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The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update

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Preface

Section 205(a)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information. To assist in meeting these responsibilities in the area of electric power, EIA has prepared this report, *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update.*

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The legislation that created EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. Its responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers, as well as by academia, the Congress, and the general public. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

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Executive Summary

The Clean Air Act Amendments of 1990 address numerous air quality problems in the United States that were not entirely covered in earlier legislation. One of these problems is acid rain caused by sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from fossil-fueled electric power plants and, to a lesser extent, from other industrial and transportation sources.

Title IV of the Act created a two-phased plan, administered by the U.S. Environmental Protection Agency (EPA), to reduce acid rain in the United States. Phase I runs from 1995 through 1999, and Phase II, which is more stringent than Phase I, begins in 2000. Title IV contains a table listing 261 generating units that are required to comply with Phase I. They are generally referred to by EPA as Table 1 units. Most of these units are coal fired with relatively high emissions. An additional 174 units are participating in Phase I based on the rules established by EPA, allowing a utility to designate substitution or compensating units as part of their Phase I compliance plans.[1] Therefore, 435 units are now considered Phase I units. More than 2,000 units will be affected by Phase II.

This report updates and expands a report published by the Energy Information Administration in 1994 titled, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990;* it describes the strategies used to comply with the Acid Rain Program in 1995, the effect of compliance on SO_2 emissions levels, the cost of compliance, and the effects of the program on coal supply and demand.

SO_2 Emissions Compliance Results in 1995

The acid rain program allocated emissions allowances to Phase I units, authorizing them to emit one ton of SO_2 for each allowance. Some utilities obtained additional allowances from three auctions and from bonus provisions in the Act. All 435 generating units had sufficient allowances to comply with Title IV in 1995. By complying with Title IV, Phase I units significantly reduced their SO_2 emissions compared to previous years; they emitted 5.3 million tons of SO_2 in 1995, 45 percent less than the 9.7 million tons emitted in 1990, and 34 percent lower than the 8.0 million tons emitted in 1994. In contrast, non-Phase I units emitted 6.6 million tons in 1995, 12 percent higher than the 5.9 million tons they emitted in 1990, and 5 percent higher than the 6.3 million tons they emitted in 1994.

Estimated SO_2 Compliance Costs

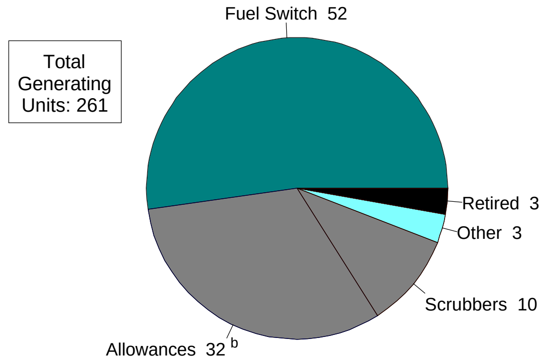
Industry-wide annualized compliance costs are estimated at $836 million (1995 dollars). These costs represent only 0.6 percent of the $151 billion electric operating expenses of investor-owned utilities in 1995. Using scrubbers is estimated to cost $322 per ton of SO_2 removal and is the most expensive compliance method. Modifying a high sulfur bituminous coal-fired plant to burn lower sulfur subbituminous coal, which is estimated to cost $113 per ton of SO_2 removal, is the least expensive.

Compliance Methods Used by Table 1 Units in 1995

A utility could use one or more of the following compliance methods: (1) fuel switching and / or fuel blending with lower sulfur coal, (2) obtaining additional allowances, (3) installing flue gas desulfurization equipment (i.e., scrubbers), (4) using previously implemented emissions controls, (5) retiring units, (6) boiler repowering, (7) substituting Phase II units for Phase I units, and (8) compensating Phase I units with Phase II units. Most utilities (52 percent of Table I units) used fuel switching and blending in 1995 (Figure ES1). This method accounted for 59 percent of the reduction in SO_2 emissions in 1995 compared to 1985 (Figure ES2). Competitive prices of lower sulfur coal, low shipping costs, lower than expected

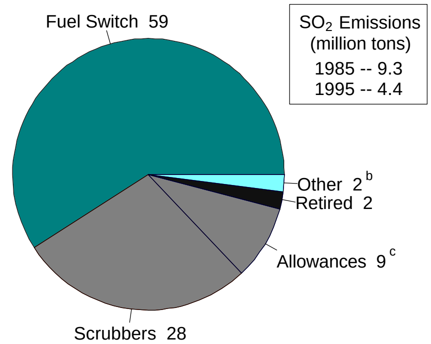
[1] Phase I affects 435 generating units powered by 445 boilers. Title IV states that 261 generating units are to be covered in Phase I of the program as Table A units (subsequently referred to in EPA's regulations as Table 1 units). These 261 generators are attached to 263 boiler units. Miami Fort generator 5 has two boilers. R.E. Burger generator 3 has two boilers. Similarly, the 182 boilers brought into Phase I as substitution and compensating units are attached to 174 generators.

Figure ES1. Compliance Methods Used by Table 1 Units in 1995[a]
(Percent of Table 1 Units)



[a]Does not include 174 substitution and compensating units.
[b]Includes switching to natural gas or petroleum and repowering.
Source: Energy Ventures Analysis, Inc., *The Utility Report*, December 1995.

Figure ES2. SO_2 Reductions by Compliance Method at Table 1 Units in 1995 [a]
(Percent of SO_2 Reductions)



[a]Does not include 174 substitution and compensating units.
[b]Includes switching to natural gas or petroleum and repowering.
[c]Nine percent of the 1995 SO_2 emissions reductions were at units that used allowances as their compliance method. The average sulfur content of coal consumed by these units was reduced by 16 percent from 1985 to 1995.
SO_2 = Sulfur dioxide.
Note: Percent reductions of SO_2 emissions were computed using 1985 as the base year.
Source: **1985 Emissions**: U.S. Environmental Protection Agency, *National Allowance Data Base*, Version 2.11 (January 1993). **1995 Emissions**: Acid Rain Division, U.S. Environmental Protection Agency.

costs for boiler modifications, and little deterioration in plant performance with lower sulfur coal were the reasons most utilities switched to lower sulfur coal. Also, because the industry is restructuring for competition, some utilities are reluctant to commit funds for more expensive solutions. For instance, scrubbers, which are relatively expensive, were chosen by only 10 percent of Table 1 units.

Effects of Compliance on Regional Coal Supply and Demand

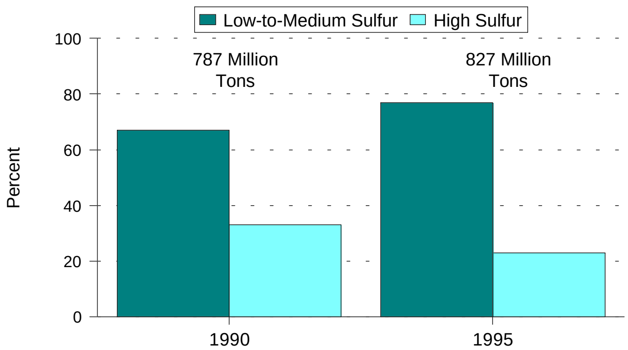
Because fuel switching has been the compliance method used by most utilities, lower sulfur coal sales in the United States have increased substantially. In 1990, for example, low-to-medium sulfur coal accounted for 67 percent of total coal receipts at electric utilities, increasing to 77 percent by 1995 (Figure ES3). This switch to lower sulfur coal has affected regional coal distribution patterns. Between 1990 and 1995, sales of low-to-medium sulfur coal from the Powder River basin (Wyoming and Montana) increased by 78 million tons; sales from the central Appalachian region (Virginia, eastern Kentucky, and southern West Virginia) increased by 15 million tons; and sales from the Rocky Mountains (Colorado and Utah), increased by 10 million tons. In contrast, for the same period, sales of higher sulfur coal from the northern Appalachian region (Maryland, Pennsylvania, Ohio, and northern West Virginia) decreased 29 million tons; and sales from the Illinois basin (Illinois, Indiana, and Western Kentucky) decreased by 40 million tons.

Compliance Strategies and Costs of Six Utilities

Compliance strategies and costs were examined in detail for six utilities with a total of 71 units (22.8 gigawatts of generating capacity) affected by Phase I. Most of the units were switched to lower sulfur coal to meet their SO_2 emissions limitations. A few scrubbers were installed, but they were expensive relative to other compliance strategies. Substitution units, which in most instances generated extra emissions allowances, were used extensively by these utilities. Although the compliance costs represented a relatively small percentage of the utilities' total costs, the costs varied widely among the six. Average costs for SO_2 and NO_x controls and continuous emissions monitoring systems[2] ranged from a low of $16.39 per

[2] Continuous emissions monitors were required to be operational on November 15, 1993 for Phase I units and on January 1, 1995 for Phase II units (with the exception of NO_x / CO_2 at oil- and gas-fired units).

Figure ES3. U.S. Coal Receipts at Electric Utility Plants by Sulfur Level, 1990 and 1995
(Percent)



Note: High sulfur level is greater than 2.5 pounds of sulfur per million Btu. Low-to-medium sulfur level is less than or equal to 2.5 pounds of sulfur per million Btu.

Source: Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

kilowatt at Cincinnati Gas & Electric to $208.90 per kilowatt at Southern Indiana Gas and Electric Company.

Annual operation and maintenance costs (which in this analysis are primarily allowance purchases) ranged from a high of $19.4 million at Illinois Power to a low of $1.8 million at Potomac Electric Power Company. Depreciating capital costs over 15 years results in annual capital costs ranging from just over $1 to almost $14 per kilowatt of Phase I capacity.

Phase II Compliance Strategies

To meet stronger emissions limits under Phase II, some utilities are planning ahead by overcomplying in Phase I. For example, some utilities are installing scrubbers now instead of using a less expensive option. Many utilities have not finalized their Phase II compliance plans. One survey of 116 utilities conducted by the Industrial Information Services Company found that 41 percent of the respondents will switch fuels for Phase II and 28 percent will acquire additional emission allowances. For many utilities, fuel switching has proved to be the most cost-effective choice in Phase I, and many of them will probably continue this strategy in Phase II. For utilities selecting allowances as a strategy for Phase II, extra allowances can be obtained from numerous sources.

Utilities receiving extra allowances for installing scrubbers or for complying earlier than required are selling some of their allowances at relatively low prices. Some higher sulfur coal producers have bundled emissions allowances with their sales to help maintain their customer base. It is estimated that only 12 to 20 gigawatts of capacity may be scrubbed to comply with Phase II because a number of utilities that had originally planned to install scrubbers have either deferred installation, or canceled them in favor of fuel switching or purchasing allowances.

1. Introduction

The Clean Air Act Amendments of 1990 (CAAA90), Public Law 101–549, are the latest revisions to the Clean Air Act. Among the numerous provisions of CAAA90 is Title IV, which requires the U.S. Environmental Protection Agency (EPA) to establish the Acid Rain Program to reduce the adverse effects of acidic deposition popularly known as acid rain. Acid rain is formed largely from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) that are emitted primarily by fossil-fueled electric power plants, other industrial sources, and transportation sources. The SO_2 reduction provisions of Title IV of the CAAA90 (hereafter referred to as Title IV) are noteworthy and creative because they represent the first large-scale attempt to set overall emissions levels by using marketable licenses (allowances) and a choice of compliance methods to control emissions rather than using regulations that specify what actions must be undertaken (command and control). An allowance permits the emission of 1 ton of SO_2. Title IV gives electric utilities several options for reducing emissions, thus introducing flexibility into compliance plans. Because they have several compliance options, many utilities have alternative plans for complying with the Acid Rain Program, depending on the circumstances (Table B1 of Appendix B).

Title IV requires a two-phase tightening of the restrictions placed on fossil-fuel fired power plants. Phase I, from 1995 through 1999, and Phase II, starting in 2000. Phase I mostly affects those power plants that are the largest sources of SO_2 and NO_x. Phase II will affect virtually all fossil-fueled electric power producers, including utilities and nonutilities. Phase II will tighten the annual emissions limits imposed on these large, higher emitting plants, and it will set restrictions on smaller plants fired by coal, oil, and natural gas. Most existing utility units with an output capacity of 25 megawatts or greater and virtually all new utility and nonutility units will be affected in Phase II. Also, other sources of SO_2 (such as industrial facilities) may elect to participate in the Acid Rain SO_2 Program.[1]

Title IV explicitly specifies 261 generating units powered by 263 boiler units at 110 utility plants for Phase I.[2] These 261 units, located in 21 eastern and midwestern States, are referred to as "Table 1" units because they were explicitly identified in Table 1 of the regulation. However, because of provisions in Title IV that allow utilities to use other units to substitute or compensate for those originally specified, 174 additional generating units were affected by Phase I in 1995 (a total of 435 affected generating units) (Figures 1 and 2).

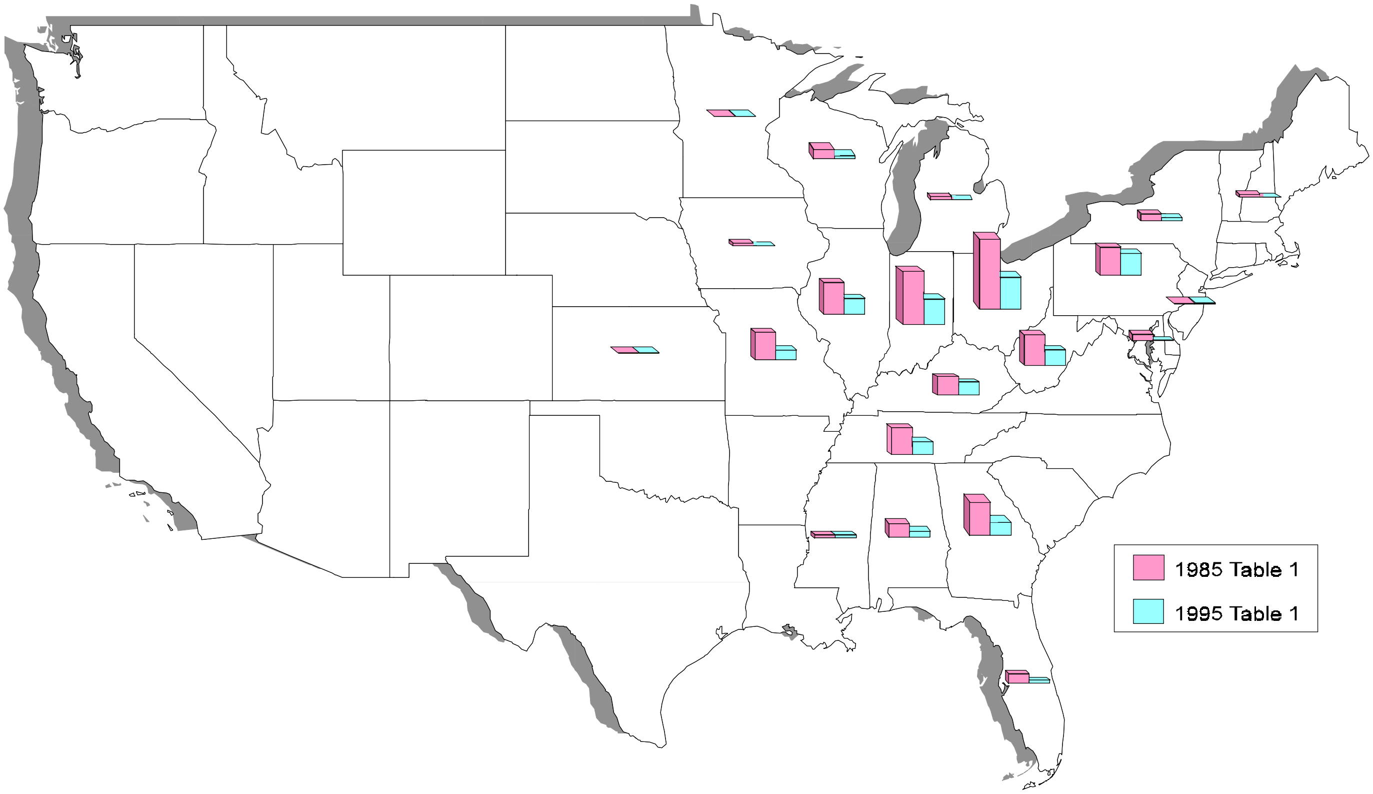
A boiler unit brought into Phase I as a substitution unit can assist a Table 1 boiler unit in meeting its emissions reductions obligations. Utilities may make cost-effective emissions reductions at the substitution unit instead of at the Table 1 unit by achieving the same overall emissions reductions that would have occurred without the participation of the substitution unit. After January 1, 1995, a Table 1 boiler unit may designate any Phase II boiler unit as a substitution unit only if both units are under the control of the same owner or operator. In 1995, 91 Table 1 boiler units designated 167 Phase II boiler units to be substitution units. Of these 91 Table 1 boiler units, almost half were located in the Midwest and almost a quarter were located in the South. Also, almost a third of these Table 1 units designated substitution units that were located at the same plant.[3] The other seven Phase II boiler units that participated in the Acid Rain Program in 1995 entered as compensating units. Table 1 units that reduced their utilization below their baseline may designate compensating units to provide compensating generation that would account for the reduced utilization of the Table 1 unit. A Table 1 unit may designate any Phase II unit as a compensating unit if the Phase II compensating unit is in the Table 1 unit's dispatch system or has a contractual agreement with the Table 1 unit, and if the emissions rate of the compensating unit has not declined substantially since 1985.

[1] Environmental Protection Agency, *Allowance System, Proposed Acid Rain Rule*, 400 / 1-91 / 034 (Washington, DC, December 1991), p.1.

[2] Phase I affects 445 boiler units that are associated with 435 generating units. CAAA90 explicitly states that 261 generating units are to be covered in Phase I of the program as Table A units (subsequently referred to in EPA's regulations as Table 1 units). These 261 generators are attached to 263 boilers. Miami Fort generator 5 has two boilers. R.E. Burger generator 3 has two boilers. Similarly, the 182 boilers brought into Phase I as substitution and compensating units are attached to 174 generators. Boilers are referred to throughout the report because SO_2 is released into the atmosphere by burning fuel in boilers and allowances are deducted from accounts based on boiler emissions.

[3] Environmental Protection Agency, *1995 Compliance Results, Acid Rain Program*, EPA / 430-R-96-012 (Washington, DC, July 1996), p. 1.

Figure 1. Table 1 Unit Emissions, 1985 and 1995
(Tons of SO_2)



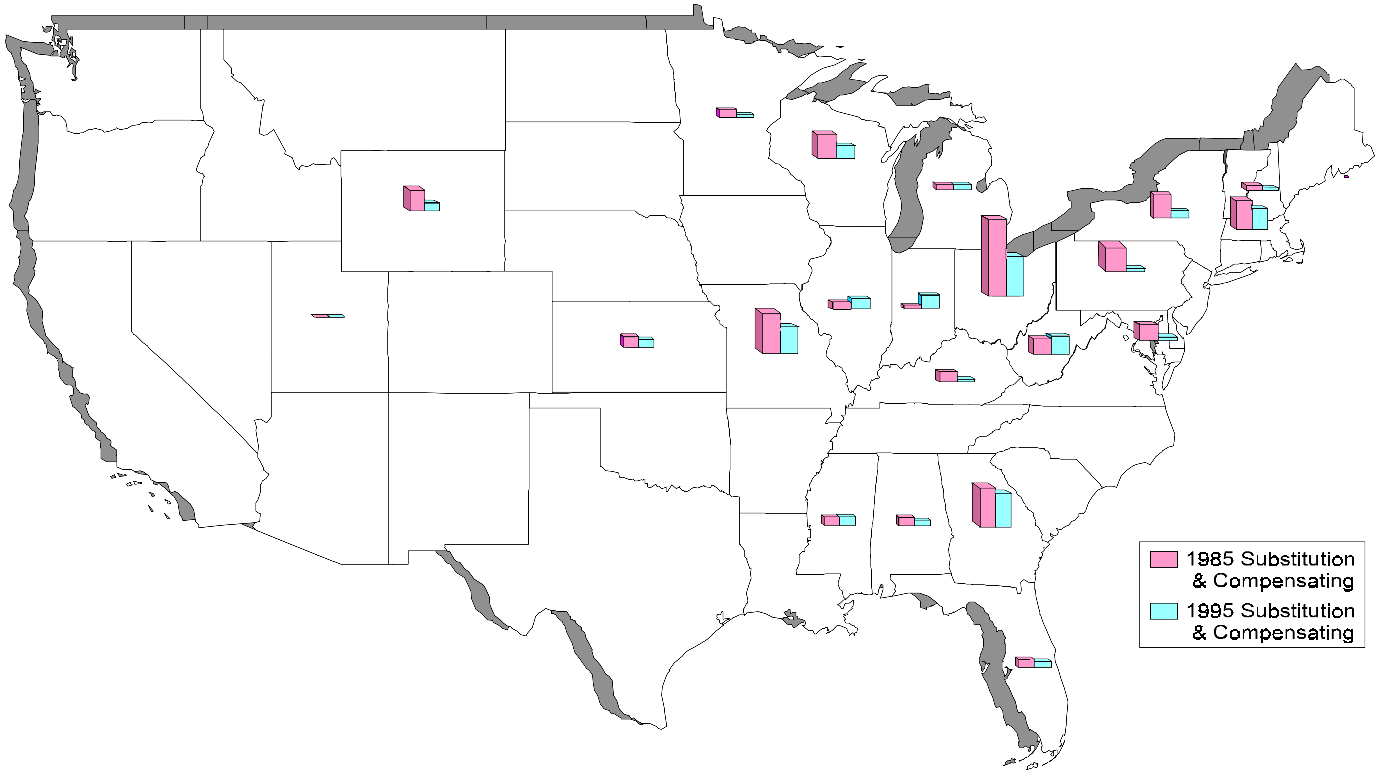
State	1985 Table 1 Unit Emissions Estimates	1995 Table 1 Unit Emissions (from CEMS)	State	1985 Table 1 Unit Emissions Estimates	1995 Table 1 Unit Emissions (from CEMS)
Alabama	297,195	132,645	Mississippi	83,365	56,621
Florida	224,089	108,552	Missouri	746,219	227,525
Georgia	795,476	276,004	New Hampshire	52,535	36,128
Illinois	766,492	392,177	New Jersey	33,735	21,720
Indiana	1,268,745	636,502	New York	173,882	70,486
Iowa	73,873	27,389	Ohio	1,711,128	770,357
Kansas	3,167	2,893	Pennsylvania	671,216	515,804
Kentucky	461,023	320,074	Tennessee	621,923	287,446
Maryland	133,081	119,804	West Virginia	715,483	372,971
Michigan	59,017	13,171	Wisconsin	220,387	54,669
Minnesota	2,033	1,493	**Total**	**9,114,064**	**4,444,431**

CEMS = Continuous Emissions Monitoring System.

Note: Totals may not equal sum of components because of independent rounding.

Source: **1995:** U.S. Environmental Protection Agency, State Summary Data for 445 Phase I Boilers, http://www.epa.gov/acidrain/comprpt/statesum.html. **1985:** Energy Information Administration, Form EIA-867, "Steam-Electric Plant Operation and Design Report."

Figure 2. Substitution and Compensating Unit Emissions, 1985 and 1995
(Tons of SO_2)



State	1985 Substitution and Compensating Unit Emissions Estimates	1995 Substitution and Compensating Unit Emissions (from CEMS)	State	1985 Substitution and Compensating Unit Emissions Estimates	1995 Substitution and Compensating Unit Emissions (from CEMS)
Alabama	25,993	17,350	Mississippi	19,379	24,617
Florida	24,599	22,178	Missouri	140,386	98,522
Georgia	142,033	121,586	New Hampshire	14,265	11,155
Illinois	31,380	40,042	New York	88,686	25,340
Indiana	17,937	44,806	Ohio	281,233	140,635
Kansas	55,567	26,156	Pennsylvania	91,693	13,755
Kentucky	27,151	14,647	Utah	1,783	2
Maryland	15,806	6,018	West Virginia	59,975	63,914
Massachusetts	100,310	72,770	Wisconsin	87,069	52,411
Michigan	21,393	16,330	Wyoming	75,121	30,754
Minnesota	27,645	11,010	**Total**	**1,349,404**	**853,998**

CEMS = Continuous Emissions Monitoring System.

Note: Totals may not equal sum of components because of independent rounding.

Source: **1995:** U.S. Environmental Protection Agency, State Summary Data for 445 Phase I Boilers, http://www.epa.gov/acidrain/comprpt/statesum.html. **1985:** Energy Information Administration, Form EIA-867, "Steam-Electric Plant Operation and Design Report."

Some utilities designated Phase II units as substitution units during Phase I, instead of waiting for Phase II, to take advantage of the Phase I NO_x reductions requirements, which are less stringent than the Phase II requirements. If the utility determines that the benefits of less stringent NO_x requirements outweigh the costs of more stringent SO_2 requirements, substitution becomes more likely.

SO_2 Compliance Results in 1995

During the past decade, utilities with Phase I units have achieved significant reductions in SO_2 emissions, most notably in 1995, the first year of the program. During 1995, 435 Phase I units emitted 5.3 million tons of SO_2 into the atmosphere. This amount was 50 percent lower than the estimated 10.5 million tons they emitted in 1985, and well below EPA's 1995 goal of 8.7 million tons for Phase I units (Table 1).

With coal prices decreasing, particularly lower sulfur coal, some industry observers have suggested that utilities would have switched to lower sulfur coal regardless of Title IV's SO_2 emissions limits. To fully address this issue, however, would require a detailed analysis of regional low- and high-sulfur coal prices and other factors, which is beyond the scope of this report. An analysis at a broader level, however, suggests that Title IV has caused, at least in part, a reduction in SO_2 emissions. While SO_2 emissions from Phase I units have steadily decreased, SO_2 emissions from nonaffected units have increased (Table 1). In 1985, Phase I units were the largest group of SO_2 emitters, accounting for 67 percent of total SO_2 emissions, and non-Phase I units accounted for 33 percent. By 1995, Phase I units emitted 45 percent of total SO_2 emissions, whereas non-Phase I units accounted for 55 percent of the total.

Contents of This Report

In 1994, the Energy Information Administration released an analysis report titled, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*. The material presented here updates that report and provides information on the strategies utilities are using to comply with SO_2 and NO_x emissions reductions requirements during Phase I of Title IV of CAAA90, and provides estimates of the costs incurred by six utilities in implementing these strategies through 1995. The discussion covers four SO_2 compliance strategies: (1) fuel switching and/or blending with lower sulfur coal, (2) obtaining additional allowances, (3) installing flue gas desulfurization equipment (scrubbers), and (4) other compliance strategies. The effects of these strategies on coal supply and demand are also examined. The report describes utilities' plans for Phase II, although many utilities have adopted a wait-and-see approach, choosing to see how the market for allowances develops and how competition in the electric power industry progresses. A key component of this strategy involves the accumulation of excess Phase I allowances, which can be used at any point in the future. This strategy allows utilities to delay installation of pollution control equipment with high capital costs until after 2000. Also, the evolution of the electric power industry toward more competition has led many utilities to view their compliance plans for the future as proprietary; therefore, they are less than forthcoming about these plans.

Other topics presented in this update are the proposed EPA rule for NO_x emissions reductions in Phase II Group 1 and Group 2 boilers, detailed descriptions of the shifts in coal supply, and an evaluation of the structure of the annual SO_2 allowance auction.

Table 1. SO_2 Emissions From Electric Utilities, 1985, 1990, 1994, and 1995
(Million Tons)

	1995 Capacity (GW)	**Total SO_2 Emissions** 1985	1990	1994	1995
Phase I Units	130.9	10.5	9.7	8.0	5.3
	(28)	(67)	(62)	(56)	(45)
Non-Phase I Units	333.2[a]	5.1	5.9	6.3	6.6
	(72)	(33)	(38)	(44)	(55)
Total	**464.1**	**15.6**	**15.6**	**14.4**	**11.9**
	(100)	**(100)**	**(100)**	**(100)**	**(100)**

[a]Includes units that had SO_2 emissions in 1995 only.

Note: SO_2 emissions for 1985, 1990, and 1994 are estimated. Percentages are shown in parenthesis.

Sources: **1995:** U.S. Environmental Protection Agency, "1995 Compliance Results, Acid Rain Program," EPA/430-R-96-012, July 1996. **1994 and prior years:** Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

2. Phase I Effects on Utilities

According to the EPA, all of the Phase I plants, housing 445 Phase I boilers, were in compliance with Title IV at the end of 1995. The 445 Phase I boilers, associated with 435 generating units, had a total capacity of 130.9 gigawatts. This figure includes 261 Table 1 generating units, explicitly referred to in the text of Title IV, with a total capacity of 89.0 gigawatts and 174 substitution and compensating units (totaling 41.9 gigawatts of capacity) brought into Phase I under provisions of Title IV. A profile of the 435 Phase I generating units can be found in Table B1 of Appendix B.

Compliance Options for Phase I

Phase I affects the largest electric utility sources of SO_2 emissions and the units that were brought into the program as substitution or compensating units. In Phase I, affected units are required to have an allowance for each ton of SO_2 they emit or they incur a penalty. Affected units are allocated emissions allowances based on the average annual British thermal units (Btu's) burned from 1985 through 1987 multiplied by 2.5 pounds of SO_2 per million Btu.[4] The initial quantity of allowances in most cases, is not sufficient to meet the amount of SO_2 emitted in 1985. Therefore, Phase I utilities must either reduce their emissions to the level of allowances allocated, or they can acquire additional allowances by purchasing them at an allowance auction or from another allowance owner.

The market-based approach for complying with environmental regulations established a firm annual limit on SO_2 emissions from Phase I units (although with substitution and compensating unit provisions, this annual limit can vary from year to year during Phase I), but permitted allowance trading and a choice of compliance strategies. Utilities with relatively high costs of pollution control can purchase additional allowances from other utilities whose emissions reductions exceed the requirements of Title IV. Together they can meet their emissions requirements more efficiently than if each utility had to meet the SO_2 limits separately. The allowance trading program gives utilities the flexibility to choose among a variety of methods to reduce SO_2 emissions and reduce their pollution control costs at the same time.

A utility could choose one or a combination of the following methods to meet its annual emissions allowance limit:

- Fuel switching and/or blending with lower sulfur coal, cofiring, switching to another fuel
- Obtaining additional allowances
- Installing flue gas desulfurization equipment (scrubbers)
- Using previously implemented controls
- Retiring units
- Boiler repowering
- Substituting Phase II units
- Compensating with Phase II units.

Compliance Methods Chosen

On January 1, 1995, Phase I compliance methods effectively went into operation for the purpose of SO_2 emissions monitoring by EPA. This section includes a discussion of the compliance methods chosen for the 261 Table 1 units and how the compliance methods relate to coal purchase price and specific plant implementation plans. The 174 substitution and compensating units are not included in the discussion.

Fuel Switching and/or Blending

Fifty-two percent (136 units) of the Table 1 units switched to or blended with a lower sulfur coal, accounting for 59 percent of the SO_2 emissions reductions achieved in 1995 (Table 2). These choices were propelled mainly by the innovation of utilities in blending coals of varying sulfur contents to reduce the average SO_2 emissions and by the availability of large quantities of lower sulfur coal on the market at favorable prices. This category includes some units in Kansas, Michigan, New Hampshire, New York, and Wisconsin that had already been switched to lower

[4] "CAAA Phase I Performance: Overcompliance," *Coal* (October 1995), p.11.

Table 2. Profile of Compliance Methods for Table 1 Units

Compliance Method	Number of Generators	Average Age[a] (years)	Affected Nameplate Capacity (megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	1995 Emissions (tons)	Percentage of Total Nameplate Capacity Affected by Phase I	Percentage of SO_2 Emission Reductions in 1995[c]
Fuel Switching and/or Blending .	136	32	47,280	2,892,422	4,768,480	1,923,691	53	59
Obtaining Additional Allowances	83	35	24,395	1,567,747	2,640,565	2,223,879	27	9
Installing Flue Gas Desulfurization Equipment (Scrubbers)	27	28	14,101	923,467	1,637,783	278,284	16	28
Retired Facilities	7	32	1,342	56,781	121,040	0	2	2
Other	8	33	1,871	110,404	134,117	18,578	2	2
Total	**261**	**32**	**88,989**	**5,550,821**	**9,301,985**	**4,444,432**	**100**	**100**

[a]Base year of 1996 was used to calculate average age.
[b]One SO_2 allowance permits one ton of SO_2 emissions.
[c]Base year of 1985 was used to calculate SO_2 emissions reductions.
SO_2 = Sulfur dioxide.

Note: Fuel switching includes Phase I units switched to a lower sulfur coal in the 1990's. This category also includes units using state-mandated previously implemented controls that may have been switched prior to 1990. Other includes units that were repowered and those that switched to natural gas or petroleum. Totals may not equal sum of components because of independent rounding.

Sources: **Compliance Method**: *The Utility Report December 1995, Energy Ventures Analysis*, Inc. **Age and Capacity**: Energy Information Administration, *Inventory of Power Plants 1994,* DOE/EIA-0095(94) (Washington, DC, October 1995). **1985 Emissions**: U.S. Environmental Protection Agency, National Allowance Data Base, Versions 2.11 (January 1993). **1995 Emissions:** Acid Rain Division, U.S. Environmental Protection Agency.

sulfur coal to meet previously implemented controls mandated by State environmental regulations.[5]

It is useful to look at the individual characteristics of a few plants to understand the decisions made regarding switching. This section discusses the variations in the way three plants switched to lower sulfur coal: Ohio Edison's Sammis plant switched to coal from the Central Appalachian region, Associated Electric Cooperatives' Thomas Hill plant switched from Missouri coal in 1990 to lower sulfur coal from the Powder River Basin in 1994 and 1995, and the Coffeen plant of Central Illinois Public Service continued using coal from the Illinois Basin in 1995 as it had in 1990.

The Sammis Plant

The Sammis plant, operated and owned by Ohio Edison, has a coal-fired nameplate capacity of 2,303.5 megawatts with four 185.0 megawatt units, one 317.5 megawatt unit and two 623.0 megawatt units. Units 5, 6, and 7 are Table 1 units and they have a total capacity of 1,563.5 megawatts. In the early and mid-1980's, in response to EPA particulate control requirements and in anticipation of the Phase I compliance requirements, the Sammis plant replaced electrostatic precipitators (ESPs) in units 5, 6, and 7 to accommodate a wide variety of coals. The ESP, one means of removing fly ash from flue gas when fuels are burned in suspension, produces an electric charge on the ash particle to be collected and then attracts the charged particle by electronic forces to the collecting curtain. Fly ash can seriously interfere with the operation of a boiler unit, and, in some low-sulfur coals, can be resistant to being charged. Thus, in many cases, the flue gas must be treated with chemical conditioning agents, such as sulfur trioxide (SO_3) to reduce ash resistivity and to increase the collection efficiency of the ESP.

In 1985 Sammis received 24 percent of its coal from Ohio, 31 percent from Pennsylvania, about 32 percent from West Virginia and the rest from Kentucky.[6] The average sulfur content of the total receipts was 1.67 percent by weight and the average delivered price was $46.76 (1995 dollars) per short ton (191.4 cents per million Btu). In 1990, over 50 percent of Sammis' coal came from Ohio and Pennsylvania.

[5] Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March 1994), p 33.
[6] Federal Energy Regulatory Commission (FERC) Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.”

However, in 1995, coal from Ohio and Pennsylvania was significantly reduced; less than one percent of Sammis' receipts came from Pennsylvania and none came from Ohio. Most of the coal came from southern West Virginia (56 percent) and eastern Kentucky (36 percent) by barge transportation, since Sammis has significant barge unloading capability. The average sulfur content went from 1.67 percent by weight in 1985 to 0.79 percent by weight in 1995 and the average delivered price of coal was reduced by 33 percent (1995 dollars) to $31.23 per ton (128.1 cents per million Btu) in 1995.

Ohio Edison currently operates one lower sulfur coal pile for fueling all generators at the Sammis plant and recently has considered using different types of coal for the various units at the plant. However, that would entail the cost and burden of maintaining multiple coal piles. Ohio Edison estimates that maintaining a single coal pile could cost as much as $1 million less than maintaining two separate piles.

The Thomas Hill Plant

The Thomas Hill plant located in Randolph County, Missouri, is one of two coal-fired plants owned by Associated Electric Coop., Inc. The Hill plant has a capacity of 1,135 megawatts, 465 megawatts of which are affected by Phase I at units 1 and 2. In 1985 and 1990 all coal receipts for the plant originated from Missouri— 2,304,000 and 2,287,000 short tons, respectively. The average sulfur content for the coal in 1985 was 4.18 percent by weight and the delivered price was $46.42 (1995 dollars) per short ton (223.4 cents per million Btu).

In 1992, the Thomas Hill plant received its first shipment of Powder River Basin coal—116,000 tons, 4 percent of its total coal purchases in 1992. In 1995, all coal receipts for the plant originated in Wyoming at an average delivered price of $12.55[7] per short ton (71.8 cents per million Btu) with an average sulfur content of 0.20 percent by weight.

The introduction of Powder River basin coal at the Thomas Hill plant necessitated plant modifications to the coal handling and crushing systems and boiler modifications, including installation of new dampers and soot blowers. Western coal brittleness and dust-forming characteristics sometimes require dust suppression equipment to reduce the potential of explosions.[8] Powder River basin coal is transported to the plant by rail in rotary car dumpers, which are rotated, tilted, and dumped by a specially designed track. In all, the coal-switching modifications totaled approximately $118 million.

Coal receipts in 1995 at the Thomas Hill plant increased to 4,723,000 tons in part because of the lower heat content (8,744 Btu's per pound as compared to a heat content of 10,382 Btu's per pound in 1985).

The Coffeen Plant

Central Illinois Public Service's Coffeen plant located in Montgomery County, Illinois, has two Table 1 units, amounting to a capacity of 1,005.5 megawatts. In 1985, Coffeen received 1,970,000 short tons of coal from Macoupin County, Illinois, with an average sulfur content of 3.68 percent. In 1990, Coffeen received all of its coal from Macoupin County—1,746,000 short tons with 3.54 percent sulfur at $38.69 (1995 dollars) per ton (182.7 cents per million Btu).

In response to Title IV, the Coffeen plant decided to continue using Illinois coal in 1995. This decision was facilitated by renegotiating a contract with the same supplier to provide lower sulfur coal and by modifying the plant with a new limestone addition system and a new electrode design for the ESP, costing approximately $1.3 million and $500,000, respectively.

Under a renegotiated contract, Coffeen received 1,690,000 short tons of coal from Macoupin County with a sulfur content of 0.91 percent by weight and average delivered price of $35.28 per short ton (171.8 cents per million Btu) in 1995, which was 9 percent lower than the 1990 average delivered price.

Total capital costs to comply with the Title IV were approximately $2.2 million with a one-time maintenance cost of approximately $1.5 million. Operating costs have increased by approximately $300,000 a year at the plant.

Obtaining Additional Allowances

An allowance authorizes the utility to emit 1 ton of SO_2. Utilities designated the use of additional allowances as the primary compliance method for 32 percent of the Table 1 units (83 units). In addition to obtaining more allowances, these units reduced their emission levels by 9 percent in 1995 compared to 1985, as they decreased coal

[7] This delivered price is an indication of the competitive price of Western coal. The average price of Wyoming coal delivered to all plants in the State of Missouri in 1995 was $15.36 per short ton.

[8] Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the CAAA90,* DOE/EIA-0582 (Washington, DC, March 1994), p. 19.

consumption by 2.5 million tons and lowered the sulfur content of coal consumed by 16 percent.

Emissions allowances are available from scrubbed plants and from plants switching to lower sulfur coal when these methods produce emissions reductions that exceed the targeted unit's reduction requirements. They are also available from the EPA's distribution of "bonus allowances" to non-Phase I utilities for using energy conservation strategies and to plants which opted to scrub earlier than required.[9] These factors have contributed to an excess of allowances on the allowance market, few participants in allowance trading, and lower than projected market prices. Many attribute the low allowance prices primarily to the recent declines in coal prices.[10] Therefore, utilities have been able to use allowances for the continued burning of higher sulfur coal from current sources or to purchase them at low prices, with plans to use the allowances to defer the higher cost of complying with Phase II.

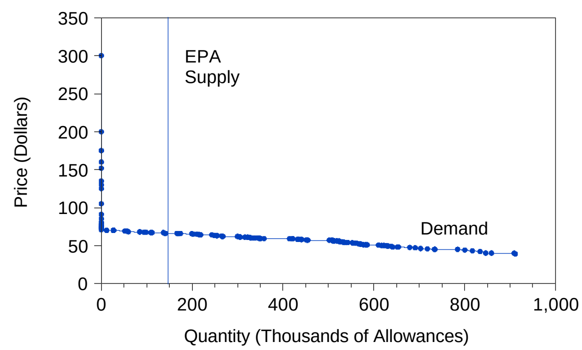
Prices for SO_2 emissions allowances have declined since their initial offering in the 1993 EPA allowance auction run by the Chicago Board of Trade and are well below the $1,500 level that was estimated by various parties around the time of passage of CAAA90[11] (Figure 3).

The allowance market has shown a level of development far removed from the uncertainty associated with the first allowance auction. Sophisticated financial instruments typically associated with commodity markets are now characteristics of the allowance market. Some of these include forward contracts, options, and futures.

Originally, many economists expressed the following concerns with the manner in which EPA conducts the annual auctions each March:[12]

1) EPA, the largest seller in the auctions, has no minimum asking price.
2) Because winning bidders pay the amount they actually bid, a range of winning prices is generated.
3) The lowest-priced offers are matched to the highest-priced bids.

Figure 3. 1996 SO_2 Emission Allowance (Spot Market) Supply and Demand at the EPA Auction, March 1996



SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Note: All bids to the left of the vertical EPA supply at quantity 150,000 were winning bids.)
Source: U.S. Environmental Protection Agency, Acid Rain Division, 1996 EPA SO_2 Allowance Auction Summary.

When EPA adopted the current auction design, it said it would monitor the auctions and identify any necessary changes to the design "that may be required to assure an orderly and competitive market." The General Accounting Office (GAO) has stated its belief that an auction with a single price is consistent with CAAA90 and the goals for the auction expressed in the legislative history. GAO goes on to say that "a single price auction could result in at least the same, if not higher, total proceeds to the extent that the incentive to submit lower bids present in the price-discriminating design would be removed."[13]

In response to the GAO report and general criticism that EPA received regarding the auction, EPA published an advanced notice of proposed rulemaking (ANPRM) in the Federal Register asking market participants whether a change in the auction design would be desired.[14] The majority of commentors responded that changing the design at this time could disrupt the allowance market rather than better inform it, that a change to a single-price

[9] "U.S. Utilities Opt Against Scrubbing," *International Coal Report* (October 30, 1995), p. 5.

[10] Juan-Pablo Montero, A. Denny Ellermen, and Richard Schmalensee, "The U.S. Allowance Trading Program for SO_2: An Update After the First Year of Compliance," Massachusetts Institute of Technology, for the Proceedings of the Second Workshop on Energy Externalities Organized by EC / OECD / IEA, Brussells, September 9-10, 1996, Draft: October 29, 1996, p. 13.

[11] Dallas Burtraw, *Cost Savings Sans Allowance Trades? Evaluating the SO_2 Emission Trading Program to Date*, Resources for the Future, (Washington, DC, February 1996), p. 9.

[12] Communication from Joe Kruger of the Environmental Protection Agency, December 6, 1996.

[13] United States General Accounting Office, *Report to the Chairman, Environment, Energy and Natural Resources, Subcommittee, Committee on Government Operations, House of Representatives, Air Pollution: Allowance Trading Offers and Opportunity to Reduce Emissions at Less Cost*, GAO / RCED-95-40, (Washington, DC, December 1994), p. 53.

