JOURNAL OF ENVIRONMENTAL ECONOMICS AND MANAGEMENT **36,** 26–45 (1998)
ARTICLE NO. EE981033

The Declining Trend in Sulfur Dioxide Emissions: Implications for Allowance Prices[1]

A. Denny Ellerman

Sloan School of Management and Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, Massachusetts 02139

and

Juan-Pablo Montero

Department of Industrial Engineering, Catholic University of Chile, Santiago, Chile and Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, Massachusetts 02139

Received September 27, 1996; revised February 26, 1998

In this paper, we find that sulfur dioxide (SO_2) emissions by electric utilities declined from 1985 to 1993 for reasons largely unrelated to the emission reduction mandate of Title IV of the 1990 Clean Air Act Amendments. The principal reason appears to be the decline in rail rates for low-sulfur western coal delivered to higher-sulfur coal-fired plants in the Midwest. Consequently, there is less sulfur to be removed to meet the Title IV cap on aggregate SO_2 emissions, and the cost of compliance and price of allowances can be expected to be less than would otherwise have been the case. © 1998 Academic Press

I. INTRODUCTION

The low price of allowances has been a frequently noted feature of the implementation of Title IV of the Clean Air Act Amendments of 1990.[2] This legislation imposed a 50% reduction of acid rain precursor emissions, primarily sulfur dioxide (SO_2), by what is the largest public policy experiment in the use of fully tradable emission permits.[3] These permits, called allowances, convey the right to emit 1 ton of SO_2 in the year of issuance or any subsequent year. Early estimates of allowance

[1]This research was funded by a grant from the National Acid Precipitation Assessment Program of the U.S. Government and by the Center for Energy and Environmental Policy Research (CEEPR) at the Massachusetts Institute of Technology (MIT). We are indebted to Larry Montgomery of EPA for comments and help with the EPA's database, to Kenny McClevey of DOE for the Form 423 data on fuel deliveries, to Richard Schmalensee, Robert Stavins, Elizabeth M. Bailey, participants in the Environmental Policy Seminar at Harvard University and the CEEPR Energy and Environmental Policy Workshop at MIT, and three anonymous referees for helpful comments. We alone are responsible for any remaining errors.

[2]For a complete description of Title IV and the 1990 Clean Air Act Amendments, see Locke and Harkawik [21] and Rico [25].

[3]For a detailed description on the theory and practice of emissions trading programs, see Hahn and Hester [17], Montero [22], Montgomery [23], Stavins [26], and Tietenberg [27].

0095-0696/98 $25.00

prices ranged from \$250 to 400.[4] Some early bilateral allowance trades were reported at prices within this range; however, the first annual auction, in March 1993, cleared at a price of \$131. At the time, this price was viewed as too low, but subsequent auctions and the development of a sizeable private market for allowances continue to indicate an early Phase I price at or below this figure.[5, 6]

This paper contributes to the ongoing discussion and growing literature on the reasons for low allowance prices.[7] In particular, we draw attention to the decline in SO_2 emissions *prior* to 1995, the year in which Title IV became effective. When Title IV was enacted in 1990, SO_2 emissions were not expected to fall, particularly with rising coal use. An unanticipated decline in SO_2 emissions would have implications for allowance prices: they would be lower because the reduction in SO_2 emissions imposed by Title IV is less than had been expected. The effectively constrained and economically meaningful reduction in emissions is to be measured from what would have occurred absent the cap, not from some earlier year nor from earlier forecasts of expected emissions. If earlier estimates of counterfactual emissions erred on the high side, actual costs would be lower than predicted and vice versa. In this paper, we conclude that SO_2 emissions have declined mostly for reasons unrelated to Title IV. As a result, the emission constraint imposed by Title IV is less binding, and the marginal cost of compliance, as well as the price of allowances, can be expected to be lower than had been initially predicted.

The remainder of the paper is organized as follows. The next section compares actual SO_2 emissions with some representative forecasts of emissions absent Title IV and develops several explanations for the disparity. Section III presents the economic model of electric utility fuel choice that underlies our regression equation and discusses some pertinent features of coal markets and utility fuel choice. Section IV contains the formal statement of hypotheses, the regression equation, and a discussion of the results. The final section summarizes and presents concluding remarks.

II. FORECAST AND ACTUAL SO_2 EMISSIONS

When acid rain legislation was being debated, SO_2 emissions were expected to rise throughout the 1990s as a result of the increase in the demand for electricity

[4]See Ellerman *et al*. [8], EPRI [12], Hahn and May [18, Table III], and GAO [30, p. 36] for early estimates of allowance prices.

[5]For a discussion of the development of the allowance market and the relation to the auction, see Joskow *et al*. [20].

[6]We began research in the summer of 1995 with the objective of explaining the disparity between then observed prices around \$130 and the earlier expectation of \$250–400. In the course of the research, the price fell to a low of about \$70 in the March 1996 auction and has remained well below \$130 since then. Our results should not be interpreted as offering a complete explanation of any one price, but as identifying a significant contributing factor to the disparity between actual and expected prices.

[7]A number of analyses have now been provided to explain the lower than expected price of allowances, namely, the auction rules [5, 6], the regulatory environment [1, 2, 32], transaction costs [26], and unspecified market imperfections [31]. More recently, in an extensive ex post analysis of compliance with Title IV in 1995, Ellerman *et al*. [8] argue that the low allowance prices observed in 1995 reflect overinvestment in compliance, in the form of both scrubbers and contract commitments to low-sulfur coal. Among recent works, see also Burtraw [3] and Burtraw and Swift [4] for a review of the variety of factors contributing to lower than expected compliance costs and allowance prices.

and continuing reliance on coal-fired generation [12, 19, 28]. For example, ICF [19] projected that, with higher load assumptions and absent acid rain controls, electric utility SO_2 emissions would rise by 2005 to as much as 25% over the 1985 level. In fact, SO_2 emissions from electric utilities were 3% below the 1985 level by 1990 and 7.3% below by 1993 despite continuing growth in coal-fired generation.

Table I provides aggregate summary data on emissions, heat input, and other variables for years 1985 and 1988–1993 for two partitions of the complete set of fossil generating units: by designation for control in Phase I (Table A) and by fuel type.[8, 9] Table I shows that the 1.2 million ton reduction in SO_2 emissions between 1985 and 1993 occurred mostly at Table A units and at coal-fired units, and that the reduction is due to a decline in the average emission rate at these units, not a reduction in heat input or generation.[10] Between 1985 and 1993, aggregate SO_2 emissions from all coal-fired plants declined by 7.5% despite a 15.4% increase in heat input at these same plants. In effect, the national average emission rate at coal-fired power plants fell by 20% over these years.

Several explanations can be offered for the observed reduction in SO_2 emissions. The occurrence of almost all of the reduction at Table A units suggests that these units were complying early with the emission reduction mandate of Title IV. Indeed, various studies of compliance plans have noted that utilities were taking actions to reduce emissions well ahead of the time when the reduction requirement would become binding.[11] Although competitive firms would not be expected to incur the higher costs implied by early compliance, regulated utilities might well do so when the additional cost of the lower-sulfur coal or a sulfur-reducing retrofit can be passed through to consumers.

A somewhat related explanation is that several states have enacted state laws or amended State Implementation Plans (SIPs) under the pre-1990 Clean Air Act to require reductions in SO_2 emissions before the effective date of Title IV. These changes in state law and regulation have been limited to only a few states, but their effect would account for some of the reduction in emissions observed as of 1993.

