above the standard that choose to make an investment incur a cost of reaching the standard: $c\left(\hat{h}_i\right) - c\left(h_i\right)$. These units are expected to increase utilization to capitalize on their lower heat rates: $u\left(p_r^f \hat{h}_i, \theta_i\right)$.

To simplify the expressions, we normalize the CO_2 emissions rate to equal 0.1 ton of CO_2 per mmBtu of heat input. Because the emissions rate is normalized to 0.1, the heat rate standard is synonymous with an emissions rate standard. The endogenous decisions of each unit under the traditional standard will determine the aggregate change in emissions. The total change in emissions is held constant for comparison with the other policies.

Flexible Heat Rate Standard

Instead of imposing a traditional heat rate standard, suppose the government sets a heat rate standard of $\bar{h}$. If the unit exceeds the standard, it generates credits equal to the difference between its heat rate and the standard, multiplied by the electricity it generates. The profit maximization problem is

$$\max_{h_i}\left(p_r - m_r - p_r^f h_i\right) u\left[p_r^f h_i + P\left(h_i - \bar{h}\right), \theta_i\right] K_i - P\left(h_i - \bar{h}\right) K_i u[p_r^f h_i + P\left(h_i - \bar{h}\right), \theta_i] - c(h_i) K_i \qquad \text{(A7)}$$

where the price of the credits is P, which is exogenous to the firm. The first-order condition is

$$\frac{\partial u[p_r^f h_i + P\left(h_i - \bar{h}\right), \theta_i]}{\partial h}\left(p_r - m_r - p_r^f h_i - P(h_i - \bar{h})\right) - (p_r^f + P)u[p_r^f h_i + P\left(h_i - \bar{h}\right), \theta_i] - c'\left(h_i\right) = 0 \quad \text{(A8)}$$

To achieve a comparable level of emissions when comparing policies, we use the emissions change under the flexible heat rate standard as the emissions target to be achieved by endogenously solving for the value of regulatory instruments with the other policies.

Coal Btu Tax

Suppose instead the government imposes a tax on coal heat input, or equivalently a tax on coal Btu. This results in the following profit maximization problem:

$$\max_{h_i}\left(p_r - m_r - (p_r^f + \tau)h_i\right)u\left(p_r^f h_i + \tau h_i, \theta_i\right)K_i - c(h_i)K_i \quad \text{(A9)}$$

The first-order condition for the heat rate is

$$\frac{\partial u[\left(p^f + \tau\right)h_i, \theta_i]}{\partial h}\left(p_r - m_r - (p^f + \tau)h_i\right) - \left(p^f + \tau\right)u[\left(p^f + \tau\right)h_i, \theta_i] - c'\left(h_i\right) = 0 \quad \text{(A10)}$$

A comparison of equations (A6) in the absence of carbon policy and (A10) shows that the Btu tax affects the firm's heat rate and utilization the same as an increase in the price of coal. Consequently, imposing the Btu tax reduces heat rates and has an ambiguous effect on utilization. Comparing equation (A10) with equation (A8) for the flexible heat rate standard, we observe that the Btu tax reduces utilization (i.e., holding the heat rate constant), whereas the emissions rate standard increases or decreases utilization, depending on whether the heat rate is lower than or greater than the standard. This comparison demonstrates the importance of the rebound effect.

CO_2 Emissions Tax

An emissions tax on all fossil fuel is modeled similarly to the Btu tax on coal because the CO_2 emissions rate is normalized to equal 0.1 ton of CO_2 per mmBtu of heat input. However, the emissions tax is applied to the backstop natural gas technology as well as to coal generation, and consequently it increases the wholesale price of electricity as well as the coal price.

Calibrating the Model

We can use equations (A6), (A8), and (A10) to assess the effect of each policy on heat rates and utilization. To do so, we must choose functional forms for the heat rate cost function

$c(h)$ and for the utilization function $u(p_r^f h_i, \theta)$. We assume that both functions can be characterized by a constant elasticity of substitution:

$$c\left(h_i, \gamma_i\right) = -\gamma_i \frac{\alpha}{1+\alpha} h_i^{\frac{1+\alpha}{\alpha}} \quad \text{(A11)}$$

$$u\left(p_r^f h_i, \theta_i\right) = \theta_i (p_r^f h_i)^{\beta} \quad \text{(A12)}$$

where $\alpha, \beta < 0$ and $\gamma > 0$. The parameters α and β are estimated from the regression of heat rate and utilization on coal prices. The constant θ_i is recovered from the unit's observed utilization rate, and γ_i is calculated from the first-order condition in the unregulated case. We make two remarks about the functional form assumption of the utilization and heat rate cost functions. First, the assumptions are consistent with the estimating equations in Section 5. The second observation is that the unobserved quality θ_i enters multiplicatively.

The cost of each policy to regulated units depends on (1) the cost of changing heat rates and (2) the change in operating profits (i.e., the difference between the electricity price and marginal costs multiplied by generation). In other words, we estimate the short-run costs of the policies, in the absence of entry, exit, or changes in capacity.