[14] *Federal Register*, Vol. 61, No. 110 (June 6, 1996), pp. 28761-28763.

auction design would probably have been more relevant in 1993 and 1994, when price discovery was very limited, and the EPA auctions played a large role in establishing market price. Now that other year-round price discovery mechanisms exist and a market price for allowances has become clearly established, the auctions are no longer setting market prices, they are reflecting them. According to the EPA, the consensus appears to be that the current auction design is neither leading nor misinforming the market and should not be changed and therefore EPA has no plans to change the auction format.[15]

One can see that there has been much activity in the allowance market. For example, the differences between Potomac Electric Power Company's (PEPCO's) 1995 allowance allocations and those deducted for emissions does not equal the number of allowances that PEPCO is carrying over to 1996 (Table 3). EPA has acknowledged that there has been more trading than is reflected in the Allowance Tracking System.

Because of the low allowance prices relative to other compliance options, particularly scrubbers, allowances are seen as an attractive compliance option in some cases. Illinois Power's (IP) Baldwin plant did not significantly reduce its emissions in 1995 because IP decided that acquiring the additional allowances needed for its SO_2 emissions was economically viable. As prices climb, other actions will become more attractive, but for now, holding allowances is seen by some as a reasonable approach for meeting Phase I compliance requirements and by most as a way to hedge against uncertainty for Phase II.

Installing Scrubbers

Units with scrubbers installed for Phase I compliance accounted for 28 percent of 1995 SO_2 emissions reductions, the second largest share after fuel-switching units (59 percent). Sixteen utilities installed scrubbers at 27 units (Table 4), 10 percent of the Table 1 units. Fewer utilities than expected opted to scrub high-sulfur coal supplies, with some utilities located in higher sulfur coalfields indicating they will postpone scrubber installations several years beyond 2000.[16] The availability of emissions allowances and the failure of State legislators in Illinois and Indiana to enact laws that would protect local higher sulfur coal supplies are factors contributing to the utilities' decisions to delay or avoid scrubbing.

All scrubber systems rely on a chemical reaction with a sorbent to remove SO_2 from flue gases. Scrubber systems are either "wet" or "dry." In the more common wet scrubber process, flue gases containing SO_2 are contacted with a sorbent liquid that results in the formation of a wet solid byproduct. The liquid sorbent is sprayed into the flue gas in an absorber vessel. Most wet scrubber systems use alkaline slurries of limestone or slaked lime as sorbents. Sulfur oxides react with the sorbent to form calcium sulfite and calcium sulfate, which is a wet

Table 3. PEPCO's 1995 Allowance Totals

Unit	1995 Allowance Allocation	1995 Allowances Deducted for Emissions	Difference	Allowances Carried Over to 1996
Chalk Point ST1	25,403	20,543	4,860	3,700
Chalk Point ST2	23,690	20,544	3,146	6,756
Morgantown ST1	39,864	28,040	11,824	7,257
Morgantown ST2	45,592	38,515	7,077	10,017
Conemaugh 1	9,389	460	8,929	106
Conemaugh 2	8,335	7,131	1,204	1,859
Chalk Point 3	9,000	3,010	5,990	5,990
Chalk Point 4	1,519	1,354	165	373
PEPCO Total	**162,792**	**119,597**	**43,195**	**36,057**

Note: One allowance permits the emission of 1 ton of sulfur dioxide.
Source: Environmental Protection Agency, Acid Rain Division, *1995 Compliance Results*, EPA/430-R-96-012, July 1996, p. D-6.

[15] Communication from Joe Kruger of the Environmental Protection Agency, December 6, 1996.
[16] "U.S. Utilities Opt Against Scrubbing," *International Coal Report*, October 30, 1995, p 5.

Table 4. Scrubber Retrofits for Compliance With Phase I

On-Line Year	State	Boiler Units	Plant	Utility
1992	Georgia	Y1BR	Yates	Georgia Power
	Indiana	7,8	Bailly	Northern Indiana Public Service
1994	Kentucky	1,2	Elmer Smith	City of Owensboro
	Ohio	1	General J.M. Govin	Ohio Power
	Pennsylvania	2	Conemaugh	Pennsylvania Electric Company
	West Virginia	1,2,3	Harrison	Monongahela Power Company
1995	Indiana	2,3	F.B. Culley	Southern Indiana Gas & Electric
	Indiana	4	Gibson	PSI Energy
	Kentucky	H1, H2	Henderson MP&L	Big Rivers Electric
	Kentucky	1	Ghent	Kentucky Utilities
	New Jersey	2	B.L.. England	Atlantic City Electric Company
	New York	1,2	Milliken	New York State Gas & Electric
	Ohio	2	General J.M. Gavin	Ohio Power
	Ohio	1	Niles	Ohio Edison
	Pennsylvania	1	Conemaugh	Pennsylvania Electric Company
	Tennessee	1,2	Cumberland	Tennessee Valley Authority
	West Virginia	3	Mt. Storm	Virginia Electric & Power Company
1996	Indiana	1,2	Petersburg	Indianapolis Power & Light

Source: U.S. Environmental Protection Agency, *Applications for Acid Rain Program Phase I Bonus and Extension SO_2 Emission Allowances* (March 31, 1993).

byproduct. Oxidation of this results in a gypsum byproduct that can be sold.

Dry scrubber systems can be grouped into three categories: spray dryers, circulating spray dryers, and dry injection systems. All three categories avoid total water saturation of the flue gas, and provide a dry, free-flowing waste product. The elimination of any liquid waste is the ma jor difference between dry scrubbers and wet scrubbers.

Scrubbers have been used for some time and are the standard by which new technology is judged. The last decade has seen improvement in process chemistry, simplified designs, and other technological enhancements. All these improvements have improved reliability, efficiency, cost, waste prevention, and reduced energy consumption of scrubbers. The wet limestone system has been the most popular scrubber choice for Phase I large-unit retrofits. The Phase II decisions on scrubbers are essentially on hold because of utility competition, the desire to avoid large capital expenditures, and low SO_2 allowance prices.

Before 1980, scrubber systems were unreliable. Scrubber components often suffered from plugging and scaling, and material failures were frequently responsible for unplanned outages. The availability of these early systems was as low as 85 percent. By simplifying process configurations, selecting better materials, and using redundant equipment in critical areas, much higher availability has now been attained. More recently, the North American Electric Reliability Council concluded that wet scrubber systems contributed, on average, to system availability of 99.7 percent.[17]

Operating data prove that wet scrubbers can reliably remove 95 percent or more of the SO_2 from stack emissions. In fact, SO_2 removal efficiencies often are as high as 98 percent or 99 percent. Many scrubbers currently retrofitted to comply with CAAA90 will remove more SO_2 than required, thus generating marketable emissions allowances. The use of recently developed additives, such as dibasic acid, formic acid, and magnesium compounds, improve efficiencies, especially for high-sulfur coal. Dry scrubbers also are quite efficient. Spray dryers often achieve greater than 90 percent SO_2 removal on coals 1 percent to 2 percent sulfur.[18]

Recent technological advances in wet scrubber systems have reduced capital and operating costs relative to

[17] "Scrubber myths and realities; don't let common misperceptions about flue gas desulfurization systems bias a realistic appraisal of this capable control technology," *Power Engineering* (January 1995), p. 35.

[18] Ibid.

historical values. Capital costs have been reduced by more than 30 percent.[19] These innovations include installing larger (and fewer) absorber modules, eliminating flue gas reheat components, incorporating additives into the process design, fitting higher velocity absorbers and alternative duct work designs, installing absorbers in the base of a new chimney, and reducing reagent preparation costs.

The retrofit costs of scrubbers are site-specific and vary considerably. Site-specific factors, such as space and access limitations, major modifications to existing equipment, and the operating condition of the units, all affect retrofit costs. The average costs of Phase I retrofits ranged from $123 per kilowatt to $317 per kilowatt for different units. Average operating and maintenance costs for scrubbers, exclusive of capital recovery, are 1.42 mills per kilowatt hour. This increase in electrical rates is about one-half that associated with pre-1990 wet scrubbers. If commercial grade gypsum, a byproduct of scrubbing, is produced and sold , it would produce revenue and reduce disposal costs.[20]

Advances in design and technology have greatly improved scrubber's energy efficiency. The current generation of wet scrubbers that incorporate advances in chimney design, construction materials, regenerative heaters, and additives to enhance pollutant removal efficiencies consumes less than 1 percent of total plant energy. Dry scrubbers consume even less. Some new scrubber designs even employ heat exchangers, which use waste heat from stack gases and actually increase power plant efficiency. Scrubbers with condensing heat exchangers can recover as much as 4 percent of additional energy, thus offsetting the scrubbers use of plant energy.[21]

Retiring Facilities

Electric utilities have retired seven Table I units, most of which are outdated and small capacity units. Retired units accounted for 2 percent of 1995 SO_2 emissions reductions. Wisconsin Electric Power Company removed four units from service at North Oak Creek in 1988 and 1989. Indiana-Michigan Power's Breed plant, shut down in March 1994, is undergoing asbestos removal and may be used again in the future. Cleveland Electric Illuminating's Avon Lake unit 8 was retired in November 1987 and Iowa Power's Des Moines unit 7 is out of service but can be brought back into service in 180 days.

Other

Units in this category accounted for 2 percent of 1995 SO_2 emissions reductions. One Table I unit, PSI Energy Inc.'s Wabash River Station unit 1, has been repowered with an integrated gasification combined-cycle generator. Using new technology, the plant burns high-sulfur coal, reduces SO_2 emissions, and increases the plant capacity by approximately 155 megawatts. One unit each at Illinois Power's Vermilion plant and Ohio Edison's Edgewater plant were switched to natural gas. Two units at the Long Island Lighting Company's Port Jefferson plant and three units at North Port plant are using No. 6 fuel oil.

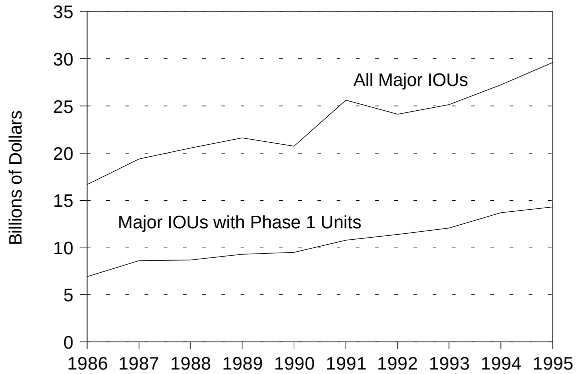
Electric Utility Compliance Strategies, Costs, and Emissions

Electric utilities in the United States have invested heavily in air pollution control equipment during the last decade. Scrubbers were installed at some utilities to reduce SO_2 emissions, and many utilities have retrofitted low-NO_x burners to reduce NO_x emissions. Some utilities have installed equipment to accommodate cleaner fuel and to monitor emissions levels. Cumulatively through 1986, major investor-owned utilities had invested $16.7 billion in air pollution control facilities (Figure 4). By 1990, investments had increased to $20.8 billion, and by the end of 1995 utilities had invested $29.6 billion.[22]

The level of investment in air pollution control equipment varies according to the location and size of the plant and the fuel mix used at the plant. Utilities owning units affected under Phase I had cumulative investments of $14.4 billion in 1995, almost half of the total utility investments in air pollution control facilities.[23] Power plants in the East Central and Mid-Atlantic regions (corresponding to the East Central Area Reliability Coordination Agreement (ECAR) and the Mid-Atlantic Area Council (MAAC) of the North American Reliability Council (NERC)) account for most of these investments

[19] Ibid.
[20] Ibid.
[21] Ibid.
[22] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437(95/1) (Washington, DC, December 1996 and previous years).
[23] These investments were for all air pollution control requirements, not just to meet the provisions of the acid rain program.

Figure 4. Cumulative Investment in Air Pollution Control Facilities by Major Investor-Owned Utilities, 1986-1995

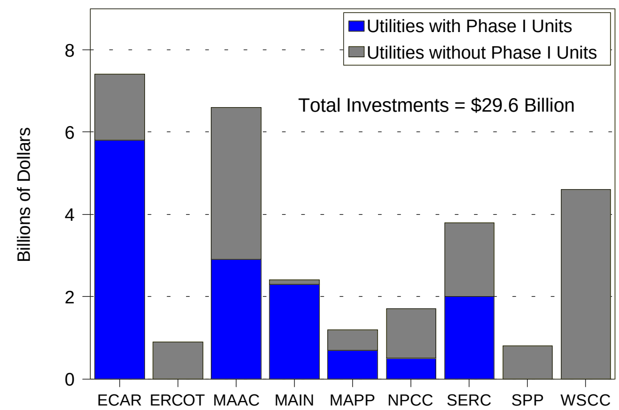


IOU = Investor-Owned Utilities.

Note: Air pollution control facilities include (1) scrubbers, electrostatic precipitators, tall smokestacks, etc.; (2) changes necessary to accommodate use of environmentally clean fuels such as low-ash or low-sulfur fuel including storage and handling equipment; (3) monitoring equipment; and (4) other equipment.

Source: Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437 (95/1) (Washington, DC, December 1996 and previous years).

Figure 5. Total Investments in Air Pollution Control Facilities by Major Investor-Owned Utilities, by NERC Region, 1995



IOU = Investor-Owned Utilities.

Note: Air pollution control facilities include (1) scrubbers, electrostatic precipitators, tall smokestacks, etc.; (2) Changes necessary to accommodate use of environmentally clean fuels such as low-ash or low-sulfur fuel including storage and handling equipment; (3) monitoring equipment; and (4) other equipment.

ECAR = East Central Area Reliability Coordination Agreement.

ERCOT = Electric Reliability Council of Texas.

MAAC = Mid-Atlantic Area Council.

MAIN = Mid-America Interconnected Network.

MAPP = Mid-Continent Area Power Pool.

NPCC = Northeast Power Coordinating Council.

SERC = Southeastern Electric Reliability Council.

SPP = Southwest Power Pool

WSCC = Western Systems Coordinating Council.

Source: Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437(95/1) (Washington, DC, December 1996).

(Figure 5). These regions have a high concentration of large coal-fired units, many of which are affected by Phase I.

Compliance Costs for Title IV

Previous studies have indicated that compliance costs for Title IV would be lower with the introduction of an allowance trading system. In 1992 for example, EPA estimated that the cost of compliance would be up to 50 percent lower using emission allowance trading compared to command and control regulation. The U.S. General Accounting Office (GAO) supported that statement. GAO estimated that by the year 2002, SO_2 reductions under traditional regulation would cost as much as $4.5 billion annually, but an SO_2 allowance trading program would reduce the costs by $2 to $3 billion annually.[24]

The Massachusetts Institute of Technology (MIT), in a preliminary report, estimated an annualized compliance cost of $836 million (Table 5).[25] This estimate, which was based on program data through 1995, represents less than 0.6 percent of the $151[26] billion of electric operating expenses of investor-owned utilities in 1995.

[24] General Accounting Office, *Air Pollution Alllowance Trading Offers an Opportunity to Reduce Emissions at Less Cost,* GAO/RC ED-95-30 (Washington, DC, December 1994), p. 37.

[25] Massachusetts Institute of Technology, for the Proceedings of the Second Workshop on Energy Externalities, Brussels, September 9-10, 1996, *The U.S. Allowance Trading Program for Sulfur Dioxide: An Update After the First Year of Compliance,* Draft (Cambridge, MA, October 29, 1996).

[26] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1995,* DOE/EIA-0437(95)/1 (Washington, DC, December 1996).

Table 5. Annualized SO_2 Compliance Cost for CAAA90 Title IV (1995 Dollars)[a]

Method of Compliance for Title IV	1995 Emissions Reduction (thousand tons of SO_2)[b]	Annualized Compliance Cost (thousand dollars)[c]	Annualized Average Cost per Ton of SO_2 Removed
Scrubbing			
Title IV Scrubbers	1,734	558,128	322
NSPS Scrubbers[d]	21	1,345	64
Switching			
Bituminous[e]	1,547	258,737	167
Subbituminous (Powder River Basin (PRB))	160	18,126	113
Subtotal	3,462	836,336	242
No Cost Switching[f]			
PRB & CO/UT	369		
Natural Gas	20		
Midwest	32		
Others	5		
Subtotal	426		
Total	**3,888**	**836,336**	**215**

[a]Preliminary annualized compliance cost for SO_2 could be changed as MIT finalizes their estimates. Costs are not included for low NO_x control and continuous emissions monitoring systems.

[b]The baseline year to compare 1995 SO_2 emissions is 1993. It is assumed that the reductions before 1993 are not due to the CAAA90, but to economic reasons. The 1995 SO_2 emissions reductions are the difference between the SO_2 emissions that would have been observed in 1995 in the absence of Title IV and the actual emissions. The SO_2 emissions that would have been observed in 1995 was calculated as the product of the emissions rates in 1993 and the heat input in 1995.

[c]A capital charge of 14 percent is used to annualize initial fixed investments in scrubbers or switching to lower sulfur coal. The 14 percent includes 9 percent of capital cost and 5 percent of 20 years' linear depreciation.

[d]The New Source Performance Standards (NSPS) scrubbers were installed before Title IV was passed. Only variable costs of extra reductions are included for these scrubbers, not any fixed cost.

[e]Bituminous switching from high-sulfur to low-sulfur coal includes premiums paid for low-sulfur bituminous coal.

[f]The "No Cost Switching" for SO_2 reductions would have taken place regardless of Title IV. Most of these are switches to low-sulfur subbituminous western coal (Powder River Basin and Colorado and Utah) due to the reduction in coal prices, especially the decline in rail rates.

Sources: Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, *SO_2 Compliance Costs with Title IV*, Memorandum (from Juan-Pablo Montero on December 24, 1996) to Art Fuldner and Ron Hankey, Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration. Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, *More on SO_2 Compliance Costs with Title IV*, Memorandum (from Juan-Pablo Montero on January 13, 1997) to Art Fuldner, Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration.

The lowest annualized average cost through 1995 for Phase I is switching of bituminous plants to burn lower sulfur subbituminous coal, with modifications, from the Powder River basin (PRB) ($113 per ton of SO_2 removed). The most expensive is retrofitting scrubbers at $322 per ton of SO_2 removed. Utilities removed more SO_2 by switching higher sulfur bituminous coal to lower sulfur bituminous coal (1,547 thousand tons) compared to switching from higher sulfur bituminous coal to lower sulfur subbituminous coal (160 thousand tons). Also, utilities switching to subbituminous coal from PRB and Colorado/Utah with no modification cost achieved a large SO_2 reduction (369 thousand tons) compared to switching with modifications from bituminous to subbituminous coal.

Specific Utility Compliance Plans and Costs

This section of the report presents a detailed look at Phase I compliance strategies and compliance costs through 1995 for six utilities,[27] updating an earlier report on Phase I compliance strategies for these utilities.[28] These utilities were selected to obtain a representative sample of generating capacities, sulfur dioxide (SO_2) emissions, locations, and initial compliance strategies. Also, the willingness to participate and share information was essential. Tables 6 through 8 and Figure 6 contain utility level data referred to throughout the discussion. Appendix C lists detailed information on the characteristics and costs of compliance for each of the six utilities' plants affected by Phase I. Because the data for these utilities cover only 1 year of a multi-year program, compliance strategies, annual compliance costs, and even total capital costs for Phase I will likely change for some units. One such cost that will most certainly change is emissions allowances. Different substitution or compensating units might also be selected for participation in future years. The point is, because utilities are constantly looking for ways to achieve minimum compliance costs, changes in compliance strategies and costs are expected over the life of the acid rain program.

Illinois Power

Illinois Power (IP) operates eight power plants with an electric-generating capacity of 5.0 gigawatts. Initially, 45 percent of IP's generating capacity (five units) was affected by Phase I. Under the substitution revisions of CAAA90, IP added 8 relatively small units to its Phase I-affected units, increasing its affected capacity to 54 percent of total generating capacity.[29] Phase I affects the generating capacity at Baldwin, Hennepin, Vermillion, Havana, and Wood River power plants.

IP originally planned to install scrubbers to meet the SO_2 emissions standards at the 1.9 gigawatts Baldwin Plant

Table 6. Characteristics of Selected Phase I Utilities

Utility[a]	**Affected Nameplate Capacity** (Utility Owned) (MW)	**Total Capacity** (MW)	**Percent Capacity Affected**	Sulfur Dioxide Emissions Allowances: 1995 Allocation of SO_2 Allowances	Allowances Deducted for 1995 SO_2 Emissions	Differences Between Allowances and 1995 Emissions	Allowances[b] Carried Over to 1996
Illinois Power	2,699	5,005	53.9	186,579	297,504	(110,925)[c]	645
Pennsylvania P&L	2,343	8,704	26.9	185,700	136,411	49,289	47,749
Potomac Electric Power	3,480	6,433	54.1	162,792	119,597	43,195	36,057
Cincinnati G&E	2,664	5,300	50.3	155,384	107,734	47,650	55,716
Georgia Power	10,252	15,995	64.1	715,187	372,586	342,601	211,835
Southern Indiana G&E	530	1,359	39.0	38,095	21,390	16,705	5,392

[a]The full utility names are Illinois Power Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Cincinnati Gas & Electric Company, Georgia Power Company, and Southern Indiana Gas & Electric Company.

[b]Allowances carried over to 1996 may not equal the differences between allocated and 1995 emissions due to purchases or sales of additional allowances. The data in this table do not account for a utility's purchases and sales of allowances.

[c]Illinois Power purchased enough emissions allowances to cover their 1995 emissions.

SO_2 = Sulfur dioxide.

MW = Megawatt.

Note: For unit level data, see Appendix C.

Source: Environmental Protection Agency, "1995 Compliance Results Acid Rain Program," EPA/430-R-96-012 (Washington, DC, July 1996).

[27] Sources of information on these utilities consisted of personal contact with each utility; the Securities and Exchange Commission's, "1995 10K"; the Federal Energy Regulatory Commission's, "Interrogatory on Fuel and Energy Purchases Practices, 1992-1993"; FERC Form 580; and various articles published in trade journals.

[28] Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March, 1994).

[29] IP also substituted five PacifiCorp units located in Wyoming and Utah. These units are not included in the total.

Table 7. Costs of Phase I Compliance for Selected Utilities

Utility[a]	Number of Low-NO_x Burners[b]	Number of CEMS[b]	Number of Scrubbers[b]	SO_2 Control		NO_x Control	CEMS		Total Capital Costs	Total Annual O&M Costs	Average Capital Cost (dollars/ kW affected)
				Capital Cost	Annual O&M Cost	Capital Cost	Capital Cost	Annual O&M Cost			
				(million dollars)							
Illinois Power	2.0	13.0	0.0	34.6	18.5	12.7	15.2	0.9	62.5	19.4	23.15
Pennsylvania P&L	7.2	5.2	0.2	51.2	2.2	70.7	11.1	c	133.0	2.2	56.76
Potomac Electric Power	6.0	6.5	0.2	62.4	1.8	120.6	12.8	c	195.8	1.8	56.27
Cincinnati G&E	1.4	5.7	1.0	12.4	c[d]	6.9	3.5	c	22.8	c	16.39
Georgia Power	15.1	19.4	1.0	47.0	2.0	125.3	17.1	c	189.5	2.0	18.48
Southern Indiana G&E	2.0	2.5	1.0	103.0	4.0	5.0	2.8	0.2	110.8	4.2	208.90

[a]The full utility names are Illinois Power Company, Pennsylvania Power & Light Company, Potomac Electric Power Company, Cincinnati Gas & Electric Company, Georgia Power Company, and Southern Indiana Gas & Electric Company.

[b]A fractional value indicates that ownership of equipment was allocated across more than one unit.

[c]Costs not estimated.

[d]The capital costs for the scrubber were not included because the scrubber was installed in 1980, before passage of the Clean Air Act Amendments of 1990.

[e]Some of these costs are offset by selling the gypsum produced by the scrubber.

NO_x = Nitrogen oxides.

SO_2 = Sulfur dioxide.

KW = Kilowatt.

CEMS = Continuous emissions monitor system.

O&M = Operation and maintenance.

Notes: In some cases the costs are low because cost estimates were not available for all of the Phase I units. For unit level data, see Appendix C.

Sources: Personal contact with Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric.

Table 8. Costs and Quality of Fuels for Selected Electric Utility Phase I Plants, 1985, 1990, and 1995
(Delivered Costs are in 1995 Dollars)

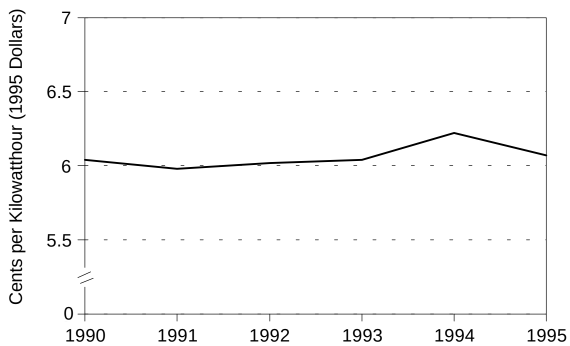
Utility/Plant	1985 Quantity (thousand short tons)	1985 Sulfur Content (percent)	1985 Delivered Cost (dollars/ton)	1990 Quantity (thousand short tons)	1990 Sulfur Content (percent)	1990 Delivered Cost (dollars/ton)	1995 Quantity (thousand short tons)	1995 Sulfur Content (percent)	1995 Delivered Cost (dollars/ton)
Illinois Power									
Baldwin	4,669	2.80	42.53	3,995	3.06	37.02	4,353	2.92	23.75
Hennepin	744	2.80	43.36	688	2.69	35.58	583	2.93	24.29
Vermillion	507	2.50	38.91	387	2.47	30.10	31	1.88	29.41
Havana	324	0.50	58.37	496	0.66	45.33	761	0.47	31.05
Wood River	701	0.70	66.31	738	0.86	47.66	707	0.73	34.01
Average	**--**	**2.46**	**45.50**	**--**	**2.54**	**38.34**	**--**	**2.39**	**25.82**
Pennsylvania P&L									
Brunner Island .	3,254	1.83	62.05	3,930	1.95	52.18	2,756	1.61	39.25
Martins Creek . .	785	1.90	73.62	738	1.96	51.74	288	1.59	38.37
Sunbury	1,283	1.39	37.10	1,103	1.54	30.91	1,205	1.02	24.31
Conemaugh[a] . .	441	2.23	51.94	552	2.21	44.07	470	2.25	28.41
Average	**--**	**1.77**	**57.30**	**--**	**1.90**	**47.71**	**--**	**1.52**	**34.30**
Potomac Elec. Power									
Chalk Point	1,578	1.72	59.66	1,909	1.85	50.99	1,428	1.34	40.60
Morgantown . . .	1,787	1.70	59.32	2,747	1.68	51.03	2,367	1.39	41.79
Conemaugh[a] . .	387	2.23	51.94	462	2.21	44.07	430	2.25	28.41
Average	**--**	**1.76**	**58.70**	**--**	**1.79**	**50.39**	**--**	**1.48**	**39.97**
Cincinnati G&E									
Miami Fort	2,627	1.75	55.16	3,269	1.70	39.93	2,663	0.82	34.76
Beckjord[a]	976	1.97	54.35	2,089	2.04	37.68	1,675	0.98	38.25
Conesville[a]	541	3.47	51.87	564	3.13	42.86	530	2.88	34.89
East Bend[a] . . .	1,236	2.56	49.57	1,048	1.89	39.37	1,202	2.28	28.31
J.M. Stuart[a]	2,347	1.39	57.59	2,713	1.42	40.14	2,266	0.88	33.43
Average	**--**	**1.92**	**54.67**	**--**	**1.80**	**39.62**	**--**	**1.21**	**34.18**
Georgia Power									
Bowen	7,945	1.83	58.96	8,340	1.60	47.62	7,545	1.04	40.72
Hammond	2,005	1.63	57.32	2,004	1.67	49.68	1,037	0.97	36.78
McDonough . . .	1,175	2.59	52.16	1,471	2.00	46.61	1,202	0.85	33.56
Wansley[a]	2,296	2.59	51.76	2,472	2.57	48.72	1,499	0.88	48.20
Yates	2,520	2.37	57.74	2,676	2.02	48.60	1,235	0.90	40.26
Gaston[a]	1,061	1.73	68.34	1,015	2.14	52.95	1,019	0.77	42.63
Arkwright	388	2.04	66.52	194	2.09	46.87	110	1.64	41.10
Harllee Branch .	4,081	1.24	62.73	4,000	1.26	50.22	3,546	1.13	40.08
Mitchell	534	1.36	68.57	269	1.37	59.72	149	1.21	58.45
Scherer[a]	713	0.68	102.06	718	0.52	49.71	2,132	0.48	34.36
Average	**--**	**1.83**	**60.42**	**--**	**1.70**	**48.83**	**--**	**0.93**	**39.80**
Southern Indiana G&E									
Culley	901	3.01	46.36	1,144	2.75	39.50	1,007	3.10	25.76
Warrick[a]	219	3.18	43.27	149	2.87	29.39	220	2.82	23.52
Average	**--**	**3.04**	**45.76**	**--**	**2.91**	**38.34**	**--**	**3.05**	**25.36**

[a]These plants are partially owned by the utility. The quantity of fuel received represents the utility's portion of the total fuel received at the plant. It should be noted that these data are available only at the plant level; therefore, Phase I data cannot be broken out.

-- = Not applicable.

Source: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* DOE/EIA-0191(various issues).

Figure 6. Average Price of Electricity for Six Utilities, 1990-1995



Note: The average is for Pennsylvania Power & Light, Illinois Power, Potomac Electric Power, Georgia Power, Cincinnati Gas & Electric, and Southern Indiana Gas & Electric.

Source: Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(94/1) (Washington, DC, December 1995 and previous years).

and to comply with the Illinois Coal Act. This Act, passed by the Illinois General Assembly in 1991, sought to discourage the use of low-sulfur western-State coal in favor of Illinois high-sulfur coal. In December 1993, the Act was found to be in violation of the Commerce Clause of the U.S. Constitution. This decision was upheld in the U.S. Court of Appeals. IP, acting in response to a forecast of lower allowance prices and anticipating that the Illinois Coal Act would be overruled, announced in August 1992 that it had suspended construction of the Baldwin Power Station scrubbers. In 1993, IP reconsidered its alternatives for compliance.

IP decided to purchase allowances for most of its plants. In 1995, it purchased almost 118,000 vintage 1995 SO_2 emissions allowances. Also, one substitution unit—Vermilion 1—switched to natural gas, freeing emissions allowances for other plants. The Havana units and Wood River Unit 1 were not operated in 1995, and the few allowances allocated to these units for 1995 were used elsewhere. IP also activated its conditional substitution plan for Wood River 4 in 1995 because actual emissions of the unit were less than its allocation. In 1995, IP acquired enough emissions allowances to meet most of its anticipated needs for 1996; it will purchase additional allowances on the spot market. The Illinois Commerce Commission has approved the recovery of emissions allowance costs through the Uniform Fuel Adjustment Clause; therefore, IP's emissions purchase costs may be added to its retail customer rates.

IP has three Phase I Group I boilers—Baldwin 3, Hennepin 2, and Vermilion 2. To comply with Phase I NO_x emission reduction requirements, low-NO_x burners were installed at Baldwin 3 and Vermilion 2. Through system-wide averaging, IP will be able to meet the NO_x emissions standards for Hennepin 2.

Through 1995, IP spent almost $63 million on capital equipment for compliance. However, more than half of that amount—approximately $35 million—was expended for the suspended scrubbers. Of course, this increased compliance costs, but perhaps IP will decide to complete the scrubbers later and then the utility will not need to rely as heavily on allowances for compliance. Of the six utilities examined, IP was the only one that used allowances as a primary compliance strategy. Through 1995, IP had spent $18.5 million on allowance purchases (classified as O&M costs in Table 7). They installed 13 continuous emission monitors (CEMS) at a cost of $15.2 million and two low-NO_x burners for $12.7 million. IP has not developed a compliance strategy for meeting Phase II requirements, but they anticipate additional capital expenditures to comply with the Phase II NO_x requirements in 2000 and with future State air quality standards for the St. Louis and Chicago metropolitan areas.

Pennsylvania Power and Light Company

Pennsylvania Power and Light Company (PP&L), headquartered in Allentown, Pennsylvania, owns 8.7 gigawatts of capacity. Two gigawatts of PP&L's generating capacity were designated as Phase I Table 1 affected units. Unlike many other Phase I utilities, PP&L did not participate in the substitution or compensation programs.

PP&L switched to lower sulfur coal at its owned and operated units to meet its Phase I obligations in 1995. Because of a general decline in coal prices throughout the United States, PP&L did not incur higher fuel prices for lower sulfur coal. From 1985 to 1995, the delivered cost of coal for PP&L's Phase I units decreased from $57.30 per ton to $34.30 per ton, while the average sulfur content fell from 1.77 percent to 1.52 percent. PP&L's Phase I units showed no major shifts to coal suppliers outside of Pennsylvania. Over the past 5 years, however, PP&L reduced its purchases of Central Pennsylvania coal, and increased its purchases of lower sulfur coal from western Pennsylvania. They also received a small amount from Utah and West Virginia in 1995. To meet the NO_x emissions requirements, PP&L installed low-NO_x burners on all its Phase I units and submitted a plan for system-wide NO_x averaging.

PP&L's Phase II compliance strategy will be similar to its Phase I strategy. PP&L plans to purchase lower sulfur coal, to utilize banked allowances, and to purchase additional emissions allowances as needed. PP&L does not plan to use scrubbers for its plants. As a hedge against the uncertainty of future compliance market conditions, PP&L, as part owner of the Conemaugh plant, will take advantage of its share of allowances generated by Conemaugh's scrubbers. PP&L estimates that further Title IV compliance operating costs will be incurred beyond 2000 in amounts that are not now determinable but could be material.

PP&L spent a total of $51.2 million on equipment for Phase I SO_2 emissions compliance. However, $41 million of this is attributable to its share of scrubbing equipment at the Conemaugh plant. The utility spent $70.7 million on low-$NO_x$ burners and $11.1 million on CEMS. PP&L's average cost of Phase I compliance per kilowatt of affected capacity was $56.76.

Potomac Electric Power Company

The Potomac Electric Power Company (PEPCO) is headquartered in Washington, DC. It owns 6.4 gigawatts of capacity. Four units at two power plants—Chalk Point and Morgantown—with 1.8 gigawatts of capacity, were designated as Phase I Table 1 affected units. Additionally, PEPCO owns 9.7 percent of the 2 Table 1 units at the Conemaugh plant in Pennsylvania. PEPCO decided that switching to lower sulfur coal would provide the best strategy for complying with Title IV SO_2 limits. No significant capital costs are associated with switching to lower sulfur coal at Chalk Point. In fact, the cost of its delivered coal fell from $58.70 per ton to $39.97 per ton, while the average sulfur fell from 1.76 percent to 1.48 percent during the same time period. Although the mix of PEPCO's coal supply for Table 1 units changed, its coal came from Pennsylvania, Maryland, and West Virginia in 1995—the same as in 1985.

By using lower sulfur coal as its primary SO_2 compliance strategy, excess allowances were accumulated at these plants. Also, Chalk Point 4 was designated as a substitution unit for Chalk Point units 1 and 2, and Chalk Point 3 was designated as a substitution unit for Morgantown units 1 and 2. PEPCO indicated that the marginal cost of adding these units to Phase I was $3.2 million, for installation of CEMS. However, by designating these substitution units, PEPCO obtained additional emissions allowances that can be banked for later use. To meet NO_x emissions requirements, PEPCO installed low-NO_x burners on all its coal-burning units; because both substitution units burn petroleum, low-NO_x burners were not installed on them.

Phase I capital compliance costs for PEPCO total $196 million. Like PP&L, most of these costs are a result of the installation of low-NO_x burners, and more than half of the capital spent on SO_2 control went toward its share of Conemaugh's scrubbers. Another large portion of the expenditures was incurred in adding gas-fired capacity to Chalk Point units 1 and 2 ($30 million). PEPCO spent almost $13 million on CEMS. The per kilowatt capital cost for PEPCO's total Title IV compliance was $56.27, which was quite similar to PP&L's $56.76 per kilowatt.

For future compliance actions, PEPCO may continue to burn lower sulfur coal or low-sulfur oil. Scrubbing is also a possibility for meeting future emissions reductions requirements. One possible strategy is fuel switching for Phase I and scrubbing for Phase II. This strategy avoids the high capital costs of installing scrubbers for as long as possible.

Cincinnati Gas and Electric Company

Cincinnati Gas and Electric Company (CG&E) serves Ohio with power from the nine plants in which it has ownership interest. These nine plants have a total nameplate generating capacity of about 5.3 gigawatts. Initially, 25 percent of the utility's total capacity was affected by Phase I. With the addition of five substitution units, Phase I capacity increased to 50 percent of total generating capacity.

In October 1994, CG&E and PSI Energy merged to form the CINergy Corporation, a holding company registered under the Public Utility Holding Company Act of 1935. CG&E's compliance plan was in place in late 1994, and the merger did not cause significant changes to the plan. CG&E and PSI will prepare a joint compliance plan for Phase II.

To meet the SO_2 emissions reduction requirements, CG&E switched to lower sulfur coal at the Miami Fort, Beckjord, and J.M. Stuart plants. Electrostatic precipitator modifications were made on Beckjord unit 5 and on Miami Fort unit 6. An SO_3 injection system was installed on Miami Fort unit 7 to accommodate the lower sulfur coals. The average sulfur content of coal received at these plants in 1995 was 0.88 percent, down from 1.64 percent in 1985. The average sulfur content of coal received at all of CG&E's Phase I plants, including those that did not switch to lower sulfur coal, decreased from 1.92 percent in 1985 to 1.21 percent in 1995.

To accumulate extra emissions allowances, CG&E designated East Bend Power Plant Unit 2 a substitution unit. This unit originally entered commercial operation in 1981, and a scrubber had been installed in 1980. By designating East Bend 2 a substitution unit, CG&E obtained overcompliance allowances that can be used for other units. SO_2 emissions in 1995 at Conesville unit 4, which is a jointly-owned unit, were higher than its allowance allocation; therefore, excess allowances from other units were applied to this unit.

For short-term contingencies, CG&E intends to build an operating reserve of SO_2 allowances containing about 13 percent of annual allotments. Extra allowances will come from overcompliance at some units and from participation in the allowance markets. CG&E purchased allowances in the 1993 and 1994 EPA allowance auctions; no purchases were made in the 1995 and 1996 auctions.

Through 1995, CG&E spent approximately $23 million on capital equipment for compliance with Title IV, and its average capital costs are $16.91 per kilowatt of affected capacity. This expenditure is relatively low compared to the other 5 utilities, primarily because the costs for East Bend's unit 2 scrubber were not included. Also, because of its original low-NO_x design, the East Bend plant did not require NO_x modifications to meet NO_x emission requirements.

Modifications to burn lower sulfur coal at the Beckjord and Miami plants have cost about $12.4 million. Capital costs for low-NO_x burners at the Beckjord plant were $6.9 million. Miami Fort 7 and J.M. Stuart units 1 through 4 have been designed with cell burner technology which is exempt from Phase I NO_x limits. Interestingly, the cell burners at the Stuarts units were installed as part of the Clean Coal Project, which was funded by the U.S. Department of Energy (DOE). Conesville 4 is able to meet NO_x limits by taking its high NO_x emitting burners out of service .

CG&E has spent $3.5 million on CEMS, but they expect to incur more costs as final project enhancements are implemented and software modifications required by the EPA are made.

CINergy is investigating alternatives to meet Phase II requirements. Its current allowance banking strategy allows them to defer plant modifications for reducing SO_2 emissions. CINergy intends to submit a system-wide NO_x averaging plan to meet Phase II requirements.

Georgia Power Company

The Georgia Power Company (GPC) is an operating company of Southern Company, a registered holding company headquartered in Atlanta, Georgia. Southern's other operating companies are Alabama Power, Mississippi Power, Savannah Power, and Gulf States Power. GPC owns 16 gigawatts of capacity at 33 plants and 7.6 gigawatts of GPC-owned-and-operated capacity at 5 plants, which were designated as Phase I Table 1 affected units. Georgia Power owns 53.5 percent of the Wansley plant, a Table 1 unit, and 75 percent of Scherer Unit 3, a substitution plant; GPC operates both Wansley and Scherer. Additionally, GPC owns 50 percent of units 1 through 4 at the EC Gaston plant, operated by Alabama Power, which were designated Phase I Table 1 affected units.

GPC's basic compliance strategy was integrated into the Southern Company's overall plan. GPC's primary method of compliance with Phase I requirements was to increase burning of lower sulfur coal. In 1994, GPC was the recipient of more coal than all but three utilities (Tennessee Valley Authority, PacifiCorp, and Texas Utilities Electric Company). Clearly, any changes in GPC's coal consumption patterns can have significant effects on the coal market. Yates unit 1 installed a scrubber at an estimated cost of $34 million, one-half of which was funded by DOE. GPC also substituted 10 Phase II units into Phase I and employed a reduced utilization plan, including increased unit efficiency and sulfur-free generation.

GPC's switch to lower sulfur coal required some equipment upgrades. Switching fuels—from an approximate mix of 1.5 percent high-sulfur coal from the Illinois basin to lower sulfur sources from central Appalachia—allowed GPC to overcomply and accumulate unused emissions allowances that were banked for future use. Additionally, the Scherer plant received subbituminous coal from Wyoming. The average delivered cost of GPC's coal fell from an average of $60.42 per ton in 1985 to $39.80 per ton in 1995. During the same period, the average sulfur content of the coal received at GPC's Phase I plants fell from 1.83 percent to 0.93 percent. Compliance with the acid rain NO_x emissions reduction requirements was achieved through the installation of new control equipment at 18 of the original 33 affected boiler units.

Construction expenditures for GPC's share of Phase I compliance totaled approximately $189.6 million through

1995. Most of this total, $125 million, was allocated to the installation of low-NO_x burners. The largest expenditure for SO_2 control was GPC's $17 million share for the scrubber at Yates unit 1. GPC so far has spent $17 million on CEMS for Phase I. On a per-kilowatt basis, GPC's capital costs for affected Phase I compliance are $18.48.

Georgia Power and the Southern Company's plan to comply with Phase II are uncertain at this point. Various options are being considered including using banked emissions allowances, continued use of fuel switching, installing scrubbers at selected plants, and / or purchasing more allowances, depending on their price and availability. In Phase II, equipment to control NO_x emissions will be installed on additional system fossil-fired plants as required to meet *anticipated* Phase II limits. From 1996 to 2000, the current compliance strategy may require total construction expenditures of approximately $45 million. However, GPC realizes that the full impact of Phase II compliance cannot be determined with certainty; much depends on the continuing development of a market for emission allowances, the completion of EPA regulations, and the possibility of new emission reduction technologies. The bottom line is that much uncertainty still exists regarding Phase II, and GPC wants to remain as flexible as possible. Phase I and Phase II are not distinct. Rational utilities will not isolate the two but will integrate their Phase I and Phase II plans to form an overall compliance plan.

An increase of up to 1 percent in GPC's annual revenue requirements could be necessary to fully recover the cost of compliance for both Phase I and Phase II. Compliance costs include construction expenditures, modification costs to facilitate switching to lower sulfur coal, and costs related to emissions allowances. GPC expects to recover a significant portion of these costs through existing ratemaking provisions. However, GPC states there are no assurances that all Clean Air Act costs will be recovered.

Southern Indiana Gas and Electric Company

Southern Indiana Gas and Electric Company (SIGECO) is a relatively small investor-owned utility serving Indiana with a total of 1.4 gigawatts of generating capacity from five power plants. Two units at the Culley Power Plant and one unit (partially owned) at the Warrick Plant are Table 1 units. SIGECO's ownership share of the affected units is 530 megawatts of capacity. Interestingly, two of SIGECO's principal coal-fired facilities (A.B. Brown Units 1 and 2) had been equipped with scrubbers and were not significantly affected by the CAAA90.

To reduce SO_2 emissions, SIGECO installed a single scrubber at the Culley Generating Station serving both Culley 2 and Culley 3. Construction of the scrubber started in 1992, and it went in-service on February 1, 1995. Because of the scrubber, SIGECO overcomplied at the Culley Power Plant and has allowances that can be sold to other parties or banked to meet future emissions reductions requirements. Some of the allowances from the Culley Plant were applied to the SO_2 emissions from the Warrick Plant. To meet Phase I NO_x emissions requirements, SIGECO installed low-NO_x burners at the Culley Plant. The Warrick Plant utilizes cell burner technology and is not affected by the Phase I NO_x emissions standards.