Yet another explanation is provided by an examination of the geographic distribution of the reduction in emissions between 1985 and 1993. Virtually all of the 1.2 million ton reduction of SO_2 emissions between 1985 and 1993 was achieved at units in the Midwest, located between approximately 600 to 1000 miles from the source of the cheapest and lowest-sulfur coal in America, the Powder River Basin (PRB) in Wyoming and Montana (see Fig. 1). At the same time, rail

[8] A generating unit corresponds to a single generator and associated boiler. A generating plant can house one or several units, which may be of different sizes, vintages, type, and fuel input.

[9] The Title IV limits on aggregate emissions are imposed in two phases. The first phase entailed a less stringent aggregate limit that would first become effective in 1995 and affect 263 large generating units with relatively high SO_2 emissions that were listed in Table A of Title IV. Phase II begins in the year 2000 and involves a more stringent aggregate limit encompassing all generating units with generating capacity greater than 25 MW^e.

[10] The analysis could be performed with any pair of years before or after enactment of the CAAA in 1990. We use 1985 as our beginning year because it is a frequent benchmark and it is associated with the baseline for the Title IV allocation of allowances. The year 1993 is the last year for which it is possible to argue that fuel choice at Table A units is not affected by the start of Phase I on January 1, 1995.

[11] Instances are noted in the review of compliance plans contained in EIA [10], EPRI [13], and Fieldston [14]. It also deserves note that some of these reductions in emissions were being made before the legislation listing Table A units was proposed (April 1989).

TABLE I
Aggregate Power Plant Data: 1985–1993

		1985	1988	1989	1990	1991	1992	1993
All units								
SO_2 Emissions (10^3 tons)		16,243	15,830	15,993	15,820	15,651	15,285	15,065
Heat input (10^{12} Btu)		18,579	19,805	20,100	19,791	19,704	19,646	20,259
Emission rate (#/mmBtu)		1.75	1.60	1.59	1.60	1.59	1.56	1.49
Nameplate capacity (MW)	533,058							
Number of units	2,918							
Table A vs. non-Table A units								
Table A units								
SO_2 Emissions (10^3 tons)		9,302	8,887	8,862	8,683	8,396	8,140	7,579
Heat input (10^{12} Btu)		4,387	4,426	4,427	4,392	4,318	4,351	4,396
Emission rate (#/mmBtu)		4.24	4.02	4.00	3.95	3.89	3.74	3.45
Nameplate capacity (MW)	88,007							
Number of units	263							
Non-Table A units[a]								
SO_2 Emissions (10^3 tons)		6,941	6,943	7,132	7,137	7,255	7,145	7,486
Heat input (10^{12} Btu)		14,192	15,379	15,673	15,398	15,386	15,295	15,863
Emission rate (#/mmBtu)		0.98	0.90	0.91	0.93	0.94	0.93	0.94
Nameplate capacity (MW)	445,051							
Number of units	2,655							
Coal- vs. oil/gas-fired units								
Coal-fired units								
SO_2 emissions (10^3 tons)		15,630	15,084	15,208	15,186	15,005	14,742	14,456
Heat input (10^{12} Btu)		14,626	15,946	16,039	16,093	16,066	16,224	16,876
Emission rate (#/mmBtu)		2.14	1.89	1.90	1.89	1.87	1.82	1.71
Nameplate capacity (MW)	347,271							
Number of units	1,417							
Oil/gas-fired units								
SO_2 Emissions (10^3 tons)		613	746	785	633	646	542	610
Heat input (10^{12} Btu)		3,953	3,860	4,060	3,698	3,638	3,422	3,383
Emission rate (#/mmBtu)		0.31	0.39	0.39	0.34	0.36	0.32	0.36
Nameplate capacity (MW)	185,787							
Number of units	1,501							

Source: Derived from EPA [28].
[a]Among non-Table A units there are 651 units that are not Phase II units.

rates for hauling low-sulfur western coal have fallen significantly as a result of railroad deregulation, and this reduction in transportation cost has extended the use of these lower-sulfur coals into the Midwest.

This trend in rail rates and the effect on fuel choice at Midwestern power plants is illustrated by Table II and Fig. 1, respectively. Table II compares the average rate per ton-mile for coal shipments from the PRB and from other sources of coal delivered to the Midwest as reported in two studies of coal transportation rates [9, 11]. The average rate for coal from the PRB has fallen steadily since 1983 to half of what was charged in 1979, the year before enactment of the legislation that deregulated the railroads. In marked contrast, short-haul rail rates for Illinois Basin coal have shown little change in real terms over these same years. Finally,

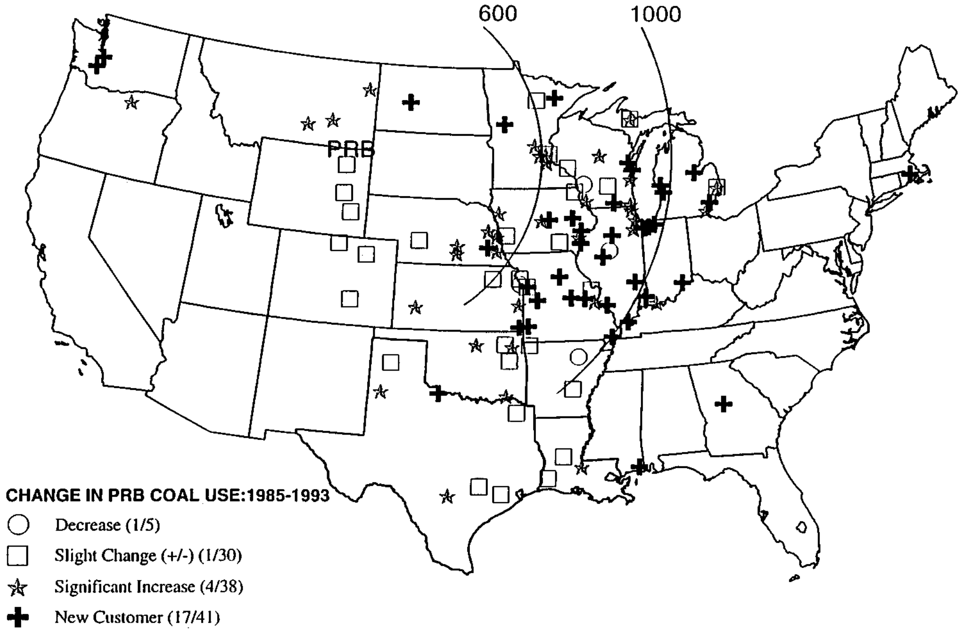

FIG. 1. Power plants burning PRB coal: 1985–1993.

rates for the competing low-sulfur coal from central Appalachia have declined only recently to about three-quarters of the pre-deregulation rates.

The effect of declining rail rates on fuel choice is shown on Fig. 1, where all plants that purchased coal from the PRB in either 1985 or 1993 are marked according to the change in PRB coal use between 1985 and 1993 as (1) plants that have decreased PRB coal use by 25% or more (decrease), (2) plants that have either increased or decreased the use of PRB coal by less than 25% (slight change), (3) plants that were burning PRB coal in 1985 and have increased purchases by 25% or more (significant increase), and (4) plants that switched or began to switch to PRB coals after 1985 (new customers). Almost all "new PRB coal customers" and most "PRB coal increases" correspond to plants located in the Midwest.

TABLE II

Average Rate per Ton-Mile for Contract Coal Rail Shipments between Midwest and Selected Supply Regions[a]

	Supply region		
Year	Powder River Basin	Illinois Basin	Appalachia
1979	2.0	3.1	3.2
1983	2.2	3.5	4.5
1987	1.8	3.2	3.0
1988	1.6	3.8	3.4
1993	1.0	3.4	2.4

Source: EIA [9, 11].