The effectiveness of each policy is equal to the change in electricity sector CO_2 emissions. Therefore, we need to characterize the effect of each policy on the rest of the sector. We make the simplifying assumptions that the policies do not affect total electricity generation in the system, and that any changes in total coal generation are offset by natural gas generation. The natural gas emissions rate is assumed to be 0.05 tons of CO_2 per mmBtu. The electricity price varies by region and is determined by the marginal cost of a natural gas combined-cycle unit; hence, the analysis does not include the profits of natural gas generators. Their marginal cost depends on the average heat rate, delivered price of natural gas, and operations and maintenance costs for combined-cycle units in the region. The national average marginal cost is $38/MWh.

We use the first-order conditions above to solve for the heat rate of each unit under each policy. We then use the utilization function to estimate generation for each unit. Finally, we calculate the change in total coal operating profits and emissions by summing across coal-fired generation units and calculating the change in natural gas generation.

Appendix 4: Measuring the Rebound Effect

We characterize the rebound effect as the change in emissions due to the change in utilization in response solely to changes in heat rate improvements at the generating units. Performance standards or taxes change the relative marginal generation costs of units. The standards lead directly to heat rate improvements and the taxes change the relative effective fuel prices between coal and natural gas, which in turn lead to heat rate improvements. To estimate the change in emissions in the absence of the rebound effect, we evaluate the new equilibrium with utilization determined by the baseline heat rates. Against this estimate, we measure the rebound effect as the further change that occurs when utilization is based on the improved heat rates.

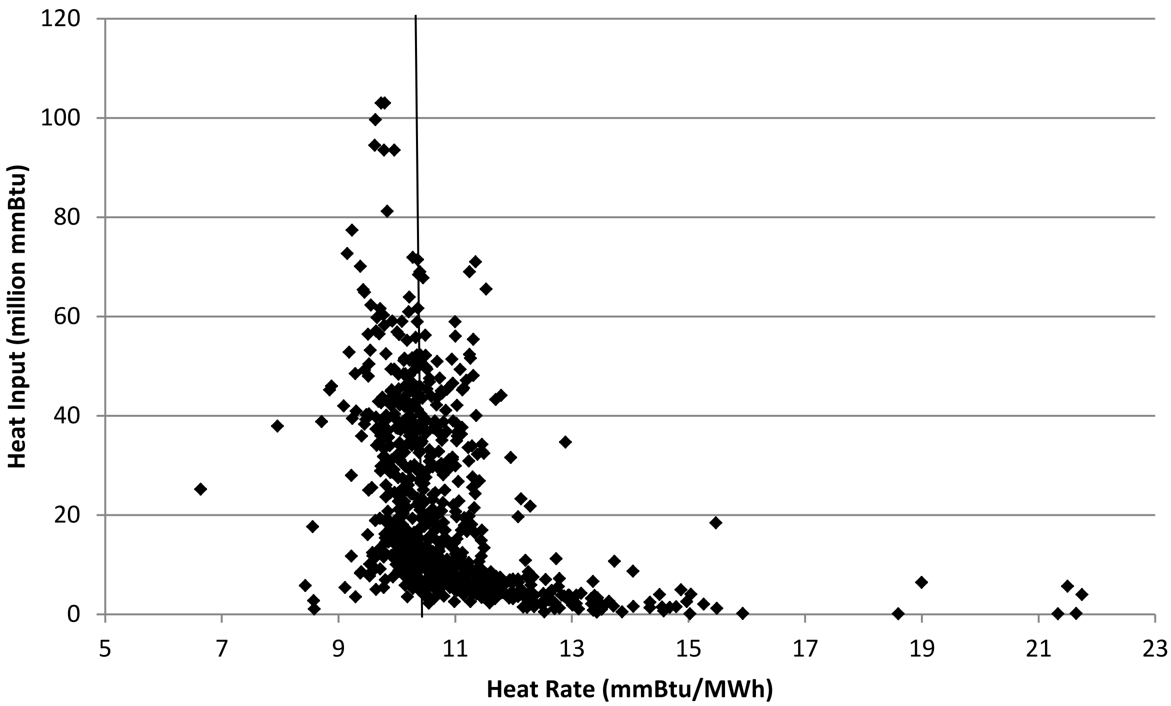
To simplify notation, let $j,k=\{0,1\}$ denote the baseline indicated by zero and the new equilibrium indicated by 1. We suppress notation for the individual unit type and describe utilization as a function of only the price of fuel and the heat rate: $u_{jk}=u\left(p_j^f h_k\right)$. We describe emissions from coal-fired units as a function of utilization and the heat rate: $e_c\left(u_{jk},h_k\right)$. For example, we represent emissions at the new effective fuel prices and heat rates but based on utilization that would occur at the new prices and the old heat rate as $e_c\left(u_{10},h_1\right)$. Utilization of natural gas units adjusts to the change in utilization of coal units to satisfy residual demand, and emissions from natural gas units is represented by $e_g\left(u_{jk}\right)$. With this notation, we measure the rebound effect as the difference between emissions that would occur if utilization depended on the baseline heat rate and the actual emissions, normalized by the former measure:

$$\begin{aligned} R &= \frac{\left\{e_c\left(u_{10},h_1\right)+e_g\left(u_{10}\right)-e_c\left(u_{00},h_0\right)-e_g\left(u_{00}\right)\right\}-\left\{e_c\left(u_{11},h_1\right)+e_g\left(u_{11}\right)-e_c\left(u_{00},h_0\right)-e_g\left(u_{00}\right)\right\}}{\left\{e_c\left(u_{10},h_1\right)+e_g\left(u_{10}\right)-e_c\left(u_{00},h_0\right)-e_g\left(u_{00}\right)\right\}} \\ &= \frac{e_c\left(u_{10},h_1\right)+e_g\left(u_{10}\right)-e_c\left(u_{11},h_1\right)-e_g\left(u_{11}\right)}{e_c\left(u_{10},h_1\right)+e_g\left(u_{10}\right)-e_c\left(u_{00},h_0\right)-e_g\left(u_{00}\right)} \end{aligned} \tag{A13}$$