A federal court overturned parts of an Indiana law that was designed to encourage State utilities to use Indiana coal to meet CAAA90 SO_2 requirements. The December 1995 decision—like several other recent cases—rules that the law violates the U.S. Constitution's Commerce Clause because it provides Indiana coal suppliers with an unfair advantage over coal mined in other States. Although recently overturned, this law perhaps influenced SIGECO to install scrubbers instead of using the more popular fuel switching strategy. In any event, by continuing to use less expensive high-sulfur coal, SIGECO reduced their real costs of fuel 34 percent from 1990 to 1995.

Through 1995, SIGECO has spent about $111 million on capital equipment for compliance, most of which, $103 million, was spent for the Culley Power Plant scrubber. SIGECO estimates that it will cost approximately $4 million annually to operate and maintain the scrubber, including the costs of chemicals used in the process. Costs for scrubber maintenance are offset somewhat by selling gypsum, which is a byproduct of scrubbing. SIGECO produces approximately 20 tons of gypsum per hour on average. About $5 million was spent on NO_x control equipment, and $2.8 million was spent on the installation of CEMS. The average capital cost through 1995 was about $209 per kilowatt affected by Phase I.

The majority of SIGECO's generating capacity is already positioned to comply with the Phase II SO_2 emissions reductions requirements. Sixty-six percent of its generating capacity has scrubbers. SIGECO plans to purchase emissions allowances and / or to blend lower sulfur coal with coal of a higher sulfur content for the remaining capacity. Meeting NO_x standards is more problematic. SIGECO's largest plant, the A.B. Brown Power Plant, is currently in compliance with the 0.5 lbs per million Btu NO_x limits. However, if this standard is lowered, equipment retrofits will be needed to comply. To meet the NO_x standards at Warrick 4, SIGECO is installing low-NO_x burners, which will cost an estimated $4 million.

Conclusions Drawn From These Case Studies

Utilities employ a variety of strategies for complying with the CAAA90 Title IV requirements. For 1995, most of the 6 utilities' units were switched to lower sulfur coal to meet the SO_2 emissions limitations. Because of declining coal prices, none of these utilities paid more for low-sulfur coal in 1995 than they paid for high-sulfur coal in previous years.[30]

Although their price has declined from levels estimated in the early 90's, only a few scrubbers were installed because they are expensive relative to other compliance methods. Designation of substitution units, which generated extra emissions allowances in most instances, was used extensively by utilities. By exceeding the required emissions reductions, most utilities have excess SO_2 emissions allowances, which they have banked or traded.

Some industry observers thought that compliance with Title IV would cause electricity prices to increase. A closer examination suggests that compliance has not caused electricity prices to increase, at least for the six utilities examined in this report. Since 1990, which is 5 years prior to the start of the program, real electricity prices of the six utilities have remained relatively stable at about 6 cents per kilowatthour. Prices increased slightly in 1994, but returned to previous levels in 1995. Admittedly, this is a rough analysis, and the effect on prices of future compliance requirements remains to be seen.

For the most part, the six utilities discussed here do not have firm plans for meeting Phase II requirements. Most of them are delaying large capital expenditures, while banking extra allowances as a hedge for the future.

[30] One could argue that regardless of declining coal prices, the difference in price between higher sulfur and lower sulfur coal represents a fuel premium. Because of the volatility of coal prices in today's market, however, the six utilities were not asked to estimate a lower sulfur coal premium.

3. Phase I Effects on Coal Supply and Demand

Compliance and Fuel Costs

Despite the increased demand for lower sulfur coal brought on by Phase I compliance programs, the average delivered price of lower sulfur coal (as well as higher sulfur coal) declined between 1990 and 1995. The delivered price of coal generally includes the mine price, transportation costs, and shipping and loading fees and may account for as much as 75 percent of the operating costs at an electric utility plant.[31] The recent decline in coal prices can be attributed to lower mine prices and lower transportation costs.

New and improved mining technologies such as longwall mining have increased coal mining productivity by almost 7 percent per year between 1990 and 1995. Also, transportation costs for coal purchased under contract have fallen for all modes of transportation in the last decade. Although transportation cost as a percentage of delivered cost varies greatly across different coal demand and supply regions because it is influenced by shipping distance, contract coal transportation costs are a significant portion of the average delivered cost of coal on average, accounting for 31 percent of the average delivered price of contract coal in the United States in 1993.[32] Transportation costs have fallen for varying reasons in different coal supply regions—in the West because of increased competition among railroads and substantial productivity gains made by railroads, and in the East because of an increase in low-cost barge shipments.[33] These declines, along with electric utilities' renegotiation of long-term contracts, may have caused the average delivered price of lower sulfur coal from almost every producing State to decrease between 1990 and 1995 (Table 9). The availability of low-cost, lower sulfur coal may have induced utilities to burn more lower sulfur coal, resulting in a greater reduction of SO_2 emissions and more allowance credits earned.

Table 9. Average Delivered Cost of Low-Sulfur Coal by Origin State, 1985, 1990, and 1995
(1995 Dollars Per Short Ton)

State	1985	1990	1995
Alabama	72.89	61.22	47.00
Arizona	27.44	27.29	24.67
Colorado	50.45	35.14	28.83
Illinois	51.39	50.20	35.77
Indiana	47.85	37.05	28.43
Kentucky (eastern)	64.55	48.60	38.98
Kentucky (western)	63.58	34.64	26.28
Louisiana	31.52	21.10	17.97
Maryland	48.29	45.89	36.79
Missouri	52.80	–[a]	–[a]
Montana	42.08	28.32	23.14
New Mexico	35.01	32.31	28.81
North Dakota	16.56	11.07	9.71
Ohio	49.87	38.68	36.00
Oklahoma	63.73	41.98	33.84
Pennsylvania	52.86	44.60	35.84
Tennessee	57.15	42.82	33.82
Texas	17.13	15.93	13.53
Utah	53.39	31.54	26.56
Virginia	68.74	50.96	40.63
W. Virginia (N)	61.44	48.15	36.07
W. Virginia (S)	66.09	47.39	37.93
Washington	37.05	29.78	23.61
Wyoming	40.08	26.43	20.45
U.S. Average	**46.25**	**33.83**	**27.00**

[a]Low-sulfur coal sales less than 1 million tons.

Note: Low-sulfur coal is defined to have less than or equal to 2.5 pounds of SO_2 per million Btu.

Source: Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

[31] "Fuel Flexibility Underpins Gibson's Long Range Plans," *Power* (April 1995).

[32] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), p. 62.

[33] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), p. 73.

Compliance and Coal Supply

In 1995, the Powder River Basin (PRB) was the leading coal supply region, producing 303.3 million tons of coal (29 percent of U.S. coal production), while the central Appalachian region was second in coal production at 269.5 million tons (26 percent) (Table 10). After leading the nation in coal production for many years, the central Appalachian region slipped to second in 1994 as utilities found that PRB was a low-cost source of lower sulfur coal that could often be burned without significantly reducing the efficiency of their plants.[34] PRB produces a lower sulfur, low-Btu subbituminous coal, which can be economically mined and transported, while a lower sulfur, high-Btu bituminous coal originates from the central Appalachian region, where recoverable reserves are limited and more difficult to mine. Northern Appalachia and the Illinois basin, with relatively high sulfur and high-Btu coal, produced 13 percent and 11 percent of total coal production, respectively, in 1995.[35] The Rocky Mountains are a primary source of lower sulfur bituminous coal for electric utilities in the Midwest and accounted for 5 percent of total coal produced in the United States in 1995.[36]

Because fuel switching and blending has proven to be the most popular Phase I compliance method, shifts from higher sulfur coal regions to lower sulfur coal regions have occurred. In 1990, low-to-medium sulfur coal accounted for 67 percent of total coal receipts at electric utilities, increasing to 77 percent by 1995. Consequently, high-sulfur coal decreased from 33 percent in 1990 to 23 percent in 1995.[37]

Of the three coal supply regions with large lower sulfur reserves—the central Appalachian region (including Virginia, eastern Kentucky, and southern West Virginia), PRB (including Wyoming and Montana), and the Rocky Mountains (including Colorado and Utah)—PRB and the Rocky Mountains increased total coal sales dramatically between 1990 and 1995, while central Appalachia's total coal sales increased marginally (6 percent) (Table 11). Central Appalachia, once thought to be the most popular choice for lower sulfur coal by the Phase I plants, increased its lower sulfur coal sales by 15 million tons as its higher sulfur coal sales fell by 5 million tons. Most of the increase was from southern West Virginia. Lower sulfur coal receipts originating from PRB in 1995 increased by 78 million tons over coal receipts from PRB in 1990, which amounted to a 37-percent increase. For Wyoming, total coal sales increased by 77 million tons between 1990 and 1995 (Table 11). Wyoming coal was shipped to 18 States in 1995, as far east as Indiana and as far south as Georgia. Several States significantly increased purchases of Wyoming coal between 1990 and 1995 (Figure 7). Missouri led with an increase of 18 million tons. Lower sulfur coal receipts from the Rocky Mountains increased by almost 10 million tons from 1990. Total coal receipts from the northern Appalachian region fell from 127 million short tons in 1990 to 103 million short tons in 1995 (a 19-percent decrease). Northern Appalachia was able to increase its lower sulfur coal sales by 5 million tons, but not enough to offset the decline of 29 million tons in higher sulfur coal sales. Total coal receipts from the Illinois Basin dropped to 96 million short tons in 1995 from 129 million tons in 1990 (26 percent). The Illinois basin was able to double its lower sulfur coal sales from 1990 to 1995; however, its higher sulfur coal sales dropped by 40 million tons at the end of 1995.

Compliance and Coal Demand

One general perception of the outcome of Phase I of Title IV is that compliance has been less costly for electric utilities than projected because the price of allowances has dropped and lower sulfur coal prices have not increased as projected. However, just as this legislation has stimulated the energy markets by producing winners with innovative and cost-saving compliance methods, it has also resulted in losses in the higher sulfur coal supply regions where there are few options to improve the productive capability and the marketability of higher sulfur coal. This section of the report compares four broad coal demand regions—the Midwest, Northeast, South, and West (each a combination of the U.S. census divisions) (Figure 8)—to observe the significant differences in coal receipts, coal suppliers, transportation costs, and employment in these regions during the 1990's. Particular attention is given to those coal-producing States with a large number of Phase I generating units to observe shifts in coal supply sources due to compliance. Reductions in mining jobs and the number of operating mines discussed in this section are primarily attributable to productivity gains in the mining industry resulting from the closing of inefficient, uneconomical mines and the more efficient

[34] *Fossil Plant News*, Fall 1996, p. 3.

[35] Energy Information Administration, *Coal Industry Annual 1995,* DOE/EIA-0584(95) (Washington, DC, October 1996), pp. 90-101.

[36] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), p. 11.

[37] Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 10. Coal Production by State, 1990 and 1995
(Thousand Short Tons)

Region	1990 Coal Production	1990 Percent of U.S. Total	1995 Coal Production	1995 Percent of U.S. Total
Northern Appalachia				
Maryland	3,487	*	3,667	*
Pennsylvania	70,514	7	61,576	6
Ohio	35,252	3	26,118	3
Northern West Virginia	56,641	6	46,114	4
Total	**165,894**	**16**	**137,475**	**13**
Central Appalachia				
Virginia	46,917	5	34,099	3
Eastern Kentucky	128,396	12	118,541	11
Southern West Virginia	112,564	11	116,883	11
Total	**287,877**	**28**	**269,523**	**26**
Southern Appalachia				
Alabama	29,030	3	24,640	2
Tennessee	6,193	1	3,221	*
Total	**35,223**	**3**	**27,861**	**3**
Illinois Basin				
Illinois	60,393	6	48,180	5
Indiana	35,907	3	26,007	3
Western Kentucky	44,926	4	35,198	3
Total	**141,226**	**14**	**109,385**	**11**
Texas and Louisiana Lignite				
Texas	55,755	5	52,684	5
Louisiana	3,186	*	3,719	*
Total	**58,941**	**6**	**56,403**	**5**
Other Western Interior[a]	**5,506**	**1**	**2,738**	*****
Powder River Basin				
Wyoming	184,249	18	263,822	26
Montana	37,616	4	39,451	4
Total	**221,865**	**22**	**303,273**	**29**
North Dakota Lignite				
North Dakota	29,213	3	30,112	3
Total	29,213	**3**	30,112	**3**
Southwest				
Arizona	11,304	1	11,947	1
California	61	*	*	*
New Mexico	24,292	2	26,813	3
Total	35,657	**3**	38,760	**4**
Rockies				
Colorado	18,910	2	25,710	2
Utah	22,058	2	25,167	2
Total	40,968	**4**	50,877	**5**
Northwest[b]	6,707	**1**	6,566	**1**
U.S. Total	**1,029,076**	**100**	**1,032,974**	**100**

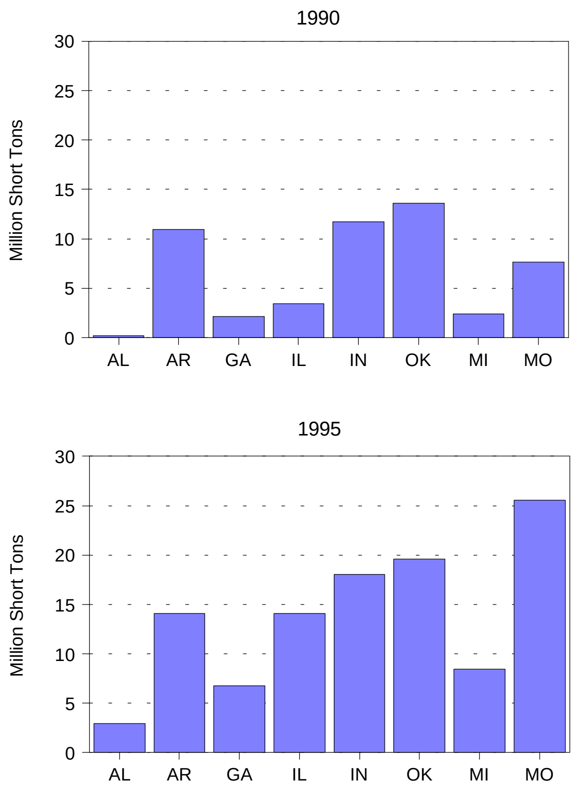
[a]Includes Iowa, Oklahoma, Kansas, Arkansas, and Missouri.
[b]Includes Alaska and Washington.
*= Less than 0.5 percent.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996), pp. 90-101.

Table 11. Coal Receipts at Electric Utility Plants by Supply Region and Sulfur Dioxide Level, 1990 and 1995

Supply Region	1990 Receipts (thousand short tons)			1995 Receipts (thousand short tons)		
	High[a] Sulfur	Low to Medium[b] Sulfur	Total	High[a] Sulfur	Low to Medium[b] Sulfur	Total
Northern Appalachia						
Maryland	1,449	1,555	3,004	544	2,678	3,222
Pennsylvania	36,389	14,100	50,489	22,098	21,170	43,268
Ohio	29,795	308	30,103	21,080	286	21,366
Northern West Virginia	33,534	9,902	43,436	28,340	7,065	35,405
Total	**101,167**	**25,865**	**127,032**	**72,062**	**31,199**	**103,261**
Central Appalachia						
Virginia	1,799	15,567	17,366	462	13,992	14,454
Eastern Kentucky	5,235	79,964	85,199	1,821	85,217	87,038
Southern West Virginia	774	44,398	45,172	66	55,257	55,323
Total	**7,808**	**139,929**	**147,737**	**2,348**	**154,466**	**156,814**
Southern Appalachia						
Alabama	6,529	9,854	16,383	4,696	10,960	15,656
Tennessee	1,192	3,426	4,618	41	1,870	1,911
Total	**7,721**	**13,280**	**21,001**	**4,736**	**12,830**	**17,566**
Illinois Basin						
Illinois	50,319	3,914	54,233	33,829	8,120	41,949
Indiana	29,040	1,859	30,899	15,649	4,498	20,147
Western Kentucky	43,114	504	43,618	33,370	334	33,704
Total	**122,473**	**6,277**	**128,750**	**82,848**	**12,952**	**95,800**
Texas and Louisiana Lignite						
Texas	15,772	33,314	49,086	26,974	22,982	49,956
Louisiana	0	3,186	3,186	1,920	1,505	3,425
Total	**15,772**	**36,500**	**52,272**	**28,894**	**24,487**	**53,381**
Other Western Interior[c]	**3,302**	**673**	**3,975**	**662**	**33**	**695**
Powder River Basin						
Wyoming	33	176,444	176,477	0	253,922	253,922
Montana	10	35,616	35,626	14	35,676	35,690
Total	**43**	**212,060**	**212,103**	**14**	**289,598**	**289,612**
North Dakota Lignite						
North Dakota	2,052	20,931	22,983	1,868	21,789	23,657
Total	**2,052**	**20,931**	**22,983**	**1,868**	**21,789**	**23,657**
Southwest						
Arizona	0	11,447	11,447	0	11,782	11,782
New Mexico	0	22,644	22,644	0	25,055	25,055
Total	**0**	**34,091**	**34,091**	**0**	**36,837**	**36,837**
Rockies						
Colorado	0	15,382	15,382	0	22,198	22,198
Utah	0	15,237	15,237	0	18,012	18,012
Total	**0**	**30,619**	**30,619**	**0**	**40,210**	**40,210**
Northwest[d]	**0**	**4,696**	**4,696**	**0**	**4,626**	**4,626**
Imported	**0**	**1,366**	**1,366**	**0**	**4,398**	**4,398**
U.S. Total	**260,338**	**526,287**	**786,625**	**193,432**	**633,425**	**826,860**

[a]High sulfur level is greater than 2.5 pounds of sulfur per million Btu's.
[b]Low-to-medium sulfur level is less than or equal to 2.5 pounds of sulfur per million Btu's.
[c]Includes Iowa, Oklahoma, Kansas, and Missouri.
[d]Includes Alaska and Washington.
Source: Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Figure 7. Coal Produced in Wyoming and Delivered to Electric Utilities, 1990 and 1995



Source: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 33 and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

operation of existing mines. Shifts in coal supply sources brought on by compliance with Phase I has a smaller impact on these statistics.

The Midwest Demand Region

The Midwest, made up of the East North Central and West North Central census divisions, had 134 Table 1 units with 42.8 gigawatts of capacity. In 1995, the Midwest was the second largest recipient of coal of the four regions, with 302 million tons; the region received about 24 million tons more than in 1990.

Railroads, the major mode of transporting coal purchased under contract to this region, were able to reduce rail transportation costs between 1988 and 1993 because of rail productivity increases and because coal transporters in certain regions renegotiated contracts with utilities to maintain market shares where possible. In 1990, five States in the Midwest—Illinois, Indiana, Michigan, Ohio, and Missouri—received more than 64 percent of the coal received in the region.

The State of Illinois

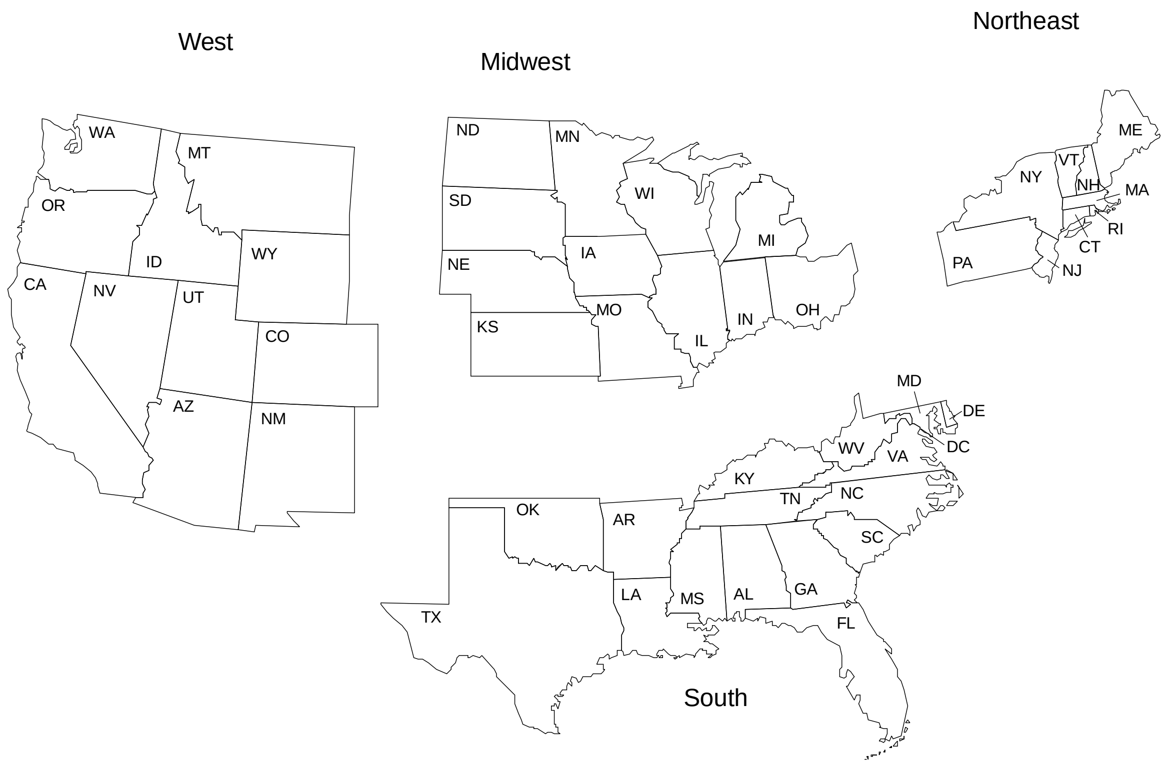
Coal is abundant in Illinois and is the most valuable mineral resource, exceeding crude oil and natural gas in estimated total value. Underlying about two-thirds of the State in relatively thick, flat-lying coalbeds, the coal is bituminous in rank and has a high-sulfur content, averaging 2 to 3 percent by weight even when cleaned.[38] In 1990, Illinois produced 60.4 million tons of coal,[39] selling 15.5 million tons in the State. A large share was sold to Missouri (12.4 million tons) and Indiana (9.7 million tons).[40] Two-thirds of the coal produced in Illinois is from underground mines, most of which are large operations.

In choosing between scrubbing and switching, the four Illinois utilities with 17 Table 1 units were faced with an important economic decision that affected both the utilities and the State: Illinois coal could continue to be used; however, switching to lower sulfur coal meant obtaining coal from sources outside of Illinois, thus reducing the demand for a valuable State resource.

In 1991, the Illinois State legislature passed a clean air law to protect Illinois coal producers. The law required utilities to inform the State whether their Title IV plans included use of Illinois coal before State approval was granted. Similar laws were passed in Indiana, Oklahoma, and Ohio. However, the Alliance for Clean Coal, a coalition of western coal producers and railroads, filed suit[41] against the Illinois clean air law, arguing that it violated Federal interstate commerce statutes; the Alliance succeeded in having the Illinois law struck down. The

[38] Energy Information Administration, *State Coal Profiles,* DOE/EIA-0576 (Washington, DC, January, 1994), p. 27.
[39] Energy Information Administration, *Coal Industry Annual 1994,* DOE/EIA-0584 (Washington, DC, October 1995), p. 5.
[40] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990,* DOE/EIA-0191 (Washington, DC, August 1991), p. 56.
[41] *Alliance for Clean Coal vs. Craig,* Docket No. 93C4391, December 15, 1993.

Figure 8. Coal Demand Regions



Coal Demand Regions

Northeast	Midwest	South	West
Connecticut	Illinois	Alabama	Arizona
Maine	Indiana	Arkansas	California
Massachusetts	Iowa	Delaware	Colorado
New Hampshire	Kansas	District of Columbia	Idaho
New Jersey	Michigan	Florida	Montana
New York	Minnesota	Georgia	Nevada
Pennsylvania	Missouri	Kentucky	New Mexico
Rhode Island	Nebraska	Louisiana	Oregon
Vermont	North Dakota	Maryland	Utah
	Ohio	Mississippi	Washington
	South Dakota	North Carolina	Wyoming
	Wisconsin	Oklahoma	
		South Carolina	
		Tennessee	
		Texas	
		Virginia	
		West Virginia	

Source: Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation* DOE/EIA-0597 (Washington, DC, October 1995).

Alliance won a similar suit in Indiana[42] and filed a suit against the Ohio law in September 1995.[43]

Illinois coal production in 1995 fell to 48.2 million tons (about 11.9 million tons were used in the State). One of Illinois' main consumers, Missouri, purchased only 4.2 million tons, a reduction of 8 million tons from 1990, and Indiana received 10.7 million tons, a slight increase from 1990. As consumers, the electric utilities in both Illinois and Missouri in 1995 substituted a substantial amount of lower sulfur coal from Wyoming for coal from Illinois—Illinois received 14 million tons from Wyoming (Figure 9) and Missouri increased its purchases from Wyoming by 17.9 million tons. Between 1990 and 1995, the number of operating mines in Illinois dropped from 45 to 31, while the average number of miners decreased on average by 11 percent per year between 1990 and 1995 (10,018 to 5,652).[44]

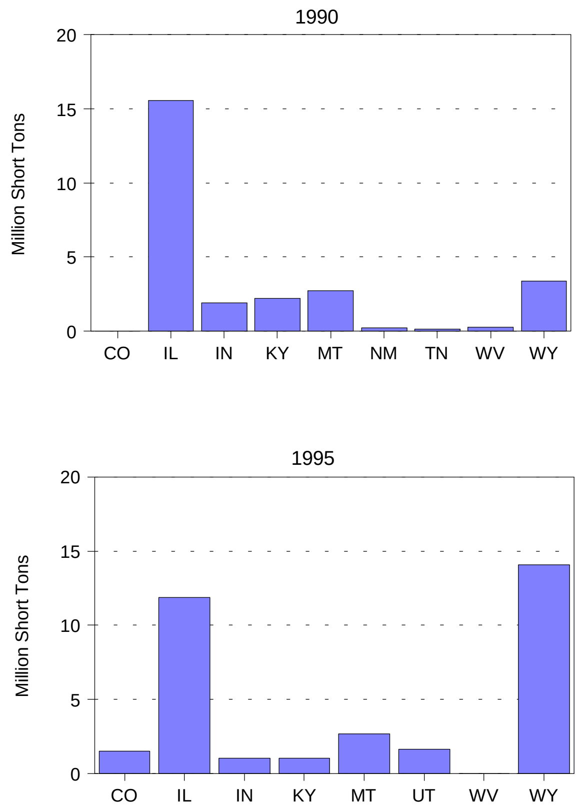
The State of Indiana

In 1995, Indiana produced 26 million tons of coal,[45] almost 10 million tons less than in 1990. Nearly all of the coal was obtained from surface mines—bituminous in rank and high in sulfur content. Second only to Texas in annual consumption, Indiana is a large consumer of coal, using about three-fifths of coal produced in the State.[46]

Indiana's excellent rail network and sophisticated port facilities on Lake Michigan to the north and on the Ohio River to the south make coal delivery to Indiana utilities easy, but also makes the State vulnerable to penetration by lower sulfur western coal.[47]

Because of the higher sulfur content of Indiana coal, Indiana utilities affected by Phase I (15 plants housing 37 units) had to either scrub or modify their boiler units to burn lower sulfur coal from other States. As of December 1995, utilities in the State installed scrubbers on seven units at four plants and constructed a coal gasification combined cycle project at the Wabash River Plant. This clean coal technology project at Wabash River removes 98 percent of the SO_2 from 2,700 tons of high-sulfur bituminous coal each day. These compliance choices have helped Indiana coal producers retain a share of the utility market and preserve some of the 3,000 jobs (mining and other coal industry jobs) in the State.[48]

Figure 9. Origin of Coal Received in Illinois, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA- (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Public Service of Indiana's Gibson plant, the third largest coal-fired power plant in the United States, chose to scrub its No. 4 unit to comply with Title IV and received virtually all of its 1995 coal from Illinois (as it had in 1990). In fact, Indiana received almost the same quantity of coal

[42] *Alliance for Clean Coal vs. Bayh*, Docket No. IT94-890-C-T/G. March 22, 1995. Appealed and affirmed December 22, 1995.
[43] In a recent ruling, U.S. District Judge John Holschuk dismissed the Alliance for Clean Coal suit to overturn a 1991 Ohio coal law (Case No. C2-95-905) that gives regulatory and tax preferences to Ohio utilities that burn Ohio coal. *Utility Environment Report*, October 25, 1996, p. 2.
[44] Energy Information Administration, *Coal Industry Annual 1995*, DOE-EIA-0584 (Washington, DC, October 1996), Tables 1 and 40.
[45] Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584 (Washington, DC, October 1996), p. 7.
[46] Energy Information Administration, *State Coal Profiles*, DOE-EIA-0576 (Washington, DC, January 1994), p. 31.
[47] Indiana Business Magazine, Vol. 39, No. 2, February 1995, p. 186.
[48] Ibid.

in 1995 as it did in 1990 (about 49 million tons); however, this coal had a significantly lower sulfur content (24 percent lower). From 1990 to 1995, in-state coal use was reduced by 5 million tons and coal from western Kentucky was reduced by 3 million tons. Indiana utilities increased their use of Wyoming coal by 6.3 million tons (Figure 10), and slightly increased their use of coal from Virginia, Illinois, and Ohio. In 1995, the number of mines in operation dropped from 64 in 1990 to 42 in 1995. Employment in the mines decreased on average by about 9 percent per year during this period.

The States of Michigan and Missouri

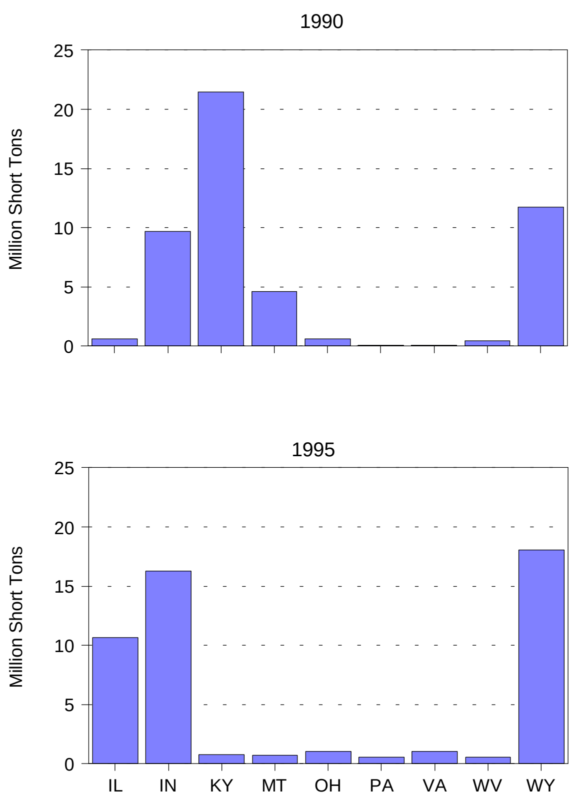
In 1990, Michigan received 30 million tons of coal and Missouri received 24 million tons; Michigan had one plant with 2 Table 1 units, while 8 Missouri plants had 16 Table 1 units. Both States received some coal from PRB in 1990; Michigan combined PRB coal with 13 million tons of coal from the central Appalachian region, while Missouri combined PRB coal with 12 million tons from Illinois.

In 1995, compliance programs in Missouri reduced Illinois coal usage by 8 million tons, a large portion of the 23-percent decline in coal originating from Illinois between 1990 and 1995. Missouri increased its 1995 total receipts by 6.5 million tons from 1990, purchasing 25.6 million tons from the PRB, and reduced its average sulfur content to 0.57 percent by weight, a 72 percent reduction in 1995 (Figure 11). Michigan replaced about 3 million tons of Central Appalachian coal with 3 million tons of Powder River Basin coal in the same period (Figure 12).

The State of Ohio

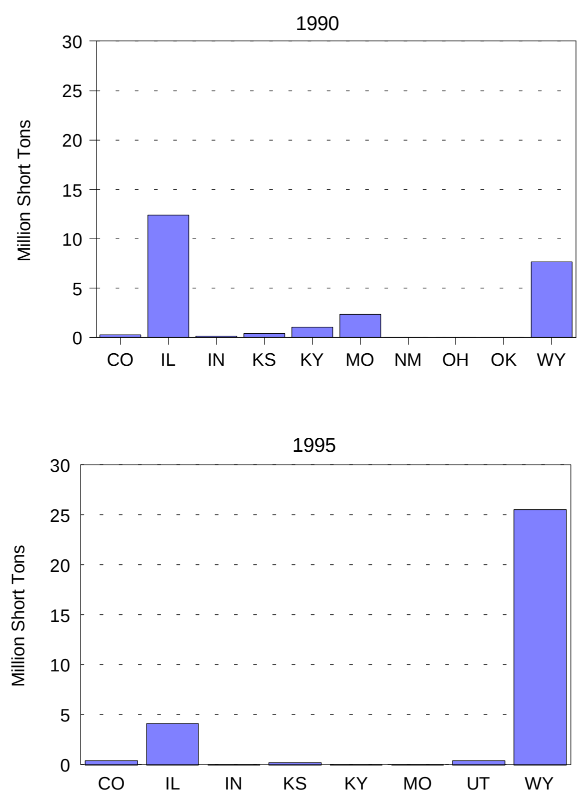
Ohio is part of the northern Appalachian coal production region, which also includes Pennsylvania, Maryland, and

Figure 10. Origin of Coal Received in Indiana, 1990 and 1995



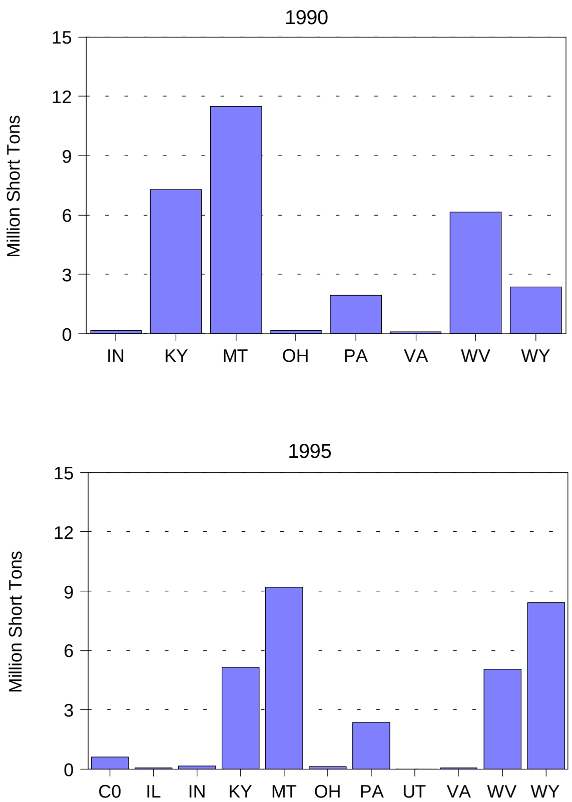
Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report on Cost and Quality of Fuels for Electric Plants."

Figure 11. Origin of Coal Received in Missouri, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Figure 12. Origin of Coal Received in Michigan, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

the northern portion of West Virginia. Ohio coal is bituminous in rank and high in sulfur content (more than 3 percent by weight). In 1995, Ohio produced 26 million tons of coal, 9 million tons less than in 1990; 66 percent of the 1995 coal production was delivered to consumers in the State. Ohio is the third largest coal-consuming State after Texas and Indiana, and second in the Nation in the amount of electricity generated from coal in 1995.[49]

Title IV targeted 14.3 gigawatts of Ohio's coal-fired capacity (57.3 percent) as Table 1 units, which translates to 41 units in 15 plants in the State. In early 1995, two wet limestone scrubbers went into commercial operation for Phase I compliance at the 2,600 MW Gavin plant of the Ohio Power Company, the largest coal-fired plant in Ohio.[50]

This $630-million-dollar project allowed the Gavin plant to continue using Ohio coal—5.8 million tons in 1995 compared to 6.4 million tons in 1990. Ohio Edison's Niles plant used almost 100 percent Ohio coal in 1995 because of the operating success of a year-old, $31 million LS-2 wet scrubber installed at generator No. 1, a 132.8 megawatt unit. Compliance strategies chosen for the remainder of the Table 1 units in the State include the following: 16 units switched to lower sulfur coal, 20 units used allowances, 1 unit was scrubbed, and 1 unit was retired.

Compliance with Phase I had some impact on Ohio's coal consumption. In 1995, Ohio received 48 million tons of coal, a decrease of about 4 million tons from the total receipts in 1990 and a decrease of 8 million tons of Ohio coal (Figure 13). An 8-million-ton increase of coal from central Appalachia supplemented Ohio receipts, resulting in a drop of the average sulfur content by weight from 2.44 in 1990 to 1.89 in 1995. The number of mines operating in Ohio in 1990 was 172, decreasing to 113 in 1995, while the number of miners decreased on average by 10 percent per year during this period.

The Northeast Demand Region

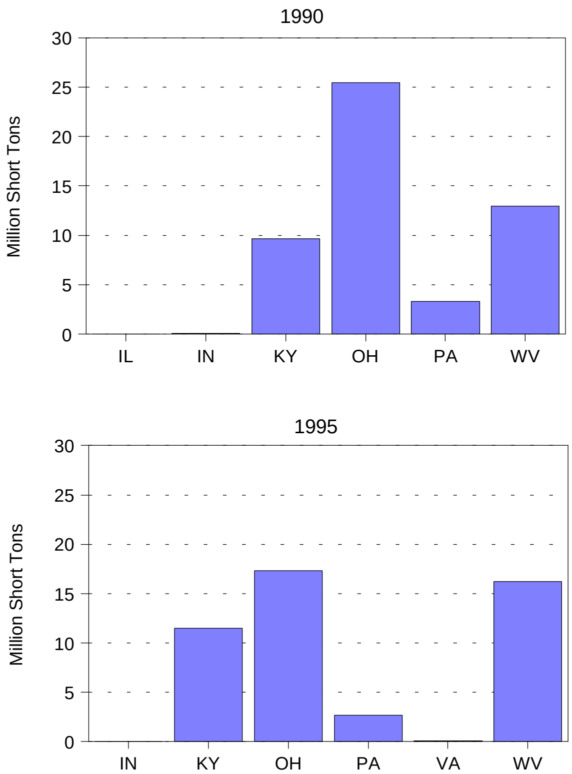
The Northeast demand region is made up of the Middle Atlantic and New England census divisions, which include Connecticut, Maine, Massachusetts, New Hampshire, New York, New Jersey, Pennsylvania, Rhode Island, and Vermont (Figure 8). In 1995, this region received 54 million tons of coal, with more than 70 percent (38 million tons) received by Pennsylvania. In this region, 35 units at 16 plants were designated as Table 1 units. Pennsylvania had the most, 21 units at 9 plants.

The Commonwealth of Pennsylvania

Pennsylvania has long been a major producer and consumer of coal and led the Nation in coal production until the early 1950's.[51] In 1995, Pennsylvania produced 62 million tons of coal; approximately 47 percent

[49] Energy Information Administration, *Electric Power Annual 1995 Volume I,* DOE/EIA-0384 (Washington, DC, July 1995).
[50] "Western Coal Suppliers, Railroads Sue to Overturn Ohio Coal Protection" *Law, Electric Utility Week,* September 25, 1995, p. 77.
[51] Energy Information Administration, *State Coal Profiles,* DOE/EIA-0576 (Washington, DC, January 1994).

Figure 13. Origin of Coal Received in Ohio, 1990 and 1995



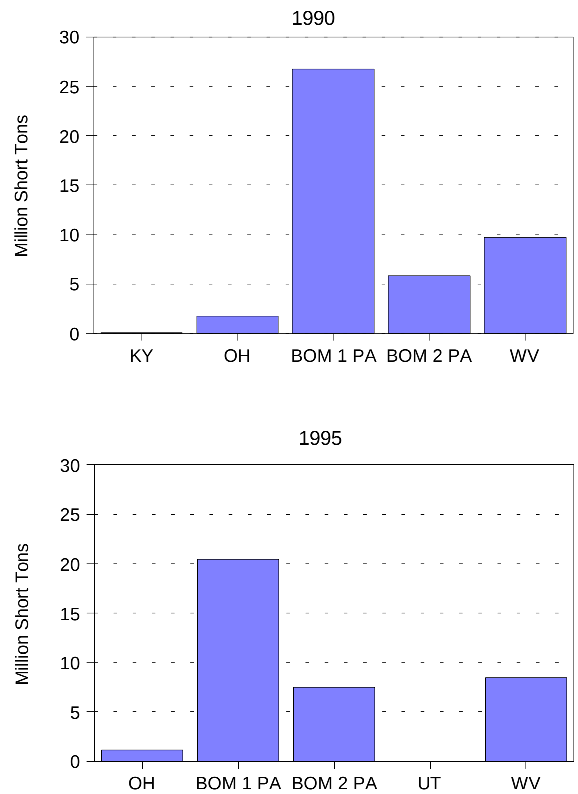
Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

remained in the State.[52] The largest out-of-state shipments went to New York, Ohio, and Michigan.

Pennsylvania is part of the northern Appalachian coal-producing region, an area that has seen a decline in shipments to electric utilities in recent years. From 1990 to 1995, Pennsylvania reduced its total coal receipts by 6.3 million tons, with almost all of this decline occurring in the central Pennsylvania coal production area (in Clearfield, Jefferson, Indiana, Cambria, Clarion, and Somerset counties) (Figure 14). These counties are part of the U.S. Bureau of Mines District 1 (BOM 1), a region populated by small to mid-size producers facing a depleting reserve base, escalating mining costs and shrinking demand.[53] One large regional coal producer, Rochester & Pittsburgh, closed two of its Helvetia mines in 1994 and three high-cost Keystone mines in December 1995.[54]

In 1990, PP&L, a utility with three of its four coal-fired plants targeted for Phase I reductions, purchased over 90 percent of its coal from central Pennsylvania. By 1995, PP&L receipts from central Pennsylvania had fallen to 43 percent of its total receipts. This utility substituted 80

Figure 14. Origin of Coal Received in Pennsylvania, 1990 and 1995

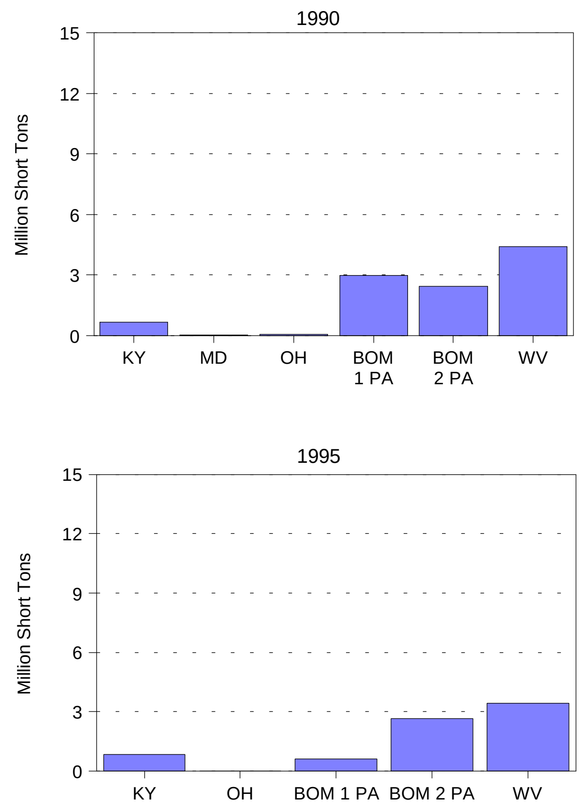


BOM 1 PA = Bureau of Mines District 1, Pennsylvania.
BOM 2 PA = Bureau of Mines District 2, Pennsylvania.
Note: See glossary for specific counties in BOM Districts 1 and 2 in Pennsylvania.
Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

52 Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584(95) (Washington, DC, October 1996).
53 "Central Pennsylvania Coal Faces an Uncertain Future," *Coal*, March 1996, p. 37.
54 Ibid.

percent of its Brunner Island plant purchases and 50 percent of its Martins Creek plant purchases with lower sulfur coal supplies from Pittsburgh No. 8 seam in Greene County (BOM District 2) (Figure 14).[55] Utilities in the State of New York reduced total coal purchases by almost 3 million tons in 1995; almost all of the decline was in the central Pennsylvania area (Figure 15). More than two-thirds of the coal produced in Pennsylvania comes from underground mines. The number of miners has dropped by 6,935 since 1990. The number of mines operating in Pennsylvania was 459 in 1995, a drop of 32 percent since 1990.