[a] Prices are in mills per ton-mile in 1990 dollars

Indeed, the largest effects are seen in states such as Missouri, Minnesota, Iowa, Wisconsin, Illinois, Michigan, and Indiana that lie within 600−1000 miles of the PRB, and that also contain a large number of Table A units.

In the legend of Fig. 1, we have also included, within parentheses for each of the four categories, the ratio between plants with Table A units and total number of plants regardless of Title IV designation. Most of the plants which registered "significant increases" or became "new customers" do not have Table A units. These numbers suggest that the penetration of Midwestern coal markets by PRB coals has proceeded regardless of the status of the receiving plant under Title IV. Thus, an alternative explanation for the reduction in SO_2 emissions is that reduced rail rates have made lower-sulfur western coals cheaper than the predominantly higher-sulfur coals previously consumed in the Midwest. As a result, utilities are switching to these lower-sulfur coals for economic reasons independently of Title IV.

Finally, there are other influences that operate to reduce sulfur emissions over the long term. For example, under the existing Clean Air Act, any new generating unit is tightly controlled to new source performance standards, and typically such new units displace power from older sources with higher emission rates. Also, the location of high- and low-sulfur coal deposits in the United States is such that electricity demand was transferred from higher- to lower-sulfur generating sources by the general shift of economic activity to the South and the West away from the Midwest during the 1980s. Finally, competition among coal suppliers has led to the virtual elimination of raw (unwashed) coal and the general upgrading of the delivered product that typically entails the removal of some of the pyritic sulfur fraction. These factors were operating during the 10 years prior to 1985 when aggregate sulfur emissions also declined despite rising coal use.[12] They may have abated in the 1990s, but these factors were likely still present and accounted for some of the observed reduction after 1985.

These explanations can be grouped into two broad categories with quite different implications for allowance prices. If the reduction of emissions after 1990 reflects early compliance and other associated causes, then positive costs are being incurred in reducing these emissions and, with the emergence of a functioning allowance market, these costs would be reflected in allowance prices.[13] Alternatively, if utilities are switching to lower-sulfur western coals because they are cheaper on a Btu basis, no costs are being incurred in reducing emissions. In the former case, the national marginal abatement curve (MAC) has not shifted and there would be no reason to expect lower marginal cost or allowance prices. In the latter case, the national MAC has shifted inward, and with an unchanged cap on aggregate emissions, lower marginal cost and allowance prices are implied.

Before formally defining hypotheses and describing the data and the testing procedure, we present the model of fuel and compliance choice underlying our regression equation, and we note briefly several aspects of coal markets and utility fuel choice that are pertinent to the reduction in SO_2 emissions after 1985.

[12] See National Coal (now Mining) Association [24] for a more extensive analysis of these factors.

[13] The marginal abatement costs being incurred at these units would constitute thresholds at which the units would be buyers of allowances when allowance prices are lower and sellers when prices are higher. To the extent that the early cost were sunk, the threshold may be lower.

III. THE ECONOMICS OF COAL CHOICE

At least as a first approximation, electric utilities minimize the delivered cost of the fuel used to generate electricity. Because coal is a bulky form of energy, transportation costs figure importantly in the delivered price of coal. If all else were equal, distant mines would never provide the least-cost fuel, but the mine-mouth cost of producing coal varies considerably among regions and even among mines within the same geographic region. Furthermore, transportation rates are typically lower on a per mile basis for longer hauls than for shorter distances. Consequently, if the mine-mouth price and the transportation rate are low enough, distant mines can and often do provide the least-cost coal to a specific plant. In choosing a particular coal, the operator of the jth power plant solves the following problem for a unit of coal input,

$$\min_{i} C_{ij} = \text{MMP}_i + r_{ij} d_{ij}, \tag{1}$$

where C_{ij} is the delivered cost of the ith fuel to the jth plant, MMP_i is the mine-mouth price for the ith coal, r_{ij} is the transportation rate from the ith mine to the jth plant, and d_{ij} is the distance from the ith mine to the jth plant. The problem is considerably more complex in reality since interactions between the boiler and specific coals may affect the calculus, a blend of coals may be chosen, or the operator may be contract constrained.

Each competing coal is associated with a certain amount of sulfur dioxide emissions per unit of coal input. The price of sulfur does not figure in the cost-minimization problem presented in Eq. (1) because the set of competing coals at any given plant is restricted by existing command-and-control regulation to those that can meet the source-specific emission rate imposed in the relevant state implementation plan (SIP).[14] Since virtually all coal-fired units are in compliance with SIP limits, we assume that the sulfur characteristic observed at each generating plant prior to the enactment of Title IV reflects the choice of the least-cost coal from among the SIP-constrained set of competing coals. It follows by assumption that lower-sulfur coals will be more costly (as well as any higher-sulfur coals within the constrained set).

For a plant affected by Title IV, the cost-minimization problem is changed by the introduction of two new terms,

$$\min_{i} C_{ij} = \text{MMP}_i + r_{ij} d_{ij} + P_a S_i + K_{ij}, \tag{2}$$

where P_a is the price of allowances, S_i is the quantity of emissions associated with a unit of the ith coal, and K_{ij} is the appropriately allocated capital (or other) cost associated with the use of the ith coal at the jth plant.

One can visualize several ways into which coal choice would change as a result of the inclusion of the last two terms. If there were lower-sulfur, higher-cost coals among the SIP-constrained set of competing coals, it is certainly possible that a positive price for allowances would alter the choice of fuel in favor of a lower-sulfur coal. In some cases, additional capital or other expenditures may be involved so

[14] Units that had installed scrubbers to meet the new source performance standard would have a wider range of coals to choose from, but those units are not included in Table A.

that the fourth term in Eq. (2) is positive and will also be taken into account. It is, of course, also possible that a positive price for sulfur content would not result in any change in the choice of fuel at particular plants. In any case, compliance with the newly constraining Title IV limit implies a positive price of allowances that would result in reduction of sulfur at enough units to ensure that the aggregate quantitative limit is met.

It is a peculiar feature of the American coal economy that the lowest cost coal at the mine has the lowest sulfur content, but is located farthest from the principal markets. Due to extraordinary geological conditions, energy from coal is available in the Powder River Basin (PRB) in northeastern Wyoming at a mine-mouth price of $0.20–0.25 mmBtu, or the crude oil equivalent of $1.20–1.50/bbl. Emissions of SO_2 from PRB coals range from 0.5 to 1.2 lb of SO_2 per mmBtu (hereafter #/mmBtu). The combination of low production cost and low sulfur content is not matched in any other coal producing region,[15] but the two principal competing regions, the Midwest and Appalachia, have the advantage of proximity to markets, particularly, to coal-fired units between the Mississippi and the Appalachian mountains. Historically, the substantial cost of transporting PRB coal to the Midwest, typically two-thirds to three-quarters of the delivered price, has diminished the appeal of these coals and permitted local, higher-sulfur, and higher-(mine-mouth) cost coals to dominate these markets.

Since PRB coal is carried to market by rail, the deregulation of railroads during the 1980s has affected the economics of coal choice. Two effects are particularly important. First, the implementing legislation, the Staggers Rail Act of 1980, effectively introduced competition in the carriage of coal out of the PRB.[16] Second, significant cost-reducing and productivity-enhancing improvements have been achieved [9]. The consequence of competition and productivity improvements has been the halving of the rail rate for long-distance hauls out of the PRB as shown in Table II. This change in transportation cost reduced the price of PRB coal delivered to midwestern locations, and concomitantly reduced the locational advantage enjoyed by midwestern and Appalachian coals in the market between the Mississippi River and the Appalachian Mountains, where most Phase I units are located.