Figures and Tables

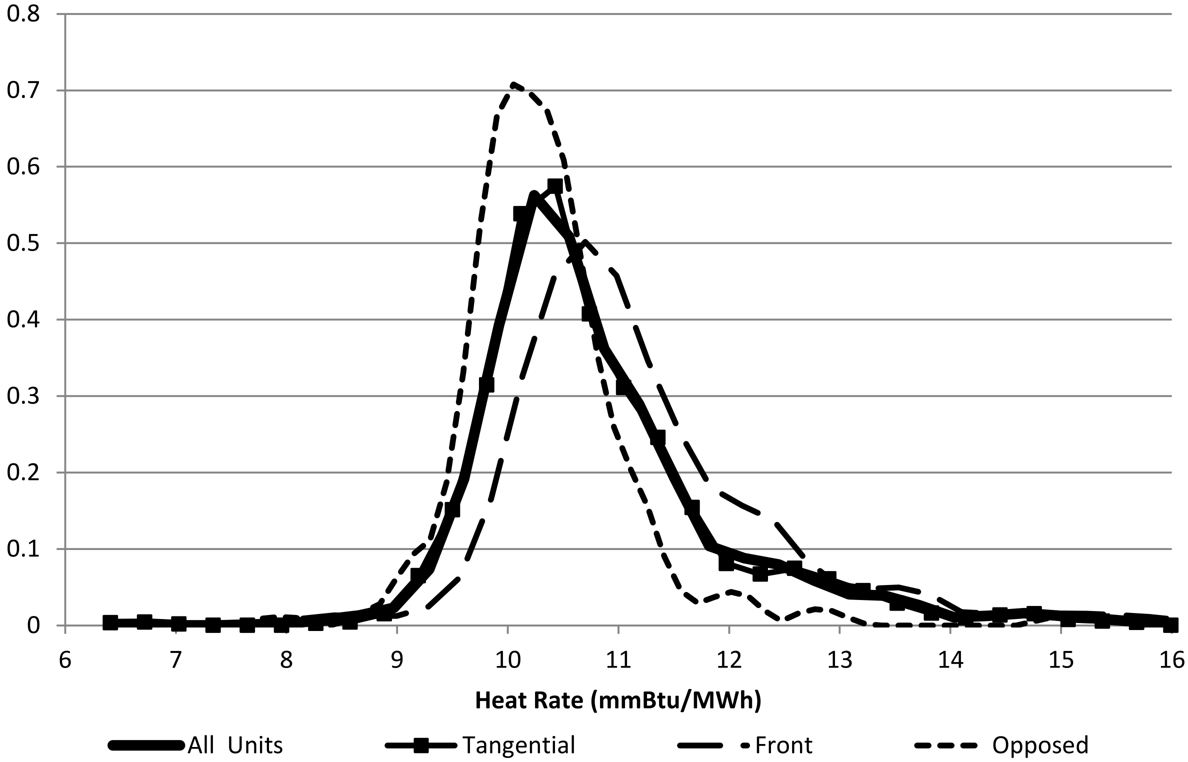
See following pages.

Figure 1: Heat Input vs. Heat Rate (2008)



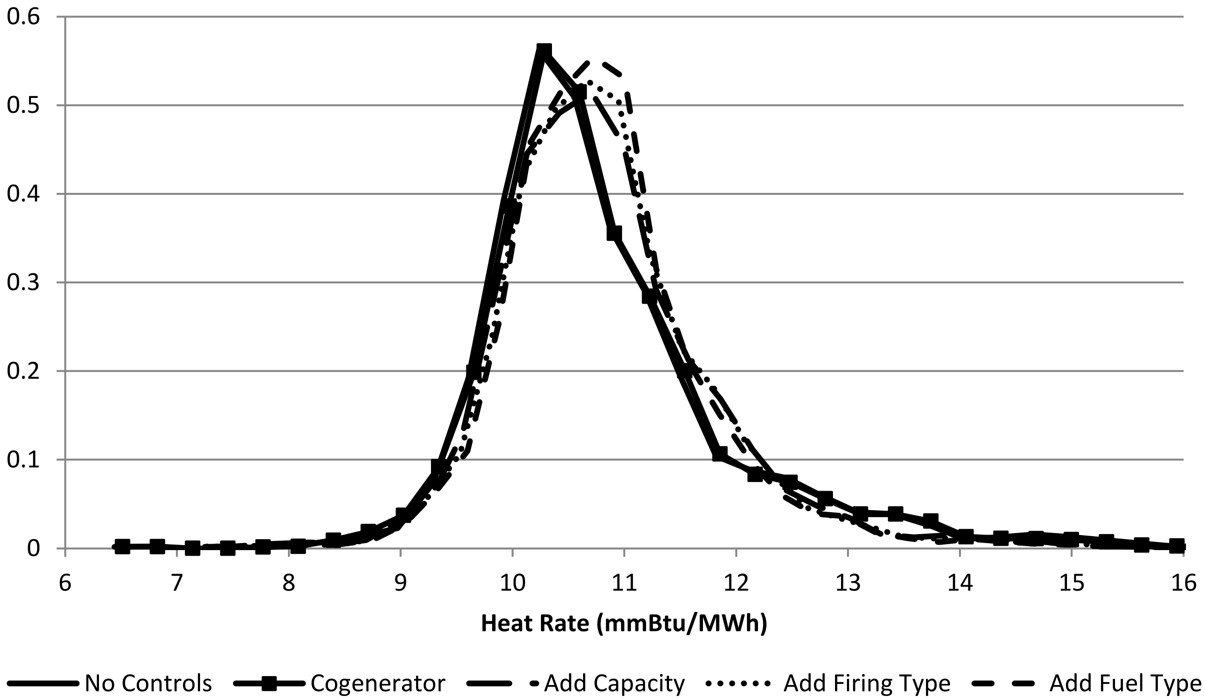
Notes: The figure plots the heat input (million megawatt hours, MWh) against the heat rate (million Btu, mmBtu, per MWh) for all units in the sample in 2008. The vertical line indicates the generation-weighted mean heat rate of 10.34 mmBtu/MWh.