Figure 15. Origin of Coal Received in New York, 1990 and 1995



BOM 1 PA = Bureau of Mines District 1, Pennsylvania.
BOM 2 PA = Bureau of Mines District 2, Pennsylvania.
Note: See glossary for specific counties in BOM Districts 1 and 2 in Pennsylvania.
Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

The South Demand Region

The broad South demand region encompasses three census divisions: the South Atlantic census division (Delaware, District of Columbia, Florida, Georgia, Maryland, North Carolina, South Carolina, Virginia, and West Virginia); the East South Central census division (Alabama, Kentucky, Mississippi, and Tennessee); and the West South Central census division (Arkansas, Louisiana, Oklahoma, and Texas). Transportation to utilities in the South region is dominated by long-distance rail hauls from Appalachian and, more recently, western mines.[56] As the distance that contract coal was shipped by rail increased and rail costs decreased slightly, more contract coal was shipped by rail to utilities in the South than in any other region in 1993.

Ninety-two generating units at 33 plants were designated as Table 1 units in the South region. Tennessee and Georgia had 19 Table 1 units each, followed by Kentucky with 17 units, West Virginia with 14, and Alabama with 10 Table 1 units. Florida, Maryland, and Mississippi had a total of 13 Table 1 units. Texas, the largest consumer of coal at electric utility plants in the United States, had no Table 1 units.

In 1995, six States dominated the coal purchases at electric utilities: Kentucky purchased 37 million tons, West Virginia purchased 30 million tons, Georgia and Alabama each purchased 28 million tons, Florida purchased 24 million tons, and Tennessee purchased 24 million tons. Of the six States, Georgia, West Virginia, and Tennessee had the highest 1985 SO_2 emissions in the South region.

The State of West Virginia

West Virginia has abundant bituminous coal resources underlying more than two-thirds of the State. The coal deposits are divided geologically into the northern and southern fields. Coalbeds in the southern field generally have a higher heating value and a lower sulfur content than the northern field.[57] With well-established railroad

[55] Ibid.
[56] Energy Information Administration, *EPACT Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), p. 61.
[57] Energy Information Administration, *State Coal Profiles*, DOE/EIA-0576 (Washington, DC, January 1994), p. 103.

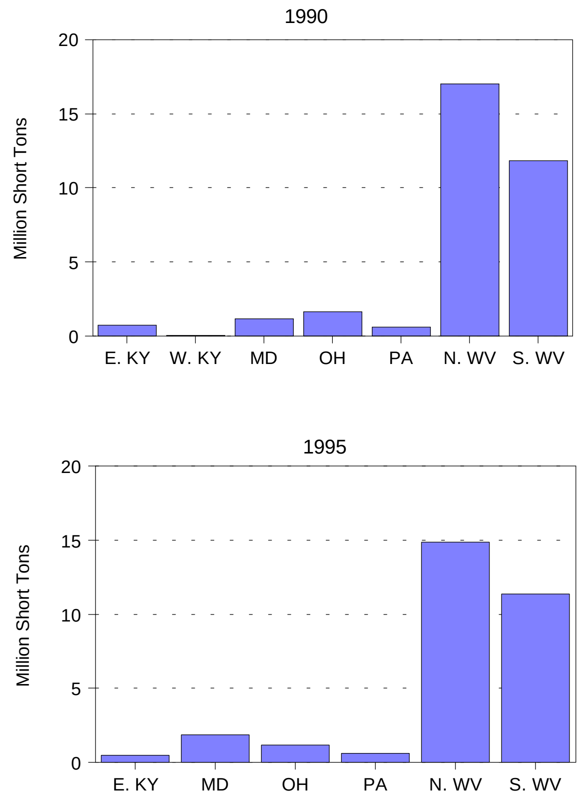
and river transportation facilities, coal production in the State was 163 million tons in 1995. Most of the coal produced is shipped outside the State.[58]

The 13 coal-fired electric utility plants in West Virginia received approximately 30 million tons of coal in 1995; about 86 percent came from within the State. Fourteen units at six West Virginia plants were designated as Table 1 units. Monongahela Power and Virginia Electric & Power installed scrubbers at two plants to comply, thus earning allowance credits for five units at three plants. Ohio Power used lower sulfur coal at two Table 1 units and allowances at three Table 1 units.

Northern West Virginia, a higher sulfur coal producing area, may have been affected by these compliance strategies because the State decreased its use of coal from northern West Virginia by about 2 million tons between 1990 and 1995 (Figure 16). The compliance programs of its other customers had greater impact on northern West Virginia, which is part of the hard-hit northern Appalachian region. The number of operating mines in northern West Virginia declined from 205 in 1990 to 98 in 1995, and the number of miners working in the mines fell on average by 9 percent per year during this period.

Between 1990 and 1995, the southern West Virginia lower sulfur coal producing area experienced little impact from the implementation of Phase I from its in-state customers because these electric utilities maintained the same level of in-state coal usage in 1995 as in 1990 (approximately 11 million tons). Total receipts originating from southern West Virginia increased substantially because out-of-state customers purchased more lower sulfur coal in 1995. Although coal production from southern West Virginia increased by 4 million short tons between 1990 and 1995, the number of operating mines decreased from 566 to 326, and the number of miners working in southern West Virginia decreased from 19,525 to 15,220 during this period.[59] A number of small high cost mines in the region are marginal producers and typically shutdown when the price of coal is low and operate when prices are higher. Between 1990 and 1995, the average delivered price of low sulfur coal from southern West Virginia declined by $10 per short ton.

Figure 16. Origin of Coal Received in West Virginia, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

The Commonwealth of Kentucky

With production of 154 million tons in 1995, Kentucky is one of the major coal-producing States, third largest after Wyoming and West Virginia. Kentucky coal deposits consist of bituminous coal in two coalfields, one in the east and the other in the west. The eastern coalfield is part of the Appalachian coal basin where the coal has a heat content of about 26 million Btu per short ton and a sulfur content of 1 to 2 percent by weight. The heat content of

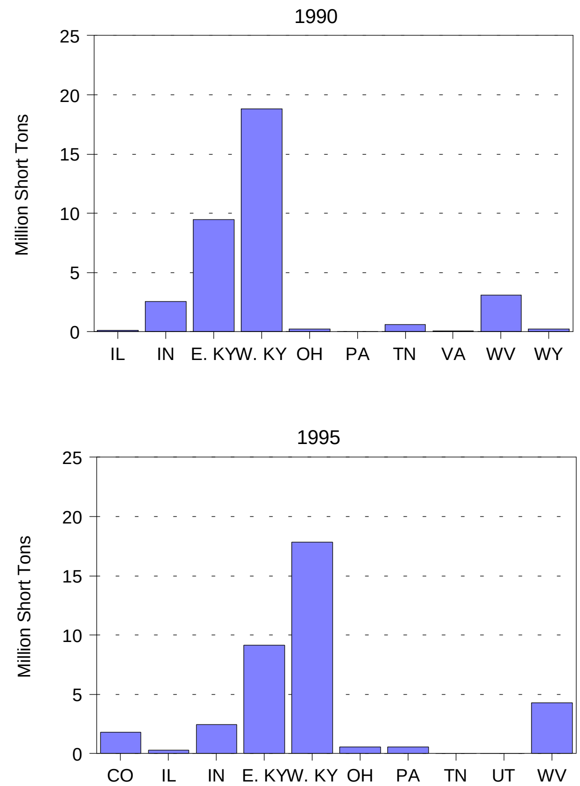
[58] Ibid.
[59] Energy Information Administration, *Coal Industry Annual 1994* and *Coal Industry Annual 1995*, DOE/EIA-0584(94) and (95) (Washington, DC, October 1994 and 1995).

the coal in the western field, which is a continuation of the Illinois basin, is slightly lower, but the sulfur content is higher (approximately 3 to 4 percent by weight).[60]

Electric utilities in Kentucky purchased 37 million tons of coal in 1995, almost 2 million tons more than were purchased in 1990. Seventeen units at 10 utilities were designated as Table 1 units. Phase I compliance programs resulted in a mixed impact on coal sales from Kentucky. Eastern Kentucky, the lower sulfur coal producing area, maintained the same level of coal sales within the State at 9 million tons in 1990 and 1995 (Figure 17). Eastern Kentucky also increased its total coal shipments to electric utilities but there was a shift from high to low and medium sulfur coal. However, total coal production declined by 10 million short tons. The operating mines in eastern Kentucky decreased from 902 to 540 and the number of miners decreased by 8,000, to 16,840. Western Kentucky's in-state coal sales were reduced by 1 million tons, having been replaced by coal from Colorado. The number of operating mines in western Kentucky was reduced from 85 in 1990 to 58 in 1995, and the number of miners fell from 5,586 in 1990 to 4,285 in 1995 (Table 12).

Of the 17 Table 1 units in Kentucky, five were retrofitted with scrubbers, 7 switched to lower sulfur coal, and 5 units were designated as using allowances. The average sulfur content of the coal received in Kentucky was reduced from 2.59 percent by weight in 1990 to 2.42 percent by weight in 1995.

Figure 17. Origin of Coal Received in Kentucky, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

The States of Georgia and Tennessee

Two other southern States of interest in the Title IV program are Georgia and Tennessee because they each had 19 units designated in Table 1. Georgia emitted 815,000 tons of SO_2 in 1985 and 638,000 tons were emitted in Tennessee. Although these States are not important coal-producing States (Tennessee produced 3 million tons in 1995 and Georgia produced none), their compliance strategies affected coal sales in other States.

Georgia purchased almost the same amount of coal in 1995 as it did in 1990, approximately 28 million tons. However, in 1995 its lower sulfur coal purchases from the central Appalachian and PRB regions increased by 8 million tons, while its higher- and medium-sulfur coal purchases fell by 8 million tons, with a 4-million ton reduction in purchases from Illinois (Figure 18). Of the 19 Table 1 units, all owned and operated by Georgia Power, 18 were switched to lower sulfur coal and one unit at the Yates plant was retrofitted with a scrubber.

In Tennessee, the total coal receipts for the State rose by almost 3 million tons between 1990 and 1995, but no significant source changes were made during that period. Lower sulfur coal receipts from Utah and higher sulfur coal receipts from Illinois increased by more than a million each (Figure 19). The average sulfur content of Tennessee's 1995 coal receipts decreased slightly from 2.00 in 1990 to 1.97 in 1995. All of the 19 Table 1 units in Tennessee are operated by the Tennessee Valley Authority (TVA). TVA designated the use of allowances as the compliance strategy for 14 units, retrofitted 2 units with scrubbers and used lower sulfur coal for 3 units.

[60] Energy Information Administration, *State Coal Profiles*, DOE/EIA-0576 (Washington, DC, January 1994).

Table 12. The Number of Mines and the Average Number of Miners Working Daily by State for 1990 and 1995

State	1990		1995	
	Mines[a]	Miners[b]	Mines[a]	Miners[b]
Alabama	97	6,534	73	5,567
Alaska	1	84	1	102
Arizona	2	951	2	831
Arkansas	7	13	3	4
California	1	5		
Colorado	23	2,009	17	1,777
Georgia				
Illinois	45	10,018	31	5,652
Indiana	64	4,195	42	2,571
Iowa	3	135		
Kansas	4	132	1	54
Kentucky				
Eastern	902	24,912	540	16,840
Western	85	5,586	58	4,285
Louisiana	2	103	2	114
Maryland	27	589	20	458
Missouri	5	347	6	92
Montana	9	821	8	722
New Mexico	7	1,472	7	1,747
North Dakota	11	931	6	716
Ohio	172	5,866	113	3,386
Oklahoma	23	415	13	241
Pennsylvania				
Anthracite	187	1,687	134	1,069
Bituminous	486	14,216	325	7,899
Tennessee	86	1,697	25	681
Texas	15	2,131	14	1,590
Utah	18	2,434	13	1,893
Virginia	340	10,342	194	6,919
Washington	4	777	3	566
West Virginia				
Northern	205	10,053	98	6,114
Southern	566	19,525	326	15,220
Wyoming	33	3,330	29	3,142
U.S. Total	**3,430**	**131,310**	**2,104**	**90,252**

[a]Excludes silt, culm, refuse bank, slurry dam, and dredge operations, except for Pennsylvania anthracite.

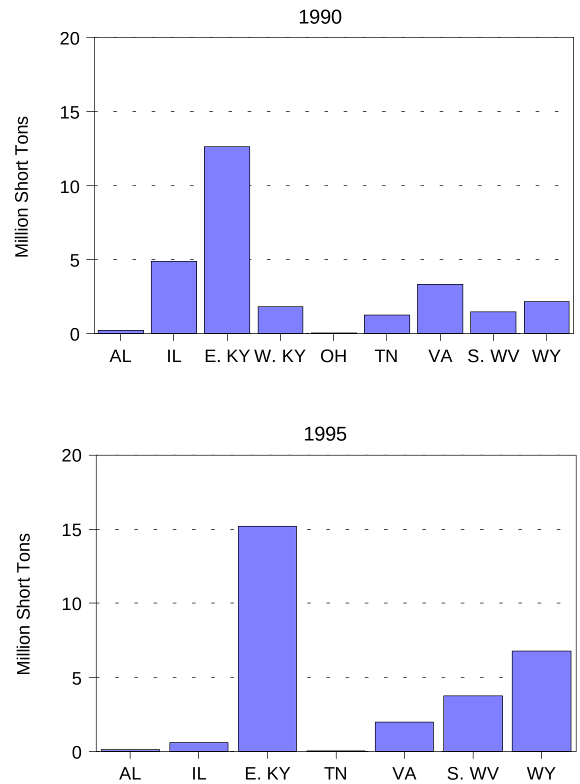
[b]Includes all employees engaged in production, preparation, processing, development, maintenance, repair, and shop or yard work at mining operations; includes mining operations management and all technical and engineering personnel; and excludes office workers. The average number of miners working daily is the arithmetic mean number of miners working each day at a mining operation.

Sources: Energy Information Administration, *Coal Industry Annual 1994*, DOE/EIA-0584 (Washington, DC, October 1995), Tables 2 and 39; and *Coal Industry Annual 1995*, DOE/EIA-0584 (Washington, DC, October 1996), Tables 2 and 40.

The West Demand Region

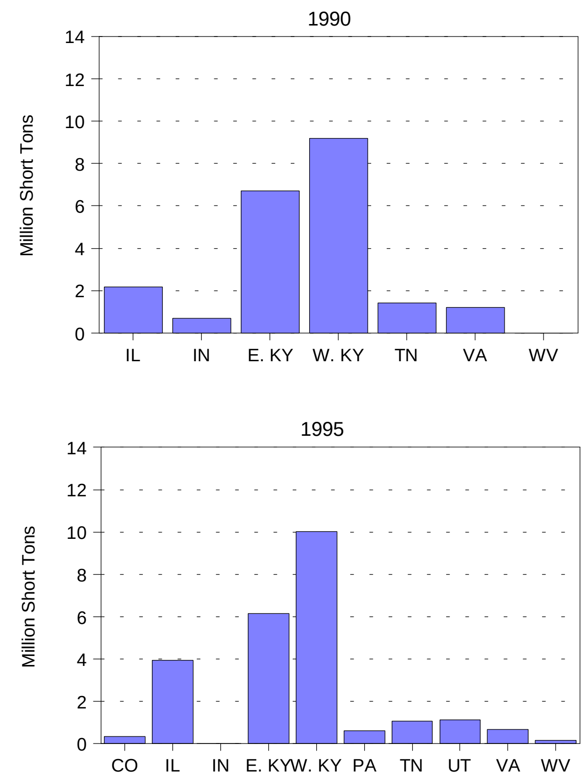
The West demand region includes the Mountain and Pacific census divisions (Arizona, Colorado, Montana, Nevada, New Mexico, Utah, Wyoming, Oregon, and Washington). This region received 108 million tons of coal in 1995. Contract coal delivered to the region was transported by rail, truck, conveyor, slurry pipeline, and a combination of modes. The West demand region had no Table 1 units because the coal burned in this region is lower sulfur coal resulting in low SO_2 emissions. Wyoming and Utah, however, each have units that were designated as substitution units. The West demand region is an integral part of the Title IV compliance

Figure 18. Origin of Coal Received in Georgia, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Figure 19. Origin of Coal Received in Tennessee, 1990 and 1995



Sources: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1990*, DOE/EIA-0191 (Washington, DC, August 1991), Table 34; and Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

program because it has become the major supplier of lower sulfur coal to utilities in the Midwest and South demand regions. Central to this growth share by the West demand region is the low delivered price of western coal. Between 1991 and 1995, the average mine price of Wyoming coal fell 5 percent per year to $6.58 per ton in 1995,[61] and rail transportation rates for contract coal originating in Wyoming, Colorado, Utah, and Montana decreased by more than 20 percent between 1988 and 1993.[62]

[61] Energy Information Administration, *Coal Industry Annual 1995*, DOE/EIA-0584 (Washington, DC, October 1996), Table 80.
[62] Energy Information Administration, *EPACT Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), pp. 32-33.

4. Developments Since Phase I Took Effect

Since Phase I began on January 1, 1995, some developments have been noteworthy. First, the U.S. Environmental Protection Agency's (EPA's) initial rule for a group of Phase I boilers' nitrogen oxides (NO_x) reductions was vacated by a U.S. Court of Appeals; EPA subsequently reissued the rule for these boilers. A rule for other Phase I and Phase II boilers has been issued. Second, the regulation of air toxics are unclear at this time. Third, significant developments have been made in air pollution control technology. This chapter summarizes these latest developments.

Programs for the Control of Nitrogen Oxides Emissions

Original Rule for Phase I, Group 1 Boilers

Title IV of the Clean Air Act Amendments of 1990 (CAAA90) calls for EPA to establish regulations for the reduction of NO_x emissions from coal-fired utility boilers in two stages. In the first stage, two categories of boilers affected by Phase I of the sulfur dioxide (SO_2) program are covered: tangentially fired boilers and dry bottom wall-fired boilers (Group 1). "Dry-bottom" refers to the form of the ash that leaves the boiler. In dry-bottom boilers, the temperature remains below the ash melting point, and the ash remains in a solid, "dry" form. Another type of boiler, called a wet-bottom boiler, gets hot enough to melt the ash before it leaves the boiler. "Wall-fired" and "tangentially fired" refer to the placement and orientation of burners in the combustion chamber. The burners of wall-fired boilers are perpendicular to the wall of the chamber, either all on one wall (front) or split between two facing walls (opposed). Tangentially fired burners are spaced around the chamber and angled to produce a rotating flame within the chamber.[63] CAAA90 instructs EPA to set less rigid standards if it finds that the legislated limits cannot be achieved using low-NO_x burner technology.[64] The legislation specifies the maximum allowable emission rates for Group 1 boilers as 0.45 pounds of NO_x/mmBtu for tangentially fired boilers and as 0.50 pounds/mmBtu for dry-bottom, wall-fired boilers (other than units applying cell-burner technology). About one-quarter of all Group 1 boilers are covered in Phase I of the SO_2 program.[65]

Final Rule for Phase I, Group 1 Boilers

On March 22, 1994, EPA promulgated a rule establishing the Phase I Group 1 NO_x emissions reduction program.[66] However, on November 29, 1994, after a challenge from utility groups, the U.S. Court of Appeals for the District of Columbia Circuit found that the definition of low-NO_x–burner technology contained in the March 22 rule exceeded EPA's statutory authority. The Court vacated the rule and sent it back to EPA. On March 28, 1995, EPA signed an agreement with environmental and utility-industry parties that addressed the March 22, 1994, regulations and the issues raised by the Court's remand,[67] and on April 13, 1995,[68] it issued a final rule revising the definition of low-NO_x–burner technology.

The final rule removed a requirement that wall-fired and tangentially fired boilers must use an over-fire air process to be eligible for the previously mentioned less stringent emissions controls. The rule also extended the date for complying with the first stage from January 1, 1995, to January 1, 1996. EPA estimates that the final Phase I rule will cut annual emissions of NO_x from Phase I, Group 1 boilers by 400,000 tons beginning in 1996.

[63] Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March 1994), p. 99.

[64] Clean Air Act, Section 407 (b) (1).

[65] Environmental Protection Agency, *EPA Fact Sheet: Nitrogen Oxides Emission Reduction Program*, EPA430/F-92/014 (Washington, DC, October 1992).

[66] *Federal* Register 40 CFR Part 76.

[67] Ibid.

[68] U.S. Environmental Protection Agency, *EPA Fact Sheet, Nitrogen Oxides Emission Reduction Program: Proposed Rule for Phase II, Group 1 and Group 2 Boilers*, EPA Number (http://www.epa.gov/docs/acidrain/noxfs2.html).

Rule for Phase II, Group 1 Boilers and for Group 2 Boilers

On December 19, 1996, EPA issued a rule to implement the second stage of the NO_x reduction program by establishing NO_x emissions limitations for additional coal-fired boiler units and by revising NO_x emissions limitations for Group 1 boilers. EPA's charge for the second stage of the NO_x program was twofold: (1) to determine whether the technology existed that would make it feasible for EPA to establish more stringent standards in Phase II for the Group 1 boilers than those established in Phase I; and (2) to establish limitations for the boilers known as Group 2 (boilers applying cell-burner technology, cyclone boilers, wet-bottom boilers, and other types of coal-fired boilers) based on NO_x control technologies that are comparable in cost to low-NO_x burners.

According to EPA, the total Group 1 reductions beginning in 2000 will be approximately 1.2 million tons. The total cost of this regulation to the industry is estimated to be $267 million per year, resulting in an overall cost of $227 per ton of NO_x removed. Group 2 reductions beginning in 2000 are estimated to be 890,000 tons annually. The annual cost of the Group 2 regulations is estimated to be approximately $200 million with an average cost of $229 per ton of NO_x removed.[69]

Toughening of Phase II, Group I Boiler Limitations Based on Modeling

From the results of two analyses, EPA concluded that data currently available on the effectiveness of low-NO_x burner technology supported revisions of the annual limitations for both dry-bottom, wall-fired boilers and tangentially fired boilers under the second stage of the NO_x program. EPA projects that 85 percent to 90 percent of the uncontrolled bottom wall-fired boilers and tangentially fired boilers could individually meet the proposed standards.

The NO_x emission limitations for each boiler type follow in Table 13.

A utility can choose to comply with the rule in one of three ways:

1. Meet the standard annual emission limitations

2. Average the emissions rates of two or more boilers (This allows utilities to "over-control" the emissions of those units that can be controlled more easily and less expensively than others.)

3. Apply for a less stringent alternative emissions limit if the utility cannot meet the standard emissions limit if it uses the applicable NO_x emission control technology.

EPA's determination of an alternative emissions limitation will be based on evidence that control equipment was properly designed, installed, and operated during a demonstration period.

Phase II, Group 1 and Group 2 boilers are required to meet applicable limits by 2000. The highlight of the new rule is that, although it relies upon target performance standards, it also allows for emissions averaging and the use of alternative, higher emissions limits where meeting the applicable limits is not feasible. Utilities choose the method of compliance that best suits their needs. EPA states that this approach provides flexibility, promotes technology development and competition, and provides opportunities to reduce the cost of control.[70] However, some industry groups state that the new rule "will impose unreasonable burdens on up to 1,000 coal-fired units."[71]

EPA has also devised an option whereby a state or group of states could petition EPA to accept an emissions cap and trade program under authority of Title I as a substitute for compliance with the final Title IV rule. Under such an option, EPA retains the authority to allow boilers subject to the final rule to achieve emissions reductions under a Title I cap and trade program as long as capping and trading would achieve lower emissions than the final rule. Existing limits for Phase I, Group 1 boilers would remain in effect. EPA believes that such a trading

[69] Ibid.
[70] Ibid.
[71] *Mining Week*, National Mining Association, Issue 48, Vol. 2, Washington, DC, December 23, 1996, p. 2.

Table 13. Phase II, Group 1 and Group 2 Boiler Statistics and Emission Limitations

Boiler Types	Number of Boilers	Proposed Phase II NO_x Emissions Limits (Pounds/mmBtu)
Phase II, Group 1		
Dry-Bottom, Wall-Fired	308	0.46
Tangentially fired	299	0.40
Group 2		
Cell Burners	36	0.68
Cyclones > 155 MW	55	0.86
Wet-Bottom, Wall-Fired > 65 MW	26	0.84
Vertically Fired	28	0.80

Source: United States Environmental Protection Agency, Nitrogen Oxides Emission Reduction Program, Final Rule for Phase II, Group 1 and Group 2 Boilers (http://www.epa.gov/docs/acidrain/noxfs3.html).

provision provides for coordination of NO_x reduction initiatives under Titles I and IV and promotes the goal of achieving necessary NO_x reductions in a cost-effective manner.[72]

Discussion of Air Toxics–Title III

Under Title III of CAAA90, EPA is responsible for determining the hazards to public health posed by 189 hazardous air pollutants (HAP's). Title III specifically directs EPA to perform a study of the HAP's (also known as air toxics) to determine which hazards are likely to occur as a result of emissions by electric utility steam-generating units, and to report the results to Congress. This study must be completed prior to promulgating any new regulations. CAAA90 also required EPA to recommend whether to control 189 air toxics, including mercury, by November 15, 1995. However, this deadline has been delayed. The mercury studies, while still pending, are intended to evaluate human health and ecological impacts of all mercury emitting sources in the United States.[73] EPA has submitted to Congress an interim final report on the "Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units" regarding the emissions, fate, and transport of utility HAP's.[74] EPA has not evaluated exposure to mercury emissions from utilities for humans or wildlife in this interim report and plans to publish a final utility HAP report at a later date.

In addition to the studies required by CAAA90, studies on air toxics and mercury and potential regulations are being considered at the State level. Minnesota, Florida, and New Jersey are among those States that are currently addressing the potential impact of air toxics.[75]

Title III states that individual facilities may not exceed emissions of 10 tons per year (t/yr) for a single HAP or 25 t/yr for any combination of HAP's. However, even if a power plant falls below these limits, control requirements for a single HAP could be imposed because limits can be lowered based on pollutant potency, persistence, bioaccumulation, or other factors.[76] Mercury is a special concern because of its environmental behavior and the level of mercury contamination in water due to its bioaccumulation in fish. The level of mercury in raw coal is very small, typically only 0.05-0.10 parts per million (ppm). This results in trace mercury concentrations from stack emissions of about 1 part per billion (ppb).[77]

The U.S. Department of Energy (DOE) and the Electric Power Research Institute (EPRI) have performed extensive research on mercury. Results of the studies show significant variations in the amount of mercury removed by

[72] U.S. Environmental Protection Agency, Nitrogen Oxides Emission Reduction Program, Final Rule for Phase II, Group 1 and Group 2 Boilers (http://www.epa.gov/docs/acidrain/noxfs3.html).

[73] "EPA's Utility Toxics Report Will Be Delayed by at Least Two Months," *Inside EPA's Clean Air Report* (April 18, 1996), p. 18.

[74] Environmental Protection Agency, Office of Air Quality Planning and Standards, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Interim Final Report,* EPA-453/R-96-013a (Research Triangle Part, NC, October 1996).

[75] Teresa Hansen, "Air Toxicities Controls Unlikely," *Electric Light & Power* (December 1995), p. 21.

[76] Ibid.

[77] "Improving Common Control Devices," *Atmospheric Monitoring & Abatement News* (August 1995), No. 7, Vol. 3.

electrostatic precipitators; these variations range from about 15 percent to 75 percent. Although data are limited, mercury removed from baghouses ranges from 10 percent to 70 percent. Mercury removal from wet scrubber systems ranged from 0 percent to about 50 percent.[78] Much of the variation in removal performance may have been caused by the difference in the chemical form of the mercury in the flue gas. Mercury emissions from coal combustion have been shown to vary considerably from site to site. The chemical composition of coal varies widely and so does the concentration of mercury. If EPA decides that hazardous air pollutants pose a risk, then it must propose air toxic emissions controls by November 15, 1998, and make them final by November 15, 2000. Such controls are potentially costly, especially for coal-fired power plants.[79]

Technology Refinements

The electric industry faces a number of potential environmental control regulations in addition to Title IV of CAAA90, such as fine particulate and air-toxics (Title III) regulations; solid-waste restrictions; global warming and carbon dioxide (CO_2) discharges; water management; and differing State, regional, and local regulations. Increased competition and the eventual disappearance of the regulated rate of return have caused the electric utility industry to attempt to reduce the costs of compliance with Title IV of Phase II in 2000 or to coordinate the compliance strategies so they also comply with other regulations. Also, efforts may be necessary to meet regional NO_x reduction requirements associated with Title I and ozone nonattainment. Thus, refinements continue with the primary NO_x reduction technologies and with particulate control.

Nitrogen Oxides Reduction

Combustion in conventional pulverized coal systems occurs at temperatures that produce significant amounts of thermal NO_x as well as fuel-bound NO_x. Advanced techniques for post-combustion NO_x control include Selective Catalytic NO_x Reduction (SCR) and Selective Noncatalytic Reduction (SNCR). SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor. SNCR involves uncatalyzed or thermal reaction with ammonia. SCR technology is now incorporated in some new coal-fired plants and is the mainstay of NO_x reduction efforts. Several large coal-fired units have incorporated SCR technology, including two plants in New Jersey and one in Florida, and a fourth plant in Florida with full-flow SCR units.[80] One development that may enhance SCR applications even further is the evolution of lightweight catalysts. Some of these new catalysts weigh more than 50 percent less than traditional extruded ceramic or metal-based catalysts.

Another technology for controlling NO_x emissions from wet-bottom boilers—SNCR—was demonstrated by Public Service Electric and Gas Company of New Jersey (PSE&G), at its coal-fired Mercer Station. This technology is less costly than SCR. The New Jersey demonstration should benefit other utilities with wall-turbo-fired boilers and cyclone-fired boilers for which SNCR is now a viable NO_x control option. The results indicate that SNCR may be adequate to bring some boilers into compliance with CAAA90. In addition, PSE&G demonstrated in subsequent testing that SNCR can be combined in a hybrid SNCR/SCR system to achieve 90 percent NO_x reductions—a level equivalent to that achievable with conventional SCR.[81]

Other methods to reduce NO_x emissions include replacing or tuning pulverizers, upgrading components, balancing coal and air flows to individual burners, and correlating coal specifications with boiler operating parameters more closely. Experts concede that these strategies can approach or exceed the reduction available from low-NO_x burners. So much progress has been made in reducing NO_x emissions through combustion modifications that the term low-NO_x burner has less meaning today than when the CAAA90 was passed. The entire fuel preparation and furnace system must be optimized for minimum NO_x formation.[82]

Control system upgrades, which are often applied in combination with hardware modifications and instrumentation additions, can also achieve low-cost NO_x reductions. By measuring and manipulating air and/or fuel flows accurately with better process software and computer technologies, it is possible to automate and optimize the

78 Teresa Hansen, "Air Toxicities Controls Unlikely," *Electric Light & Power* (December 1995), p. 21.
79 Ibid.
80 Jason Makansi, "Despite market uncertainty, a few new approaches come forward," *Power* (March, 1996), p. 25.
81 Electric Power Research Institute, *PSE&G Demonstrated SNCR Technology for NOx Control at Mercer Station* (July / August 1996), p. 34.
82 Jason Makansi, "Work with existing hardware to maximize emissions control," *Power* (March 1995), p. 41.

process. A variety of software packages have been developed for this process, resulting in sizeable reductions in NO_x emissions. These software packages have the potential to greatly reduce or possibly eliminate the hardware component of a NO_x control retrofit.[83]

Particulate Collection

U.S. utilities have used electrostatic precipitators (ESP's) and fabric filters or baghouses to control particulate emissions at coal-fired plants for some time. These devices have enabled utilities to meet applicable emissions and opacity standards. However, the possible impact of more stringent particulate emissions requirements and the differences in ash quality as coals are switched to low-sulfur have prompted utilities to make these control devices more effective. Given these factors and the pressures of competition, utilities with coal-fired plants will have to determine how to cost-effectively improve particulate control. A list of some options follows.

- Flue-gas conditioning (FGC), usually with sulfur trioxide (SO_3) injection, is a proven method of improving the collection of fly ash in ESP's. With increasing competition among suppliers in emissions-control systems, costs are falling and performance is improving. This system converts the SO_2 already in the gas stream into SO_3 and avoids a separate feedstock / reagent. This system has been demonstrated and commercially installed.[84]

- Another approach to improving fly ash removal is to enhance the conventional FGC process electrostatically. The electrostatic force promotes the attraction between SO_3 and fly ash particle surfaces. A discharge frame with a high-tension power source is added to the ductwork upstream, which complements the diffusion mass transfer process that normally occurs with FGC.[85]

- In the last 2 years the Compact Hybrid Particulate Collection System (COHPAC) was developed, which is a high-efficiency, compact pulse-jet fabric filter (PJFF) that operates downstream as a separate collector of an existing ESP or in the last one or two fields of the ESP. COHPAC systems utilize PJFF's because utilities can pack the filter bags closely in baghouse compartments with a reduction in baghouse size and cost when compared to a conventional fabric-filter application. At a minimum, COHPAC systems allow utilities to upgrade some underperforming ESP's and achieve clear stacks. In addition, because this process collects fine particles efficiently, it shows promise for its ability to control air toxics as well.[86] [87]

These techniques can form the basis for improvements in basic power plant design when emissions control considerations are factored into every major power plant component. Selection of techniques or equipment is based on optimizing project priorities, such as initial capital cost, operating costs, efficiency, emissions, maintainability, and unit operating flexibility. Most of these techniques seek to accomplish critical processes in smaller spaces, which leads to constraints on residence times, flow distribution, measuring capabilities, maintenance procedures, and operating flexibility.

[83] Ibid.
[84] Ibid.
[85] Ibid.
[86] Jason Makansi, "Despite market uncertainty, a few new approaches come forward," *Power* (March 1996), p. 25.
[87] Ramsy Chang, "COHPAC compacts emission equipment into smaller, denser unit: Compact Hybrid Particulate Collector," *Power Engineering* (July 1996), p. 22

5. Phase II

Increased competition has caused the electric utility industry to face major changes in the way it is structured. On April 24, 1996, the Federal Energy Regulatory Commission (FERC) issued the final rule, Order No. 888,[88] in response to provisions of the Energy Policy Act (EPACT) of 1992. Order No. 888 opens wholesale electric power sales to competition and requires each utility that owns transmission lines to allow buyers and sellers of power the same access to those lines as the utility provides to its own generation.

In a noncompetitive environment, State regulators allowed electric utilities to pass on the costs of pollution control requirements to consumers in the form of higher electricity rates. In a competitive market, utilities that have higher rates because of environmental controls would be at a relative disadvantage, while those with lower overall costs could increase their market share. With increasing competition and with Phase II of CAAA90 slated for implementation on January 1, 2000, utilities are showing less interest in making capital investments in expensive pollution control equipment, are uncertain about cost recovery, and want to be more competitive. In 1995, an Edison Electric Institute survey of investor-owned utilities for Phase II compliance shows they have not yet significantly increased construction spending; however, utilities are expected to spend $789 million per year from 1996 through 1998.[89]

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Current Strategies for Phase II

Compliance with Phase I of CAAA90 has required major investments by utilities. In Phase I, allowances are allocated at the rate of 2.5 pounds of sulfur dioxide (SO_2) times the number of million British thermal units (Btu's) consumed in the 1985-1987 baseline.

However, Phase II, which takes effect on January 1, 2000, will have an even larger impact on more generating units than Phase I. In Phase II, allowances are allocated at the rate of 1.2 pounds of SO_2 times the number of million Btu's consumed in the baseline. Although utilities have not finalized their plans to comply with the more stringent Phase II requirements, most of them have elected to overcomply with Phase I requirements, thus creating a surplus of excess allowances. This is one way of deferring higher-cost Phase II compliance strategies beyond 2000.

The following is a general discussion of what is currently known about compliance plans for Phase II. It is derived from a survey of 116 utilities conducted by Industrial Information Services of Reno, Nevada. Forty-one percent of the respondents plan to switch fuels. The acquisition of acid-rain emissions allowances is the second most popular compliance choice, with 28 percent indicating they will do so.[90]

Fuel Switching/Blending

Fuel switching/blending to lower sulfur coal in generating units will probably be the predominant strategy used by utilities to comply with Phase II of the CAAA90, just as it was for Phase I. Compared to scrubbing and repowering, the fuel switching/blending strategy involves lower capital costs, takes less time to implement, and offers flexibility in meeting future emission requirements. Because power plants are generally designed for a particular type of coal, switching to a different coal, such as lower sulfur coal, requires an assessment of the new fuel's effects on the individual plant. The new coal can affect the performance of boilers and ESP's, as well as operations and maintenance procedures.[91]

[88] "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Docket Nos. RM95-8-000 and RM94-7-001, Order No. 888 (April 24, 1996).

[89] Edison Electric Institute, Financial Information, *1995 Construction Expenditures Surveys* (Washington, DC, September 9, 1996).

[90] "Fuel-Switching Outpacing Scrubbers as U.S. Utilities Comply with CAA," *Asbestos & Lead Report*, No. 1, Vol. 8 (January 23, 1995).

[91] For the impact of lower sulfur coal on an individual plant, see Energy Information Administration, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*, DOE/EIA-0582 (Washington, DC, March 1994), p. 13.

Because lower sulfur coal is usually lower in heating value (Btu rating), fuel switching/blending may require the firing of a larger volume of coal to generate the same amount of power. A larger volume of coal requires more storage space and an increase in coal-handling facilities. Generating capability could be constrained by coal-handling considerations if the volume of lower sulfur coal is increased substantially. In addition, an increased volume of coal could require ESP modifications to handle the increased fly ash or boiler derating so as not to overload the ESP. Also, the boiler heat rate could be adversely affected if boiler redesign is required to accommodate the new lower sulfur coal.

Burning western lower sulfur coal results in more particulate matter (PM) emissions than burning eastern high-sulfur coal. In addition, the coal resistivity[92] may change and degrade ESP collection efficiency. These changes can require alterations to the ESP's. Finally, different coals may cause different HAP emissions. Because utility coal-fired plants are designed for certain coal types, it takes a couple of years to test fire several lower sulfur coals to determine which one reduces emissions.

Co-firing With Natural Gas

Natural gas is the cleanest of the fossil fuels available for use in power generation and has the potential to reduce emissions without great cost. The use of nearly sulfur-free natural gas instead of sulfur-containing coal can significantly reduce SO_2 emissions, and the potential exists for reduced NO_x emissions, depending on burner characteristics. Co-firing with natural gas can also reduce HAP's, carbon dioxide, fly ash, and disposal needs. Natural gas firing has lower operation and maintenance costs than coal firing. However, the fuel costs are higher, and access to a nearby pipeline is a requirement for this option to be economical. In addition, few coal-fired boilers are designed to co-fire natural gas. Although many can be retrofitted, usually with separate burners for gas and coal, a boiler switched from coal to gas may experience a decrease in efficiency. However, the high capital cost of retrofitting coal-fired boilers to burn natural gas is the reason that utilities seldom choose this strategy for meeting emission requirements of CAAA90.

Allowances

Just as it has been for Phase I, allowance acquisition is expected to be the second most popular choice for Phase II compliance—after fuel switching/blending. According to a study by Resource Data International, a Colorado research firm, utilities are over complying because the price of buying and using lower sulfur coal is less than originally projected and because of the flexibility provided by the EPA Title IV sulfur dioxide allowance program. The coincidence of mining efficiencies and rail deregulation and competition have made clean-burning coal from Wyoming's Powder River Basin as cheap, or cheaper, than the high-sulfur coal of the Midwest.[93]

Allowance credits are so inexpensive today that years of allowance credits can be purchased for less than the cost of the capital equipment for pollution control. Allowance prices are much lower than expected primarily because of the reduction in lower sulfur coal prices. Allowance and the coal markets are increasingly integrated.[94] This activity in emission allowance credits, which can be traded or sold, creates the possibility of running a pollution control system as a revenue source at least in the short term.[95]

The typical allowance sales have been made by an eastern utility that has installed scrubbers to a midwestern utility without scrubbers. Also, many utilities bank their allowances. For instance, the Atlantic City Electric Company, which owns two coal-fired generating stations, cut its emissions in half between 1990 and 1995, primarily by adding a stack scrubber. The excess emission allowances will be held for use in Phase II. The allowances will be depleted by 2012, so the company must decide before then how to meet future long-term generating and emission requirements.[96]

[92] A layer of ash, resistant to being charged, accumulates on the precipitator causing the degrading of the performance and necessitating manual cleaning. Sodium treatment of the particulate material can be used to reduce ash resistivity and improve the precipitator performance.

[93] "Environment Week: Environmental Brokerage Services SO_2 Allowance's Sharp Price Decline Attributed Mainly to Low-Sulfur Coal," *Air/Water Pollution Report*, No. 4, Vol. 34 (January 19, 1996).

[94] Massachusetts Institute of Technology, for the Proceedings of the Second Workshop on Energy Externalities, Brussels, September 9-10, 1996, Draft, *The U.S. Allowance Trading Program for Sulfur Dioxide: An Update After the First Year of Compliance* (Cambridge, MA, October 29, 1996), p. 14.

[95] "Pollution Control for Cash," *Independent Energy*, Vol. 25, No. 1 (January 1995), p. 52.

[96] "Environment Week: Environmental Brokerage Services SO_2 Allowance's Sharp Price Decline Attributed Mainly to Low-Sulfur Coal," *Air/Water Pollution Report*, No. 4, Vol. 34 (January 19, 1996).

Some utilities have expressed that the Federal tax system interferes with the intended operation of the emission allowance market. Because the Internal Revenue Service (IRS) assigns a zero tax basis to the allowances in the hands of the original owners, all proceeds from the sale of allowances are fully taxable and subject to a capital gains tax. Internal utility uses, however, such as stockpiling of emissions allowances, do not trigger taxation. This situation obviously favors internal use by utilities. Legislation has been submitted to Congress to address this problem.[97]

The SO_2 allowance and market trading system has been successful in producing SO_2 reductions faster and less expensively than expected. It has also encouraged technological and economic innovation. For example, high-sulfur coal companies are buying allowances to package with their coal sales. By bundling allowances with the coal, these companies can compete with lower sulfur coal because the allowances included in the "bundle" compensates for the higher sulfur content.

Scrubbers

A number of scrubbers planned for Phase II are being deferred. For example, scrubbers on Mount Storm No. 1 and No. 2, Virginia Power; Montour, Pennsylvania Power and Light (PP&L); and Homer City No. 3, Pennsylvania Electric are no longer planned for 2000, although they may be retrofitted later. The two 750-megawatt coal-fired generating units at the Montour station will not be fitted with scrubbers before 2004 at the earliest, a decision that PP&L projects will save an estimated $400 million in capital costs over the next 5 years. PP&L will buy lower sulfur coal, use emission allowances already earned, and purchase additional allowances[98] to achieve Phase II compliance.

Carolina Power & Light plans to switch all of its plants to compliance coal by 2000. In 2007, it will install a scrubber at one of the largest of its 20 coal-fired units. Dayton Power & Light, owner or part-owner of a number of plants located in the high-sulfur coalfields of Ohio, plans to switch to lower sulfur coal and to bank a substantial number of credits during Phase I, to make up for the expected allowance deficits after 2000.[99]

The Electric Power Research Institute (EPRI) estimates that no more than 12 gigawatts to 20 gigawatts of generation capacity may be scrubbed to comply with Phase II requirements, and the actual total is likely to be closer to 12 gigawatts than 20 gigawatts. This modest scrubber forecast reflects the impact of fuel switching, low SO_2 allowance prices, and the delay in fulfilling scrubber commitments for as long as possible. The utilities that are over complying with Phase I have allowance credits they can use to delay their own Phase II scrubbing, or to sell to other utilities that want to delay Phase II actions.[100] Planning and building a scrubber takes 4 years, so in many cases capital for scrubbers will not be committed until after the year 2000.