IV. ECONOMETRIC ANALYSIS

We can now formulate the two competing hypotheses: (1) early SO_2 reductions are the result of early and costly compliance with Title IV and (2) early SO_2 reductions are the result of decreasing rail rates that have made distant PRB coals more economically attractive than local, higher-sulfur midwestern coals. Early compliance implies that electric utility operators have incurred additional cost, usually by choosing a higher-cost, lower-sulfur coal and perhaps incurring some

[15]Among the factors that contribute to the low cost of PRB coals is the low degree of concentration and very competitive nature of production. Ownership of mines change and the definition of the market can vary (contract vs. spot, mine-mouth vs. rail); however, at 1000, the HHI Herfindahl index of concentration for the PRB as a whole is well below a level that would suggest an ability to raise prices.

[16]The Staggers Act ended the Burlington Northern Railroad's monopoly over transportation out of the PRB by removing various obstacles to the Chicago and Northwestern spur that connected the PRB to the Union Pacific Railroad to the south.

additional compliance expenditure. Under the alternative hypothesis of rail-rate-induced economic switching to PRB coals, there is no violation of the cost-minimizing assumption. The critical difference is that the first hypothesis implies additional cost for the observed emission reduction because of Title IV, while the second does not.

We cannot observe the cost at plants, but we do observe emission rates. Given our assumption of cost-minimizing fuel choices from within the SIP-constrained set, we can infer changes in cost—and test the two hypotheses—by the association of the observed unit-level changes in emission rates with proxies for Title IV and declining rail rates. If the hypothesis of early compliance is correct, we would not expect to find non-Table A units making the same emission reductions, and the geographic distribution of the reductions should be that associated with Table A units. Conversely, if the hypothesis of rail-rate-induced economic switching is true, we would expect to find geographic differentiation in observed emission reductions among Table A units and little distinction between similarly located Table A and non-Table A units. Finally, the data also permit us to control for the effect of state-imposed limits and other factors that contribute to the observed reduction in SO_2 emissions.

4.1. *The Data*

To perform the analysis we use a data base provided by EPA's Acid Rain Division that contains information on about 3000 units [28]. In addition to identifying information concerning boiler number, location, ownership, nameplate capacity, and predominant fuel use, this data base provides unit-specific data concerning heat input and SO_2 emissions for 1985 and for 1988–1993, as shown in Table I.

For our analysis, we select only those units that are affected by Title IV in either Phase I or II and that use coal as the primary fuel.[17] Since we are interested in the change of emission rates between 1985 and 1993, all units with zero emissions in either 1985 or 1993 are deleted. This last truncation of the sample eliminates some new units and units that may have been retired, but it also removes the effect of units which were active but, for maintenance or other reasons, were not generating electricity in either 1985 or 1993.

Also eliminated from the sample are nine non-Table A units with scrubbers that had relatively low emission rates in 1985, but for which the 1993 emissions, as reported in the database, would be typically associated with nonscrubbed units. It is possible that the scrubbers were not operating in 1993, but we are also advised that the 1985 data were subjected to a much higher degree of quality control than other years since emission allocations were often dependent on 1985 emission rates.[18] After deletion of these units, the sample includes 251 Table A and 788 non-Table

[17] The primary fuel is defined as that for which heat input is greater than 50% of the total at the generating unit in the baseline period, 1985–1987.

[18] Personal communication from Larry Montgomery, Acid Rain Division, Environmental Protection Agency. In fact, for units co-located with nonscrubbed units, the rates reported in 1993 for the scrubbed units are similar to those reported for the nonscrubbed units.

A units that together account for 94% of SO_2 emissions, 77% of heat input, and 57% of U.S. fossil-fuel generating capacity in 1985.[19]

4.2. *The Model*

We have advanced two hypotheses—early compliance and rail-rate-induced switching to PRB coals—to explain the observed reduction in SO_2 emissions. To test these two hypotheses and to disentangle the effect of other factors, we use a simple linear specification that relates unit-specific emission rates in 1993 (or any previous year) to the 1985 rates with abundant use of dummy variables. We focus on emission rates, rather than tons of SO_2 emitted, to normalize for heat input. Our equation for the ith unit is

$$\begin{aligned} \mathrm{RTE93}_i = {} & b_0 + b_1\mathrm{RTE85}_i + b_2\mathrm{TA}_i + b_3\mathrm{TAR}_i + b_4\mathrm{DPRB}_i \\ & + b_5\mathrm{DPRB2}_i + b_6\mathrm{DPRB3}_i + b_7\mathrm{STATELIM}_i + b_8\mathrm{LCOAL}_i \\ & + b_9\mathrm{CCT}_i + b_{10}\mathrm{PHISCRUB}_i + b_{11}\mathrm{EXTREME}_i + u_i, \end{aligned} \tag{3}$$

where RTE93 is the SO_2 emission rate in 1993 (#/mmBtu); RTE85 is the rate in 1985; TA is a dummy variable equal to 1 for all Table A units; TAR is TA multiplied by RTE85; DPRB is distance from PRB (mile); DPRB2 is the squared distance from PRB; DPRB3 is the cubic distance from PRB; STATELIM is a dummy variable equal to 1 if the unit is subject to SO_2 limits imposed since 1985 by state laws or regulations other than Title IV and effective in 1993; LCOAL is a dummy variable equal to 1 for Table A units located in states that adopted local coal protection provisions after 1990; CCT is a dummy variable equal to 1 if the unit has installed scrubbers in 1993 or before as part of the Clean Coal Technology (CCT) program of the U. S. Department of Energy; PHISCRUB is a dummy variable equal to 1 if the unit is planning to install scrubbers in 1994 or later to comply with Phase I requirements; EXTREME is a dummy variable equal to 1 for four units that are extreme outliers in that they were burning very high-sulfur coal in 1985 and very low-sulfur coal soon thereafter; and u is the error term. Table III provides basic statistics for the sample and predicted signs of each variable's coefficient.

Our specification attempts to capture many of the unit- and location-specific factors determining fuel choice at a particular unit through the variable RTE85 (b_1). By necessity the specification is a year prior to the passage of the 1990 Clean Air Act Amendments, and sufficiently close to the enactment of the Staggers Rail Act (1980) that the effects of railroad deregulation had only begun to be felt. If there was no change in emission rates at the unit level or our other explanatory variables completely accounted for observed reductions in emission rates at the unit level, we would expect this coefficient to be unity.

We impose a common slope coefficient for Table A and non-Table A units across all categories and add three subsets of variables. The first set contains the

[19] The number of Table A units is reduced from the 263 named in the legislation to the 251 used in this sample by the deletion of 6 coal units that were retired by 1993 and 6 oil-fired units. Similarly, the sample does not include 378 coal-fired units that are either too small to be subject to Title IV, unutilized, new, or retired. These 378 units account for only 2% of 1985 heat input and SO_2 emissions at coal-fired units.