Figure 2: Estimated Heat Rate Distribution by Firing Type



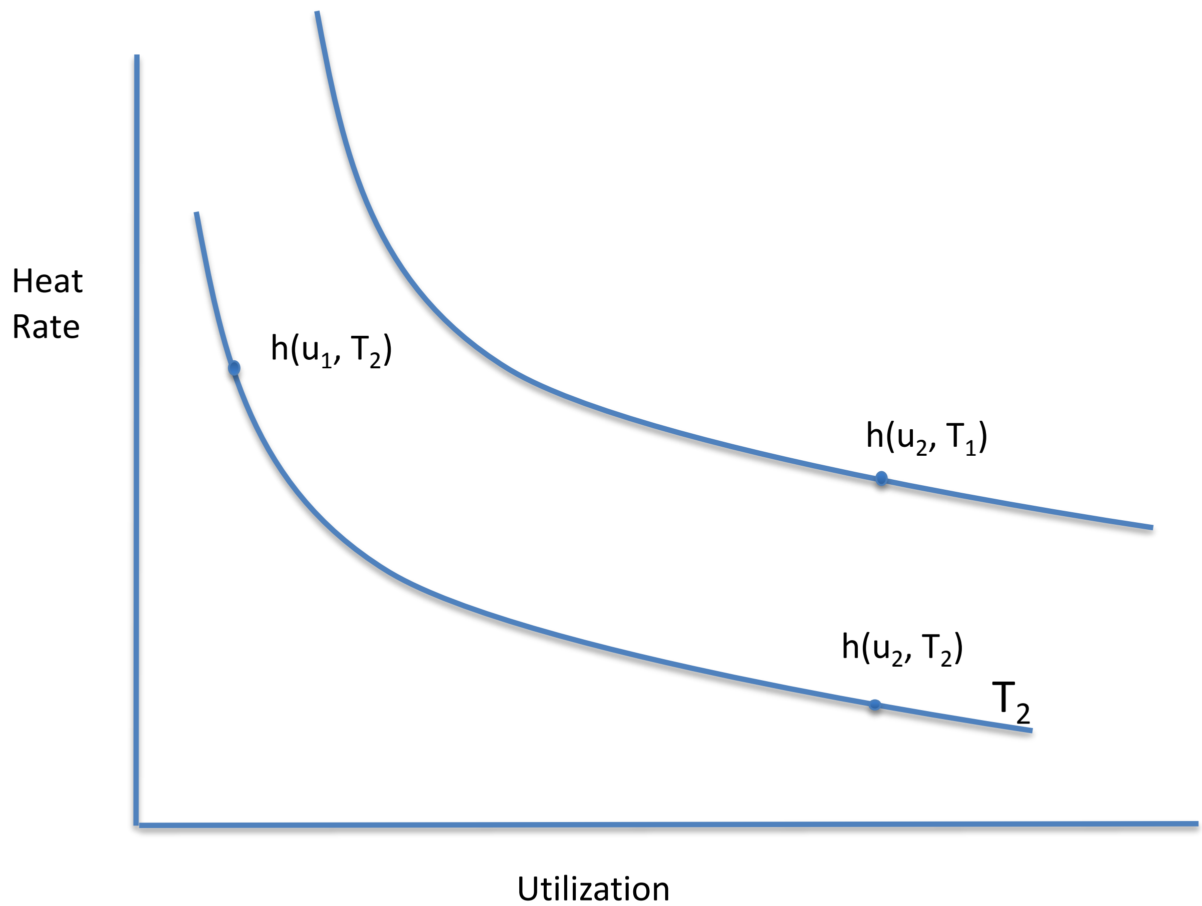
Notes: The figure plots the estimated heat rate kernel density function for all units and for the three most common firing types in the sample using observations from 2008.