This scenario could change if EPA air toxics regulations are issued in the future, requiring reductions in air toxics, including mercury. Most of these hazardous emissions are fairly easily controlled, except mercury, with wet scrubbers. Some States in the East and the Midwest are considering air toxics control.

Repowering

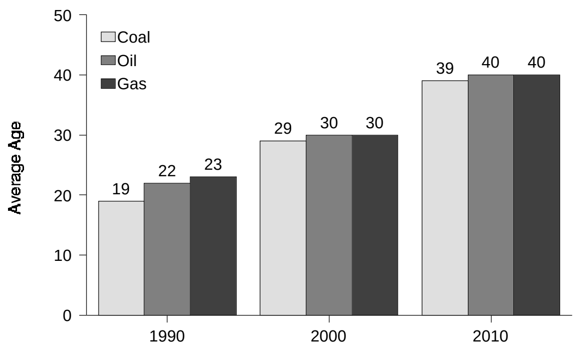
As of January 1, 1996, fossil-fuel electric operable capacity accounted for 72 percent of U.S. electric utility net summer generating capability.[101] In the year 2010, average age—weighted by capacity—of the Nation's coal-fired units will be 39 years, gas-fired units 40 years, and oil-fired units 40 years (Figure 20). One method for maintaining generating capacity online or adding capacity to a utility system, while working toward meeting SO_2 requirements, is to repower older fossil-fuel units.

Repowering existing power plants can be an economical way to turn unused or underutilized plants into profitable assets. The newer technology can be used to reduce emissions to comply with CAAA90 and increase efficiency. The technologies used for repowering include gas turbines; heat-recovery steam generators and feed water heaters; and coal-gasification combined-cycle, atmospheric fluidized-bed, or pressurized fluidized-bed combustion combined-cycle systems.

Repowering candidates include oil- and gas-fired plants as well as coal-fired plants that face significant emissions

[97] "Why Taxes Do Distort Emission Trading," *Fortnightly* (February 15, 1995), p. 42.
[98] "U.S. Utilities Opt Against Scrubbing," *International Coal Report* (October 30, 1995).
[99] Ibid.
[100] Ibid.
[101] Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(95) (Washington, DC, December 1996), p. 20.

Figure 20. Average Age (Weighted by Capacity) of Fossil-Fuel Units, 1990, 2000, and 2010, as of January 1, 1996



Note: The average unit age includes existing units, planned retirements, and planned capacity additions.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

reductions to satisfy Phase II of CAAA90. Repowering power plants usually increases their capacity, the extent of which depends on the repowering procedure is used. However, even though Title IV includes specific incentives to repower fossil plants with clean-coal technology, barring the DOE's Clean Coal Technology projects, no utility has announced a repowering project for the sole purpose of meeting CAAA90 Phase I or II emission requirements.[102]

Most of the fossil units proposed for repowering from 1996 through 2005 (Table 14) have relatively small net summer capabilities. The proposed repowering of fossil capacity from 1996 through 2005 is 2,501.1 megawatts. This includes repowering 589.5 megawatts of natural gas steam turbine-boilers to burn natural gas again, repowering 219.0 megawatts of bituminous steam-turbine boilers to burn bituminous coal again, repowering 536.9 megawatts of natural gas combustion turbines to burn natural gas, repowering 43.2 megawatts of No. 2 fuel oil combustion turbines to burn natural gas, and repowering 80.0 megawatts of No. 6 fuel oil steam turbines to burn natural gas. The last two repowering options are the only ones that change fuel. Repowering with natural gas is a significant option for fossil units.

Some estimates indicate that utilities could bank an excess of up to 15 million SO_2 allowance credits by the time Phase II begins on January 1, 2000. After the Phase I credits are depleted, the utilities will then have to reduce emissions, and repowering can help meet that need. Because repowering is cheaper than building a new generating unit, repowering will be used to meet some of the future capacity needs.[103]

Retirements

The planned fossil-fuel capacity retirements slated to take place from 1996 through 2005 (Table 15) include much smaller percentages of coal-fired units than petroleum or gas when compared to the generator nameplate capacity for the energy source. Just six coal-fired units are projected to retire before the start of Phase II, with six other coal-fired units retiring after the year 2000. However, 79 petroleum- and 70 gas-fired units will retire throughout the 10-year period.

Synergy With Clean Air Act Requirements

As utilities make plans to meet the requirements of CAAA90 for SO_2 and NO_x, they must also consider other existing Clean Air Act (CAA) requirements and possible new regulations. Through 2005, the CAA requires EPA to consider a number of actions and new regulations that would directly or indirectly result in the need to reduce emissions from electric power generation (Figure 21).

CAAA90 contain many requirements that will affect the electric power generating industry well into the future, such as NO_x limitations under Titles I and IV, New Source Performance Standards, new Ozone and Fine Particle Standards, and possibly, Utility Air Toxics requirements. EPA has traditionally implemented standards and requirements on a statutory provision-by-provision basis. This approach has been effective in protecting the environment though it is not likely to be the most economically efficient. For this reason, EPA is working with power generators to develop a more efficient approach called the Clean Air Power Initiative (CAPI).

[102] Teresa Hansen, "Utilities to Spend $1.4 Billion on Power Plant Maintenance," *Electric Light & Power* (February 1996), p. 17.
[103] "SO_2 Banking Allows Utilities to Delay Repowering of Coal-Fired Plants," *Energy Report*, No. 42, Vol. 23 (October 30, 1995).

Table 14. Fossil Units Proposed for Repowering, 1996-2005, as of January 1, 1996

State Company **Plant** (County)	Unit ID	Net Summer Capability (Megawatts)[a]	Unit Type	Energy Source	Repowering Year	Repowering Fuel
Alabama						
Alabama Electric Coop Inc.						
Charles R. Lowman (Washington)	1	79.4	ST	BIT	2001	WH
McWilliams (Covington)	1	9.7	ST	NG	1996	WH
	2	9.7	ST	NG	1996	WH
	3	23.0	ST	NG	1996	WH
California						
City of Pasadena						
Glenarm (Los Angeles)	GT1	30.3	GT	NG	2000	UNK
	GT2	30.3	GT	NG	2000	UNK
Delaware						
Delmarva Power & Light Co.						
Indian River (Sussex)	1	89.0	ST	BIT	2003	BIT
	2	89.0	ST	BIT	2001	BIT
Florida						
Florida Power Corp.						
G E Turner (Volusia)	ST3	70.0	ST	NG	2003	NG
	ST4	71.0	ST	NG	2004	NG
Higgins (Pinellas)	ST1	39.0	ST	NG	2004	NG
	ST2	41.0	ST	FO6	2004	NG
	ST3	39.0	ST	FO6	2004	NG
City of Lakeland						
Larsen Memorial (Polk)	6	25.0	ST	NG	1998	WH
City of Tallahassee						
S O Purdom (Wakulla)	5	23.0	ST	NG	2000	NG
	6	23.0	ST	NG	2000	NG
Illinois						
Commonwealth Edison Co.						
Bloom (Cook)	333	11.2	GT	FO2	2000	FO2
	334	16.1	GT	FO2	2000	FO2
	341	19.2	GT	FO2	2000	FO2
	344	19.2	GT	FO2	2000	FO2
Calumet (Cook)	311	14.7	GT	NG	1998	NG
	312	14.1	GT	NG	1998	FO2
	313	12.3	GT	NG	1998	NG
	314	14.8	GT	NG	1998	NG
	331	15.1	GT	NG	1998	NG
	332	13.0	GT	NG	1998	NG
	333	13.6	GT	NG	1998	NG
	341	14.0	GT	NG	1998	NG
	342	13.6	GT	NG	1998	NG
	343	8.3	GT	NG	1998	NG
Crawford (Cook)	311	13.3	GT	NG	1996	NG
	312	10.9	GT	NG	1996	NG
	313	14.5	GT	NG	1996	NG
	314	14.2	GT	NG	1996	NG
	321	13.7	GT	NG	1996	NG
	322	11.8	GT	NG	1996	NG
	323	11.9	GT	NG	1996	NG

See notes at end of table.

Table 14. Fossil Units Proposed for Repowering, 1996-2005, as of January 1, 1996 (Continued)

State Company **Plant** (County)	Unit ID	Net Summer Capability (Megawatts)[a]	Unit Type	Energy Source	Repowering Year	Repowering Fuel
Crawford (Cook) (continued)	324	10.8	GT	NG	1996	NG
	331	10.9	GT	NG	1996	NG
	332	10.0	GT	NG	1996	NG
	333	13.5	GT	NG	1996	NG
	334	13.3	GT	NG	1996	NG
Electric Junction (Kane)	311	14.6	GT	NG	1996	NG
	312	13.1	GT	NG	1996	NG
	313	14.4	GT	NG	1996	NG
	314	14.9	GT	NG	1996	NG
	321	14.3	GT	NG	1996	NG
	322	15.5	GT	NG	1996	NG
	323	7.3	GT	NG	1996	NG
	324	8.7	GT	NG	1996	NG
	331	15.6	GT	NG	1996	NG
	332	15.3	GT	NG	1996	NG
	333	9.7	GT	NG	1996	NG
	334	10.4	GT	FO2	1996	FO2
	343	10.4	GT	NG	1996	NG
Fish (Cook)	311	20.0	JE	JF	1999	JF
	312	19.0	JE	JF	1999	JF
	321	18.0	JE	JF	1999	JF
	322	20.0	JE	JF	1999	JF
	331	20.0	JE	JF	1999	JF
	332	20.0	JE	JF	1999	JF
	341	20.0	JE	JF	1999	JF
	342	20.0	JE	JF	1999	JF
Joliet 9 (Will)	311	14.1	GT	NG	1996	NG
	312	15.5	GT	NG	1996	NG
	313	8.1	GT	NG	1996	NG
	314	12.0	GT	NG	1996	NG
	321	15.2	GT	NG	1996	NG
	322	12.8	GT	NG	1996	NG
	323	11.0	GT	NG	1996	NG
	324	14.2	GT	NG	1996	NG
Lombard (Du Page)	311	18.6	JE	JF	1998	NG
	321	17.4	JE	JF	1998	JF
	322	17.8	JE	JF	1998	NG
Sabrooke (Winnebago)	311	14.1	GT	FO2	1997	FO2
	312	13.0	GT	FO2	1997	FO2
	321	13.9	GT	FO2	1997	NG
	322	15.8	GT	FO2	1997	NG
	331	14.0	GT	FO2	1997	FO2
	332	13.5	GT	FO2	1997	NG
	341	10.6	GT	FO2	1997	FO2
Waukegan (Lake)	311	24.6	JE	JF	1997	JF
	312	29.9	JE	JF	1997	FO1
	321	28.8	JE	JF	1997	FO1
	322	29.9	JE	JF	1997	FO1

See notes at end of table.

Table 14. Fossil Units Proposed for Repowering, 1996-2005, as of January 1, 1996 (Continued)

State Company **Plant** (County)	Unit ID	Net Summer Capability (Megawatts)[a]	Unit Type	Energy Source	Repowering Year	Repowering Fuel
Mississippi						
City of Clarksdale						
Wilkins (Coahoma)	8	12.0	GT	NG	1996	NG
Public Service Commission of Yazoo City						
Yazoo (Yazoo)	3	11.5	ST	NG	1996	NG
South Mississippi El Power Assn.						
Moselle (Jones)	3	59.0	ST	NG	2001	NG
Oklahoma						
Oklahoma Gas & Electric Co.						
Arbuckle (Murray)	1	74.0	ST	NG	2001	NG
Mustang (Canadian)	1	58.0	ST	NG	2001	NG
	2	57.0	ST	NG	2000	NG
Pennsylvania						
Borough of Chambersburg						
Chambersburg Diesel (Franklin)	5	2.1	IC	NG	1996	NG
Pennsylvania Electric Co.						
Warren (Warren)	2	41.0	ST	BIT	1997	BIT
Texas						
Central Power & Light Co.						
J L Bates (Hidalgo)	1	72.0	ST	NG	2002	NG
Laredo (Webb)	2	32.0	ST	NG	2001	NG
Southwestern Electric Power Co.						
Wilkes (Marion)	2	357.0	ST	NG	2002	UNK
U.S. Total		**2,501.1**				

[a]Summer Capability is the maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress at the time of summer peak demand.

Notes: **Unit Type**: GT = Combustion (gas) Turbine, IC = Internal Combustion (diesel), ST = Steam Turbine-Boiler. **Energy Source**: BIT = Bituminous Coal, FO2 = No. 2. Fuel Oil, NG = Natural Gas, WH = Waste Heat, and UNK = Unknown.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

CAPI recognizes the need to improve and coordinate the development of air pollution regulations for the electric power generation sector. This sector includes utilities, independent power producers, cogenerators, and industrial boilers that produce electricity for their own needs.[104] The numerous air pollution regulations and possible future regulatory mandates have potential synergies and conflicts. A complete analysis of utility compliance strategies should contemplate the entire range of environmental regulations, including CAAA90. For example, certain control options and strategies can reduce two or more pollutants at a lower cost than separate controls for each of those pollutants. Failure to take advantage of cost-effective synergies and incremental compliance planning could increase control costs and utility user rates, and possibly reduce environmental benefits.

Title IV gives utilities the innovative allowance trading mechanism for SO_2, as well as other potential market-based mechanisms for NO_x. However, this unprecedented flexibility gives rise to other concerns. Each fuel or process change adopted by a utility for SO_2 compliance

[104] U.S. Environmental Protection Agency, *EPA'S Clean Air Power Initiative*, EPA Number (Washington, DC, April 1996), p. 1.

Table 15. U.S. Electric Utility Planned Coal-, Petroleum-, and Gas-Fired Capacity Retirements, 1996-2005, as of January 1, 1996

	Coal		Petroleum		Gas	
	Number of Units	Generator Nameplate (megawatts)	Number of Units	Generator Nameplate (megawatts)	Number of Units	Generator Nameplate (megawatts)
1996	–	–	4	60.9	–	–
1997	2	60.0	20	43.0	5	147.6
1998	–	–	1	2.5	3	39.4
1999	4	392.0	2	24.6	2	48.5
2000	–	–	6	19.5	2	125.6
2001	–	–	8	67.0	4	165.0
2002	–	–	14	232.5	30	776.3
2003	–	–	11	424.6	1	22.5
2004	3	159.2	11	472.4	9	664.1
2005	3	155.1	2	83.7	14	611.9
U.S. Total	**12**	**766.4**	**79**	**1,430.6**	**70**	**2,600.9**

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

will also affect other combustion emissions and by-products. In addition to SO_2 and NO_x, the uncontrolled combustion of fossil fuels produces fly ash emitted as particulates; HAP's such as mercury; and other trace metals, radionuclides, and CO_2. Many of these pollutants are subject to their own regulatory requirements. However, fossil-fuel utility units have not been regulated for HAP's, radionuclides, or CO_2 emissions.

The uncontrolled combustion of fossil fuels also produces discharges of heat, waste water, and potentially large amounts of slag and bottom ash as solid waste. Thermal and wastewater discharges are regulated by the Clean Water Act (CWA). Thermal discharges are controlled through cooling towers, cooling pools, and recycling. Combustion wastes are regulated as solid wastes by the Resource Conservation and Recovery Act (RCRA), which requires waste generators to dispose of such wastes in sludge pools or landfills.[105]

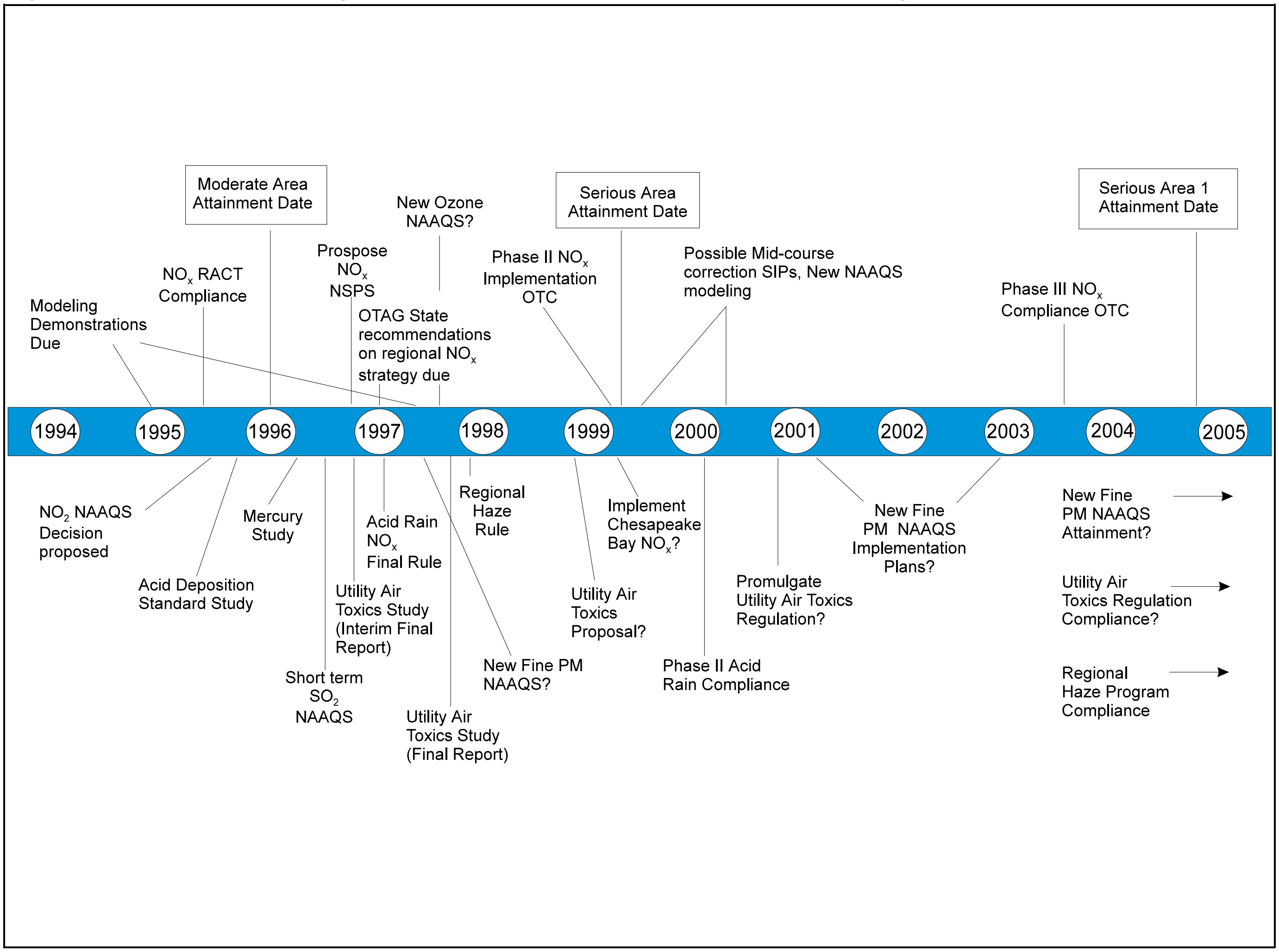
A number of examples demonstrate the synergy of control options in reducing pollutants of fossil-fired utility plants. For example, many of the options to reduce particulate or SO_2 emissions also reduce many of the air toxics. Utilities emit three types of air toxics: trace metals as particulates, mercury, and organic HAP's. Flue gas treatment technologies have important HAP-SO_2 control synergies. Except for mercury emissions, most trace metal emissions from coal-fired plants either are absorbed onto the fly ash or they precipitate with the bottom ash. Trace metal emissions absorbed onto the fly ash can be controlled by particulate control technologies, such as baghouses and ESP's. Mercury emissions can be partially removed with wet scrubber controls. Mercury emissions are usually reduced if a utility selects low-NO_x burners. Combustion temperatures are lowered, and mercury is absorbed in the fly ash. The mercury can then be effectively controlled with particulate controls. While particulate controls reduce trace metal emissions, and wet scrubbers partially reduce mercury, organic HAPs, and in particular, chlorine may not be controlled using these two methods.[106]

Fuel switching/blending between coals have different effects on co-pollutants and synergies, and a trade-off exists between Title IV and Title III in coal fuel switching and blending. When utilities switch from high-sulfur eastern coal to low-sulfur western coal, there is some indication that toxic particulates may result from combustion. In addition, coals vary by trace metal contents. Fuel switching or blending may reduce SO_2 emissions,

[105] Argonne National Laboratory, Policy and Economic Analysis Group, Decision and Information Sciences Division, *Synergies and Conflicts in Multimedia Pollution Control Related to Utility Compliance with Title IV of the Clean Air Act Amendments of 1990,* ANL/DIS/TM-3 (January 1994), p. 4.

[106] Ibid., pp. 79-80.

Figure 21. Electric Power Regulations Timeline for Provisions Enacted Through the Clean Air Act



NO_x = Nitrogen oxides.
SO_2 = Sulfur dioxide.
PM = Particulate matter.
? = Under study–possible future regulation.
NAAQS = National Ambient Air Quality Standards.
OTC = Ozone Transportation Commission.
NSR = New Source Review.
OTAG = Ozone Transport Assessment Group.
NSPS = New Source Performance Standards.
RACT = Reasonably Available Control Technology.
SIP = State Implementation Plan.
Source: Environmental Protection Agency, Clean Air Power Initiative Forum, April 1996.

but without the presence of a wet scrubber or a low-NO_x burner, toxic metal emissions may grow.

Synergies resulting from controls to reduce the interaction of SO_2 reductions with the regulation of high-volume combustion waste streams are limited. Many of the flue gas treatment processes generate greater levels of bottom and fly ash waste, and, to a certain extent, fuel switching or blending do the same thing. Scrubbing options tend to be less economical because of landfill disposal costs and the need for additional sludge treatment ponds. Some types of coal fuel switching also become less economical based on the amount of ash and slag generated. To reduce disposal costs, some utilities are finding commercial uses for wastes, such as gypsum for wall board, roadfill, concrete additives, and fertilizers.

In assessing the control costs of a single pollutant, both the direct costs associated with the control of that pollutant and the indirect costs associated with controlling multiple pollutants should be considered. In addition, the synergistic control effects of particular strategies should be examined. To be cost-effective, utilities choose, if possible, those controls that minimize the total cost of compliance with all pollutant regulations. Regulatory barriers and control uncertainties, however, make the choice of cost-effective compliance difficult. Under these circumstances, flexibility is a key component of any utility compliance strategy. CAPI is an attempt to reduce the administrative complexity and break the costly pattern of regulation by providing the power-generation industry with more certainty of future regulatory requirements, greater flexibility, and cost savings.[107]

Utility Compliance Plans on the Internet

In many cases, utilities are uncertain about their Phase II compliance strategies, and even when utilities are certain, some are less than forthcoming about their plans. The evolution of the industry toward more competition makes some utilities reluctant to discuss their plans because they feel that doing so would erode their competitive edge. A list of some known Phase II compliance strategies can be found on the Internet at the home page of the Energy Information Administration (http://www.eia.doe.gov). Once the connection to the home page has been established, click on "Electricity" in Fuel Groups. A new screen will appear. Scroll down through "Publications" and "Data" to "Applications." Go to the "Clean Air Act Browser" and follow the instructions.

[107] U.S. Environmental Protection Agency, *EPA's Clean Air Power Initiative,* EPA Number (Washington, DC, April 1996), p. 6.

6. Conclusion

The first year of Phase I demonstrated that the new market-based sulfur dioxide emissions control system could achieve significant reductions in emissions at lower than expected costs. The U.S. General Accounting Office has estimated an annual savings of $2-3 billion with the market-based system (versus traditional regulation) depending upon the level of allowance trading taking place. Utilities reduced their aggregate emissions far below what was required by law. CAAA90 provided an economic incentive to overcomply, and many utilities seized the opportunity.

The $2,000 per ton penalty for noncompliance dwarfed the unexpectedly low prices of sulfur dioxide allowances throughout the first year of Phase I. Many utilities exceeded the required emissions reductions for Phase I through fuel switching and the use of scrubbers, but even those units that emitted more sulfur dioxide than their original allowance allocation would have permitted found it easy to acquire enough allowances to avoid the fine.

More than half of the Phase I plants switched to or blended with lower sulfur coal partially because of the allowance trading program. The allowance trading program helped to create an active coal market in which the delivered price of higher and lower sulfur coal dropped between 1990 and 1995. Other factors contributed to this price reduction, including an oversupply of lower sulfur coal, penetration of competitively priced western lower sulfur coal, and lower transportation costs. Also, utility boiler modifications to burn lower sulfur coal were less expensive than predicted. The tendency for utilities to purchase lower sulfur coal may have resulted in early reduction of sulfur dioxide emissions and more allowance credits earned.

The evolution of the electric power industry toward more competition has led utilities to delay capital expenditures for pollution control equipment as long as possible. Phase II emissions requirements are more stringent and affect many more generating units than those of Phase I. Utilities are reluctant to make commitments for Phase II because of competition and uncertainty about possible future regulatory requirements. Utility Phase I allowances are estimated to last until 2005. Utilities will have to reduce emissions to meet the more stringent Phase II requirements, and scrubbers and repowering most likely will be more attractive options than they are currently.

Appendix A

Federal Legislation To Control Air Pollution

Appendix A

Federal Legislation To Control Air Pollution

Federal legislative efforts aimed at controlling air pollution in the United States began in the mid-1950's when Congress passed an act requiring the provision of research and technical assistance relating to air pollution control to the States. Since then, the Federal role in air pollution control has grown considerably, and today the Federal Government sets national emissions standards for specific air pollutants. It also monitors industry's compliance with these standards.

The Clean Air Act Amendments of 1990 is the latest air pollution control legislation enacted by the U.S. Congress. Other Federal legislation controlling air pollution includes the Clean Air Act of 1963, the Air Quality Act of 1967, the Clean Air Act Amendments of 1970 and 1977, and various additional amendments and extensions of the Clean Air Act passed in 1971, 1973, 1974, and 1976 (Table A1).

Table A1. Chronology of Historic Federal Legislation To Control Air Pollution

Legislation and Date	Role of Federal Government
An Act To Provide Research and Technical Assistance Relating to Air Pollution Control (1955)	Provide research, technical, and financial aid to States
Clean Air Act of 1963	Mediate among States, if requested
Air Quality Act of 1967	Create air quality control regions; establish criteria for health protection; recommend control techniques; set national emissions standards for vehicles
Clean Air Act Amendments of 1970	Set national primary and secondary air quality standards; review and approve State implementation plans; assess hazards from additional named pollutants; set national emissions standards for stationary sources; set statutory reductions and timetable for vehicle emissions; regulate fuels, fuel additives, aircraft emissions, noise
Amendments and extensions of Clean Air Act (1971, 1973, 1974, 1976)	Establish waivers and extensions of motor vehicle emissions standards
Clean Air Act Amendments of 1977	Classify air quality control regions as attainment or nonattainment; establish program for prevention of significant deterioration; provide special treatment for eastern coal; strengthen new source performance standards and hazardous pollutant sections; tighten motor vehicle emissions standards.
Clean Air Act Amendments of 1990	Establish new provisions designed to reduce emissions of SO_2. Establish an allowance system, based on a nationwide limit of 8.9 million tons of SO_2 per year. Establish a list of 189 regulated hazardous air pollutants. Require all major sources of air pollution to obtain an operating permit. Strengthen enforcement provisions for EPA.

Sources: Lester B. Lave and Gilbert S. Omenn, *Clearing the Air: Reforming the Clean Air Act* (Washington, DC: Brookings Institution, 1981), p. 6. Environmental Law Institute, *Clean Air Deskbook* (Washington DC, March 1992) and *Clean Air Act Handbook, A Practical Guide to Compliance*, Third Edition, 1993.

An Act To Provide Research and Technical Assistance Relating to Air Pollution Control

Passed in 1955, an Act To Provide Research and Technical Assistance Relating to Air Pollution Control was, in part, a response to the growing concentration of the U.S. population in urban areas, many of which were spread over more than one State (e.g., New York, Chicago, and Washington, D.C.). Congress found that "the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, had resulted in mounting dangers to the public's health and welfare, including injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation."

The 1955 act sought to remedy the growing air pollution problem by supporting research and providing information and financial aid to the States. The act expressly acknowledged the primary responsibilities and rights of State and local governments to control air pollution. The Federal Government had no direct regulatory role.

The Clean Air Act of 1963

The Clean Air Act of 1963 began to expand the role of the Federal Government in curbing air pollution by including direct regulation. Air pollution that "endangered the health or welfare of any persons" was made "subject to abatement" under certain circumstances. The law provided two additional tools for use in the fight against air pollution. Federal funds were to be made available to State and local pollution-control agencies, and, because the effects of air pollution often crossed State boundaries, the negotiation of interstate compacts establishing joint control agencies was authorized.

The Air Quality Act of 1967

The Air Quality Act of 1967 further extended the role of the Federal Government into air pollution standards. It authorized the Secretary of Health, Education, and Welfare to create air quality regions and establish criteria for setting air quality levels that would protect public health. The States were required to adopt ambient air quality standards consistent with these criteria.

The Clean Air Act Amendments of 1970

The Clean Air Act Amendments of 1970 substantially expanded the Federal role in air pollution control. The act came about because, with the exception of California, State and local governments had taken only limited action to control air pollution. Congress decided that the National Ambient Air Quality Standards (NAAQS) were the appropriate criteria for protecting public health, and it dismissed the relevance of abatement cost in setting the standards. The newly created Environmental Protection Agency (EPA) was given responsibility for setting the standards. The States implemented the program by designing, seeking EPA approval for, and then enforcing State Implementation Plans that would ensure attainment of the NAAQS by 1975. Standards were promulgated for 6 criteria pollutants: particulate matter, sulfur oxides, carbon monoxide, nitrogen dioxide, ozone, and nonmethane hydrocarbons. A standard for lead was added in 1978, and the standard for ozone was revised in 1979. All of these standards are still in place.

For enforcement purposes, the United States was divided into 274 air quality control regions. NAAQS limits were required to be met in each region. Control regions within State boundaries where the ambient pollutant concentrations were below or met the NAAQS were designated as "attainment areas" by the 1970 amendments. Conversely, areas where the ambient pollutant concentrations did not meet NAAQS were labeled "nonattainment areas."

Distinct from ambient standards, the 1970 amendments also introduced national emissions standards for new stationary sources of air pollution, limiting the amounts of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulates that coal-fired boilers of certain classes could emit. In general, these technology-based standards called for the application of the "best available control technology," under which Congress did allow some consideration of the cost of the abatement. However, Congress imposed stringent deadlines for achieving national standards.

The Clean Air Act Amendments of 1977

The Clean Air Act Amendments of 1977 further emphasized the classification of air quality control regions as attainment or nonattainment areas with regard to all established ambient air standards. Sanctions and special implementation strategies were introduced for nonattainment areas. The amendments stipulated that sources in nonattainment areas must use "reasonably available pollution control technologies," taking into consideration both cost and technological feasibility.

The amendments also imposed new requirements on areas already in attainment. The concept of prevention of significant deterioration (PSD) was introduced whereby the amendments established specific increments for maximum allowable increases in ambient concentrations for three classes of PSD areas. The PSD program included a permit program for new major emission sources and modifications to existing sources. It required sources to apply “best available technology,” which would be determined case by case.

The Clean Air Act Amendments of 1990

The 1990 amendments establish a list of 189 regulated hazardous air pollutants. EPA is required to establish standards for major sources, which are defined as those with the potential to emit 10 tons per year of any single hazardous pollutant or 25 tons of any combination of pollutants.

The amendments establish a new permit program whereby all major sources are required to obtain an operating permit. States with approved permitting programs issue permits, but EPA has the power to veto State permits. Citizens also have certain rights to challenge State permits.

The 1990 amendments also establish the Acid Rain Program, which is designed to reduce the adverse effects of acid deposition. This improvement will be achieved primarily through reductions of SO_2 and NO_x emissions by electricity producers, while concurrently encouraging energy conservation and the use of renewable and clean alternative technologies in electricity production. The primary goal of the Acid Rain Program, which will be nstituted in 2010, is to reduce annual SO_2 emissions from electric utilities to a level that is 10 million tons below the 1980 level. Emission allowances serve as the mechanism for compliance. Each affected unit is allocated its allowances based on its baseline fuel consumption. The baseline is calculated from the average yearly fuel consumption for the period 1985-1987. In Phase I, allowances are allocated at the rate of 2.5 pounds of SO_2 times the number of mmBtu consumed in the baseline. In Phase II, allowances are allocated at the rate of 1.2 pounds of SO_2 times the number of mmBtu consumed in the baseline.

The legislation also requires a reduction of 2 million tons of NO_x emissions from utility boilers. Utilities were required to apply low-NO_x–burner technologies to meet regulations that become effective on the date the unit must meet the SO_2 standard, i.e., January 1, 1995, for Phase I units; January 1, 1997, for Phase I units employing scrubber technology; and January 1, 2000, for all Phase II units. However, a lawsuit pushed the date of compliance back to January 1, 1996, for the Phase I units that had been required to be in compliance on January 1, 1995. NO_x limits for dry-bottom, wall-fired and tangentially fired boilers affected in Phase I have been selected as 0.50 pounds per million Btu and 0.45 pounds per million Btu, respectively. Regarding Phase II compliance, NO_x limits must be established by no later than January 1, 1997, for two categories of boilers exempted from Phase I: cell- and cyclone-fired units. Also by that date, the limits for dry-bottom, wall-fired and tangentially fired boilers can be revised, if EPA deems it feasible with new technology. An emissions averaging provision allows individual utilities to average NO_x emissions over multiple units, if the same or lower emissions result.

Appendix B

Profiles of the 261 Table 1 Generators Affected by Phase I (Table B1) and a Profile of the Coal Received at Table 1 Plants (Table B2)

Appendix B

Profiles of the 261 Table 1 Generators Affected by Phase I (Table B1) and a Profile of the Coal Received at Table 1 Plants (Table B2)

Table B1 presents detailed information about the 261 Table 1 generator units affected by Phase I of the Clean Air Act Amendments of 1990 and the 174 substitution and compensating generator units associated with them. The table is organized around those generators that were explicitly named in the legislation as Table 1 units. The substitution and compensating units are listed to the right of each Table 1 unit.

Capacities and annual Phase I allowance allocations are provided along with 1985 sulfur dioxide (SO_2) emissions estimates and 1995 SO_2 emissions as determined by continuous emissions monitors (CEMS). Compliance methods and ages are also provided for the 261 Table 1 generators.

For each associated substitution and compensating unit, 1985 SO_2 emissions estimates and 1995 SO_2 emissions as determined by CEMS are provided.

Table B2 shows the origin, quality, and delivered price of coal received at the Table 1 plants in 1995.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Alabama	**Alabama Power**													
	E C Gaston	ST4	245	18,773	23,485	7,251	1							
	E C Gaston	1	272	17,624	22,220	8,017	1							
	E C Gaston	2	272	18,052	21,862	7,515	1							
	E C Gaston	3	272	17,828	23,369	9,785	1							
	E C Gaston	5	952	58,265	68,352	23,170	1	Alabama	Alabama Power	Gadsden	1	1	5,158	4,278
								Alabama	Alabama Power	Gadsden	2	2	5,374	4,043
	TVA													
	Colbert	1	200	13,213	20,522	8,234	1							
	Colbert	2	200	14,907	20,227	10,846	1							
	Colbert	3	200	14,995	23,325	9,218	1							
	Colbert	4	200	15,005	24,748	9,209	1							
	Colbert	5	550	45,923	52,318	39,400	1							
Florida	**Gulf Power**													
	Crist	6	370	18,695	27,469	9,678	1							
	Crist	7	578	50,703	55,921	18,352	1	Florida	Gulf Power	Crist	4	4	9,953	3,849
								Florida	Gulf Power	Crist	5	5	9,374	3,071
								Florida	Gulf Power	Scholz	1	1	8,282	2,087
								Florida	Gulf Power	Scholz	2	2	8,572	2,561
	Tampa Electric													
	Big Bend	ST2	446	26,387	53,820	35,489	1	Florida	Tampa Electric	Big Bend	BB04	ST4	6,400	10,610
	Big Bend	ST3	446	26,036	32,901	9,101	1	Florida	Tampa Electric	Big Bend	BB04	ST4	6,400	10,610
	Big Bend	1	446	27,662	56,181	35,932	1	Florida	Tampa Electric	Big Bend	BB04	ST4	6,400	10,610
Georgia	**Georgia Power**													
	Bowen	1	806	54,838	71,428	32,617	1	Georgia	Georgia Power	Harllee Branch	1	1	19,221	12,295
	Bowen	2	789	53,329	63,727	39,641	1	Georgia	Georgia Power	Harllee Branch	2	2	22,735	15,135
	Bowen	3	952	69,862	82,488	42,137	1	Georgia	Georgia Power	Harllee Branch	3	3	31,280	26,085
	Bowen	4	952	69,852	87,659	46,258	1	Georgia	Georgia Power	Harllee Branch	4	4	31,042	27,944
	Hammond	1	125	8,549	9,830	3,516	1	Georgia	Georgia Power	Arkwright	1	ST1	2,437	795
	Hammond	2	125	8,977	9,997	1,834	1	Georgia	Georgia Power	Arkwright	2	ST2	2,240	667
	Hammond	3	125	8,676	9,068	2,047	1	Georgia	Georgia Power	Arkwright	3	3	3,944	971
	Hammond	4	578	36,650	35,539	14,297	1	Georgia	Georgia Power	Arkwright	4	4	3,159	701
	Jack McDonough	1	299	33,290	32,738	8,862	1							
	Jack McDonough	2	299	20,058	33,749	10,724	1	Georgia	Georgia Power	Mitchell	3	3	10,792	3,570
	Wansley	1	952	68,908	128,505	26,797	1							
	Wansley	2	952	113,801	120,146	27,004	1	Georgia	Georgia Power	Scherer	3	3	0	22,868
	Yates	1	123	7,863	11,673	118	3							

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Georgia	Yates	2	123	6,855	11,199	2,267	1	Georgia	Savannah Electric and Power	Kraft	1	1	2,265	1,051
	Yates	3	123	6,767	11,279	1,787	1	Georgia	Savannah Electric and Power	Kraft	2	2	2,137	954
	Yates	4	156	8,676	13,758	1,738	1	Georgia	Savannah Electric and Power	Kraft	3	3	4,121	1,940
	Yates	5	156	9,162	15,754	2,141	1	Georgia	Savannah Electric and Power	McIntosh	1	1	7,146	6,611
	Yates	6	404	28,726	42,207	6,535	1							
	Yates	7	404	22,318	23,974	5,683	1							
Illinois	**Central Illinois Public Service**													
	Coffeen	1	389	12,925	38,013	8,085	1							
	Coffeen	2	617	39,102	102,616	23,143	1							
	Grand Tower	4	114	6,479	9,754	6,950	2							
	Meredosia	3	239	15,227	27,015	19,610	2	Illinois	Central IL Public Service Co.	Meredosia	1	1	1,245	1,021
								Illinois	Central IL Public Service Co.	Meredosia	2	1	1,355	985
								Illinois	Central IL Public Service Co.	Meredosia	3	2	1,173	918
								Illinois	Central IL Public Service Co.	Meredosia	4	2	1,078	1,101
								Illinois	Central IL Public Service Co.	Meredosia	6	4	44	63
								Illinois	Central IL Public Service Co.	Hutsonville	5	3	9,661	4,455
								Illinois	Central IL Public Service Co.	Hutsonville	6	4	9,837	3,355

See notes at end of table

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com- pliance Method[c]	Substitution/ Compen- sating State	Substitution/ Compen- sating Utility	Substitution/ Compen- sating Plant	Substitution/ Compen- sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Illinois								Illinois	Central IL Public Service Co.	Newton	1	1	14,599	11,221
								Illinois	Central IL Public Service Co.	Newton	2	2	6,346	12,258
								Illinois	Central IL Public Service Co.	Grand Tower	7	3	1,068	1,043
								Illinois	Central IL Public Service Co.	Grand Tower	8	3	1,015	1,017
	Commonwealth Edison													
	Kincaid	1	660	34,564	94,042	4,292	1	Illinois	Commonwealth Edison	Collins	1	1	1,263	153
								Illinois	Commonwealth Edison	Collins	2	2	1,079	118
								Illinois	Commonwealth Edison	Collins	3	3	1,905	104
	Kincaid	2	660	37,063	79,919	6,878	1	Illinois	Commonwealth Edison	Collins	1	1	1,263	153
								Illinois	Commonwealth Edison	Collins	2	2	1,079	118
	Electric Energy Inc.							Illinois	Commonwealth Edison	Collins	3	3	1,905	104
	Joppa Steam	1	183	12,259	18,354	3,960	1							
	Joppa Steam	2	183	10,487	16,585	4,130	1							
	Joppa Steam	3	183	11,947	18,839	3,818	1							
	Joppa Steam	4	183	11,061	18,843	3,874	1							
	Joppa Steam	5	183	11,119	19,415	5,532	1							
	Joppa Steam	6	183	10,341	16,348	6,634	1							
	Illinois Power													
	Baldwin	1	623	46,052	89,277	75,004	2	Illinois	Illinois Power	Wood River	4	4	2,018	1,316
	Baldwin	2	635	48,695	78,477	104,172	2	Wyoming	PacifiCorp	Jim Bridger	BW71	1	12,775	7,919
								Wyoming	PacifiCorp	Jim Bridger	BW72	2	12,212	6,760
								Wyoming	PacifiCorp	Jim Bridger	BW73	3	11,988	7,794
								Wyoming	PacifiCorp	Wyodak	BW91	1	11,958	8,281

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Illinois								Utah	PacifiCorp	Gadsby	3	3	766	2
	Baldwin	3	635	46,644	96,840	86,789	2	Illinois	Illinois Power	Havana	1	1-5	34	0
								Illinois	Illinois Power	Havana	2	1-5	43	0
								Illinois	Illinois Power	Havana	3	1-5	34	0
								Illinois	Illinois Power	Havana	4	1-5	34	0
								Illinois	Illinois Power	Havana	5	1-5	34	0
								Illinois	Illinois Power	Havana	6	1-5	34	0
								Illinois	Illinois Power	Havana	7	1-5	34	0
								Illinois	Illinois Power	Havana	8	1-5	34	0
								Illinois	Illinois Power	Wood River	1	1-3	0	0
	Hennepin	2	231	20,182	39,436	27,560	2							
	Vermilion	2	109	9,735	18,600	1,706	5	Illinois	Illinois Power	Vermilion	1	ST1	12,972	917
Indiana	**Hoosier Energy REC Inc.**													
	Frank E. Ratts	1	117	9,131	19,069	10,038	1							
	Frank E. Ratts	2	117	9,296	18,436	10,604	1							
	Indiana Michigan Power													
	Breed	1	496	20,280	70,365	0	4							
	Tanners Creek	4	580	27,209	59,646	29,318	1							
	Indiana-Kentucky Electric													
	Clifty Creek	1	217	19,620	45,690	16,357	1							
	Clifty Creek	2	217	19,289	44,275	15,724	1							
	Clifty Creek	3	217	19,873	46,489	15,553	1							
	Clifty Creek	4	217	19,552	44,856	13,979	1							
	Clifty Creek	5	217	18,851	41,989	15,313	1							
	Clifty Creek	6	217	19,844	45,563	14,578	1							
	Indianapolis Power & Light													
	Elmer W. Stout	5	114	4,253	5,665	5,282	1							
	Elmer W. Stout	6	114	5,229	7,743	6,151	1							
	Elmer W. Stout	7	471	25,883	35,007	27,424	1							
	H T Pritchard	6	114	6,325	7,586	4,579	1							
	Petersburg	ST1	253	18,011	21,765	20,586	3	Indiana	Indianapolis Power &Light	H T Pritchard	3	3	586	749
								Indiana	Indianapolis Power &Light	H T Pritchard	4	4	1,305	1,184