TABLE III
Sample Statistics (1039 units)

Variables	Mean	Min	Max	Total	Exp. sign
RTE93 (#/mmBtu)	2.01	0.00	8.08	—	—
RTE85 (#/mmBtu)	2.40	0.08	10.18	—	Positive
TA	0.244	0	1	253	Negative
TAR	1.04	0	10.18	—	Negative
DPRB (mile)	1072	0	1733	—	N.A.[a]
STATELIM	0.071	0	1	74	Negative
LCOAL	0.129	0	1	134	Positive
CCT	0.003	0	1	3	Negative
PHISCRUB	0.023	0	1	24	Positive
EXTREME	0.004	0	1	4	Negative

[a] We have no *priors* for any of the distance variable coefficients.

dummy variables, TA and TAR, used to test for early compliance or the additional effect that is associated with designation as a Table A unit. A dummy variable for the slope coefficient is introduced for Table A, but not for the other categories, because the emission rate is the primary determinant of whether a unit is listed in Table A and we want to allow for any interaction between intercept and slope coefficients. If the hypothesis of early compliance is correct, the two coefficients will jointly predict a lower emission rate for Table A units.

To test the second hypothesis that declining rail rates have reduced emission rates, we use a second set of variables that control for location in relation to the PRB. Ideally, we would use a relative price term in which the delivered cost of PRB coal would be expressed relative to delivered cost of the local coals. The data exist to construct such an index only for some plants and some years, but not for our full sample. Accordingly, we test for evidence of the spatial pattern that would result as cost-minimizing utilities respond to the changing relative prices of competing coals.

We use a third degree polynomial to control for distance instead of a single continuous variable because our a priori expectation is that distance will not affect coal choice uniformly.[20] For locations closest to and farthest away from the PRB, declining rail rates will have little effect on coal choice. For close locations, the low mine-mouth price implies that PRB coals would have been chosen over competing coals in 1985, almost regardless of the ton/mile rate. For far locations, the lower delivered price in 1993 would still be too high to compete with nearby eastern coals. The principal effect of lower rail rates will be felt in some intermediate region in which PRB coals will have become newly competitive. As suggested by Fig. 1, this intermediate zone lies somewhere between 600 and 1000 miles from the PRB. If declining rail rates have caused utilities to switch to PRB coals in such a nonuniform pattern, the three distance coefficients will show statistical significance when tested jointly.

The third set of variables, STATELIM, LCOAL, CCT, PHISCRUB, and EXTREME, account for causes other than the basic two hypotheses and for a data

[20] To increase the number of degrees of freedom used up in estimating the parameters we use a third degree polynomial instead of discrete distance dummies, as in [7]. As we shall see, results do not change.

anomaly. Three states, Wisconsin, Minnesota, and New Hampshire, had enacted acid rain laws or taken regulatory actions to reduce SO_2 emissions that were in effect by 1993, and the 74 coal-fired units affected by these actions are indicated by STATELIM.[21] Next, five states, Kentucky, Illinois, Indiana, Ohio, and Pennsylvania, have enacted legislation or taken other measures to alleviate the impact of Title IV on the local high-sulfur coal industry.[22] Since the only units affected currently by such provisions would be those subject to Phase I, we limit the dummy LCOAL to the 134 Table A units located in these states. We expect coefficients for STATELIM and LCOAL to be negative and positive, respectively.

Three Table A units had already installed scrubbers by 1993 as part of the DOE's Clean Coal Technology Program, and are designated by CCT,[23] and our expectation is that these coefficients will be negative. The possible effect of announced intentions to install scrubbers for Phase I compliance at an additional 24 units is represented by the dummy PHISCRUB.[24] These scrubbers were not in place in 1993, but utilities that are planning to install scrubbers would not be switching to more costly lower-sulfur coals at these units. Accordingly, we expect the coefficient for this variable to be positive.

A categorical variable is also used to isolate some unusual data observations. The final variable, EXTREME, is associated with four Table A units in Missouri which are distinct outliers in that they burned higher-sulfur coal than any other unit in 1985, but were among the lowest emitters in 1993.[25] Their circumstance reflects the unique circumstance that these units are located at mine-mouth plants in the coal producing region with the highest-sulfur coal which by geographic coincidence is also the coal province closest to the PRB from the east (excluding North Dakota lignite).[26]

Before turning to the econometric results, we note that we have not addressed long-term contracts, a prominent but diminishing feature of coal markets. Their effect is to delay any switch to another coal that might be justified for economic or other reasons. Although we believe that the inclusion of an appropriate variable for contracts would improve the explanatory power of the regression, we do not expect the omission of this variable to have a pronounced effect on the relative importance of early compliance or declining rail rates since the contract would delay switching in both cases.

[21] Other states had enacted acid rain laws or regulations, e.g., New York, Michigan, and Massachusetts, but they were not applicable to coal-fired units in 1993.

[22] Various issues of Clean Air Compliance Review (previously Compliance Strategy Review) [15] provide details on attempts to institute local coal protection measures and the challenges raised in opposition. In particular, see the issues of Jan. 15, 1996, Sept. 25, 1995, May 8, 1995, April 10, 1995, Jan. 16, 1995, Sept. 12, 1994, Aug. 29, 1994, Jan. 17, 1994, and Jan. 3, 1994.

[23] These units are Yates #1 and Bailly #7 and #8.

[24] These units are selected based on a review of compliance intentions contained in EPRI [12, 13] and Fieldston [14].

[25] Three units at the Montrose plant switched to PRB coal prior to 1988 and the remaining unit at the Asbury plant switched to PRB coal in 1990.

[26] The Missouri–Kansas seam runs roughly from the northeastern corner of Oklahoma along the Missouri–Kansas border and into central Iowa. Except for a few mine-mouth and small plants, most production from this seam was shut down long ago.

4.3. *Econometric Results*

Results of the ordinary least squares (OLS) regression of Eq. (3) for years 1993 back to 1989 are presented in Table IV. For the year of primary interest, 1993, the basic intercept, dummy, and slope coefficients take significantly different values than zero and unity, the values they would have if there were no discernible change from unit emission rates in 1985. Since the relevant tests indicate nonuniform variance in the error term, we report heteroskedastic-consistent (White) estimates of the standard errors in Table IV and throughout the analysis.[27]

As shown in Table IV, for the year 1993 the coefficients for Table A (b_2 and b_3) fail the 99% significance level when tested individually, but when tested jointly using a Wald test, the hypothesis that Table A has no effect upon observed emissions in 1993 is rejected. Distance from the PRB is highly significant. When tested jointly, the three distance variables (b_4, b_5, and b_6) easily exceed the 99% significance level and, individually, all pass the 99% level.

The coefficients in year 1993 for variables other than Table A or distance have the expected signs and, with one exception, are statistically significant at a level well above 99%. The STATELIM coefficient (b_7) indicates that state-imposed limits in Wisconsin, Minnesota, and New Hampshire caused an additional 0.65 #/mmBtu reduction in the emission rate beyond what would be otherwise expected in these states. The LCOAL coefficient (b_8) suggests that state actions to protect local coal have resulted in 0.54 #/mmBtu less of a reduction in the emission rate at these Table A units. As expected, the three early scrubbers that are part of the DOE's Clean Coal Technology Program (b_9) show a large reduction in emission rate over what would otherwise have been expected for these units. The PHISCRUB coefficient (b_{10}), denoting the 24 units that have announced the intent to install a scrubber for Phase I compliance, has the expected positive sign, but the effect is not statistically discernible.[28] Finally, no broader meaning can be attached to the very significant coefficient for EXTREME (b_{11}) that represents very special circumstances.

When the regression is run with unit emission rates in 1992, 1991, 1990, and 1989 as the dependent variable, the same qualitative results are obtained, but with further indication of the effects of declining rail rates and Table A. As shown in Table IV, distance from the PRB is always significant in these years and increasingly so with each advancing year. In contrast, the Table A coefficients do not show any statistical significance in 1989-1992. These regressions suggest that 1993 is the first year in which Table A had begun to make a difference in SO_2 emissions.