Figure 3: Estimated Heat Rate Distribution Controlling For Technology Variables



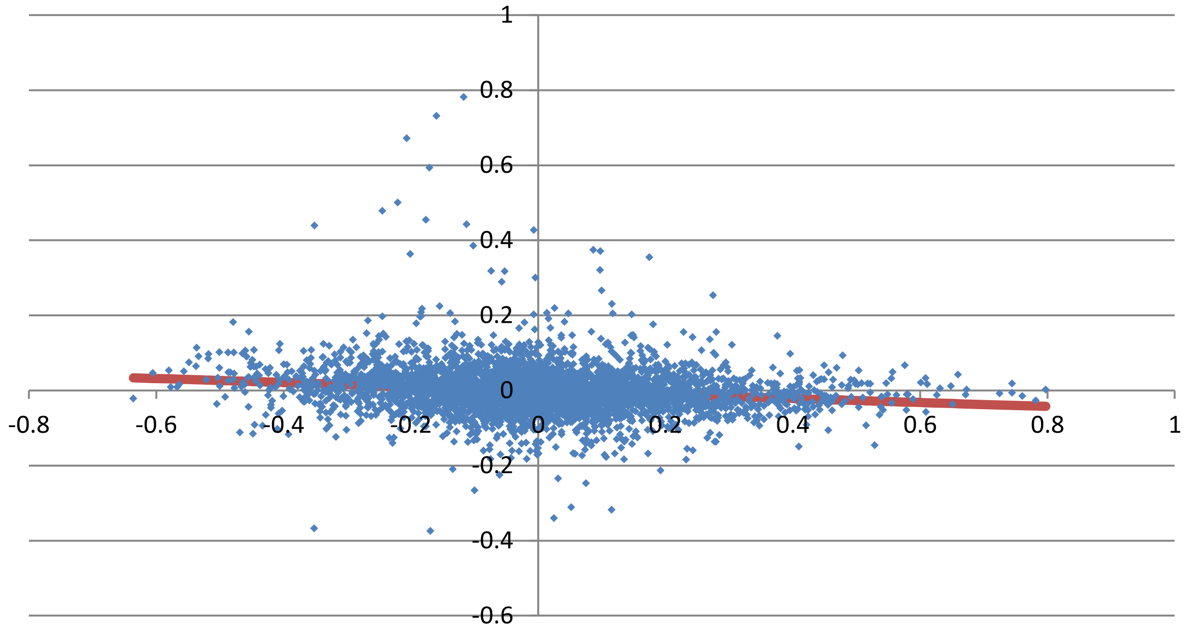
Notes: The figure plots the estimated kernel density function of heat rates for 2008. The first series plots the function using the heat rates observed in the data set. To construct the other plots, each unit's heat rate is regressed on the indicated control variables. The figure plots the residuals after adding the mean heat rate across units in the sample.

Figure 4: Utilization, Heat Rates, and Technology



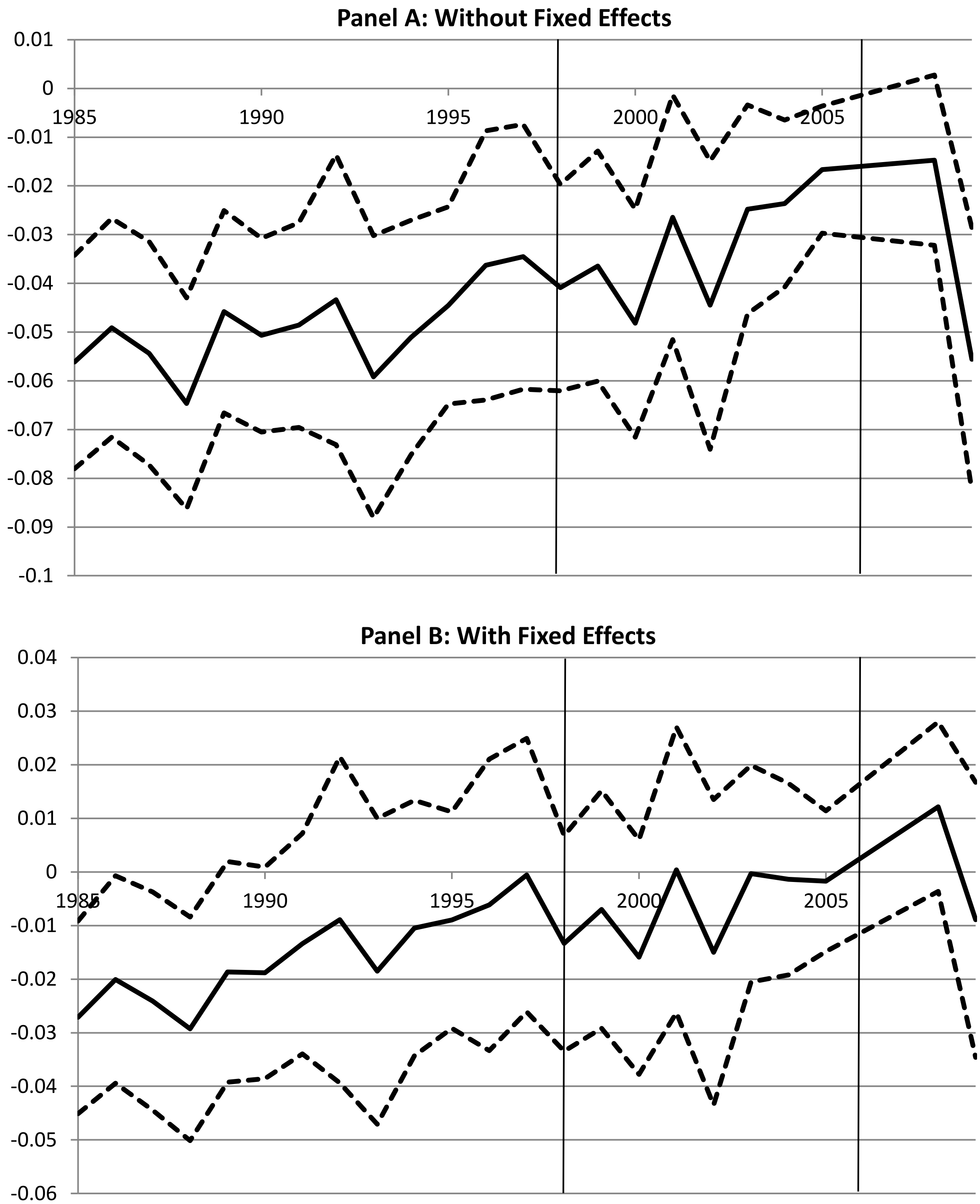
Notes: Heat rate, h, is a function of utilization, u, and heat rate technology, T. The figure plots two hypothetical technologies, T_1 and T_2. The figure shows that at the same level of utilization, u_2, the heat rate using technology T_2 is lower than the heat rate using technology T_1.