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Indiana								Indiana	Indianapolis Power &Light	H T Pritchard	5	5	1,458	1,353
								Indiana	Indianapolis Power &Light	Petersburg	3	ST3	15,471	20,479
								Indiana	Indianapolis Power &Light	Petersburg	4	4	12,864	21,041
	Petersburg	ST2	471	35,496	53,110	42,075	3	Indiana	Indianapolis Power &Light	H T Pritchard	3	3	15,471	749
								Indiana	Indianapolis Power &Light	H T Pritchard	4	4	12,864	1,184
								Indiana	Indianapolis Power &Light	H T Pritchard	5	5	1,458	1,353
								Indiana	Indianapolis Power &Light	Petersburg	3	ST3	15,471	20,479
								Indiana	Indianapolis Power &Light	Petersburg	4	4	12,864	21,041
	Northern Indiana Public Service													
	Bailly	7	194	30,088	26,874	2,307	3							
	Bailly	8	422	39,951	12,312	3,938	3							
	Michigan City	12	540	48,963	45,434	12,261	1							
	PSI Energy													
	Cayuga	1	531	47,631	56,848	44,666	1							
	Cayuga	2	531	40,579	69,254	46,504	1							
	Gibson	1	668	44,288	71,467	51,701	2							
	Gibson	2	668	44,956	77,864	48,279	2							
	Gibson	3	668	45,033	67,787	60,912	2							
	Gibson	4	668	64,632	77,551	3,783	3							
	R Gallagher	1	150	13,908	1,770	13,127	2							
	R Gallagher	2	150	12,644	19,178	12,266	2							
	R Gallagher	3	150	13,127	20,883	11,766	2							
	R Gallagher	4	150	12,512	21,980	14,471	2							
	Wabash River	1	113	5,558	6,713	197	5							
	Wabash River	2	113	5,874	6,308	2,867	2							
	Wabash River	3	123	4,111	6,889	3,149	2							
	Wabash River	5	125	4,838	8,201	2,615	2							
	Wabash River	6	387	17,362	26,239	13,902	2							

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com- pliance Method[c]	Substitution/ Compen- sating State	Substitution/ Compen- sating Utility	Substitution/ Compen- sating Plant	Substitution/ Compen- sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Indiana	**Southern Indiana Gas & Electric**													
	FB Culley	2	104	4,703	16,361	564	3							
	FB Culley	3	265	18,603	38,456	1,985	3							
	Warrick	4	323	29,577	58,813	37,682	2							
Iowa	**Interstate Power**													
	Milton L Kapp	2	219	13,437	31,379	7,450	1							
	Iowa Electric Light & Power													
	Prairie Creek	4	149	7,965	12,466	5,279	1							
	Iowa Power													
	Des Moines	7	114	2,259	2,490	0	4							
	Iowa Public Service													
	George Neal North	1	147	2,571	1,048	3,812	1							
	Iowa Southern Utilities													
	Burlington	1	212	10,428	23,093	9,020	1							
	Iowa-Illinois Gas & Electric													
	Riverside	5	136	3,885	4,707	1,828	1							
Kansas	**City of Kansas City**													
	Quindaro	ST2	158	4,109	3,255	2,893	1							
Kentucky	**Big Rivers Electric**													
	Coleman	1	174	20,912	18,537	15,759	2	Kentucky	Big Rivers	R D Green	G1	1	5,041	1,580
								Kentucky	Big Rivers	R D Green	G2	2	6,073	1,689
	Coleman	2	174	19,363	19,862	18,500	2	Kentucky	Big Rivers	R D Green	G1	1	5,041	1,580
								Kentucky	Big Rivers	R D Green	G2	2	6,073	1,689
	Coleman	3	173	16,205	19,007	18,013	2							
	HMP&L Station 2	1	180	19,533	22,040	11,638	3							
	HMP&L Station 2	2	185	18,597	22,831	9,594	3							
	City of Owensboro													
	Elmer Smith	1	151	6,348	10,176	3,171	3							
	Elmer Smith	2	265	14,031	26,755	4,684	3							
	East Kentucky Power													
	Cooper	1	100	7,254	8,605	5,836	1							
	Cooper	2	221	14,917	14,870	12,553	1							
	H L Spurlock	1	305	22,181	29,745	15,297	1							

See notes at end of table

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Kentucky	**Kentucky Utilities**													
	E W Brown	1	114	6,923	6,242	4,259	1							
	E W Brown	2	180	12,121	10,029	8,622	1							
	E W Brown	3	446	35,334	38,577	14,824	1							
	Ghent	1	557	63,448	71,102	8,311	3							
	Green River	4	114	15,597	12,939	10,448	2							
	TVA													
	Paradise	3	1,150	135,688	106,835	155,612	2							
	Shawnee	10	175	9,902	34,077	2,953	1							
Maryland	**Baltimore Gas & Electric**													
	C P Crane	1	190	12,492	9,722	6,138	1							
	C P Crane	2	209	8,987	9,657	6,024	1	Alabama	Alabama Electric Coop	Charles Lowman	2	2	6,226	4,443
								Alabama	Alabama Electric Coop	Charles Lowman	3	3	5,281	4,586
								Mississippi	South MS El Power Assn.	R D Morrow	1	1	4,571	2,914
								Mississippi	South MS El Power Assn.	R D Morrow	2	2	5002	3,618
	Potomac Electric Power													
	Chalk Point	ST1	364	25,403	20,258	18,660	1	Maryland	PEPCO	Chalk Point	4	4	1,519	1,354
	Chalk Point	ST2	364	23,690	27,482	22,427	1	Maryland	PEPCO	Chalk Point	4	4	1,519	1,354
	Morgantown	ST1	626	39,864	29,388	28,040	1	Maryland	PEPCO	Chalk Point	3	3	9,000	3,010
	Morgantown	ST2	626	45,592	37,988	38,515	1	Maryland	PEPCO	Chalk Point	3	3	9,000	3,010
Michigan	**Consumers Power**													
	J H Campbell	1	265	18,773	27,180	10,175	1	Michigan	Consumers Power	Dan E Karn	1	1	10,151	7,272
								Michigan	Consumers Power	J R Whiting	2	2	4,304	4,251
								Michigan	Consumers Power	J R Whiting	3	3	5,498	4,807
	J H Campbell	2	385	22,453	33,350	2,996	1	Michigan	Consumers Power	Dan E Karn	1	1	10,151	7,272
								Michigan	Consumers Power	J R Whiting	2	2	4,304	4,251
								Michigan	Consumers Power	J R Whiting	3	3	5498	4,807

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Minnesota	**Northern States Power**													
	High Bridge	6	163	4,158	2,176	1,493	1	Minnesota	Northern States Power	High Bridge	3	3	1,771	233
								Minnesota	Northern States Power	High Bridge	4	4	1,326	426
								Minnesota	Northern States Power	High Bridge	5	5	2,436	888
								Minnesota	Northern States Power	Sherburne Co.	1	1	10,420	4,681
								Minnesota	Northern States Power	Sherburne Co.	2	2	10,493	4,782
Mississippi	**Mississippi Power**													
	Jack Watson	4	250	17,439	26,218	18,577	2							
	Jack Watson	5	500	35,734	46,401	38,044	2	Mississippi	Mississippi Power	Victor J Daniel	1	1	9,427	7,917
								Mississippi	Mississippi Power	Victor J Daniel	2	2	9,851	10,168
Missouri	**Associated Electric Coop**													
	New Madrid	1	600	27,497	74,430	8,827	1							
	New Madrid	2	600	31,625	77,895	7,926	1							
	Thomas Hill	1	180	9,980	35,874	2,817	1	Missouri	Associated Electric Coop	Thomas Hill	MB3	3	14,011	10,404
	Thomas Hill	2	285	18,880	56,866	3,749	1	Missouri	Associated Electric Coop	Thomas Hill	MB3	3	14,011	10,404
	City of Springfield													
	James River	5	105	4,722	9,096	2,054	1	Missouri	City of Springfield	James River	3	3	3,802	744
								Missouri	City of Springfield	James River	4	4	6,828	966
								Missouri	City of Springfield	Southwest	1	ST1	3,922	2,144
	Empire District Electric													
	Asbury	1	213	15,764	68,769	8,112	1							
	Kansas City Power & Light													
	Montrose	1	188	7,196	28,740	2,317	1	Missouri	Kansas City P&L	Hawthorn	5	5	25,734	5,634
								Missouri	Kansas City P&L	Iatan	1	1	14,479	19,289

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Missouri								Kansas	Kansas City P&L	La Cygne	1	1	23,489	3,872
								Kansas	Kansas City P&L	La Cygne	2	2	12,682	22,284
	Montrose	2	188	7,984	32,165	2,735	1	Missouri	Kansas City P&L	Hawthorn	5	5	25,734	5,634
								Missouri	Kansas City P&L	Iatan	1	1	14,479	19,289
								Kansas	Kansas City P&L	La Cygne	1	1	23,489	3,872
								Missouri	Kansas City P&L	La Cygne	2	2	12,682	22,284
	Montrose	3	188	9,824	35,192	2,909	1	Missouri	Kansas City P&L	Hawthorn	5	5	25,734	5,634
								Missouri	Kansas City P&L	Iatan	1	1	14,479	19,289
								Kansas	Kansas City P&L	La Cygne	1	1	23,489	3,872
								Kansas	Kansas City P&L	La Cygne	2	2	12,682	22,284
	Union Electric													
	Labadie	1	574	125,282	72,811	23,321	1	Missouri	Union Electric	Meramec	1	1	1,816	1,852
								Missouri	Union Electric	Meramec	2	2	1,948	1,209
								Missouri	Union Electric	Meramec	3	3	4,166	4,702
								Missouri	Union Electric	Meramec	4	4	4,507	5,161
								Missouri	Union Electric	Rush Island	1	1	26,935	21,412
								Missouri	Union Electric	Rush Island	2	2	30,146	22,209
	Labadie	2	574	117,392	63,653	23,236	1	Missouri	Union Electric	Meramec	1	1	1,816	1,852
								Missouri	Union Electric	Meramec	2	2	1,948	1,209
								Missouri	Union Electric	Meramec	3	3	4,166	4,702
								Missouri	Union Electric	Meramec	4	4	4,507	5,161
								Missouri	Union Electric	Rush Island	1	1	26,935	21,412
								Missouri	Union Electric	Rush Island	2	2	30,146	22,209
	Labadie	3	621	111,919	67,587	38,025	1	Missouri	Union Electric	Meramec	1	1	1,816	1,852
								Missouri	Union Electric	Meramec	2	2	1,948	1,209
								Missouri	Union Electric	Meramec	3	3	4,166	4,702
								Missouri	Union Electric	Meramec	4	4	4,507	5,161
								Missouri	Union Electric	Rush Island	1	1	26,935	21,412
								Missouri	Union Electric	Rush Island	2	2	30,146	22,209

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Missouri	Labadie	4	621	106,044	65,591	44,223	1	Missouri	Union Electric	Meramec	1	1	1,816	1,852
								Missouri	Union Electric	Meramec	2	2	1,948	1,209
								Missouri	Union Electric	Meramec	3	3	4,166	4,702
								Missouri	Union Electric	Meramec	4	4	4,507	5,161
								Missouri	Union Electric	Rush Island	1	1	26,935	21,412
								Missouri	Union Electric	Rush Island	2	2	30,146	22,209
	Sioux	1	550	25,603	42,688	27,477	1	Missouri	Kansas City Power &Light	Hawthorn	5	5	25,734	5,634
								Missouri	Kansas City Power &Light	Iatan	1	1	14,479	19,289
								Kansas	Kansas City Power &Light	La Cygne	1	1	23,489	3,872
								Kansas	Kansas City Power &Light	La Cygne	2	2	12,682	22,284
	Sioux	2	550	23,067	14,504	20,379	1	Missouri	Kansas City Power &Light	Hawthorn	5	5	25,734	5,634
								Missouri	Kansas City Power &Light	Iatan	1	1	14,479	19,289
								Missouri	Kansas City Power &Light	La Cygne	1	1	23,489	3,872
								Missouri	Kansas City Power &Light	La Cygne	2	2	12,682	22,284
	Utilcorp United													
	Sibley	3	419	15,170	26,812	9,417	1	Missouri	UtilCorp United	Sibley	1	1	2,810	1,414
								Missouri	UtilCorp United	Sibley	2	2	3,462	1,382
New Hampshire	**Public Service of New Hampshire**													
	Merrimack	1	114	9,922	15,258	10,450	1	New Hampshire	Public Service of NH	Newington	1	1	20,127	11,155
								Massachusetts	Holyoke Water Power	Mount Tom	1	1	10,708	8,223
	Merrimack	2	346	21,421	38,980	25,678	1	New Hampshire	Public Service of NH	Newington	1	1	20,127	11,155
								Massachusetts	Holyoke Water Power	Mount Tom	1	1	10,708	8,223
New Jersey	**Atlantic City Electric**													
	BL England	1	136	14,365	16,300	18,101	2							
	BL England	2	163	18,357	17,822	3,619	3							
New York	**Long Island Lighting**													
	Northport	ST1	387	19,824	26,583	4,114	5	New York	LILCO	Northport	4	4	5,516	538
	Northport	2	387	23,476	25,915	2,228	5	New York	LILCO	Northport	4	4	5,516	538

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
New York	Northport	3	387	25,783	27,360	4,047	5	New York	LILCO	Northport	4	4	5,516	538
	Port Jefferson	3	188	10,194	10,602	3,640	5	New York	LILCO	Northport	4	4	5,516	538
	Port Jefferson	4	188	12,006	12,195	2,636	5	New York		Northport	4	4	5,516	538
	New York State Gas & Electric													
	Greenidge	4	113	7,342	11,548	9,824	2							
	Milliken	1	155	11,018	9,400	5,158	3							
	Milliken	2	167	12,083	15,398	4,218	3							
	Niagara Mohawk													
	Dunkirk	ST4	218	13,690	16,846	19,061	2	New York	Niagara Mohawk	C R Huntley	63	63	5,460	3,497
								New York	Niagara Mohawk	C R Huntley	64	64	5,803	3,350
								New York	Niagara Mohawk	C R Huntley	65	65	5,969	6,265
								New York	Niagara Mohawk	C R Huntley	66	66	5,916	6,866
								New York	Niagara Mohawk	Oswego	3	3	86	0
								New York	Niagara Mohawk	Oswego	4	4	379	0
								New York	Niagara Mohawk	Oswego	5	ST5	14,898	0
								New York	Niagara Mohawk	Oswego	6	ST6	4,578	837
								New York	Central Hudson G&E	Roseton	1	1	19,147	1,607
								New York	Central Hudson G&E	Roseton	2	2	16,872	2,381
	Dunkirk	3	218	13,162	18,214	15,560	2	New York	Niagara Mohawk	C R Huntley	63	63	5,460	3,497
								New York	Niagara Mohawk	C R Huntley	64	64	5,803	3,350
								New York	Niagara Mohawk	C R Huntley	65	65	5,969	6,265
								New York	Niagara Mohawk	C R Huntley	66	66	5,916	6,866
								New York	Niagara Mohawk	Oswego	3	3	86	0
								New York	Niagara Mohawk	Oswego	4	4	379	0

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
New York								New York	Niagara Mohawk	Oswego	5	ST5	14,898	0
								New York	Niagara Mohawk	Oswego	6	ST6	4,578	837
								New York	Central Hudson G&E	Roseton	1	1	19,147	1,607
								New York	Central Hudson G&E	Roseton	2	2	16,872	2,381
Ohio	**Cardinal Operating Co.**													
	Cardinal	1	615	84,106	69,012	83,160	2							
	Cardinal	2	615	42,008	71,532	22,146	1							
	Cincinnati Gas & Electric													
	Miami Fort	[d]5	100	834	262	332	1							
	Miami Fort	6	163	12,475	21,111	3,862	1							
	Miami Fort	7	557	42,216	62,456	21,301	1	Kentucky	Cinergy	East Bend	2	2	17,447	11,378
	Walter C Beckjord	5	245	9,822	12,735	8,347	1							
	Walter C Beckjord	6	461	25,235	39,140	17,479	1							
	Cleveland Electric Illum.													
	Ashtabula	5	256	18,351	37,621	18,183	2	Ohio	Toledo Edison	Acme	13	1,4,5,TOPR	9	0
								Ohio	Toledo Edison	Acme	14	1,4,5,TOPR	13	0
								Ohio	Toledo Edison	Acme	15	1,4,5,TOPR	17	0
								Ohio	Toledo Edison	Acme	16	2	1,930	0
								Ohio	Toledo Edison	Acme	91	6	740	0
								Ohio	Toledo Edison	Acme	92	6	662	0
								Ohio	Cleveland Electric Illum.	Lake Shore	18	18	4,767	0
								Ohio	Cleveland Electric Illum.	Lake Shore	91	14	44	0
								Ohio	Cleveland Electric Illum.	Lake Shore	92	15	80	0
								Ohio	Cleveland Electric Illum.	Lake Shore	93	16	62	0
								Ohio	Cleveland Electric Illum.	Lake Shore	94	17	102	0
								Ohio	Toledo Edison	Bay Shore	1	1	7,546	5,901
								Ohio	Toledo Edison	Bay Shore	2	2	7,311	5,722
								Ohio	Toledo Edison	Bay Shore	3	3	7,585	5,920
								Ohio	Toledo Edison	Bay Shore	4	4	12,481	7,508

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio	Avon Lake	8	233	12,771	16,952	0	4							
	Avon Lake	9	680	33,413	41,322	21,921	1	Ohio	Cleveland Electric Illum.	Avon Lake	9	6	9,849	2,594
								Ohio	Cleveland Electric Illum.	Avon Lake	10	7	8,648	3,309
	Eastlake	1	123	8,551	16,550	8,635	2							
	Eastlake	2	123	9,471	17,267	13,025	2							
	Eastlake	3	123	10,984	19,545	14,451	2							
	Eastlake	4	208	15,908	24,997	23,405	2							
	Eastlake	5	680	42,495	79,918	57,855	2							
	Columbus Southern Power													
	Conesville	1	148	8,924	6,468	6,734	2							
	Conesville	2	136	5,360	7,008	13,019	2							
	Conesville	3	162	12,593	9,646	8,125	2							
	Conesville	4	842	53,463	98,256	62,940	2	Ohio	Dayton Power and Light	J M Stuart	1	1	41,189	22,861
								Ohio	Dayton Power and Light	J M Stuart	2	2	39,041	31,903
								Ohio	Dayton Power and Light	J M Stuart	3	3	38,712	25,034
								Ohio	Dayton Power and Light	J M Stuart	4	4	40,925	27,841
	Picway	5	106	11,967	13,671	4,722	2	Ohio	Columbus Southern	Poston	1	1	3,797	0
								Ohio	Columbus Southern	Poston	2	2	3,542	0
								Ohio	Columbus Southern	Poston	3	3	4,642	0
	Edgewater	4	114	5,536	6,149	10	5	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
								Massachusetts	New England Power	Brayton Point	1	1	15,085	11,379
								Massachusetts	New England Power	Brayton Point	2	2	15,838	11,130
								Massachusetts	New England Power	Brayton Point	3	3	32,977	21,915
								Massachusetts	New England Power	Brayton Point	4	4	21,238	7,564
								Massachusetts	New England Power	Salem Harbor	1	1	6,555	3,206
								Massachusetts	New England Power	Salem Harbor	2	2	6,696	3,141
								Massachusetts	New England Power	Salem Harbor	3	3	10,727	5,852
	Niles	2	133	14,806	16,264	12,340	3	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
	Niles	1	133	18,240	14,054	13,080	1	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com-pliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
	R E Burger	[e]3	104	9,383	12,965	2,252	2	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Com- pliance Method[c]	Substitution/ Compen- sating State	Substitution/ Compen- sating Utility	Substitution/ Compen- sating Plant	Substitution/ Compen- sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio	R E Burger	4	156	21,973	21,956	13,826	2	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
	R E Burger	5	156	23,127	25,973	23,539	2	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio	W H Sammis	5	334	26,496	34,632	12,627	1	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
	W H Sammis	6	680	43,773	61,391	27,041	1	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Ohio	W H Sammis	7	680	47,380	54,557	22,162	1	Ohio	Ohio Edison	Edgewater	11	2, 3	1,062	0
								Ohio	Ohio Edison	Edgewater	12	2, 3	1,145	0
								Ohio	Ohio Edison	R E Burger	1	1	2,820	708
								Ohio	Ohio Edison	R E Burger	2	1	2,751	604
								Ohio	Ohio Edison	R E Burger	3	2	2,891	518
								Ohio	Ohio Edison	R E Burger	4	2	2,956	212
								Ohio	Ohio Edison	Gorge	25	6	2,553	0
								Ohio	Ohio Edison	Gorge	26	7	2,860	0
								Ohio	Ohio Edison	Toronto	9	5, 6, 7	5,325	0
								Ohio	Ohio Edison	Toronto	10	5, 6, 7	9,505	0
								Ohio	Ohio Edison	Toronto	11	5, 6, 7	10,274	0
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	1	1	10,510	7,388
								Pennsylvania	Pennsylvania Power	Bruce Mansfield	2	2	11,537	5,532
								Pennsylvania	Pennsylvania Power	New Castle	1	1, 2	1,367	0
								Pennsylvania	Pennsylvania Power	New Castle	2	1, 2	1,520	0
	Ohio Power													
	Gen Jm Gavin	1	1,300	192,637	177,338	11,945	3							
	Gen Jm Gavin	2	1,300	188,168	185,911	11,533	3							
	Muskingum River	1	220	38,001	41,429	19,235	2							
	Muskingum River	2	220	34,026	41,796	25,074	2							
	Muskingum River	3	238	36,130	36,195	26,647	2							
	Muskingum River	4	238	34,153	35,108	31,952	2							
	Muskingum River	5	615	44,364	98,907	14,648	2							
	Ohio Valley Electric													
	Kyger Creek	1	217	18,773	45,319	18,313	1							
	Kyger Creek	2	217	18,072	44,494	18,487	1							
	Kyger Creek	3	217	17,439	42,499	19,265	1							
	Kyger Creek	4	217	18,218	43,345	18,018	1							
	Kyger Creek	5	217	18,247	46,886	18,723	1							
Pennsylvania	**Duquesne Light**													
	Cheswick	1	565	38,139	41,927	42,900	2							
	Metropolitan Edison Co.													
	Portland	1	172	9,373	6,436	11,088	2							
	Portland	2	255	17,309	10,892	11,055	2							

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Pennsylvania	**Pennsylvania Electric Co.**													
	Conemaugh	1	936	96,594	92,088	4,729	3							
	Conemaugh	2	936	85,753	89,804	73,364	3							
	Shawville	1	125	10,048	13,485	14,265	2							
	Shawville	2	125	10,048	14,310	10,837	2							
	Shawville	3	188	13,846	18,692	17,155	2							
	Shawville	4	188	13,700	17,683	16,147	2							
	Pennsylvania Power & Light													
	Brunner Island	1	363	27,030	32,078	21,128	1							
	Brunner Island	2	405	31,995	34,103	19,933	1							
	Brunner Island	3	790	60,571	58,775	56,335	1							
	Martin's Creek	1	156	12,327	14,627	5,988	1							
	Martin's Creek	2	156	12,483	14,131	4,774	1							
	Sunbury	3	104	9,133	10,046	9,847	1							
	Sunbury	4	156	11,392	14,077	9,511	1							
	West Pennsylvania Power													
	Armstrong	1	163	17,738	16,434	4,711	2	West Virginia	Monongahela Power	Albright	1	1	4,831	2,386
	Armstrong	2	163	15,024	15,423	17,196	2	West Virginia	Monongahela Power	Albright	2	2	5,024	2,358
	Hatfield's Ferry	1	576	55,732	54,286	66,839	2	West Virginia	Monongahela Power	Pleasants	1	1	16,762	23,614
	Hatfield's Ferry	2	576	57,506	51,986	47,799	2	West Virginia	Monongahela Power	Pleasants	2	2	19,230	23,704
	Hatfield's Ferry	3	576	56,580	54,809	50,203	2	Pennsylvania	West Penn Power	Mitchell	33	3	1,101	835
Tennessee	**TVA**													
	Allen	1	330	14,917	21,866	13,144	1							
	Allen	2	330	16,329	25,986	16,512	1							
	Allen	3	330	15,258	19,696	18,618	1							
	Cumberland	1	1,300	165,080	148,104	12,445	3							
	Cumberland	2	1,300	172,416	196,049	13,685	3							
	Gallatin	1	300	32,218	28,846	24,174	2							
	Gallatin	2	300	31,674	30,410	23,069	2							
	Gallatin	3	328	36,179	35,789	26,797	2							
	Gallatin	4	328	33,879	35,351	24,325	2							

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Tennessee	Johnsonville	1	125	7,585	11,123	9,722	2							
	Johnsonville	2	125	7,828	10,657	9,278	2							
	Johnsonville	3	125	8,189	9,712	8,543	2							
	Johnsonville	4	125	7,780	8,968	9,853	2							
	Johnsonville	5	147	8,023	8,544	12,233	2							
	Johnsonville	6	147	7,682	8,767	10,583	2							
	Johnsonville	7	173	8,744	10,389	15,784	2							
	Johnsonville	8	173	8,471	10,207	12,397	2							
	Johnsonville	9	173	6,894	8,922	13,292	2							
	Johnsonville	10	173	7,351	8,835	12,991	2							
West Virginia	**Monongahela Power**													
	Albright	3	140	11,684	11,938	11,444	2	Maryland	Potomac Edison	R P Smith	9	3	386	118
	Fort Martin	1	576	41,905	44,309	26,803	2							
	Fort Martin	2	576	44,118	44,824	43,171	2	Maryland	Potomac Edison	RP Smith	11	4	3,128	1,536
	Harrison	1	684	82,613	78,231	3,323	3	West Virginia	Monongahela Power	Rivesville	7	5	1,009	488
								West Virginia	Monongahela Power	Rivesville	8	6	3,059	1,357
	Harrison	2	684	91,180	78,231	3,373	3							
	Harrison	3	684	90,727	78,231	3,249	3	West Virginia	Monongahela Power	Willow Island	1	1	1,855	2,099
								West Virginia	Monongahela Power	Willow Island	2	2	7,765	7,908
	Ohio Power													
	Kammer	1	238	18,247	48,863	36,224	2							
	Kammer	2	238	18,948	57,963	42,224	2							
	Kammer	3	238	16,932	50,208	43,745	2							
	Mitchell	1	816	42,823	48,079	26,492	1							
	Mitchell	2	816	44,312	55,247	35,131	1							
	Virginia Electric & Power													
	Mt. Storm	1	570	49,481	48,587	45,556	2							
	Mt. Storm	2	570	45,203	35,817	49,688	2							
	Mt. Storm	3	522	49,859	43,906	2,549	3							

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compen-sating State	Substitution/ Compen-sating Utility	Substitution/ Compen-sating Plant	Substitution/ Compen-sating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Wisconsin	**Dairyland Power Coop.**													
	Genoa	ST3	346	22,103	35,035	15,304	1	Wisconsin	Dairyland Power Coop	Alma	B4	4	5,105	572
								Wisconsin	Dairyland Power Coop	Alma	B5	5	8,155	2,192
	Wisconsin Electric Power													
	North Oak Creek	1	120	5,083	6,810	0	4							
	North Oak Creek	2	120	5,005	7,916	0	4							
	North Oak Creek	3	130	5,229	7,184	0	4							
	North Oak Creek	4	130	6,154	9,323	0	4							
	South Oak Creek	5	275	9,416	16,586	5,343	1	Wisconsin	WEPCO	Port Washington	1	1	1,968	1,432
								Wisconsin	WEPCO	Port Washington	2	2	3,782	3,555
								Wisconsin	WEPCO	Port Washington	3	3	3,108	3,869
								Wisconsin	WEPCO	Port Washington	4	4	2,745	2,242
								Wisconsin	WEPCO	Port Washington	5	5	3,412	0
								Wisconsin	WEPCO	Valley	1	1	3,675	4,299
								Wisconsin	WEPCO	Valley	2	1	3,713	4,219
								Wisconsin	WEPCO	Valley	3	2	3,404	3,627
								Wisconsin	WEPCO	Valley	4	2	3,311	3,420
	South Oak Creek	6	275	11,723	17,748	5,663	1							
	South Oak Creek	7	318	15,754	27,888	9,658	1							
	South Oak Creek	8	324	15,375	22,553	6,005	1							
	Wisconsin Power & Light													
	Edgewater	4	330	24,099	39,722	6,482	1	Wisconsin	WEPCO	Edgewater	3	3	4,493	1,166
								Wisconsin	Dairyland Power Coop	J P Madgett	B1	1	6,862	5,746
	Nelson Dewey	1	100	5,852	13,289	2,046	1	Wisconsin	WEPCO	Rock River	1	1	5,398	1,637
								Wisconsin	WEPCO	Rock River	2	2	4,034	1,434
	Nelson Dewey	2	100	6,504	12,273	2,081	1	Wisconsin	WEPCO	Rock River	1	1	5,398	1,637
								Wisconsin	WEPCO	Rock River	2	2	4,034	1,434
	Pulliam	8	136	7,312	10,446	2,087	1	Wisconsin	Wisconsin Public Service	Pulliam	5	5	2,097	432

See notes at end of table.

Table B1. Profile of the 261 Table 1 Generators Affected by Phase I (Continued)

State	Operating Utility/ Plant	Generator Number[a]	Affected Nameplate Capacity (megawatts)	1995 Allowance[b] Allocations	1985 SO_2 Emissions Estimates (tons)	1995 SO_2 Emissions (tons)	Code of Compliance Method[c]	Substitution/ Compensating State	Substitution/ Compensating Utility	Substitution/ Compensating Plant	Substitution/ Compensating Boilers	Affected Generators	1985 SO_2 Emissions Estimates (tons)	1995 Sub/Comp SO_2 Emissions (tons)
Wisconsin								Wisconsin	Wisconsin Public Service	Pulliam	6	6	2,844	720
								Wisconsin	Wisconsin Public Service	Pulliam	7	7	7,317	1,466
								Wisconsin	Wisconsin Public Service	Weston	1	1	1,579	969
								Wisconsin	Wisconsin Public Service	Weston	2	2	3,580	1,936
								Wisconsin	Wisconsin Public Service	Weston	3	3	6,555	7,478

[a]Cincinnati Gas & Electric's Miami Fort generator 5 has two boilers as does Ohio Edison's R.E. Burger generator 3. Therefore, the total number of Table 1 boilers is 263 and the number of Table 1 generators is 261.
[b]One SO_2 allowance permits one ton of SO_2 emissions.
[c]The codes for the method of compliance are: (1) fuel switching and/or blending with lower-sulfur coal; (2) obtaining additional allowances; (3) scrubbing; 4) retired; and (5) other–includes repowering, switching to natural gas or petroleum.
[d]Miami Fort generator 5 has two boilers. Allowances, 1985 SO_2 emissions estimates, and 1995 emissions for the boilers were added to provide generator-level data.
[e]R.E. Burger generator 3 has two boilers. Allowances and 1985 SO_2 emissions estimates and 1995 emissions for the boilers were added to provide generator-level data.
SO_2 = Sulfur dioxide.
TVA = Tennessee Valley Authority.
Sources: *The Utility Report*, December 1995, Energy Ventures Analysis, Inc. **List of Table 1 Units**: *Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691. **Capacity**: Energy Information Administration, *Inventory of Power Plants 1992*, DOE/EIA-0095(92) (Washington, DC, October 1993). **1985 Emissions**: U.S. Environmental Protection Agency, National Allowance Data Base, Versions 2.11 (January 1993). **1995 Emissions**: U.S. Environmental Protection Agency.

Table B2. Profile of Coal Received at Table 1 Plants, 1995

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Power Co Gaston	**3,832**	**12,318**	**0.77**	**0.62**	**11.60**	**173.1**	**42.63**
Alabama	2,664	12,387	.77	.62	11.52	184.0	45.60
Fayette	107	12,060	1.84	1.53	12.28	116.3	28.05
Jefferson	278	12,829	.83	.65	10.53	207.7	53.30
Shelby	653	12,663	.84	.67	10.33	150.1	38.00
Tuscaloosa	624	12,583	.65	.52	10.40	212.7	53.52
Walker	1,000	11,995	.67	.56	13.19	189.2	45.38
Unknown[1]	2	12,700	1.20	.94	10.00	102.4	26.01
Kentucky	214	12,173	.94	.77	10.48	143.9	35.04
Breathitt	9	12,402	.81	.65	11.50	148.3	36.78
Harlan	97	12,512	1.01	.81	9.16	146.2	36.59
Jackson	108	11,848	.88	.74	11.58	141.4	33.50
Leslie	*	12,500	1.01	.81	10.00	151.1	37.77
West Virginia	954	12,156	.73	.60	12.08	148.3	36.06
Lincoln	934	12,169	.73	.60	12.02	148.4	36.11
Mingo	20	11,543	.79	.68	14.64	147.3	34.01
Associated Electric Coop Inc Hill	**4,723**	**8,744**	**.20**	**.23**	**4.56**	**71.8**	**12.55**
Wyoming	4,723	8,744	.20	.23	4.56	71.8	12.55
Campbell	4,723	8,744	.20	.23	4.56	71.8	12.55
Associated Electric Coop Inc Madrid	**4,263**	**8,761**	**.23**	**.26**	**4.61**	**94.5**	**16.56**
Illinois	19	10,704	2.95	2.76	10.46	118.0	25.26
Randolph	19	10,704	2.95	2.76	10.46	118.0	25.26
Indiana	19	10,879	2.92	2.68	9.03	118.0	25.67
Warrick	19	10,879	2.92	2.68	9.03	118.0	25.67
Wyoming	4,225	8,743	.20	.23	4.56	94.2	16.48
Campbell	4,225	8,743	.20	.23	4.56	94.2	16.48
Atlantic City Electric Co England	**594**	**12,822**	**2.43**	**1.89**	**10.31**	**168.4**	**43.19**
West Virginia	594	12,822	2.43	1.89	10.31	168.4	43.19
Marion	221	12,865	2.49	1.94	9.88	168.4	43.33
Monongalia	7	13,304	1.90	1.43	6.20	145.5	38.71
Upshur	366	12,787	2.40	1.88	10.66	168.9	43.19
Baltimore Gas & Electric Co Crane	**645**	**13,528**	**.93**	**.69**	**6.65**	**170.6**	**46.14**
Pennsylvania	8	13,122	1.57	1.20	6.80	144.9	38.03
Greene	8	13,122	1.57	1.20	6.80	144.9	38.03
Virginia	394	13,798	.71	.52	5.97	180.2	49.74
Buchanan	394	13,798	.71	.52	5.97	180.2	49.74
West Virginia	243	13,103	1.26	.96	7.76	154.9	40.59
Barbour	221	13,078	1.15	.88	7.88	157.8	41.28
Monongalia	22	13,355	2.34	1.75	6.50	125.9	33.63
Big Rivers Electric Corp Coleman	**1,367**	**11,437**	**1.94**	**1.69**	**9.74**	**107.6**	**24.62**
Indiana	258	11,490	1.45	1.26	8.02	116.7	26.81
Knox	2	11,119	1.44	1.30	13.30	124.5	27.69
Spencer	256	11,493	1.45	1.26	7.98	116.6	26.81
Kentucky	877	11,301	2.18	1.93	8.80	107.6	24.33
Floyd	72	11,810	1.45	1.23	11.46	116.2	27.44
Henderson	608	11,202	2.51	2.24	8.27	102.8	23.04
Lawrence	22	11,841	1.47	1.24	11.12	123.5	29.24
Martin	22	11,841	1.47	1.24	11.12	123.5	29.24
Ohio	136	11,250	1.43	1.27	8.46	119.1	26.80
Pike	18	11,686	1.42	1.21	13.25	107.1	25.04
Pennsylvania	186	11,885	1.45	1.22	14.96	96.7	22.99
Greene	186	11,885	1.45	1.22	14.96	96.7	22.99
West Virginia	45	11,926	1.86	1.56	16.20	102.2	24.37
Kanawha	1	11,119	1.44	1.30	13.30	124.5	27.69
Monongalia	44	11,944	1.87	1.57	16.26	101.7	24.29
Big Rivers Electric Corp Reid-Henderson II	**796**	**11,827**	**2.77**	**2.34**	**9.29**	**109.9**	**25.99**
Kentucky	796	11,827	2.77	2.34	9.29	109.9	25.99
Daviess	181	11,194	2.46	2.20	9.57	101.0	22.61
Henderson	12	11,204	2.72	2.43	9.54	76.5	17.15
Webster	603	12,030	2.86	2.38	9.21	112.9	27.17
Cardinal Operating Co Cardinal	**4,123**	**12,187**	**1.47**	**1.21**	**11.56**	**158.1**	**38.55**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cardinal Operating Co Cardinal							
Kentucky	611	12,111	0.67	0.55	10.56	138.3	33.49
Floyd	43	12,139	.71	.59	12.28	138.0	33.51
Knott	175	12,099	.65	.54	9.89	138.4	33.49
Magoffin	219	12,099	.65	.54	9.89	138.4	33.49
Perry	44	12,099	.65	.54	9.89	138.4	33.49
Pike	130	12,140	.71	.59	12.25	138.0	33.51
Ohio	254	11,906	2.87	2.41	12.30	103.9	24.73
Belmont	211	11,836	2.83	2.39	12.37	110.3	26.12
Jefferson	43	12,254	3.09	2.52	11.94	72.9	17.86
West Virginia	3,258	12,223	1.51	1.24	11.69	166.0	40.57
Boone	89	12,146	.68	.56	12.24	136.9	33.25
Brooke	1,040	12,306	3.27	2.66	9.96	194.4	47.84
Kanawha	331	12,344	.70	.57	12.07	164.7	40.67
Logan	1,477	12,125	.65	.53	12.67	156.3	37.91
Mingo	89	12,151	.68	.56	12.11	137.2	33.34
Webster	232	12,356	.92	.74	12.26	122.8	30.34
Central Illinois Pub Serv Co Coffeen	**1,690**	**10,266**	**.91**	**.88**	**8.16**	**171.8**	**35.28**
Illinois	1,690	10,266	.91	.88	8.16	171.8	35.28
Macoupin	1,690	10,266	.91	.88	8.16	171.8	35.28
Central Illinois Pub Serv Co Grand Tower	**150**	**11,401**	**2.85**	**2.50**	**11.40**	**190.8**	**43.50**
Illinois	150	11,401	2.85	2.50	11.40	190.8	43.50
Perry	28	10,923	3.05	2.79	10.20	192.3	42.01
Williamson	122	11,509	2.81	2.44	11.67	190.5	43.84
Central Illinois Pub Serv Co Meredosia	**509**	**11,067**	**2.19**	**1.98**	**5.69**	**152.6**	**33.79**
Illinois	509	11,067	2.19	1.98	5.69	152.6	33.79
Macoupin	116	10,311	.89	.86	8.15	138.3	28.52
Schuyler	393	11,290	2.57	2.28	4.97	156.5	35.34
Cincinnati Gas & Electric Co Beckjord	**2,192**	**11,915**	**.98**	**.82**	**12.88**	**160.5**	**38.25**
Kentucky	1,781	11,820	.88	.74	13.45	171.1	40.44
Breathitt	100	12,016	.91	.76	10.52	119.5	28.72
Floyd	52	11,858	.86	.73	12.09	109.3	25.93
Johnson	10	11,513	.93	.80	13.04	102.5	23.61
Knott	8	11,650	.91	.78	12.61	113.6	26.48
Knox	8	11,979	1.17	.98	12.50	101.8	24.39
Magoffin	167	11,744	1.14	.97	12.43	154.5	36.28
Martin	1,189	11,763	.84	.72	14.60	192.8	45.36
Pike	245	12,074	.85	.70	10.10	120.1	29.00
Ohio	55	12,478	4.01	3.21	9.48	94.0	23.46
Belmont	49	12,521	3.98	3.18	9.34	94.3	23.62
Harrison	6	12,115	4.25	3.51	10.68	91.2	22.11
Pennsylvania	35	13,186	1.62	1.23	7.39	104.9	27.66
Greene	35	13,186	1.62	1.23	7.39	104.9	27.66
West Virginia	320	12,206	.97	.79	10.93	121.9	29.76
Boone	11	12,245	.71	.58	13.32	114.1	27.94
Fayette	5	12,157	2.20	1.81	13.70	83.7	20.35
Kanawha	169	12,129	.83	.68	11.48	124.4	30.17
Logan	3	11,310	1.12	.99	14.10	101.0	22.85
Mingo	108	12,102	.86	.71	10.56	125.0	30.27
Monongalia	24	13,348	2.36	1.77	6.49	105.7	28.21
Cincinnati Gas & Electric Co Miami Fort	**2,663**	**12,138**	**.82**	**.68**	**11.79**	**143.2**	**34.76**
Kentucky	1,254	11,901	.82	.69	12.55	149.0	35.46
Breathitt	42	11,950	.88	.73	10.30	117.9	28.18
Floyd	567	11,980	.69	.57	12.09	127.8	30.63
Johnson	8	11,316	.93	.82	14.58	99.4	22.50
Knott	48	11,867	.68	.57	11.13	123.0	29.20
Lawrence	8	11,742	1.77	1.51	11.32	91.1	21.40
Magoffin	174	11,657	1.29	1.11	13.92	189.7	44.22
Martin	296	11,865	.83	.70	13.59	187.0	44.38
Pike	110	12,027	.72	.60	11.34	125.2	30.12

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cincinnati Gas & Electric Co Miami Fort							
Ohio	31	12,554	4.01	3.20	9.31	92.2	23.15
Belmont	30	12,579	4.00	3.18	9.24	92.0	23.14
Harrison	2	12,124	4.22	3.48	10.60	96.0	23.28
Pennsylvania	11	13,204	2.46	1.86	8.00	103.8	27.41
Greene	11	13,204	2.46	1.86	8.00	103.8	27.41
West Virginia	1,367	12,338	.74	.60	11.18	139.6	34.44
Boone	9	12,340	.72	.58	12.90	118.3	29.20
Clay	381	12,206	.68	.55	11.88	119.8	29.25
Kanawha	805	12,403	.71	.57	11.06	152.7	37.87
Logan	102	12,155	.69	.57	10.97	126.3	30.71
Marion	2	12,742	2.61	2.05	10.00	114.8	29.26
Mingo	42	12,094	.80	.66	10.14	124.6	30.13
Monongalia	26	13,339	2.40	1.80	6.49	106.2	28.33
Cleveland Electric Illum Co Ashtabula	**621**	**12,635**	**3.86**	**3.06**	**9.31**	**165.3**	**41.76**
Ohio	621	12,635	3.86	3.06	9.31	165.3	41.76
Belmont	539	12,682	4.03	3.18	9.07	171.2	43.42
Columbiana	82	12,324	2.75	2.23	10.91	125.3	30.88
Cleveland Electric Illum Co Avon Lake	**1,615**	**12,741**	**.85**	**.67**	**8.88**	**152.3**	**38.82**
Kentucky	263	12,416	.66	.53	8.91	155.5	38.62
Pike	263	12,416	.66	.53	8.91	155.5	38.62
Virginia	89	12,646	.85	.67	8.51	146.7	37.10
Buchanan	89	12,646	.85	.67	8.51	146.7	37.10
West Virginia	1,263	12,815	.89	.70	8.90	152.1	38.98
Mingo	1,123	12,767	.69	.54	9.07	155.4	39.68
Monongalia	140	13,196	2.48	1.88	7.59	126.7	33.43
Cleveland Electric Illum Co Eastlake	**2,398**	**12,999**	**2.39**	**1.84**	**7.69**	**142.0**	**36.90**
Ohio	1,008	12,726	3.55	2.79	8.83	162.9	41.45
Belmont	758	12,762	4.10	3.21	8.99	175.5	44.80
Columbiana	250	12,615	1.89	1.50	8.37	124.0	31.28
Pennsylvania	1,279	13,215	1.50	1.13	6.87	127.8	33.78
Clarion	60	12,949	1.45	1.12	7.83	129.5	33.54
Greene	876	13,177	1.50	1.14	6.84	127.7	33.66
Washington	343	13,361	1.49	1.12	6.77	127.7	34.12
West Virginia	111	12,987	2.13	1.64	6.68	121.8	31.64
Monongalia	93	13,030	2.17	1.67	6.21	120.5	31.40
Nicholas	9	12,785	1.68	1.31	8.70	133.9	34.24
Preston	9	12,739	2.16	1.70	9.60	124.0	31.59
Columbus & Southern Ohio El Co Conesville	**3,417**	**11,910**	**2.88**	**2.42**	**8.81**	**146.5**	**34.89**
Ohio	3,417	11,910	2.88	2.42	8.81	146.5	34.89
Belmont	64	11,609	3.61	3.11	12.25	93.8	21.78
Coshocton	1,625	11,953	2.52	2.10	7.27	180.9	43.24
Guernsey	17	11,519	3.12	2.71	11.83	101.1	23.28
Harrison	608	12,618	3.02	2.39	8.62	115.1	29.04
Holmes	27	11,238	3.63	3.23	10.72	94.9	21.33
Jefferson	88	11,963	2.54	2.13	11.46	101.4	24.27
Perry	316	11,294	3.20	2.83	11.93	112.2	25.35
Pike	102	11,941	2.60	2.18	6.80	192.8	46.04
Tuscarawas	570	11,438	3.58	3.13	11.07	108.1	24.72
Columbus & Southern Ohio El Co Picway	**91**	**11,236**	**3.05**	**2.71**	**11.33**	**103.4**	**23.24**
Ohio	91	11,236	3.05	2.71	11.33	103.4	23.24
Jackson	7	11,147	4.07	3.65	12.80	97.1	21.65
Vinton	85	11,243	2.97	2.64	11.21	103.9	23.36
Commonwealth Edison Co Kincaid	**1,266**	**11,620**	**.45**	**.39**	**7.78**	**145.2**	**33.75**
Illinois	41	10,398	.85	.82	8.20	100.8	20.95
Macoupin	41	10,398	.85	.82	8.20	100.8	20.95
Utah	1,153	11,842	.45	.38	7.93	138.7	32.85
Carbon	795	11,743	.44	.38	7.77	136.9	32.15
Emery	328	12,105	.46	.38	8.38	143.1	34.65
Sevier	30	11,598	.34	.29	7.20	137.5	31.89