In summary, except for the announced intention to install a scrubber, we find that all of the factors expected to influence SO_2 emissions did so. With respect to our two hypotheses, both Title IV and declining rail rates had an effect in 1993.

[27] White, Goldfield–Quandt, and Breusch–Pagan tests all indicate heteroskedasticity at the 99% significance level. Attempts at removing the heteroskedasticity by several transformations of the data were unsuccessful; hence, for testing joint hypotheses, we rely on the OLS estimator with robust variances and the Wald test, instead of the F test [16].

[28] Since it is occasionally asserted that scrubbers are installed only as a result of the local coal provisions captured by the variable LCOAL, we note that 11 of the 24 units intending to install scrubbers for Phase I compliance are not located in these five states, and that 3 are located in states with no coal production whatsoever (New York and New Jersey).

TABLE IV
OLS Results of Specification (3) for Years 1993–1989[a]

	RTE93	RTE92	RTE91	RTE90	RTE89
RTE85[b]	0.7356	0.7851	0.7857	0.8167	0.8261
	(6.6377)	(5.6310)	(5.2312)	(6.2322)	(5.1447)
TA	−0.5290	−0.1046	−0.2394	−0.1831	−0.1683
	(2.9960)	(0.6690)	(1.4880)	(1.2880)	(1.0650)
TAR	0.0660	0.0173	0.0700	0.0650	0.0745
	(1.0690)	(0.3260)	(1.1990)	(1.4030)	(1.4780)
DPRB	−4.43E − 03	−3.88E − 03	−3.79E − 03	−2.15E − 03	−7.23E − 04
	(5.2340)	(4.9930)	(4.7070)	(3.5840)	(1.2710)
DPRB2	5.86E − 06	5.07E − 06	5.09E − 06	3.13E − 06	1.55E − 06
	(5.8710)	(5.5520)	(5.4250)	(4.4420)	(2.3100)
DPRB3	−1.99E − 09	−1.70E − 09	−1.76E − 09	−1.11E − 09	−6.14E − 10
	(5.8200)	(5.4170)	(5.5090)	(4.5720)	(2.6510)
STATELIM	−0.6532	−0.3768	−0.3850	−0.4490	−0.5072
	(5.5240)	(3.4720)	(3.4090)	(3.9960)	(4.4250)
LCOAL	0.5406	0.2510	0.3112	0.2251	0.2036
	(5.1190)	(2.8010)	(3.2380)	(2.7990)	(2.8100)
CCT	−3.7563	−2.8853	−0.0582	−0.0329	−0.3799
	(9.6110)	(2.2770)	(0.8130)	(0.3940)	(2.6590)
PHISCRUB	0.1403	0.1045	0.1080	0.1618	0.0558
	(0.8240)	(0.6610)	(0.8560)	(1.7360)	(0.7400)
EXTREME	−5.9212	−6.2740	−6.5651	−6.2669	−5.2784
	(18.3120)	(21.3070)	(21.0880)	(18.7890)	(3.9770)
CONSTANT	0.8080	0.6807	0.6733	0.3402	0.0258
	(4.0030)	(3.6330)	(3.3790)	(2.3070)	(0.2020)
Wald-stat. Table A[c]	17.22	0.61	2.22	2.01	2.32
Wald-stat. distance[c]	123.01	112.71	81.61	83.27	57.29
R-squared	0.77	0.80	0.80	0.85	0.83
No. observations[d]	1039	1037	1029	1020	1010

[a] t-statistics, which are shown in parentheses, were calculated using heteroskedastic-consistent estimates for the standard errors.

[b] t-statistics are calculated with H_0: $\beta = 1$.

[c] For the Wald tests, the critical values for 99% significance are 10.60 and 16.75 for Table A and distance, respectively.

[d] Number observations differs among years due to some non-Table A units with zero SO_2 emissions.

The Title IV effect is significant only in 1993, in contrast to the clearly discernible influence of distance from the PRB, our proxy for declining rail rates, in all years.[29]

4.4. *The Time and Spatial Dynamics of the Emission Rate Decline*

The penetration of midwestern markets by PRB coals can be described as an advancing front resulting from a complex interaction of lower rail rates for western coal, transportation and delivery capabilities, contract constraints, and technical

[29] Our results are robust to alternative specifications (quadratic, log-log, and specification (3) without the EXTREME variable) and to an alternative sample in which only units with 1985 emission rates above 2.5 #/mmBtu were included. These results are available upon request from the authors.

limitations concerning the extent to which boilers built for bituminous coals can be adapted to burn lower rank, subbituminous coals. As noted above, the effect will be most evident in some intermediate zone beyond where PRB coals already dominate and not so far away that these distant coals remain uncompetitive even with lower transportation rates. Figure 1 provided one picture of the geographic expansion of this frontier. The polynomial approximation of the effect of distance from the PRB in Eq. (3) can be used to illustrate and quantify the same effect.

We use the results of Eq. (3) to predict emissions rates for each year from 1989 through 1993. To isolate the effects of distance from PRB, we consider a representative unit with an emission rate of 2.5 #/mmBtu in 1985 and set all dummy variables equal to zero (including Table A). Two patterns clearly emerge from the results presented in Fig. 2. First, the effect is progressive with time and strongest in a zone extending from 400 to 1000 miles from the PRB. For instance, at a distance of 600 miles, an expected reduction of 17%, to 2.08 #/mmBtu, could be observed by 1989, and a further reduction over the next four years to an expected level of 1.67 #/mmBtu in 1993. Second, the effect diminishes with increasing distance, so that at 1000 miles from the PRB, the expected reduction in 1993 is roughly that which was achieved four years earlier for plants located 500 miles closer to the PRB. At a distance of 1200 miles, the effect largely disappears.[30]

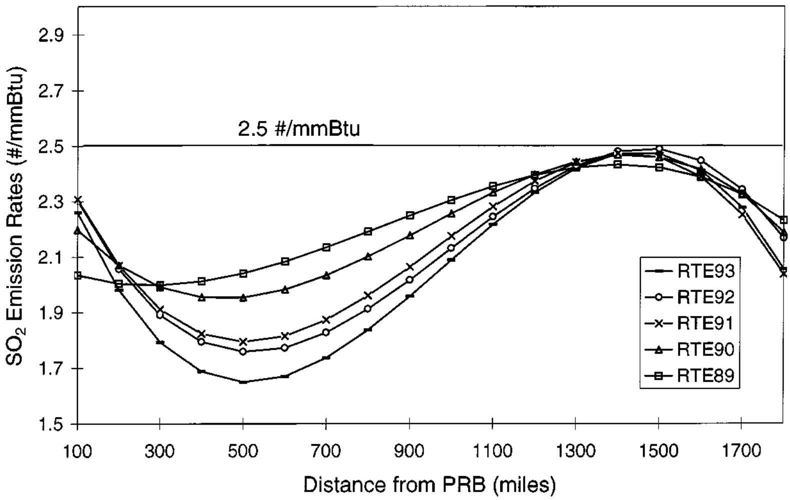

FIG. 2. Predicted SO_2 emission rates by distance from PRB: 1989–1993.

[30]One of the referees raised a question about the reduction of emissions indicated by the polynomial fit for plants located beyond 1500 miles. Observations at these distances from the PRB are sparse, and we suspect that the indicated reduction in emission rates reflects little more than an almost out-of-sample extrapolation of the polynomial, dictated by the much greater density of units in the 400–1500 mile range. A similar out-of-sample effect can be observed for the close-in region within 400 miles where there are in fact no units with emissions at 2.5 #/mmBtu or higher.