Figure 5: Heat Rate vs. Coal Price Residuals



Notes: Heat rate and coal prices are obtained from a regression of log heat rate and log coal price on the control variables in column 1 of Panel A in Table 4, omitting the log coal price as an independent variable. The figure plots the heat rate residuals against the coal price residuals. The red line shows the fitted values from a regression of the heat rate residuals on the coal price residuals. The slope of the fitted values is the same as the estimated coefficient in Table 4.

Figure 6: Effect of Coal Prices on Heat Rates by Year



Notes: The log coal price is interacted in a set of year fixed effects, and the interactions are added to the specification in column 1 of Table 4. The figure plots the effect of coal prices on heat rates for each year as the sum of the coefficient on the coal price and the coeffcient on the corresponding year-coal price interaction. The dashed curves show the 95 percent confidence intervals. In Panel A unit fixed effects are not included in the regression, and in Panel B, fixed effects are included. The vertical lines indicate the end of the first and second NSR regimes (see text).

Table 1

The Determinants of Heat Rates Associated with How Boilers are Used

Determinant	Hypotheses
Cogeneration	Traditional measures of heat rate do not account for the thermal output produced by cogenerators and are misleading.
Utilization	Higher utilization rates are associated with lower heat rates because it is less costly to run a more efficient plant and there are efficiency losses associated with varying utilization and with starting up and shutting down the unit.
Pollution Controls	Pollution controls impose a heat rate penalty because of the heat input or electricity required to run them. Also, investment in pollution controls may crowd out other investments.
Fuel Choice	Low sulfur coal is associated with increased efficiency because it reduces the need for pollution controls. However, low sulfur (sub-bituminous) coal also has a higher rate of CO_2 emission per BTU than high sulfur (bituminous) coal. Coal type may also signal an economic decision based on location and availability.
Regulation and Incentives	Fear of triggering NSR for other pollutants may delay efficiency improvements. Fuel cost adjustment clauses allow plants to pass through fuel costs to customers, which may reduce incentives for making efficiency improvements. Competition in wholesale markets incentivizes efficiency improvements.
Ownership	Competition in wholesale power markets provides an incentive for efficiency improvements.

Table 2

Summary Statistics by Time Period							
	Number of Observations	Age (years)	Capacity (MW)	Utilization Rate	Scrubber	Heat Rate (mmBtu/MWh)	Coal Price ($/mmBtu)
1985-1989	1014	22.4	314.6	0.48	0.13	10.9	1.57
		(11.1)	(259.1)	(0.19)		(1.6)	(0.40)
1990-1994	1004	26.9	319.7	0.51	0.14	10.8	1.45
		(11.4)	(262.0)	(0.19)		(1.5)	(0.37)
1995-1999	996	31.7	323.5	0.57	0.17	10.8	1.29
		(11.6)	(267.4)	(0.18)		(1.4)	(0.32)
2000-2004	998	36.0	324.9	0.62	0.20	10.9	1.30
		(11.7)	(269.0)	(0.16)		(1.4)	(0.31)
2005-2009	915	39.9	337.1	0.60	0.30	11.0	2.01
		(12.4)	(275.7)	(0.18)		(1.5)	(0.65)

Notes: The table preports summary statistics for all units in the sample. Observations are aggregated to five-year time intervals by taking generation-weighted means over years. The table reports the number of observations in each time period and the means of the variables indicated in the column headings; standard deviations are in parentheses. Age is reported in years and capacity in MW. Utilization rate is total generation divided by generation if the unit operates at full capacity throughout the time period. The scrubber variable is an indicator for whether the unit is connected to a scrubber. Heat rat is reported in mmBtu/MWh. Coal price is in dollars per mmBTU.