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Commonwealth Edison Co Kincaid							
Wyoming	72	8,766	0.29	0.33	5.07	315.5	55.31
Campbell	24	8,776	.21	.24	4.50	295.3	51.83
Converse	48	8,761	.32	.37	5.35	325.6	57.05
Consumers Power Co Campbell	**3,030**	**11,631**	**.65**	**.56**	**9.54**	**158.2**	**36.81**
Kentucky	1,201	12,586	.76	.60	9.54	161.8	40.73
Breathitt	105	12,356	.71	.57	9.65	165.4	40.87
Floyd	305	12,455	.87	.70	10.56	160.5	39.97
Knott	114	12,304	.78	.64	10.93	158.5	39.00
Perry	10	12,178	.89	.73	10.77	178.7	43.53
Pike	655	12,732	.71	.56	8.83	162.3	41.33
Unknown[1]	13	12,900	.90	.70	7.50	157.3	40.58
Montana	12	9,352	.36	.38	4.10	122.0	22.82
Big Horn	12	9,352	.36	.38	4.10	122.0	22.82
West Virginia	1,170	12,263	.72	.59	11.93	169.8	41.64
Boone	988	12,220	.73	.60	12.02	170.7	41.72
Logan	182	12,499	.63	.51	11.46	164.9	41.22
Wyoming	648	8,759	.33	.38	5.30	120.1	21.04
Campbell	616	8,756	.34	.39	5.30	119.9	21.00
Converse	31	8,815	.21	.24	5.23	124.4	21.94
Dairyland Power Coop Genoa No.3	**953**	**10,723**	**.75**	**.70**	**5.15**	**127.5**	**27.35**
Illinois	592	12,093	.99	.82	5.23	131.1	31.72
Jefferson	592	12,093	.99	.82	5.23	131.1	31.72
Wyoming	361	8,475	.36	.42	5.02	119.1	20.19
Campbell	361	8,475	.36	.42	5.02	119.1	20.19
Duquesne Light Co Cheswick	**1,237**	**13,016**	**1.72**	**1.33**	**8.69**	**115.9**	**30.17**
Pennsylvania	981	13,060	1.92	1.47	8.55	112.8	29.46
Fayette	302	12,790	1.19	.93	9.36	133.1	34.05
Greene	679	13,181	2.25	1.70	8.18	104.0	27.42
West Virginia	256	12,848	.98	.76	9.23	128.1	32.92
Fayette	256	12,848	.98	.76	9.23	128.1	32.92
East Kentucky Power Coop Cooper	**609**	**12,398**	**1.28**	**1.03**	**9.74**	**120.4**	**29.85**
Kentucky	609	12,398	1.28	1.03	9.74	120.4	29.85
Bell	50	12,690	.98	.77	8.17	107.8	27.37
Breathitt	4	12,166	1.26	1.04	10.75	121.3	29.51
Clay	147	12,769	1.15	.90	7.19	114.2	29.16
Laurel	1	11,145	1.63	1.46	12.70	74.1	16.52
Lee	6	11,974	1.15	.96	9.05	99.8	23.91
Leslie	22	12,456	1.13	.91	9.53	114.7	28.57
Letcher	2	12,344	1.21	.98	10.30	114.3	28.22
Perry	33	12,473	.91	.73	8.94	111.9	27.90
Pulaski	318	12,194	1.41	1.16	11.27	128.1	31.25
Whitley	18	12,440	1.71	1.38	8.77	108.6	27.01
Wolfe	8	11,908	1.52	1.28	11.00	111.8	26.63
East Kentucky Power Coop Spurlock	**2,203**	**12,424**	**.76**	**.61**	**10.55**	**116.8**	**29.03**
Kentucky	1,250	12,461	.74	.59	9.73	117.9	29.39
Boyd	407	12,563	.76	.60	8.80	116.2	29.19
Breathitt	219	12,223	.69	.56	10.19	121.2	29.62
Floyd	96	12,163	.74	.61	10.49	117.1	28.49
Greenup	236	12,379	.80	.65	12.26	114.5	28.36
Knott	157	12,634	.67	.53	8.49	125.8	31.78
Letcher	81	13,118	.75	.57	6.74	114.7	30.09
Pike	54	12,053	.66	.55	10.63	116.6	28.11
Pennsylvania	61	13,210	1.54	1.17	7.06	107.2	28.32
Greene	61	13,210	1.54	1.17	7.06	107.2	28.32
West Virginia	892	12,319	.73	.59	11.93	116.0	28.57
Boone	24	12,256	.67	.54	12.97	109.3	26.80
Fayette	365	12,333	.80	.65	12.70	114.8	28.32
Kanawha	79	12,387	.66	.53	10.94	118.3	29.32
Logan	340	12,318	.71	.58	11.78	115.3	28.41
Wayne	84	12,218	.61	.50	9.81	123.2	30.11
Electric Energy Inc Joppa	**4,890**	**8,746**	**.28**	**.32**	**4.53**	**84.5**	**14.79**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Electric Energy Inc Joppa							
Illinois	96	12,414	1.65	1.33	7.92	108.5	26.94
Franklin	12	12,308	.77	.63	4.70	108.5	26.71
Saline	84	12,429	1.77	1.43	8.38	108.5	26.97
Wyoming	4,794	8,673	.25	.29	4.46	83.8	14.54
Campbell	4,794	8,673	.25	.29	4.46	83.8	14.54
Empire District Electric Co Asbury	**860**	**9,136**	**.58**	**.64**	**5.58**	**103.5**	**18.90**
Kansas	101	11,811	3.42	2.89	13.47	125.8	29.72
Crawford	101	11,811	3.42	2.89	13.47	125.8	29.72
Wyoming	759	8,781	.21	.24	4.53	99.5	17.47
Campbell	759	8,781	.21	.24	4.53	99.5	17.47
Georgia Power Co Atkinson-Mcdonough	**1,202**	**12,572**	**.85**	**.68**	**9.74**	**133.5**	**33.56**
Kentucky	1,202	12,572	.85	.68	9.74	133.5	33.56
Harlan	1,202	12,572	.85	.68	9.74	133.5	33.56
Georgia Power Co Bowen	**7,545**	**12,493**	**1.04**	**.83**	**9.90**	**163.0**	**40.72**
Kentucky	7,545	12,493	1.04	.83	9.90	163.0	40.72
Harlan	427	12,561	.97	.77	9.54	139.2	34.97
Knott	249	12,289	1.02	.83	11.03	141.3	34.73
Leslie	4,173	12,472	1.11	.89	10.07	175.1	43.68
Letcher	296	12,835	.96	.75	8.20	137.7	35.34
Perry	2,400	12,497	.92	.74	9.74	151.6	37.90
Georgia Power Co Hammond	**1,037**	**12,552**	**.97**	**.77**	**10.02**	**146.5**	**36.78**
Illinois	71	12,108	1.16	.96	5.99	140.6	34.04
Saline	71	12,108	1.16	.96	5.99	140.6	34.04
Kentucky	333	12,513	.86	.69	9.08	143.5	35.90
Martin	294	12,415	.86	.69	9.67	144.2	35.80
Whitley	39	13,267	.88	.66	4.60	138.4	36.72
Virginia	450	12,647	1.15	.91	11.38	148.5	37.56
Lee	20	12,455	1.11	.89	11.22	184.2	45.88
Wise	430	12,656	1.15	.91	11.39	146.9	37.17
West Virginia	183	12,563	.66	.52	9.96	149.3	37.53
Logan	79	12,753	.66	.52	10.39	151.9	38.74
Mingo	104	12,421	.65	.53	9.63	147.4	36.62
Georgia Power Co Wansley	**2,801**	**12,722**	**.88**	**.69**	**8.40**	**189.4**	**48.20**
Alabama	104	12,178	1.85	1.52	12.22	133.7	32.55
Fayette	104	12,178	1.85	1.52	12.22	133.7	32.55
Illinois	487	12,086	1.11	.92	6.41	157.1	37.97
Saline	487	12,086	1.11	.92	6.41	157.1	37.97
Kentucky	1,663	12,948	.72	.56	8.50	204.0	52.82
Bell	9	11,913	.90	.76	10.14	205.3	48.91
Harlan	1,634	12,989	.73	.56	8.26	204.6	53.15
Pike	20	10,001	.56	.56	27.14	132.5	26.50
Virginia	113	12,769	.96	.75	10.06	151.2	38.63
Wise	113	12,769	.96	.75	10.06	151.2	38.63
West Virginia	434	12,690	.95	.75	8.93	189.9	48.19
Logan	30	12,748	.83	.65	10.37	154.0	39.26
Mingo	404	12,686	.96	.76	8.82	192.6	48.85
Georgia Power Co Yates	**1,235**	**12,534**	**.90**	**.72**	**10.14**	**160.6**	**40.26**
Alabama	29	12,191	1.89	1.55	11.96	132.4	32.28
Fayette	29	12,191	1.89	1.55	11.96	132.4	32.28
Illinois	46	12,109	1.12	.92	6.72	146.9	35.58
Saline	46	12,109	1.12	.92	6.72	146.9	35.58
Kentucky	108	12,239	.83	.68	10.94	155.2	37.99
Martin	50	12,126	.87	.72	10.75	147.6	35.79
Pike	58	12,336	.80	.65	11.10	161.6	39.87
Virginia	682	12,608	.98	.78	10.27	168.5	42.50
Lee	357	12,426	1.10	.89	11.17	189.8	47.18
Wise	325	12,809	.84	.66	9.29	145.8	37.36
West Virginia	370	12,564	.67	.53	9.94	151.2	37.99
Logan	174	12,813	.67	.52	9.56	152.2	39.01
Mingo	196	12,343	.68	.55	10.27	150.3	37.10

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Gulf Power Co Crist	**1,574**	**12,354**	**0.93**	**0.75**	**6.31**	**229.6**	**56.74**
Illinois	797	12,346	.95	.77	6.34	228.4	56.40
Franklin	20	11,690	2.17	1.86	8.29	128.1	29.96
Saline	777	12,363	.92	.74	6.29	230.9	57.09
Imported	777	12,363	.92	.74	6.29	230.9	57.09
Imported Coal	777	12,363	.92	.74	6.29	230.9	57.09
Hoosier Energy R E C Inc Frank E Ratts	**753**	**11,151**	**1.30**	**1.16**	**7.45**	**132.6**	**29.57**
Indiana	753	11,151	1.30	1.16	7.45	132.6	29.57
Pike	753	11,151	1.30	1.16	7.45	132.6	29.57
Illinois Power Co Baldwin	**4,353**	**10,824**	**2.92**	**2.70**	**10.16**	**109.7**	**23.75**
Illinois	4,353	10,824	2.92	2.70	10.16	109.7	23.75
Perry	2,074	10,941	2.93	2.68	10.04	113.0	24.72
Washington	2,279	10,718	2.91	2.72	10.27	106.7	22.87
Illinois Power Co Hennepin	**583**	**10,703**	**2.93**	**2.74**	**10.32**	**113.5**	**24.29**
Illinois	583	10,703	2.93	2.74	10.32	113.5	24.29
Washington	583	10,703	2.93	2.74	10.32	113.5	24.29
Illinois Power Co Vermilion	**31**	**11,142**	**2.10**	**1.88**	**8.81**	**132.0**	**29.41**
Indiana	31	11,142	2.10	1.88	8.81	132.0	29.41
Sullivan	31	11,142	2.10	1.88	8.81	132.0	29.41
Indiana & Michigan Electric Co Tanners Creek	**1,428**	**12,265**	**1.19**	**.97**	**8.78**	**146.9**	**36.04**
Illinois	61	11,377	1.88	1.66	8.74	109.1	24.82
Franklin	61	11,377	1.88	1.66	8.74	109.1	24.82
Kentucky	713	12,514	1.65	1.32	7.40	134.2	33.60
Hopkins	336	11,611	1.95	1.68	9.63	111.9	25.98
Letcher	377	13,320	1.38	1.04	5.42	151.6	40.39
West Virginia	553	12,684	.70	.56	11.34	168.8	42.82
Fayette	249	12,743	.70	.55	11.06	174.1	44.36
Kanawha	249	12,743	.70	.55	11.06	174.1	44.36
Logan	53	12,155	.67	.55	13.99	119.3	29.01
Marshall	2	11,822	2.67	2.26	11.60	98.7	23.34
Wyoming	100	8,730	.19	.22	4.39	131.0	22.87
Campbell	100	8,730	.19	.22	4.39	131.0	22.87
Indiana-Kentucky Electric Corp Clifty Creek	**4,890**	**10,297**	**1.03**	**1.00**	**6.42**	**109.4**	**22.53**
Ohio	912	11,156	4.01	3.60	11.85	100.6	22.44
Belmont	93	12,213	4.40	3.60	10.18	94.4	23.05
Jackson	819	11,036	3.97	3.60	12.04	101.4	22.37
Virginia	1,014	13,792	.73	.53	6.06	152.4	42.04
Buchanan	1,014	13,792	.73	.53	6.06	152.4	42.04
West Virginia	7	12,050	3.96	3.29	13.57	110.3	26.58
Marshall	7	12,050	3.96	3.29	13.57	110.3	26.58
Wyoming	2,957	8,830	.20	.23	4.86	89.8	15.85
Campbell	95	8,774	.19	.22	4.26	81.9	14.37
Converse	2,862	8,831	.20	.23	4.88	90.0	15.90
Indianapolis Power & Light Co Petersburg	**4,598**	**11,099**	**2.42**	**2.18**	**8.95**	**101.1**	**22.45**
Indiana	4,598	11,099	2.42	2.18	8.95	101.1	22.45
Daviess	1,901	11,319	2.24	1.98	8.67	92.7	20.98
Greene	4	11,531	2.44	2.12	8.03	88.7	20.46
Knox	360	10,871	.63	.58	8.35	120.4	26.18
Pike	156	11,114	2.56	2.31	8.62	96.5	21.44
Warrick	2,177	10,942	2.86	2.62	9.32	106.0	23.19
Indianapolis Power & Light Co Pritchard	**340**	**11,368**	**1.24**	**1.09**	**7.31**	**112.0**	**25.45**
Indiana	340	11,368	1.24	1.09	7.31	112.0	25.45
Daviess	52	11,169	1.31	1.17	8.04	109.8	24.52
Greene	147	11,487	1.28	1.11	6.99	111.3	25.57
Owen	141	11,316	1.17	1.03	7.37	113.4	25.67
Indianapolis Power & Light Co Stout	**1,335**	**11,255**	**1.46**	**1.30**	**8.11**	**113.5**	**25.54**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Indianapolis Power & Light Co Stout							
Indiana	1,335	11,255	1.46	1.30	8.11	113.5	25.54
Daviess	505	11,151	1.49	1.33	8.48	111.9	24.95
Greene	665	11,392	1.48	1.30	7.47	118.0	26.88
Knox	42	11,199	1.43	1.28	8.22	115.6	25.90
Sullivan	123	10,956	1.28	1.17	10.06	93.7	20.54
Interstate Power Co Kapp	**372**	**11,334**	**.58**	**.52**	**11.32**	**126.9**	**28.78**
Colorado	372	11,334	.58	.52	11.32	126.9	28.78
Mesa	372	11,334	.58	.52	11.32	126.9	28.78
Iowa Electric Light & Power Prairie Creek 1-4	**846**	**8,868**	**.56**	**.63**	**5.66**	**112.7**	**19.98**
Illinois	117	11,459	1.96	1.71	8.70	121.6	27.86
Franklin	103	11,603	2.10	1.81	8.78	121.8	28.27
Macoupin	14	10,401	.92	.88	8.06	119.4	24.83
Wyoming	729	8,452	.33	.39	5.17	110.7	18.72
Campbell	729	8,452	.33	.39	5.17	110.7	18.72
Iowa Public Service George Neal	**5,934**	**8,728**	**.38**	**.44**	**5.31**	**81.4**	**14.21**
Wyoming	5,934	8,728	.38	.44	5.31	81.4	14.21
Campbell	5,316	8,526	.37	.44	5.14	76.9	13.11
Carbon	618	10,467	.45	.43	6.79	113.3	23.72
Iowa Southern Utilities Co Burlington	**482**	**9,691**	**1.05**	**1.08**	**6.46**	**99.5**	**19.29**
Illinois	179	11,589	2.02	1.74	8.81	105.4	24.42
Franklin	179	11,589	2.02	1.74	8.81	105.4	24.42
Indiana	18	11,434	2.68	2.34	8.33	132.2	30.23
Warrick	18	11,434	2.68	2.34	8.33	132.2	30.23
Wyoming	285	8,389	.33	.40	4.86	91.7	15.38
Campbell	285	8,389	.33	.40	4.86	91.7	15.38
Iowa-Illinois Gas&Electric Co Riverside	**348**	**8,779**	**.67**	**.76**	**6.65**	**123.1**	**21.62**
Illinois	55	11,281	1.96	1.74	8.67	108.2	24.41
Franklin	55	11,281	1.96	1.74	8.67	108.2	24.41
Wyoming	293	8,309	.43	.51	6.28	127.0	21.10
Campbell	293	8,309	.43	.51	6.28	127.0	21.10
Kansas City City of Quindaro	**402**	**10,817**	**1.07**	**.99**	**7.84**	**207.4**	**44.88**
Illinois	138	11,521	2.33	2.02	10.25	339.2	78.16
Franklin	9	11,280	1.90	1.68	10.05	112.5	25.38
Williamson	128	11,538	2.36	2.04	10.26	355.5	82.05
Wyoming	264	10,450	.41	.39	6.59	131.7	27.53
Carbon	264	10,450	.41	.39	6.59	131.7	27.53
Kansas City Power & Light Co Montrose	**1,653**	**8,674**	**.21**	**.24**	**5.02**	**97.5**	**16.91**
Wyoming	1,653	8,674	.21	.24	5.02	97.5	16.91
Campbell	1,653	8,674	.21	.24	5.02	97.5	16.91
Kentucky Utilities Co Brown	**1,031**	**11,913**	**1.29**	**1.08**	**11.72**	**118.3**	**28.18**
Kentucky	1,022	11,905	1.28	1.07	11.72	118.3	28.17
Breathitt	387	11,845	1.05	.89	11.56	118.2	28.00
Perry	635	11,943	1.42	1.19	11.82	118.3	28.27
Tennessee	9	12,791	2.54	1.99	11.56	115.8	29.62
Morgan	9	12,791	2.54	1.99	11.56	115.8	29.62
Kentucky Utilities Co Ghent	**4,728**	**12,234**	**1.38**	**1.13**	**9.92**	**117.3**	**28.70**
Indiana	285	11,204	2.97	2.65	9.37	94.5	21.17
Pike	178	11,331	3.21	2.83	9.19	94.5	21.42
Spencer	90	10,976	2.44	2.23	9.61	96.5	21.18
Warrick	17	11,075	3.13	2.83	10.08	83.6	18.51
Kentucky	1,837	12,060	1.28	1.07	9.53	125.7	30.31
Boyd	23	11,864	.65	.55	10.59	121.2	28.77
Daviess	157	11,178	2.91	2.60	9.66	95.6	21.38
Floyd	213	12,155	.66	.54	11.71	121.3	29.49
Harlan	327	12,589	.73	.58	8.37	136.7	34.43
Henderson	250	11,228	2.88	2.56	9.16	101.2	22.73
Knott	334	12,524	.67	.54	8.81	143.5	35.94
Ohio	80	11,166	3.32	2.98	10.28	81.6	18.23
Pike	452	12,225	.66	.54	9.83	135.3	33.09

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Kentucky Utilities Co Ghent							
Pennsylvania	198	13,228	2.50	1.89	8.16	102.8	27.20
Greene	198	13,228	2.50	1.89	8.16	102.8	27.20
West Virginia	2,408	12,407	1.18	.95	10.42	114.8	28.48
Boone	43	12,430	.68	.55	11.18	118.3	29.40
Clay	43	12,073	.69	.57	12.10	126.3	30.50
Kanawha	821	12,657	.70	.55	10.51	120.2	30.41
Logan	345	12,253	.67	.54	11.89	124.0	30.40
Marshall	436	12,339	3.46	2.80	10.17	84.0	20.73
Mingo	398	12,298	.68	.55	9.78	119.6	29.41
Wayne	322	12,201	.62	.51	9.45	124.7	30.43
Kentucky Utilities Co Green River	**372**	**11,605**	**2.49**	**2.14**	**8.36**	**103.7**	**24.08**
Kentucky	372	11,605	2.49	2.14	8.36	103.7	24.08
Hopkins	372	11,605	2.49	2.14	8.36	103.7	24.08
Metropolitan Edison Co Portland	**496**	**13,111**	**1.88**	**1.43**	**7.47**	**136.1**	**35.70**
Pennsylvania	23	12,732	1.85	1.46	8.81	166.1	42.29
Armstrong	15	12,852	2.04	1.58	8.97	166.9	42.90
Jefferson	8	12,500	1.50	1.20	8.50	164.5	41.12
West Virginia	473	13,129	1.88	1.43	7.40	134.7	35.38
Monongalia	473	13,129	1.88	1.43	7.40	134.7	35.38
Mississippi Power Co Watson	**1,247**	**12,436**	**2.33**	**1.87**	**8.86**	**123.2**	**30.65**
Colorado	11	11,972	.50	.42	7.91	145.8	34.91
Gunnison	11	11,972	.50	.42	7.91	145.8	34.91
Illinois	1,236	12,440	2.35	1.89	8.86	123.0	30.61
Gallatin	765	12,678	2.73	2.15	9.00	120.0	30.44
Jefferson	10	12,120	.83	.68	5.03	142.8	34.61
Saline	460	12,052	1.75	1.45	8.73	127.8	30.81
Missouri Public Service Comm Sibley	**1,275**	**10,103**	**.43**	**.42**	**5.63**	**100.8**	**20.36**
Utah	56	11,484	.34	.30	8.05	118.4	27.19
Carbon	22	11,573	.37	.32	8.99	118.8	27.50
Sevier	33	11,424	.32	.28	7.41	118.1	26.98
Wyoming	1,219	10,040	.43	.43	5.52	99.9	20.05
Campbell	200	8,747	.22	.26	4.59	70.9	12.41
Carbon	1,019	10,294	.47	.46	5.70	104.7	21.56
Monongahela Power Co Albright	**467**	**12,452**	**1.65**	**1.32**	**12.44**	**96.9**	**24.13**
Pennsylvania	65	12,217	1.70	1.39	13.02	94.8	23.15
Fayette	65	12,217	1.70	1.39	13.02	94.8	23.15
West Virginia	401	12,491	1.64	1.31	12.34	97.2	24.29
Monongalia	64	12,154	1.70	1.40	13.46	94.2	22.89
Preston	337	12,555	1.63	1.30	12.13	97.8	24.56
Monongahela Power Co Ft Martin	**1,946**	**12,736**	**1.59**	**1.25**	**10.34**	**148.7**	**37.88**
Kentucky	471	12,651	.83	.66	8.45	188.7	47.75
Martin	471	12,651	.83	.66	8.45	188.7	47.75
Maryland	285	12,732	1.52	1.20	13.41	134.9	34.34
Garrett	285	12,732	1.52	1.20	13.41	134.9	34.34
Pennsylvania	57	12,902	1.87	1.45	9.60	130.6	33.70
Greene	57	12,902	1.87	1.45	9.60	130.6	33.70
West Virginia	1,133	12,764	1.90	1.49	10.38	136.6	34.88
Monongalia	1,133	12,764	1.90	1.49	10.38	136.6	34.88
Monongahela Power Co Harrison	**4,992**	**12,483**	**3.48**	**2.79**	**12.30**	**112.0**	**27.95**
West Virginia	4,992	12,483	3.48	2.79	12.30	112.0	27.95
Harrison	4,351	12,457	3.58	2.88	12.56	113.6	28.30
Lewis	30	12,577	2.99	2.38	11.64	92.8	23.35
Marion	84	12,370	3.54	2.86	12.68	87.3	21.60
Monongalia	446	12,768	2.58	2.02	9.62	107.5	27.45
Upshur	81	12,373	3.18	2.57	12.44	81.8	20.25
New York State Elec & Gas Corp Milliken	**716**	**13,035**	**2.00**	**1.53**	**7.65**	**130.4**	**33.99**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
New York State Elec & Gas Corp Milliken							
Pennsylvania	239	13,013	1.56	1.20	6.97	134.0	34.87
Greene	232	13,023	1.54	1.19	6.80	133.7	34.82
Jefferson	8	12,693	2.06	1.62	12.10	143.2	36.35
West Virginia	477	13,046	2.21	1.70	7.99	128.6	33.55
Monongalia	477	13,046	2.21	1.70	7.99	128.6	33.55
New York State Gas & Elect Greenridge	**242**	**13,005**	**1.80**	**1.39**	**8.54**	**131.1**	**34.10**
Pennsylvania	108	12,589	1.30	1.04	10.78	133.8	33.68
Greene	67	12,869	1.51	1.17	7.28	133.1	34.26
Lycoming	37	11,976	.90	.75	17.64	133.6	32.00
Washington	5	13,367	1.52	1.14	7.00	143.3	38.31
West Virginia	133	13,344	2.21	1.66	6.72	129.1	34.45
Monongalia	133	13,344	2.21	1.66	6.72	129.1	34.45
Niagara-Mohawk Power Corp Dunkirk	**1,356**	**13,044**	**2.06**	**1.58**	**8.30**	**126.6**	**33.03**
Pennsylvania	1,043	12,969	1.92	1.48	8.57	126.8	32.89
Armstrong	49	13,052	2.38	1.83	7.02	136.0	35.50
Elk	34	11,256	1.03	.92	13.00	122.1	27.49
Greene	960	13,026	1.93	1.48	8.49	126.5	32.95
West Virginia	313	13,294	2.50	1.88	7.40	126.0	33.51
Marion	17	13,143	2.50	1.90	7.95	129.9	34.15
Monongalia	296	13,303	2.50	1.88	7.37	125.8	33.48
Northern Indiana Pub Serv Co Bailly	**1,336**	**10,970**	**2.94**	**2.68**	**9.99**	**137.6**	**30.18**
Illinois	1,227	10,968	3.01	2.75	10.04	139.5	30.59
Montgomery	79	10,750	3.28	3.05	8.28	113.1	24.31
Perry	1,148	10,984	2.99	2.72	10.16	141.2	31.03
Indiana	109	10,993	2.08	1.90	9.45	116.4	25.60
Sullivan	109	10,993	2.08	1.90	9.45	116.4	25.60
Northern Indiana Pub Serv Co Michigan City	**1,444**	**9,782**	**.46**	**.47**	**5.84**	**146.5**	**28.66**
Wyoming	1,444	9,782	.46	.47	5.84	146.5	28.66
Campbell	770	8,719	.33	.38	5.33	102.6	17.89
Carbon	674	10,997	.60	.55	6.43	186.2	40.96
Northern States Power High Bridge	**580**	**8,753**	**.21**	**.23**	**4.64**	**114.9**	**20.12**
Wyoming	580	8,753	.21	.23	4.64	114.9	20.12
Campbell	526	8,750	.21	.23	4.64	114.8	20.10
Converse	54	8,777	.21	.24	4.60	115.5	20.27
Ohio Edison Co Burger	**564**	**12,470**	**2.98**	**2.39**	**10.57**	**93.1**	**23.23**
Ohio	226	12,444	3.78	3.04	10.17	95.2	23.68
Belmont	106	12,580	4.22	3.35	9.35	82.6	20.79
Harrison	120	12,324	3.39	2.75	10.89	106.5	26.24
Pennsylvania	180	12,635	2.41	1.90	10.26	93.0	23.49
Greene	73	13,231	2.43	1.84	8.05	94.7	25.06
Washington	64	11,951	2.83	2.37	11.93	87.4	20.88
Westmoreland	42	12,638	1.72	1.36	11.54	97.9	24.74
West Virginia	158	12,320	2.49	2.02	11.49	90.5	22.29
Brooke	10	12,113	3.52	2.91	10.20	86.7	21.00
Marshall	73	12,426	3.31	2.66	10.13	79.0	19.63
Monongalia	75	12,245	1.55	1.27	12.99	102.3	25.04
Ohio Edison Co Niles	**473**	**12,154**	**2.92**	**2.40**	**10.98**	**107.3**	**26.08**
Ohio	460	12,145	2.91	2.40	11.02	107.2	26.03
Carroll	133	12,127	2.64	2.18	10.84	121.7	29.51
Columbiana	59	12,100	2.69	2.22	10.36	112.1	27.13
Harrison	147	12,390	3.40	2.74	10.44	96.6	23.93
Jefferson	86	11,964	2.43	2.04	12.20	106.0	25.35
Mahoning	10	11,923	3.02	2.53	11.58	104.5	24.92
Tuscarawas	25	11,628	3.64	3.13	12.51	86.5	20.12
Pennsylvania	13	12,487	3.00	2.40	9.76	111.8	27.92
Armstrong	2	12,579	2.88	2.29	8.90	110.5	27.79
Butler	11	12,468	3.02	2.42	9.93	112.1	27.95
Ohio Edison Co Sammis	**5,449**	**12,188**	**.79**	**.65**	**10.92**	**128.1**	**31.23**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ohio Edison Co Sammis							
Kentucky	1,954	12,057	0.80	0.67	10.65	124.0	29.89
Breathitt	115	11,900	.83	.70	10.89	114.0	27.13
Floyd	821	12,093	.82	.68	10.12	121.1	29.28
Johnson	16	11,766	.88	.75	10.91	113.6	26.73
Knott	10	11,639	.75	.65	10.72	113.3	26.38
Lawrence	25	11,797	.89	.76	11.56	116.3	27.44
Magoffin	144	11,711	.80	.69	11.24	117.4	27.49
Martin	711	12,147	.80	.66	10.90	132.3	32.14
Pike	112	11,955	.63	.53	11.79	114.3	27.32
Pennsylvania	32	12,192	.81	.67	10.27	119.2	29.06
Fayette	3	11,987	.96	.80	10.80	124.0	29.73
Washington	9	11,949	.87	.73	9.16	113.8	27.20
Westmoreland	19	12,342	.76	.62	10.72	120.9	29.85
West Virginia	3,464	12,263	.78	.64	11.08	130.5	32.00
Boone	13	11,875	.77	.65	12.10	115.6	27.45
Clay	48	12,208	.77	.63	12.86	112.9	27.55
Fayette	69	12,596	.73	.58	8.82	118.6	29.89
Kanawha	2,054	12,290	.76	.62	11.06	131.1	32.23
Lincoln	12	11,542	.81	.70	11.30	127.2	29.36
Logan	60	11,990	.82	.68	11.04	113.5	27.22
Mingo	821	12,190	.78	.64	10.72	137.3	33.46
Webster	387	12,301	.86	.70	12.09	120.4	29.61
Ohio Power Co Gavin	**5,805**	**11,416**	**3.02**	**2.65**	**11.58**	**160.3**	**36.60**
Kentucky	2	12,000	.72	.60	12.00	131.3	31.51
Knott	1	12,000	.72	.60	12.00	131.3	31.51
Magoffin	1	12,000	.72	.60	12.00	131.3	31.51
Perry	*	12,000	.72	.60	12.00	131.3	31.51
Ohio	5,804	11,416	3.02	2.65	11.58	160.3	36.60
Belmont	225	11,866	2.83	2.39	12.27	114.0	27.05
Gallia	305	11,112	2.99	2.69	11.85	109.6	24.36
Jackson	305	11,112	2.99	2.69	11.85	109.6	24.36
Meigs	4,656	11,454	3.04	2.65	11.50	172.4	39.48
Vinton	313	11,112	2.99	2.69	11.85	109.6	24.36
Ohio Power Co Kammer	**1,952**	**12,307**	**3.44**	**2.79**	**10.76**	**86.3**	**21.23**
West Virginia	1,952	12,307	3.44	2.79	10.76	86.3	21.23
Marshall	1,952	12,307	3.44	2.79	10.76	86.3	21.23
Ohio Power Co Mitchell	**3,257**	**12,310**	**.96**	**.78**	**12.88**	**141.9**	**34.95**
West Virginia	3,257	12,310	.96	.78	12.88	141.9	34.95
Boone	1,445	12,431	.75	.60	11.73	147.9	36.76
Clay	488	12,195	.74	.61	13.41	142.3	34.72
Kanawha	54	12,643	.72	.57	11.09	112.5	28.45
Logan	154	12,328	.66	.54	12.74	117.9	29.06
Marion	855	12,120	1.51	1.24	14.75	148.2	35.93
Monongalia	38	12,227	1.33	1.08	13.31	101.8	24.89
Webster	223	12,426	.85	.68	12.42	109.9	27.30
Ohio Power Co Muskingum	**2,229**	**12,010**	**2.56**	**2.13**	**11.54**	**182.3**	**43.80**
Ohio	1,064	11,722	4.57	3.90	11.59	239.3	56.10
Columbiana	12	12,336	1.11	.90	8.38	173.2	42.72
Gallia	3	10,920	.87	.80	8.75	186.0	40.63
Jackson	3	10,920	.87	.80	8.75	186.0	40.63
Jefferson	77	12,274	.68	.55	10.46	180.0	44.19
Muskingum	106	11,678	4.63	3.97	11.75	245.7	57.38
Noble	858	11,678	5.01	4.29	11.75	245.7	57.38
Vinton	3	10,919	.87	.80	8.75	186.0	40.62
Unknown[1]	1	12,463	1.11	.89	8.40	179.5	44.74
West Virginia	1,165	12,273	.72	.58	11.49	132.7	32.58
Boone	95	12,040	.78	.65	12.77	122.1	29.40
Logan	998	12,281	.70	.57	11.37	134.3	32.98
Webster	72	12,473	.88	.70	11.49	124.9	31.17
Ohio Valley Electric Corp Kyger Creek	**2,663**	**13,092**	**1.56**	**1.19**	**6.65**	**122.9**	**32.18**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ohio Valley Electric Corp Kyger Creek							
Kentucky	1,224	13,333	1.39	1.04	5.69	125.7	33.51
Floyd	238	13,203	1.39	1.05	6.36	124.9	32.97
Letcher	986	13,364	1.39	1.04	5.53	125.9	33.65
Ohio	132	11,294	3.71	3.29	11.94	86.8	19.60
Belmont	22	12,171	3.93	3.23	12.15	83.1	20.24
Jackson	110	11,118	3.67	3.30	11.89	87.6	19.47
Pennsylvania	977	13,047	1.49	1.14	6.96	122.2	31.88
Greene	977	13,047	1.49	1.14	6.96	122.2	31.88
West Virginia	330	13,049	1.54	1.18	7.18	127.0	33.15
Mingo	330	13,049	1.54	1.18	7.18	127.0	33.15
Owensboro City of Smith	**1,065**	**11,202**	**2.97**	**2.65**	**8.71**	**95.1**	**21.30**
Indiana	278	11,352	3.00	2.64	7.96	97.0	22.02
Warrick	278	11,352	3.00	2.64	7.96	97.0	22.02
Kentucky	787	11,149	2.95	2.65	8.98	94.4	21.05
Daviess	551	11,177	2.81	2.52	8.38	96.0	21.46
Ohio	236	11,082	3.28	2.96	10.38	90.7	20.10
Pennsylvania Electric Co Conemaugh	**4,123**	**12,502**	**2.25**	**1.80**	**13.40**	**114.1**	**28.53**
Pennsylvania	4,123	12,502	2.25	1.80	13.40	114.1	28.53
Armstrong	508	12,579	2.36	1.88	11.63	108.4	27.27
Cambria	144	12,770	2.18	1.70	11.15	112.8	28.81
Centre	18	12,355	2.44	1.98	15.10	116.3	28.72
Clearfield	42	12,480	2.31	1.85	14.41	106.2	26.51
Fayette	247	12,523	2.37	1.90	13.24	103.1	25.81
Indiana	375	12,400	2.14	1.72	13.70	110.7	27.46
Somerset	2,589	12,497	2.23	1.78	13.82	117.4	29.35
Westmoreland	200	12,361	2.37	1.92	13.23	107.9	26.68
Pennsylvania Electric Co Shawville	**1,530**	**12,279**	**1.82**	**1.48**	**13.30**	**113.3**	**27.82**
Pennsylvania	1,530	12,279	1.82	1.48	13.30	113.3	27.82
Cambria	84	12,238	1.65	1.35	12.18	117.1	28.67
Clearfield	1,401	12,285	1.83	1.49	13.37	113.2	27.80
Indiana	14	12,162	1.84	1.51	14.36	112.8	27.44
Somerset	16	12,201	1.68	1.38	11.99	110.6	26.98
Westmoreland	15	12,129	2.09	1.72	13.93	109.2	26.48
Pennsylvania Power & Light Co Brunner Island	**2,756**	**13,067**	**1.61**	**1.23**	**8.06**	**150.2**	**39.25**
Pennsylvania	2,747	13,070	1.61	1.23	8.05	150.1	39.23
Clarion	90	12,704	1.60	1.26	8.97	139.7	35.49
Greene	2,257	13,127	1.56	1.19	7.43	151.5	39.78
Indiana	351	12,786	2.00	1.56	11.57	145.3	37.17
Jefferson	49	13,166	1.16	.88	9.83	135.7	35.74
Utah	9	12,239	.50	.41	10.10	184.9	45.26
Carbon	9	12,239	.50	.41	10.10	184.9	45.26
Pennsylvania Power & Light Co Martins Creek	**288**	**13,055**	**1.59**	**1.21**	**8.71**	**146.9**	**38.37**
Pennsylvania	269	13,030	1.55	1.19	8.83	148.5	38.71
Clarion	21	12,776	1.65	1.29	8.83	143.3	36.61
Greene	147	13,106	1.58	1.21	7.72	155.2	40.68
Indiana	10	12,817	2.30	1.79	11.90	137.6	35.27
Jefferson	81	13,044	1.31	1.00	9.77	139.8	36.48
Somerset	10	12,557	2.04	1.62	14.50	142.1	35.69
West Virginia	19	13,412	2.13	1.59	7.00	124.8	33.48
Monongalia	19	13,412	2.13	1.59	7.00	124.8	33.48
Pennsylvania Power & Light Co Sunbury	**1,205**	**9,729**	**1.02**	**1.05**	**26.15**	**124.9**	**24.31**
Pennsylvania	1,205	9,729	1.02	1.05	26.15	124.9	24.31
Butler	2	9,305	1.16	1.25	27.90	96.7	18.00
Centre	31	12,321	1.17	.95	15.08	130.8	32.24
Clarion	26	12,676	1.60	1.26	9.47	135.7	34.41
Clearfield	363	12,263	1.55	1.27	14.76	142.8	35.03
Fulton	3	12,306	1.54	1.25	14.27	136.4	33.58
Indiana	2	12,522	1.82	1.45	13.50	139.0	34.81
Jefferson	25	12,784	1.61	1.26	11.08	136.1	34.80
Lycoming	12	12,303	.89	.72	16.57	134.8	33.17
Northumberland	79	7,738	.74	.95	33.48	71.2	11.02
Schuylkill	384	7,253	.50	.69	38.01	95.6	13.86