4.5. *A Quantitative Summary*

The relative effect of the two hypotheses, early compliance and declining rail rates, can be quantified with the help of the econometric analysis presented above. Table V presents a decomposition of the reduction in SO_2 emissions into constituent elements by the use of the regression coefficients to simulate the various effects. The difference presented in this table is that between the regression estimate of the 1993 emissions, obtained by multiplying actual 1993 heat input by the fitted estimates of unit emission rates, and a counterfactual estimate formed by multiplying the 1993 heat input for each unit by that unit's 1985 emission rate. When summed across units, the counterfactual provides an estimate of what aggregate SO_2 emissions would have been in 1993 absent any reduction in emission rates, but allowing for the growth of demand for electricity and for changes in the dispatch of generating units as observed in 1993.

The first panel in Table V presents the counterfactual and full regression estimates for 1993 emissions, as well as actual 1985 and 1993 emissions for reference. The second panel attributes the reduction from the counterfactual to the various causes and locates those reductions at Table A and non-Table A units. Two general causes are simulated: (1) changing sulfur economics, as indicated by the intercept (b_0) and the coefficients for RTE85 (b_1), the distance variables (b_4, b_5, and b_6), and EXTREME (b_{11}); and (2) Title IV related factors, as indicated by early compliance (b_2 and b_3), state limits (b_7), local coal provisions (b_8), the intended installation of scrubbers (b_{10}), and the Clean Coal Technology program (b_9).

TABLE V

SO_2 Emissions and Emissions Reduction

	All units[a]	Table A units[a]	Non-Table A units[a]
	Emissions		
Actual 1985	15.27	9.15	6.12
Actual 1993	13.75	7.55	6.20
Counterfactual 1993	16.04	9.29	6.75
Estimated 1993	13.87	7.61	6.26
	Emissions reduction		
Actual 1985 to actual 1993	1.52	1.60	−0.08
Counterfactual 93 to estimated 93	2.17	1.68	0.49
	Decomposition of the reduction from the counterfactual		
(a) Changing sulfur economics	2.00	1.68	0.32
(b) Title IV related factors	0.18	0.00	0.18
Early compliance	0.54	0.54	0.00
Other state limits	0.22	0.04	0.18
Installing scrubbers	−0.06	−0.06	0.00
Clean coal technology	0.07	0.07	0.00
Local coal provisions	−0.59	−0.59	0.00

[a] Million tons of SO_2.

The effect of each is calculated by first setting all the dummies for Title IV related factors equal to zero, summing emissions across units, classifying the units by Table A status, and calculating the difference from the counterfactuals for each category. Then, the effect of Title IV related factors is estimated by setting the respective dummies to 1, summing, and calculating the further changes in emissions.

The relative strength of Title IV related causes and of changing coal economics depends on how one views the indicated effect of the local coal provisions. Changing coal economics accounts for about 2.0 million tons of the reduction from the counterfactual; however, the 760,000 ton reduction attributed to early compliance and state limits is almost entirely offset by the indicated effects of local coal provisions. Given our thesis that PRB coals were invading midwestern high-sulfur markets independently of Title IV, it is possible that local coal provisions might have been proposed without Title IV (as they were in Oklahoma), although Title IV provides a far more justifiable rationale for protective action than loss of competitiveness.[31] When the local coal provisions are considered part of the Title IV related effects, as in Table V, changing coal economics has had 10 times more effect than Title IV in reducing SO_2 emissions before 1995. When the local coal provisions are considered a part of changing coal economics, the effect is still twice that of Title IV (0.76 vs. 1.41 million tons). In either case, the aggregate effect of changing coal economics is more important than Title IV related causes in accounting for the pre-1995 reduction of emissions.

Of course, what is true for the whole is not necessarily true for the parts. It should be evident from our use of dummies for Title IV effects and the polynomial specification for distance that for any given unit the relative strength of the two effects depends on location. In addition, the coefficient estimates are not exact predictors. We have performed parameter restriction tests on the relative strength of the two effects to take into account the underlying imprecision of any point estimate and the effects of location. For a Table A unit that burned 3.5 #/mmBtu coal in 1985 and is located 600 miles from the PRB, we found that the distance effect is anywhere from 1.5 to 12.8 times stronger than the Title IV effects in explaining the decline in the emission rate by 1993. For the same unit 1000 miles from the PRB, the distance effect ranges from being weaker, 0.6, to 7.5 times stronger.[32]

Any interpretation of the two effects leads to the conclusion that changing sulfur economics has made a significant contribution to the aggregate reduction of SO_2 emissions observed between 1985 and 1993. Even under the most conservative interpretation, changing coal economics has more than offset the effects of load growth (approximately 720,000 tons since 1985) and caused a continuing decline in SO_2 emissions, unlike what was predicted in earlier forecasts of emissions absent Title IV. As a result, these earlier forecasts erred in predicting more emissions and a greater quantity of sulfur that would have to be removed to meet the Phase I and Phase II caps on aggregate SO_2 emissions.

[31] In the same vein but with opposite effect, it could be argued also that the Clean Coal Technology Program and the actions of several states in enacting separate acid rain limits were independent of Title IV.

[32] The parameter restriction tests consisted in estimating the range of x for which the null hypothesis b_4 DPRB + $b5$ DPRB2 + b_6 DPRB3 = x (b_2 TA + b_3 TAR) cannot be rejected with 95% confidence.

One further feature of Table V deserves note. The puzzling occurrence of the largest reductions in emissions at Table A units for reasons largely unrelated to Title IV can be explained. Table A units are disproportionately located in the areas most affected by the declining rail rates for PRB coals. Also, by definition, Table A units (a.k.a., the ‘‘big, dirties’’) have higher emission rates and larger generating capacity, so that switching to a lower-sulfur coal has more effect on tons emitted at these units.

V. CONCLUDING REMARKS

We have performed an econometric analysis of unit-level SO_2 emission rates at electric-utility-owned generating plants to determine potential causes of the reduction of aggregate SO_2 emissions that was observed before Title IV became effective in 1995. Our analysis indicates that, as of 1993, designation for early control by Table A has had relatively little effect and that the largest part of the reduction in SO_2 emissions since 1985 is attributable to changes in the economics of coals of differing sulfur content. The implication for allowance prices is clear. If the emission reduction imposed by Title IV is less than had been initially anticipated, the price will be lower. In effect, the marginal abatement cost curve has shifted downward, such that the total and marginal cost of meeting the unchanged emission cap imposed by Title IV is lower.

Based on the distinct geographic pattern of observed emission reductions and the consistently large statistical significance of distance in our regressions, we believe that the principal cause of the change in the economics of coal choice is the reduction of rail rates out of the Powder River Basin (PRB). The reduction of rail rates was a result of the deregulation of the railroads in the 1980s. This development made a very low-sulfur coal economically attractive in areas where local, higher-sulfur coals had previously dominated. It is a geographic coincidence, and a felicitous one, that the market being captured by the lower delivered price of PRB coal encompasses many of the plants designated for early control in Phase I. Switching to lower cost PRB coals has probably been impeded by long-term contracts and the often limited ability of plants built for midwestern bituminous coals to burn lower rank, subbituminous coals. However, time and a surprising degree of innovation in blending and the adaptation of existing plants have and will continue to reduce these impediments.