Table 3

Estimated Abatement Opportunities for Traditional Emissions Rate Standards

Uniform Standard	Standard by Firing Type	Standard by Firing Type and Size	Standard by Firing Type, Size, and Scrubber	Standard by Firing Type, Size, Scrubber, and Cogenerator
Panel A: Percent Abatement Without Rebound Effect				
5.84	5.92	6.87	6.34	6.29
Panel B: Percent Abatement With Rebound Effect				
4.72	4.79	5.56	5.13	5.09

Notes: The table reports abatement opportunties under different hypothetical emissions rate standards. The calculations do not account for abatement costs or technical constraints, but capture only the heterogeneous operating performance of existing coal generators. The standards are defined as the 10th percentile heat rate for the indicated categories (i.e., 90 percent of units initially have a higher heat rate than the standard). Size categories are assigned based on the unit's quartile of generation capacity. Scrubber and cogenerator categories are assigned based on whether the unit has a scrubber or whether the unit is a cogenerator. Panel A assumes that the standards do not affect generation and Panel B assumes that a 10 percent heat rate decrease causes a 2 percent generation increase.

Table 4

Effect of Coal Prices on Heat Rates

	Dependent Variable: Log Heat Rate		
	(1)	(2)	(3)
		Panel A: No Unit Fixed Effects	
Log Coal Price (α)	-0.053 (0.008)	-0.056 (0.015)	-0.058 (0.012)
Number of Observations	4,927	1,883	2,492
R-Squared	0.75	0.80	0.79
		Panel B: Unit Fixed Effects	
Log Coal Price (α)	-0.016 (0.009)	0.004 (0.010)	0.006 (0.009)
Number of Observations	4,927	1,883	2,492
R-Squared	0.93	0.95	0.95
Specification	Baseline	Include 10 Largest Firms	Include 20 Largest Firms

Notes: The table reports estimates of equation (3), in which α is the coefficient on the log coal price. Standard errors, in parentheses, are clustered by state. The unit of observation is a generation unit by 5-year time period from 1985-2009. The dependent variable is the log of heat input divided by generation over the time period. Log coal price is the log of the average price of coal for the corresponding plant and time period. Utilization is the total generation of the unit over the time period divided by the unit's capacity multiplied by the number of hours in the time period. All specifications include utilization; separate indicator variables for whether the unit is a cogenerator, whether the unit has SCR, and whether the unit has a scrubber; age fixed effects; period fixed effects; firing type fixed effects; fuel type fixed effects; state fixed effects; and ownersip type fixed effects. Deciles are constructed for the unit's rated capacity, and all specifications include a set of fixed effets for each capacity decile. All specifications include a set of fixed effects for the number of months in the time period that the unit operates at below 10 percent or below 30 percent of rated capacity. Panel B also includes unit fixed effects. Each column reports the indicated specification. Columns 2 and 3 included the 10 or 20 largest firms, where firms are ranked by total coal capacity in 2009.

Table 5

Coal Price Persistence

	Dep var: log coal price	Dep var: log contract price	Dep var: log spot price
	(1)	(2)	(3)
		Panel A: Include State Fixed Effects	
Log Price	0.724 (0.030)	0.294 (0.079)	0.582 (0.089)
Number of Observations	3,852	3,682	3,472
R-Squared	0.84	0.54	0.51
		Panel B: Omit State Fixed Effects	
Log Price	0.926 (0.038)	0.721 (0.114)	0.744 (0.076)
Number of Observations	3,852	3,682	3,472
R-Squared	0.80	0.38	0.42

Notes: Standard errors, in parentheses, are clustered by state. The unit of observation is a generation unit by 5-year time period from 1985-2009. The dependent variable is the average price of coal in column 1, the contract price in column 2, and the spot price in column 3. Each regression includes the one-period lag of the corresponding price. All specifications include period fixed effects, and Panel A also includes state fixed effects.

Table 6

Persistence Results

	Dependent Variable: Log Heat Rate				
	(1)	(2)	(3)	(4)	(5)
	Panel A: No Unit Fixed Effects				
Log Coal Price		-0.066 (0.007)		-0.043 (0.006)	-0.038 (0.041)
Log Contract Price	0.001 (0.003)		-0.005 (0.003)		
Log Spot Price	0.000 (0.002)		-0.004 (0.002)		
Log Coal Price X Peristence					-0.027 (0.055)
Number of Observations	4,527	4,927	4,527	4,777	4,361
R-Squared	0.73	0.68	0.70	0.73	0.72
	Panel B: Unit Fixed Effects				
Log Coal Price				-0.012 (0.006)	0.005 (0.089)
Log Contract Price	0.000 (0.002)				
Log Spot Price	-0.001 (0.001)				
Log Coal Price X Peristence					-0.031 (0.124)
Number of Observations	4,527			4,777	4,361
R-Squared	0.93			0.92	0.93
Specification	Separate spot and contract prices	Drop state fixed effects	Separate spot and contract prices without state fixed effects	Use coal price in first year of time period	Interact coal price with NERC region price persistence

Notes: The table reports the same specifications as column 1 of Table 4, except as noted in the bottom row of the table. The first column replaces the log average coal price with the log spot price and log contract price. Column 2 repeats column 1 of Table 2 except that state fixed effects are omitted. Column 3 repeats column 1 omitting state fixed effects. Column 4 uses the coal price in the first year of the corresponding time period in place of the average price over the period. For the five NERC regions with the most coal units, the coal price persistence is estimated using the same specification as column 1 in Panel A of Table 5. Column 5 includes the interaction of the log coal price with the estimated persistence.