Our analysis has been conducted within a static framework in which productivity improvements in rail transportation and the consequent lower rates are treated as exogenous to Title IV. Several observers [3, 4, 29] advance the argument that the flexibility associated with emissions trading under Title IV, and more particularly the lack of any technology mandate, has encouraged innovation and investment in a wide array of SO_2 compliance options, including the transportation of low-sulfur coal from the West. Emissions trading under Title IV has likely stimulated innovation in compliance, but we are not aware of any studies that have addressed the issue of endogeneity and of inducement mechanisms empirically. In the present instance, we would observe that productivity improvements in rail transport were being realized and that boilers were being modified to accommodate cheaper PRB coals before emissions trading became part of a serious proposal to address acid rain concerns in 1989.

There are several policy-related implications of this analysis. First, it has been maintained that low allowance prices and the alleged low volume of trades indicate that the allowance trading is not ''working'' [31]. This argument is fallacious in that neither the price nor the volume of trading imply much about the functioning of any market, but our analysis shows that there are good reasons for allowance prices to be less than had been expected and that no appeal need be made to market failure.

Second, to the extent that our analysis contributes to an explanation of the relatively low price of allowances to date, it provides strong support for the market-revealing properties of auctions. In this case, it is evident that expert and informed opinion failed to anticipate the reduction in rail rates or the effect on coal choice. That a forecast should turn out to be off the mark is not so surprising, but the experience here demonstrates the importance of having a market alternative that can challenge or confirm expert opinion, especially where compliance options with long lead times require early decisions. In this instance, a number of intentions to build scrubbers were deferred or dropped after the first auction revealed that overcompliance might not be worth \$300–400 a ton of SO_2 removed.

Finally, one cannot help but be impressed by the cumulative effect of reliance on market mechanisms. The cost of compliance has been reduced in the Midwest by the earlier embrace of market mechanisms in an associated industry, and the market mechanism incorporated in Title IV will permit these cost savings to be transmitted to other regions beyond the reach of PRB coals. It is impossible to know what would have happened to rail rates for PRB coals if the railroads had continued to be regulated, but experience with deregulated industries suggests that we would have experienced neither the much lower rail rates nor the serendipitous reduction in the cost of meeting other societal objectives.

REFERENCES

1. D. R. Bohi and D. Burtraw, Avoiding regulatory gridlock in the acid rain program, *J. Policy Anal. Management* **10**, 676–684 (1991).
2. D. R. Bohi and D. Burtraw, Utility investment behavior and the emissions trading market, *Res. Energy* **14**, 129–153 (1992).
3. D. Burtraw, The SO_2 emissions trading program: Cost savings without allowance trades, *Contemp. Econom. Policy* **14**, 79–94 (1996).
4. D. Burtraw and B. Swift, A new standard of performance: An analysis of the Clean Air Act's acid rain program, *Environ. Law Reporter News Anal.* **26**, 10411–10423 (1996).
5. T. N. Cason, Seller incentive properties of EPA's emission trading auction, *J. Environ. Econom. Management* **25**, 177–195 (1993).
6. T. N. Cason, An experimental investigation of the seller incentives in the EPA's Emission Trading Auction, *Amer. Econom. Rev.* **85**, 905–922 (1995).
7. A. D. Ellerman and J. P. Montero, ''Why are Allowance Prices so Low? An Analysis of the SO_2 Emissions Trading Program,'' Working Paper 96-001WP, Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA (1996).
8. A. D. Ellerman, R. Schmalensee, P. L. Joskow, J. P. Montero, and E. M. Bailey, ''Emissions Trading under the U.S. Acid Rain Program: Evaluation of Compliance Costs and Allowance Market Performance,'' Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology, Cambridge, MA (1997).
9. Energy Information Administration, ''Trends in Contract Coal Transportation: 1979–1987,'' Report DOE/EIA-0549, Department of Energy, Washington, DC (1991).

10. Energy Information Administration, ''Electric Utility Phase I: Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990,'' Report DOE/EIA-0582, Department of Energy, Washington, DC (1994).
11. Energy Information Administration, ''Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation,'' Report DOE/EIA-0597, Department of Energy, Washington, DC (1995).
12. Electric Power Research Institute, ''Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990,'' Report EPRI TR-102510, Electric Power Research Institute, Palo Alto, CA (1993).
13. Electric Power Research Institute, ''The Emission Allowance Market and Electric Utility SO_2 Compliance in a Competitive and Uncertain Future.'' Report EPRI TR-105490s, Electric Power Researh Institute, Palo Alto, CA (1995).
14. Fieldston, ''Fieldston's Guide to Phase I and Phase II units,'' 4th ed., Fieldston Publications, Washington, DC (1994).
15. Fieldston, ''Clean Air Compliance Review,'' selected issues, Fieldston Publications, Washington, DC (1994–1996).
16. W. H. Green, ''Econometric Analysis,'' Prentice-Hall, Englewood Cliffs, NJ (1990).
17. R. W. Hahn and G. Hester, Marketable permits: Lessons for theory and practice, *Ecol. Law Quart.* **16**, 361–406 (1989).
18. R. W. Hahn and C. May, The behavior of the allowance market: Theory and evidence, *Electricity J.* **7**, 28–37 (1995).
19. ICF Resources Incorporated, ''Comparison of the Economics Impacts of the Acid Rain Provisions of the Senate Bill (S.1630) and the House Bill (S.1630),'' Draft Report prepared for the U.S. Environmental Protection Agency, Washington, DC (July 1990).
20. P. L. Joskow, R. Schmalensee, and E. M. Bailey, The Development of the Sulfur Dioxide Emission Market, *Amer. Econ. Rev.*, forthcoming.
21. R. Locke and D. P. Harkawik (Eds.), ''The New Clean Air Act: Compliance and Opportunity,'' Public Utilities Reports, Arlington, VA (1991).
22. J. P. Montero, Marketable pollution permits with uncertainty and transaction costs, *Res. Energy Econom.*, 20, 27–50 (1998).
23. W. D. Montgomery, Markets in licenses and efficient pollution control programs, *J. Econom. Theory* **5**, 395–418 (1972).
24. National Coal Association, ''Reduction in Sulfur Dioxide Emissions at Coal-Fired Electric Utilities: The Trend Continues,'' National Coal Association, Washington, DC (1987).
25. R. Rico, The US allowance trading system for sulfur dioxide: An update on market experience, *Environ. Res. Econom.* **5**, 115–129 (1995).
26. R. N. Stavins, Transaction costs and tradeable permits, *J. Environ. Econom. Management* **29** 133–148 (1995).
27. T. H. Tietenberg, ''Emissions Trading: An Exercise in Reforming Pollution Policy,'' Resources for the Future, Washington, DC (1985).
28. U.S. Environmental Protection Agency, Acid Rain Division, ''The Acid Rain Database Version 1 (ARDBV1),'' prepared by E.H. Pechan & Associates, Inc., Contract 68-D3-0005, Washington, DC (1995).
29. U.S. Environmental Protection Agency, Acid Rain Division, ''Acid Rain Program Update No. 3: Technology and Innovation,'' EPA Report 430-R-96-004, Washington, DC (1996).
30. U.S. Government Accounting Office, ''Allowance Trading Offers an Opportunity to Reduce Emissions at Less Cost,'' Report GAO/RCED-95-30, Washington, DC (1994).
31. M. Wald, Acid-rain pollution credits are not enticing utilities, *New York Times*, June 5 (1995).
32. J. Winebrake, A. E. Farrell, and M. A. Bernstein, The Clean Air Act's sulfur dioxide emissions market: Estimating the costs of regulatory and legislative intervention, *Res. Energy Econom.* **17** 239–260 (1995).