Table 7

Time-Varying Omitted Variables

	Dependent Variable: Log Heat Rate						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Log Coal Price	-0.050 (0.008)	-0.052 (0.009)	-0.061 (0.010)	-0.078 (0.013)	-0.015 (0.009)	-0.046 (0.008)	-0.009 (0.009)
Number of Observations	3,414	4,275	4,807	4,807	4,807	3,908	3,908
R-Squared	0.69	0.73	0.76	0.80	0.95	0.77	0.94
Specification	Include high utilization units	Balanced panel	Include parent company fixed effects	Include parent company X period fixed effects	Column (4) plus unit fixed effects	Include state-period controls	Column (6) plus unit fixed effects

Notes: Standard errors, in parentheses, are clustered by state. See Table 2 for sample and variable construction. All specifications include the same unreported control variables as in Table 4. Column 1 includes units whose median utilization across all periods exceeds 0.5. Column 2 includes units that operate in all time periods. Column 3 includes parent company fixed effects. Column 4 includes parent company by period fixed effects. Column 5 adds to column 4 unit fixed effects. Column 6 includes total capacity, coal capacity, natural gas capacity, total generation, coal generation, natural gas generation, gross state product, employment, and population by state and period, where all variables are in logs. Column 7 adds to column 6 unit fixed effects.

Table 8

Effect of Coal Prices on Utilization Rates

Dependent Variable: Log Utilization Rate

	(1)	(2)	(3)	(4)	(5)
			Panel A: No Unit Fixed Effects		
Log Coal Price (β)	-0.458 (0.070)	-0.400 (0.092)	-0.418 (0.079)	-0.348 (0.074)	-0.250 (0.059)
Number of Observations	21,690	8,494	11,264	4,927	6,043
R-Squared	0.85	0.86	0.87	0.84	0.87
			Panel B: Unit Fixed Effects		
Log Coal Price (β)	-0.398 (0.043)	-0.408 (0.067)	-0.415 (0.064)	-0.365 (0.088)	-0.171 (0.054)
Number of Observations	21,690	8,494	11,264	4,927	6,043
R-Squared	0.93	0.92	0.92	0.94	0.95
Specification	Baseline	Include 10 Largest Firms	Include 20 Largest Firms	5-year Intervals	Include 2001-2009

Notes: The table reports estimates of equation (4), in which β is the coefficient on the log coal price. Standard errors, in parentheses, are clustered by state. Specifications in columns 1-3 are identical to Table 4, except that the dependent variable is the log of the utilizaiton rate, utilization controls are omitted, and observations are annual rather than aggregated to five-year time periods. Column 4 uses 5-year time intervals. Column 5 is the same as column 1 except that it includes only observations from 2001-2009.

Table 9

Utilization: Time-Varying Omitted Variables

	Dependent Variable: Utilization Rate							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Log Coal Price	-0.277 (0.033)	-0.324 (0.050)	-0.385 (0.048)	-0.399 (0.063)	-0.388 (0.049)	-0.363 (0.077)	-0.260 (0.044)	-0.452 (0.070)
Number of Observations	15,016	13,823	21,222	21,202	21,222	16,798	16,798	21,534
R-Squared	0.90	0.88	0.86	0.88	0.95	0.86	0.94	0.85
Specification	Include high utilization units	Balanced panel	Include parent company fixed effects	Include parent company X period fixed effects	Column (4) plus unit fixed effects	Include state-period controls	Column (6) plus unit fixed effects	Add natural gas price to baseline

Notes: Standard errors, in parentheses, are clustered by state. Specifications in columns 1-7 are identical to Table 7, except that the dependent variable is the log of the utilizaiton rate, utilization controls are omitted, and observations are annual rather than aggregated to five-year time periods. Column 8 adds to the baseline from Table 8 the log of the state's natural gas price.

Table 10

Policy Impacts				
	Traditional Standard	Flexible Standard	Coal Btu Tax	Emissions Tax
Percent Change in Heat Rates	-1.00	-1.01	-0.16	-0.18
Percent Change in Coal Generation	0.19	0.21	-1.11	-1.09
Percent Change in Coal Emissions	-0.82	-0.81	-1.27	-1.26
Change in Investment Costs (million $)	709.0	343.0	50.1	55.1
Change Investment Costs/Change Emissions ($/ton)	-54.71	-26.48	-3.87	-4.25
Capacity Factor (percent)	60.71	60.72	59.93	59.94
Rebound in Emissions per Change in Emissions	0.13	0.15	0.02	0.02

Notes: The table reports results of simulations of the electricity market model. See text and Appendix 3 for a detailed description of the model. Each column reports the results of a separate policy scenario. The scenarios are calibrated to achieve the same total emissions reduction. Under the inflexible standard units must achieve a heat rate of 10.78 mmBtu/MWh or reduce heat rate by 10 percent, whichever results in a higher heat rate. The flexible standard sets a benchmark heat rate of 10.26 mmBtu/MWh. The coal Btu tax imposes a tax of $0.115 per mmBtu of coal. The emissions tax is $1.13 per ton of CO_2 emissions. Each row reports the change in the indicated variable as compared to the baseline (no policy) case. Investment costs include the annualized capital costs of heat rate improvements using a fixed charge rate of 0.1. Capacity factor is the ratio of generation of the coal units to the generation if all units operated at full capacity. The rebound in emissions is the change in emissions resulting from the change in heat rates, holding fixed the effective coal price under each policy (see appendix 4 for details on the rebound calculation).