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Pennsylvania Power & Light Co Sunbury							
Pennsylvania							
Somerset	19	12,641	1.77	1.40	13.92	137.6	34.79
Unknown[1]	259	9,172	.93	1.02	28.32	133.8	24.54
Potomac Electric Power Co Chalk	**1,353**	**13,206**	**1.36**	**1.03**	**9.20**	**153.7**	**40.60**
Maryland	244	13,210	1.46	1.11	9.60	162.3	42.88
Garrett	244	13,210	1.46	1.11	9.60	162.3	42.88
Pennsylvania	872	13,190	1.34	1.02	9.24	149.5	39.45
Cambria	186	12,860	1.35	1.05	9.18	147.6	37.95
Clearfield	344	13,285	1.51	1.14	8.94	149.4	39.69
Somerset	342	13,273	1.17	.88	9.56	150.8	40.02
West Virginia	237	13,261	1.34	1.01	8.67	160.2	42.48
Barbour	28	14,210	.98	.69	6.65	151.8	43.15
Grant	150	13,139	1.38	1.05	9.21	158.0	41.51
Preston	59	13,122	1.41	1.07	8.27	170.0	44.62
Potomac Electric Power Co Morgantown	**2,250**	**13,169**	**1.39**	**1.06**	**9.35**	**158.7**	**41.79**
Maryland	776	13,247	1.49	1.12	9.57	161.5	42.78
Garrett	776	13,247	1.49	1.12	9.57	161.5	42.78
Pennsylvania	694	13,084	1.34	1.02	9.77	152.6	39.93
Cambria	154	13,022	1.33	1.02	9.21	147.8	38.50
Clearfield	235	12,893	1.52	1.18	10.39	157.2	40.54
Jefferson	16	12,925	1.49	1.16	9.75	147.9	38.22
Somerset	289	13,282	1.19	.90	9.55	151.7	40.30
West Virginia	780	13,166	1.35	1.02	8.75	161.2	42.45
Barbour	105	13,242	1.16	.88	7.59	163.2	43.22
Grant	477	13,134	1.35	1.03	9.25	157.8	41.44
Preston	198	13,205	1.45	1.10	8.17	168.3	44.46
Public Service Co of IN Inc Cayuga	**2,514**	**10,978**	**1.56**	**1.42**	**9.56**	**129.0**	**28.32**
Indiana	2,514	10,978	1.56	1.42	9.56	129.0	28.32
Greene	10	11,153	1.33	1.19	8.80	127.6	28.46
Sullivan	2,504	10,978	1.56	1.42	9.57	129.0	28.32
Public Service Co of IN Inc Gallagher	**1,126**	**12,405**	**1.86**	**1.50**	**7.80**	**111.9**	**27.75**
Illinois	445	11,913	1.43	1.20	7.05	123.4	29.41
Jefferson	120	11,698	1.62	1.38	7.42	119.6	27.99
Saline	325	11,993	1.36	1.14	6.91	124.8	29.93
Indiana	133	11,064	1.31	1.18	9.65	116.2	25.72
Clay	6	11,210	1.05	.94	7.80	114.6	25.69
Dubois	114	11,100	1.24	1.12	9.69	119.0	26.42
Pike	2	12,132	2.40	1.98	8.00	101.5	24.63
Spencer	11	10,431	2.00	1.92	10.50	88.6	18.48
Pennsylvania	547	13,131	2.35	1.79	7.97	102.4	26.90
Greene	538	13,128	2.37	1.80	8.01	102.6	26.95
Washington	9	13,299	1.21	.91	5.60	89.3	23.75
Public Service Co of IN Inc Gibson Station	**7,517**	**10,951**	**2.22**	**2.03**	**9.42**	**143.9**	**31.52**
Illinois	7,108	10,937	2.26	2.07	9.47	145.0	31.72
Clinton	3,002	10,868	3.30	3.03	7.92	142.9	31.07
Wabash	4,106	10,988	1.50	1.37	10.61	146.6	32.21
Indiana	409	11,198	1.53	1.37	8.58	125.1	28.01
Clay	26	10,977	.78	.71	8.81	124.8	27.40
Daviess	111	11,873	.63	.53	5.51	124.1	29.46
Knox	271	10,943	1.97	1.80	9.82	125.5	27.47
Public Service Co of IN Inc Wabash River	**1,156**	**11,126**	**1.58**	**1.42**	**8.50**	**118.8**	**26.43**
Indiana	1,156	11,126	1.58	1.42	8.50	118.8	26.43
Clay	50	11,075	1.28	1.16	8.83	123.8	27.43
Daviess	16	11,335	1.55	1.37	7.50	119.1	27.00
Greene	794	11,240	1.64	1.46	8.05	121.3	27.27
Owen	58	11,106	1.38	1.25	8.63	124.9	27.74
Sullivan	239	10,747	1.48	1.38	9.95	107.2	23.05
Public Service Co of NH Merrimack	**1,013**	**13,234**	**1.64**	**1.24**	**6.73**	**157.9**	**41.80**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Public Service Co of NH Merrimack							
Pennsylvania	759	13,203	1.49	1.12	6.90	161.1	42.53
Greene	750	13,202	1.49	1.13	6.91	161.1	42.53
Westmoreland	9	13,345	1.44	1.08	6.20	159.8	42.65
Virginia	19	13,910	.68	.49	7.00	203.5	56.61
Buchanan	19	13,910	.68	.49	7.00	203.5	56.61
West Virginia	223	13,366	2.29	1.72	6.28	141.7	37.89
Monongalia	223	13,366	2.29	1.72	6.28	141.7	37.89
Imported	12	11,578	.53	.46	3.80	192.9	44.67
Imported Coal	12	11,578	.53	.46	3.80	192.9	44.67
Southern Indiana Gas & Elec Co Culley	**1,007**	**11,265**	**3.10**	**2.75**	**9.50**	**114.3**	**25.76**
Indiana	1,000	11,262	3.11	2.76	9.53	114.1	25.71
Dubois	106	11,022	1.83	1.66	10.21	132.4	29.19
Gibson	130	11,390	3.22	2.83	9.27	120.2	27.38
Knox	10	10,979	1.33	1.21	8.90	146.5	32.17
Warrick	753	11,278	3.30	2.92	9.48	110.1	24.84
Kentucky	8	11,581	1.76	1.52	6.21	141.6	32.81
Daviess	2	11,024	3.50	3.17	10.20	119.8	26.41
Ohio	6	11,719	1.33	1.13	5.22	146.7	34.38
Southern Indiana Gas & Elec Co Warrick	**439**	**11,276**	**2.82**	**2.50**	**8.46**	**104.3**	**23.52**
Indiana	439	11,276	2.82	2.50	8.46	104.3	23.52
Daviess	14	11,451	2.24	1.96	9.10	102.0	23.36
Dubois	9	11,193	2.73	2.44	9.70	96.7	21.65
Gibson	265	11,441	2.78	2.43	8.07	103.3	23.64
Warrick	150	10,972	2.97	2.71	9.02	106.8	23.44
Springfield City of (MO) James River	**351**	**11,786**	**.54**	**.46**	**8.31**	**150.3**	**35.42**
Illinois	18	11,658	2.56	2.20	8.53	138.6	32.33
Franklin	18	11,658	2.56	2.20	8.53	138.6	32.33
Utah	333	11,793	.43	.37	8.30	150.9	35.58
Carbon	333	11,793	.43	.37	8.30	150.9	35.58
Tampa Electric Co Davant Transfer[2]	**5,388**	**11,713**	**1.95**	**1.66**	**7.76**	**162.5**	**38.06**
Colorado	811	12,745	.43	.34	9.84	184.3	46.99
Las Animas	811	12,745	.43	.34	9.84	184.3	46.99
Illinois	2,371	11,536	2.26	1.96	8.27	170.5	39.33
Gallatin	28	12,703	2.71	2.13	8.85	142.9	36.30
Perry	1,132	11,002	3.03	2.75	9.44	195.1	42.94
Randolph	119	10,995	3.06	2.78	9.56	135.9	29.88
Saline	1,092	12,120	1.36	1.12	6.89	151.4	36.70
Kentucky	1,737	11,818	2.62	2.22	7.35	139.0	32.86
Henderson	388	11,249	2.48	2.21	8.26	130.0	29.26
Knox	2	12,541	.90	.72	10.50	166.6	41.79
Ohio	335	11,407	2.69	2.36	8.89	122.0	27.83
Union	783	12,028	2.79	2.32	6.18	135.7	32.65
Webster	146	12,704	2.82	2.22	7.44	160.9	40.88
Whitley	84	12,572	1.09	.87	7.73	227.8	57.28
Tennessee	120	12,565	1.12	.89	8.66	229.2	57.59
Campbell	120	12,565	1.12	.89	8.66	229.2	57.59
Imported	349	9,696	.31	.32	1.16	143.8	27.88
Imported Coal	349	9,696	.31	.32	1.16	143.8	27.88
Tennessee Valley Authority Allen	**873**	**12,040**	**1.98**	**1.64**	**8.42**	**116.9**	**28.15**
Illinois	338	11,913	1.81	1.52	8.47	112.9	26.91
Jefferson	166	11,746	1.79	1.52	7.69	112.5	26.44
Saline	173	12,074	1.83	1.51	9.22	113.3	27.36
Kentucky	459	12,207	2.13	1.75	8.54	120.5	29.43
Hopkins	245	11,906	2.03	1.71	8.15	119.8	28.52
Union	13	12,200	2.37	1.94	12.00	117.8	28.75
Webster	201	12,574	2.24	1.78	8.80	121.6	30.58
West Virginia	76	11,600	1.80	1.55	7.50	111.9	25.96
Monongalia	76	11,600	1.80	1.55	7.50	111.9	25.96
Tennessee Valley Authority Colbert	**2,746**	**12,000**	**1.23**	**1.02**	**11.04**	**118.9**	**28.53**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tennessee Valley Authority Colbert							
Colorado	10	11,013	0.37	0.34	8.79	126.9	27.95
Delta	10	11,013	.37	.34	8.79	126.9	27.95
Illinois	660	11,658	1.74	1.49	8.26	107.0	24.95
Franklin	49	11,500	2.24	1.95	8.46	118.0	27.15
Jefferson	516	11,576	1.68	1.45	8.13	106.5	24.65
Saline	94	12,193	1.80	1.48	8.89	104.4	25.45
Kentucky	904	12,003	1.27	1.05	10.74	119.2	28.62
Daviess	3	11,300	1.15	1.02	9.54	116.0	26.22
Floyd	323	11,883	.86	.72	11.04	119.2	28.33
Harlan	25	12,182	.62	.51	11.72	129.7	31.59
Johnson	161	11,903	1.14	.96	10.76	127.1	30.27
Knox	17	11,832	.82	.69	11.80	113.0	26.74
Martin	3	11,331	.71	.63	11.96	132.2	29.95
Perry	7	12,307	.78	.63	9.96	115.1	28.32
Pike	54	11,881	1.04	.88	11.17	115.6	27.46
Webster	310	12,204	1.89	1.55	10.21	115.4	28.16
Pennsylvania	38	13,259	1.63	1.23	7.02	120.6	31.98
Greene	38	13,259	1.63	1.23	7.02	120.6	31.98
Tennessee	114	12,356	.88	.71	12.71	135.4	33.45
Sequatchie	114	12,356	.88	.71	12.71	135.4	33.45
West Virginia	1,020	12,141	.89	.74	13.09	123.9	30.08
Boone	33	11,999	1.00	.83	12.97	111.7	26.81
Kanawha	966	12,151	.88	.73	13.10	124.5	30.25
Mcdowell	19	11,842	1.03	.87	13.29	114.3	27.08
Monongalia	2	12,725	2.34	1.84	8.77	113.6	28.90
Tennessee Valley Authority Cumberland	**8,619**	**11,637**	**2.83**	**2.43**	**8.97**	**102.4**	**23.84**
Illinois	1,639	11,620	2.63	2.27	9.08	93.2	21.66
Franklin	1,128	11,346	2.59	2.29	9.09	93.3	21.18
Gallatin	199	12,722	2.76	2.17	8.90	96.7	24.60
Randolph	152	11,621	2.52	2.17	8.48	82.8	19.25
Saline	159	12,182	2.89	2.37	9.76	97.1	23.67
Kentucky	6,416	11,513	2.91	2.53	9.03	104.3	24.02
Christian	81	11,057	2.79	2.53	9.93	102.0	22.55
Henderson	9	11,190	2.57	2.30	8.40	94.5	21.15
Hopkins	280	11,936	2.55	2.13	8.46	108.7	25.94
Ohio	257	11,439	3.27	2.85	9.09	85.7	19.60
Union	5,371	11,435	2.89	2.53	9.08	104.2	23.84
Webster	419	12,371	3.26	2.64	8.48	113.9	28.18
Pennsylvania	543	13,136	2.43	1.85	7.86	107.0	28.12
Greene	543	13,136	2.43	1.85	7.86	107.0	28.12
West Virginia	21	12,200	4.00	3.28	11.00	103.3	25.20
Monongalia	21	12,200	4.00	3.28	11.00	103.3	25.20
Tennessee Valley Authority Gallatin	**2,322**	**12,264**	**2.04**	**1.67**	**9.50**	**122.7**	**30.09**
Colorado	23	11,600	.70	.60	9.75	141.6	32.86
Gunnison	23	11,600	.70	.60	9.75	141.6	32.86
Illinois	119	11,565	2.37	2.05	9.75	132.5	30.65
Jefferson	18	11,519	1.66	1.44	7.33	136.0	31.34
Saline	101	11,573	2.50	2.16	10.18	131.9	30.53
Indiana	9	10,949	1.55	1.42	8.14	115.2	25.23
Sullivan	9	10,949	1.55	1.42	8.14	115.2	25.23
Kentucky	2,172	12,314	2.04	1.66	9.49	122.0	30.05
Hopkins	425	12,073	2.57	2.12	7.81	108.8	26.28
Perry	17	12,194	1.44	1.18	10.02	132.6	32.34
Union	268	12,282	2.16	1.76	11.03	129.6	31.84
Webster	1,462	12,391	1.88	1.51	9.69	124.2	30.79
Tennessee Valley Authority Johnsonville	**2,901**	**11,936**	**1.77**	**1.49**	**9.16**	**119.7**	**28.58**
Illinois	1,853	11,728	1.78	1.52	8.75	123.4	28.95
Franklin	1,219	11,639	1.79	1.54	9.20	131.3	30.56
Jefferson	275	11,700	1.68	1.44	7.50	109.5	25.62
Saline	359	12,052	1.81	1.51	8.21	108.1	26.05
Kentucky	919	12,252	1.78	1.46	9.93	112.5	27.57
Webster	919	12,252	1.78	1.46	9.93	112.5	27.57

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tennessee Valley Authority Johnsonville							
Pennsylvania	73	13,040	1.59	1.22	7.33	121.5	31.68
Greene	73	13,040	1.59	1.22	7.33	121.5	31.68
West Virginia	56	12,211	1.58	1.29	12.62	118.3	28.88
Monongalia	56	12,211	1.58	1.29	12.62	118.3	28.88
Tennessee Valley Authority Paradise	**7,095**	**10,677**	**4.35**	**4.07**	**17.90**	**92.7**	**19.81**
Illinois	22	11,649	2.83	2.43	8.80	112.5	26.20
White	22	11,649	2.83	2.43	8.80	112.5	26.20
Kentucky	7,073	10,674	4.35	4.08	17.93	92.7	19.79
Christian	1,419	10,479	4.56	4.35	16.11	85.4	17.90
Henderson	225	11,231	2.64	2.35	8.59	91.4	20.54
Hopkins	1,165	10,840	3.96	3.65	18.10	88.8	19.24
Muhlenberg	2,263	10,317	4.64	4.50	20.60	95.4	19.69
Ohio	587	11,366	3.58	3.15	10.84	80.2	18.23
Union	275	10,252	3.94	3.84	18.86	89.7	18.38
Webster	1,137	11,091	4.77	4.30	19.99	107.7	23.88
Tennessee Valley Authority Shawnee	**3,821**	**11,861**	**.84**	**.71**	**10.83**	**121.4**	**28.79**
Colorado	1,781	11,536	.49	.42	9.42	121.4	28.02
Delta	30	11,336	.50	.44	8.01	98.3	22.28
Gunnison	1,018	11,804	.49	.41	8.53	123.3	29.11
Routt	734	11,174	.48	.43	10.72	119.6	26.73
Illinois	11	10,700	3.65	3.41	8.50	91.9	19.67
Macoupin	11	10,700	3.65	3.41	8.50	91.9	19.67
Kentucky	1,518	12,009	1.30	1.08	12.30	118.9	28.56
Floyd	38	11,776	.69	.59	12.69	122.7	28.91
Harlan	1,009	12,143	.67	.55	13.04	122.3	29.71
Hopkins	422	11,653	2.92	2.50	10.82	107.9	25.14
Martin	3	12,000	.72	.60	13.50	118.8	28.50
Pike	45	12,542	.63	.50	9.24	137.9	34.59
Utah	12	12,395	.65	.52	9.98	144.0	35.71
Carbon	12	12,395	.65	.52	9.98	144.0	35.71
West Virginia	499	12,581	.66	.52	11.42	128.4	32.31
Boone	499	12,581	.66	.52	11.42	128.4	32.31
Union Electric Co Labadie	**6,951**	**9,591**	**.92**	**.96**	**6.65**	**110.6**	**21.22**
Colorado	395	11,750	.47	.40	9.60	160.2	37.65
Gunnison	395	11,750	.47	.40	9.60	160.2	37.65
Illinois	1,937	11,280	2.61	2.31	10.61	134.6	30.36
Jefferson	519	11,500	1.27	1.10	12.00	142.1	32.67
Perry	1,418	11,200	3.10	2.77	10.10	131.7	29.51
Wyoming	4,619	8,698	.24	.28	4.73	91.8	15.98
Campbell	4,619	8,698	.24	.28	4.73	91.8	15.98
Union Electric Co Sioux	**2,108**	**9,119**	**1.13**	**1.24**	**6.62**	**108.1**	**19.71**
Illinois	583	11,209	3.07	2.74	10.05	144.9	32.48
Perry	573	11,200	3.10	2.77	10.10	144.9	32.45
Saline	10	11,700	1.28	1.09	7.10	147.2	34.44
Wyoming	1,525	8,320	.38	.46	5.31	89.1	14.83
Campbell	1,525	8,320	.38	.46	5.31	89.1	14.83
Virginia Electric & Power Co Mount Storm	**4,230**	**12,341**	**1.68**	**1.36**	**14.45**	**126.8**	**31.31**
Maryland	1,573	12,563	1.60	1.28	13.51	123.2	30.95
Allegany	79	11,904	1.66	1.40	16.89	110.2	26.24
Garrett	1,494	12,598	1.60	1.27	13.33	123.8	31.20
Pennsylvania	32	11,683	1.55	1.33	16.46	108.0	25.24
Somerset	32	11,683	1.55	1.33	16.46	108.0	25.24
West Virginia	2,625	12,216	1.73	1.41	14.99	129.3	31.59
Barbour	123	11,770	1.75	1.49	17.98	110.4	25.98
Grant	2,426	12,251	1.73	1.41	14.83	130.7	32.03
Mineral	53	11,811	1.66	1.40	14.76	114.1	26.94
Randolph	4	11,782	1.86	1.58	13.37	100.0	23.56
Upshur	19	11,952	1.49	1.25	16.56	110.4	26.39
West Penn Power Co Armstrong	**551**	**12,598**	**1.68**	**1.33**	**10.70**	**129.5**	**32.63**

See footnotes at end of table.

Table B2. Profile of Coal Received at Table 1 Plants, 1995 (Continued)

Electric Utility Plant Origin State County	Receipts (thousand short tons)	Average Quality				Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Sulfur (pounds per MM Btu)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
West Penn Power Co Armstrong							
Pennsylvania	551	12,598	1.68	1.33	10.70	129.5	32.63
Armstrong	72	12,278	1.94	1.58	11.68	99.9	24.54
Butler	29	12,110	1.97	1.63	12.37	99.1	24.01
Jefferson	450	12,681	1.62	1.28	10.43	136.0	34.49
West Penn Power Co Hatfield	**3,361**	**13,013**	**2.31**	**1.77**	**8.86**	**130.9**	**34.06**
Pennsylvania	485	13,021	2.30	1.76	8.77	130.7	34.03
Greene	485	13,021	2.30	1.76	8.77	130.7	34.03
West Virginia	2,877	13,012	2.31	1.77	8.87	130.9	34.07
Marion	14	13,149	2.25	1.71	7.80	123.8	32.56
Monongalia	2,862	13,011	2.31	1.77	8.88	130.9	34.07
Wisconsin Electric Power Co Oak Creek	**2,091**	**12,289**	**.60**	**.49**	**11.21**	**150.8**	**37.08**
Illinois	258	12,227	.88	.72	7.49	126.2	30.87
Jefferson	258	12,227	.88	.72	7.49	126.2	30.87
New Mexico	1,578	12,372	.50	.41	12.53	158.1	39.13
Colfax	1,578	12,372	.50	.41	12.53	158.1	39.13
Pennsylvania	124	13,146	1.54	1.17	6.70	133.0	34.98
Greene	124	13,146	1.54	1.17	6.70	133.0	34.98
West Virginia	57	12,908	.66	.51	9.39	152.7	39.42
Mingo	57	12,908	.66	.51	9.39	152.7	39.42
Wyoming	73	8,809	.18	.20	4.92	93.9	16.54
Campbell	73	8,809	.18	.20	4.92	93.9	16.54
Wisconsin Power & Light Co Edgewater	**2,633**	**8,831**	**.34**	**.38**	**5.57**	**122.8**	**21.70**
Illinois	108	12,127	1.00	.83	5.74	157.9	38.29
Jefferson	108	12,127	1.00	.83	5.74	157.9	38.29
Utah	72	12,585	.55	.44	8.02	154.4	38.87
Emery	72	12,585	.55	.44	8.02	154.4	38.87
Wyoming	2,452	8,576	.30	.35	5.49	119.3	20.46
Big Horn	111	10,398	.49	.47	6.63	144.8	30.12
Campbell	2,342	8,490	.29	.34	5.43	117.8	20.00
Wisconsin Power & Light Co Nelson Dewey	**588**	**9,472**	**.37**	**.39**	**4.33**	**119.3**	**22.61**
Illinois	30	12,126	.95	.79	5.09	140.0	33.96
Jefferson	30	12,126	.95	.79	5.09	140.0	33.96
Montana	499	9,394	.34	.36	4.14	118.3	22.23
Big Horn	499	9,394	.34	.36	4.14	118.3	22.23
Wyoming	59	8,763	.33	.37	5.51	113.9	19.96
Converse	59	8,763	.33	.37	5.51	113.9	19.96
Wisconsin Public Service Corp Pulliam	**1,171**	**8,834**	**.21**	**.24**	**4.54**	**115.3**	**20.36**
Wyoming	1,171	8,834	.21	.24	4.54	115.3	20.36
Campbell	1,171	8,834	.21	.24	4.54	115.3	20.36
Total	**226,244**	**11,406**	**1.62**	**1.42**	**9.39**	**129.3**	**29.49**

1 Refers to coal in which the county of origin in not known.

2 The Tampa Electric Company reports coal destined for the Big Bend power plant as it is received at this facility located in Louisiana. The cost reported under Davant Transfer is the weighted average cost of coal delivered to this facility. The Tampa Electric Company incurs additional costs for transporting coal from Davant to the Big Bend power plant located in Florida.

* = Number less than 0.5 thousand short tons.

Notes: • Plants affected by Phase 1 but not shown in this table include the following: Edgewater (Ohio Edison) is using natural gas. Northport and Port Jefferson (Long Island Lighting) use petroleum. Des Moines (Midwest Power) is out of service. Breed (Indiana Michigan Power) is retired. • Totals may not equal sum of components because of independent rounding. • Data are for electric generating plants with a total steam-electric and combined-cycle nameplate capacity of 50 or more megawatts.

Source: Federal Energy Regulatory Commission, FERC Form 423, ''Monthly Report of Cost and Quality of Fuels for Electric Plants.''

Appendix C

Costs and Characteristics of Selected Phase I Units, by Utility

Appendix C

Costs and Characteristics of Selected Phase I Units, by Utility

This appendix presents detailed information pertaining to the compliance activities of the six utilities discussed in Chapter 2. These utilities were selected to obtain a representative sample of generating capacities, sulfur dioxide (SO_2) emissions, locations, and initial compliance strategies. Also, the willingness to participate and share information was essential. The six utilities are Cincinnati Gas and Electric Company, Georgia Power Company, Illinois Power Company, Potomac Electric Power Company, Pennsylvania Power and Light Company, and Southern Indiana Gas and Electric Company.

Information on allowance allocations and sulfur dioxide (SO_2) emissions, compliance strategies and compliance costs is provided for each unit. Cost information covers SO_2, nitrogen oxides (NO_x), and Continuous Emission Monitoring System (CEMS) components. Capital costs and operations and maintenance costs are also provided.

A detailed analysis of compliance strategies and preliminary compliance costs for these six utilities was presented in a previous report.[108] This report updates the earlier analysis by (1) taking into consideration substitution units, (2) finalizing cost data, and (3) accounting for changes in compliance strategies.

Each utility was asked to update its compliance strategies and costs for all units affected by Phase I and to provide similar information on Phase II units. Definitive plans for Phase II have not been developed. Further, because of increased competition in the electric industry, some utilities are reluctant to share detailed information.

[108] Energy Information Administration, *Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990,* DOE/EIA-0582 (Washington, DC, March 1994).

Table C1. Characteristics of Selected Phase I Units, by Utility

Type of Unit	Unit	Plant	State	Year Online	Affected Utility Owned Nameplate Capacity (MW)	1995 Allocation of SO_2 Allowances	Allowances Deducted for Emissions (tons)	Difference Between Total and 1995 Emissions Deductions	Allowances[a] Carried Over to 1996	1995 SO_2 Compliance Strategy
Cincinnati Gas & Electric Company										
Table 1	5	Miami Fort	OH	1949	100	834	263	571	571	Fuel Switch
Table 1	6	Miami Fort	OH	1960	163	12,475	3,930	8,545	8,545	Fuel Switch
Table 1	7	Miami Fort *	OH	1975	320	27,018	13,633	13,385	6,609	Fuel Switch
Table 1	5	Beckjord	OH	1962	238	9,822	8,347	1,475	4,525	Fuel Switch
Table 1	6	Beckjord *	OH	1969	158	9,463	6,555	2,908	3,213	Fuel Switch
Table 1	4	Conesville *	OH	1973	312	21,385	25,176	(3,791)	8,498	Allowances
Substitution	2	East Bend*	KY	1981	414	12,038	7,851	4,187	3,425	Scrubber
Substitution	1	J. M. Stuart*	OH	1971	238	16,064	8,916	7,148	7,109	Fuel Switch
Substitution	2	J. M. Stuart*	OH	1970	238	15,226	12,442	2,784	2,784	Fuel Switch
Substitution	3	J. M. Stuart*	OH	1972	238	15,098	9,763	5,335	5,334	Fuel Switch
Substitution	4	J. M. Stuart*	OH	1974	238	15,961	10,858	5,103	5,103	Fuel Switch
Total for Utility . .					**2,657**	**155,384**	**107,734**	**47,650**	**55,716**	
Georgia Power Company										
Table 1	1	Bowen	GA	1971	806	54,838	32,617	22,221	4,217	Fuel Switch
Table 1	2	Bowen	GA	1972	789	53,329	39,641	13,688	5,684	Fuel Switch
Table 1	3	Bowen	GA	1974	952	69,862	42,137	27,725	10,221	Fuel Switch
Table 1	4	Bowen	GA	1975	952	69,852	46,258	23,594	6,090	Fuel Switch
Table 1	1	Hammond	GA	1954	125	8,549	2,466	6,083	6,083	Fuel Switch
Table 1	2	Hammond	GA	1954	125	8,977	2,466	6,511	6,511	Fuel Switch
Table 1	3	Hammond	GA	1955	125	8,676	2,466	6,210	6,210	Fuel Switch
Table 1	4	Hammond	GA	1970	578	36,650	14,297	22,353	14,353	Fuel Switch
Table 1	1	McDonough	GA	1963	299	33,290	9,793	23,497	11,285	Fuel Switch
Table 1	2	McDonough	GA	1964	299	20,058	9,793	10,265	10,265	Fuel Switch
Table 1	1	Wansley *	GA	1976	509	36,866	14,336	22,530	8,817	Fuel Switch
Table 1	2	Wansley *	GA	1978	509	60,884	14,447	46,437	9,313	Fuel Switch
Table 1	1	Yates	GA	1950	123	7,863	118	7,745	7,659	Scrubber
Table 1	2	Yates	GA	1950	123	6,855	2,027	4,828	4,828	Fuel Switch
Table 1	3	Yates	GA	1952	123	6,767	2,027	4,740	4,740	Fuel Switch
Table 1	4	Yates	GA	1957	156	8,676	1,939	6,737	6,737	Fuel Switch
Table 1	5	Yates	GA	1958	156	9,162	1,940	7,222	7,222	Fuel Switch
Table 1	6	Yates	GA	1974	404	28,726	6,535	22,191	13,718	Fuel Switch
Table 1	7	Yates	GA	1974	404	22,318	5,683	16,635	8,491	Fuel Switch
Table 1	1	Gaston *	AL	1960	136	8,812	4,009	4,803	4,804	Fuel Switch
Table 1	2	Gaston *	AL	1960	136	9,026	3,758	5,268	5,269	Fuel Switch
Table 1	3	Gaston *	AL	1961	136	8,914	4,893	4,021	4,022	Fuel Switch
Table 1	ST4	Gaston *	AL	1962	122	9,387	3,626	5,761	5,761	Fuel Switch
Substitution	ST1	Arkwright	GA	1941	46	2,437	784	1,653	1,653	Fuel Switch
Substitution	ST2	Arkwright	GA	1942	46	2,240	783	1,457	1,457	Fuel Switch
Substitution	3	Arkwright	GA	1943	40	3,944	783	3,161	3,161	Fuel Switch
Substitution	4	Arkwright	GA	1948	49	3,159	784	2,375	2,375	Fuel Switch
Substitution	1	Harlee Branch	GA	1965	299	19,221	13,715	5,506	5,506	Fuel Switch
Substitution	2	Harlee Branch	GA	1967	359	22,735	13,715	9,020	9,020	Fuel Switch
Substitution	3	Harlee Branch	GA	1968	544	31,280	27,014	4,266	4,266	Fuel Switch
Substitution	4	Harlee Branch	GA	1969	544	31,042	27,015	4,027	4,027	Fuel Switch
Substitution	3	Mitchell	GA	1964	163	10,792	3,570	7,222	7,222	Fuel Switch
Substitution	3	Scherer*	GA	1986	75	0	17,151	(17,151)	849	Fuel Switch
Total for Utility . .					**10,252**	**715,187**	**372,586**	**342,601**	**211,835**	

See notes at end of table.

Table C1. Characteristics of Selected Phase I Units, by Utility (Continued)

Type of Unit	Unit	Plant	State	Year Online	Affected Utility Owned Nameplate Capacity (MW)	1995 Allocation of SO_2 Allowances	Allowances Deducted for Emissions (tons)	Difference Between Total and 1995 Emissions Deductions	Allowances[a] Carried Over to 1996	1995 SO_2 Compliance Strategy
Illinois Power Company[b]										
Table 1	1	Baldwin	IL	1970	623	46,052	75,044	(28,992)	303	Allowances
Table 1	2	Baldwin	IL	1973	635	48,695	104,172	(55,477)	35	Allowances
Table 1	3	Baldwin	IL	1975	635	46,644	86,789	(40,145)	24	Allowances
Table 1	2	Hennepin	IL	1959	231	20,182	27,560	(7,378)	122	Allowances
Table 1	1&2	Vermilion(c)	IL	1956	183	22,707	2,623	20,084	134	Burn Nat. Gas
Substitution	1-5	Havana	IL	1947	230	281	0	281	0	Shutdown
Substitution	1&4	Wood River	IL	1954	163	2,018	1,316	702	27	Allowances
Total for Utility . .					**2,699**	**186,579**	**297,504**	**(110,925)**	**645**	
Potomac Electric Power Company										
Table 1	ST1	Chalk Point	MD	1964	364	25,403	20,543	4,860	3,700	Fuel Switch
Table 1	ST2	Chalk Point	MD	1965	364	23,690	20,544	3,146	6,756	Fuel Switch
Table 1	ST1	Morgantown	MD	1970	626	39,864	28,040	11,824	7,257	Fuel Switch
Table 1	ST2	Morgantown	MD	1971	626	45,592	38,515	(7,077)	10,017	Fuel Switch
Table 1	1	Conemaugh *	PA	1970	91	9,389	460	8,929	106	Scrubber
Table 1	2	Conemaugh *	PA	1971	91	8,335	7,131	1,204	1,859	Scrubber
Substitution	3	Chalk Point	MD	1975	659	9,000	3,010	5,990	5,990	Burn Oil
Substitution	4	Chalk Point	MD	1981	659	1,519	1,354	165	373	Burn Oil
Total for Utility . .					**3,480**	**162,792**	**119,597**	**43,195**	**36,057**	
Pennsylvania Power & Light Company										
Table 1	1	Brunner Island	PA	1961	363	27,030	20,530	6,500	6,500	Fuel Switch
Table 1	2	Brunner Island	PA	1965	405	31,995	20,531	11,464	9,751	Fuel Switch
Table 1	3	Brunner Island	PA	1968	790	60,571	56,335	4,236	10,713	Fuel Switch
Table 1	1	Martins Creek	PA	1954	156	12,327	5,381	6,946	6,946	Fuel Switch
Table 1	2	Martins Creek	PA	1956	156	12,483	5,381	7,102	7,102	Fuel Switch
Table 1	3	Sunbury	PA	1951	104	9,133	9,847	(714)	2,797	Fuel Switch
Table 1	4	Sunbury	PA	1953	156	11,392	9,511	1,881	1,638	Fuel Switch
Table 1	1	Conemaugh *	PA	1970	107	11,002	539	10,463	124	Scrubber
Table 1	2	Conemaugh *	PA	1971	107	9,767	8,356	1,411	2,178	Scrubber
Total forUutility . .					**2,343**	**185,700**	**136,411**	**49,289**	**47,749**	
Southern Indiana Gas & Electric Company										
Table 1	2	Culley	IN	1966	104	4,703	2,549	2,154	2,154	Scrubber
Table 1	3	Culley	IN	1973	265	18,603	0	18,603	2,003	Scrubber
Table 1	4	Warrick *	IN	1970	162	14,789	18,841	(4,052)	1,235	Allowances
Total for Utility . .					**530**	**38,095**	**21,390**	**16,705**	**5,392**	

[a] Allowances carried over to 1996 may not equal the differences between allocated and 1995 emissions (e.g., Cincinnati Gas and Electric) due to purchases or sales of additional allowances. The data in this table do not account for purchases and sale transactions of the utility.

[b]Illinois Power purchased enough emission allowances to cover its 1995 emissions.

[c]Vermillion 1 is a substitution unit.

SO_2 = Sulfur dioxide.

MW = Megawatt.

* = Plant jointly owned by more than one utility.

Sources: Personal contact with Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas and Electric; Environmental Protection Agency, "1995 Compliance Results Acid Rain Program," EPA/430-R-96-012 (Washington, DC, July 1996).

Table C2. Cost of Phase I Compliance for Selected Units, by Utility

Type of Unit	Unit	Plant	Number[a] of Low-NOx Burners	Number[a] of CEMs	Number[a] of Scrubbers	SO_2 Control Capital Cost	SO_2 Control O&M Cost	NOx Control Capital Cost	CEMS Capital Cost	CEMS O&M Cost	Total Capital Cost	Annual O&M Cost	Average Capital Cost (dollars/KW affected)
						million dollars							
Cincinnati Gas & Electric Company													
Table 1	5	Miami Fort	0.0	0.5	0.0	0.00	0.00	0.00	0.59	c	0.59	0.00	5.90
Table 1	6	Miami Fort	0.0	0.5	0.0	2.24	c	0.00	0.62	c	2.86	0.00	17.51
Table 1	7	Miami Fort *	0.0	0.6	0.0	4.89	c	0.00	0.52	c	5.41	0.00	16.90
Table 1	5	Beckjord	1.0	1.0	0.0	5.28	c	5.00	0.90	c	11.17	0.00	46.94
Table 1	6	Beckjord *	0.4	0.4	0.0	0.00	0.00	1.90	0.29	c	2.19	0.00	13.89
Table 1	4	Conesville *	0.0	0.4	0.0	0.00	b	0.00	b	c	b	0.00	b
Substitution	2	East Bend*	0.0	0.7	1.0	b	b	0.00	0.61	b	0.61	b	1.47
Substitution	1	J. M. Stuart*	0.0	0.4	0.0	b	b	0.00	b	b	b	b	b
Substitution	2	J. M. Stuart*	0.0	0.4	0.0	b	b	0.00	b	b	b	b	b
Substitution	3	J. M. Stuart*	0.0	0.4	0.0	b	b	0.00	b	b	b	b	b
Substitution	4	J. M. Stuart*	0.0	0.4	0.0	b	b	0.00	b	b	b	b	b
Total for Utility . .			**1.4**	**5.7**	**1.0**	**12.40**	**b**	**6.90**	**3.53**	**b**	**22.83**	**b**	**16.39**
Georgia Power Company													
Table 1	1	Bowen	1.0	1.0	0.0	0.40	0.00	7.19	0.74	b	8.33	0.00	10.34
Table 1	2	Bowen	1.0	1.0	0.0	0.27	0.00	8.23	0.82	b	9.32	0.00	11.82
Table 1	3	Bowen	1.0	1.0	0.0	2.06	0.00	9.11	0.61	b	11.78	0.00	12.37
Table 1	4	Bowen	1.0	1.0	0.0	1.94	0.00	9.28	0.55	b	11.77	0.00	12.36
Table 1	1	Hammond	0.0	0.5	0.0	1.45	0.00	0.00	0.53	b	1.98	0.00	15.84
Table 1	2	Hammond	0.0	0.5	0.0	2.77	0.00	0.00	0.73	b	3.50	0.00	28.00
Table 1	3	Hammond	0.0	0.5	0.0	0.64	0.00	0.00	0.47	b	1.16	0.00	8.88
Table 1	4	Hammond	1.0	0.5	0.0	1.00	0.00	22.00	0.45	b	23.45	0.00	40.57
Table 1	1	McDonough	1.0	0.5	0.0	2.35	0.00	9.18	0.62	b	12.15	0.00	40.61
Table 1	2	McDonough	1.0	0.5	0.0	2.34	0.00	8.47	0.48	b	11.29	0.00	37.73
Table 1	1	Wansley *	0.5	0.3	0.0	2.51	0.00	9.13	0.77	b	12.41	0.00	24.37
Table 1	2	Wansley *	0.5	0.3	0.0	2.15	0.00	5.95	0.59	b	8.69	0.00	17.06
Table 1	1	Yates (d)	0.0	0.7	1.0	17.00	2.00	0.00	0.78	b	17.78	2.00	145.14
Table 1	2	Yates	0.0	0.7	0.0	1.98	0.00	0.00	0.47	b	2.45	0.00	20.00
Table 1	3	Yates	0.0	0.7	0.0	1.53	0.00	0.00	0.40	b	1.93	0.00	15.76
Table 1	4	Yates	1.0	0.7	0.0	1.59	0.00	2.07	0.40	b	4.06	0.00	25.98
Table 1	5	Yates	1.0	0.7	0.0	1.36	0.00	2.07	0.33	b	3.76	0.00	24.06
Table 1	6	Yates	1.0	0.7	0.0	1.82	0.00	6.13	0.85	b	8.80	0.00	21.79

See notes at end of table.

Table C2. Cost of Phase I Compliance for Selected Units, by Utility (Continued)

Type of Unit	Unit	Plant	Number[a] of Low-NOx Burners	Number[a] of CEMs	Number[a] of Scrubbers	SO_2 Control Capital Cost	SO_2 Control O&M Cost	NOx Control Capital Cost	CEMS Capital Cost	CEMS O&M Cost	Total Capital Cost	Annual O&M Cost	Average Capital Cost (dollars/KW affected)
						million dollars							
Table 1	7	Yates	1.0	0.7	0.0	1.89	0.00	6.51	0.52	b	8.92	0.00	22.09
Table 1	1	Gaston *	0.5	0.5	0.0	0.00	0.00	2.00	0.25	c	2.25	0.00	16.54
Table 1	2	Gaston *	0.5	0.5	0.0	0.00	0.00	3.00	0.25	c	3.25	0.00	23.90
Table 1	3	Gaston *	0.5	0.5	0.0	0.00	0.00	7.00	0.25	c	7.25	0.00	53.31
Table 1	ST4	Gaston *	0.5	0.5	0.0	0.00	0.00	3.00	0.25	c	3.25	0.00	26.55
Substitution	ST1	Arkwright	0.0	0.3	0.0	0.00	0.00	0.00	0.34	b	0.34	0.00	7.39
Substitution	ST2	Arkwright	0.0	0.3	0.0	0.00	0.00	0.00	0.27	b	0.27	0.00	5.87
Substitution	3	Arkwright	0.0	0.3	0.0	0.00	0.00	0.00	0.30	b	0.30	0.00	7.50
Substitution	4	Arkwright	0.0	0.3	0.0	0.00	0.00	0.00	0.30	b	0.30	0.00	6.12
Substitution	1	Harlee Branch	0.0	0.5	0.0	0.00	0.00	0.00	0.34	b	0.34	0.00	1.14
Substitution	2	Harlee Branch	1.0	0.5	0.0	0.00	0.00	5.00	0.87	b	5.87	0.00	16.35
Substitution	3	Harlee Branch	0.0	0.5	0.0	0.00	0.00	0.00	0.30	b	0.30	0.00	0.55
Substitution	4	Harlee Branch	0.0	0.5	0.0	0.00	0.00	0.00	0.30	b	0.30	0.00	0.55
Substitution	3	Mitchell	0.0	1.0	0.0	0.00	0.00	0.00	1.23	b	1.23	0.00	7.55
Substitution	3	Scherer*	0.0	1.0	0.0	0.00	0.00	0.00	0.77	b	0.77	0.00	10.27
Total for Utility .			**15.1**	**19.4**	**1.0**	**47.05**	**2.00**	**125.32**	**17.13**	**b**	**189.50**	**2.00**	**18.48**
Illinois Power Company													
Table 1	1	Baldwin (e)	0.0	1.0	0.0	34.60	3.90	0.00	2.10	0.10	36.70	4.00	58.90
Table 1	2	Baldwin	0.0	1.0	0.0	0.00	7.40	0.00	2.20	0.10	2.20	7.50	3.47
Table 1	3	Baldwin	1.0	1.0	0.0	0.00	5.40	9.00	2.10	0.10	11.10	5.50	17.49
Table 1	2	Hennepin	0.0	1.0	0.0	0.00	1.70	0.00	1.90	0.10	1.90	1.80	8.21
Table 1	1&2	Vermilion(f)	1.0	2.0	0.0	0.00	0.10	3.70	1.70	0.10	5.40	0.20	29.51
Substitution	1-6	Havana	0.0	4.0	0.0	0.00	0.00	0.00	2.60	0.20	2.60	0.20	11.30
Substitution	1&4	Wood River	0.0	3.0	0.0	0.00	0.00	0.00	2.60	0.20	2.60	0.20	15.95
Total for Utility .			**2.0**	**13.0**	**0.0**	**34.60**	**18.50**	**12.70**	**15.20**	**0.90**	**62.50**	**19.40**	**23.15**
Potomac Electric Power Company													
Table 1	ST1	Chalk Point	1.0	0.5	0.0	15.00	b	18.10	1.60	b	34.70	0.00	95.33
Table 1	ST2	Chalk Point	1.0	0.5	0.0	15.00	b	18.10	1.60	b	34.70	0.00	95.33
Table 1	ST1	Morgantown	1.0	1.0	0.0	0.00	b	40.20	3.10	b	43.30	0.00	69.17
Table 1	ST2	Morgantown	1.0	1.0	0.0	0.00	b	40.20	3.10	b	43.30	0.00	69.17
Table 1	1	Conemaugh *	1.0	1.0	0.1	16.20	0.90	2.00	0.10	0.00	18.30	0.90	201.14
Table 1	2	Conemaugh *	1.0	0.5	0.1	16.20	0.90	2.00	0.10	0.00	18.30	0.90	201.14

See notes at end of table.

Table C2. Cost of Phase I Compliance for Selected Units, by Utility (Continued)

Type of Unit	Unit	Plant	Number[a] of Low-NOx Burners	Number[a] of CEMs	Number[a] of Scrubbers	SO_2 Control: Capital Cost	SO_2 Control: O&M Cost	NOx Control: Capital Cost	CEMS: Capital Cost	CEMS: O&M Cost	Total Capital Cost	Annual O&M Cost	Average Capital Cost (dollars/KW affected)
						million dollars							
Substitution	3	Chalk Point	0.0	1.0	0.0	0.00	0.00	0.00	1.60	b	1.60	b	2.43
Substitution	4	Chalk Point	0.0	1.0	0.0	0.00	0.00	0.00	1.60	b	1.60	b	2.43
Total for Utility .			**6.0**	**6.5**	**0.2**	**62.40**	**1.80**	**120.60**	**12.80**	**b**	**195.80**	**1.80**	**56.27**
Pennsylvania Power & Light Company													
Table 1	1	Brunner Island	1.0	0.5	0.0	0.00	b	13.00	1.20	b	14.20	0.00	39.12
Table 1	2	Brunner Island	1.0	0.5	0.0	3.00	b	15.00	1.20	b	19.20	0.00	47.41
Table 1	3	Brunner Island	1.0	1.0	0.0	0.00	b	17.00	2.40	b	19.40	0.00	24.56
Table 1	1	Martins Creek	1.0	1.0	0.0	2.00	b	6.00	1.25	b	9.25	0.00	59.29
Table 1	2	Martins Creek	1.0	1.0	0.0	2.00	b	5.00	1.25	b	8.25	0.00	52.88
Table 1	3	Sunbury	1.0	0.5	0.0	1.50	b	5.00	1.80	b	8.30	0.00	79.81
Table 1	4	Sunbury	1.0	0.5	0.0	1.70	b	5.30	1.80	b	8.80	0.00	56.41
Table 1	1	Conemaugh *	0.1	0.1	0.1	20.50	1.10	2.20	0.10	0.00	22.80	1.10	213.86
Table 1	2	Conemaugh *	0.1	0.1	0.1	20.50	1.10	2.20	0.10	0.00	22.80	1.10	213.86
Total for Utility .			**7.2**	**5.2**	**0.2**	**51.20**	**2.20**	**70.70**	**11.10**	**b**	**133.00**	**2.20**	**56.76**
Southern Indiana Gas & Electric Company													
Table 1	2	Culley	1.0	1.0	0.5	28.84	1.12	1.41	0.75	0.06	31.00	1.18	298.90
Table 1	3	Culley	1.0	1.0	0.5	74.16	2.88	3.59	0.75	0.06	78.50	2.94	296.02
Table 1	4	Warrick *	0.0	0.5	0.0	0.00	0.00	0.00	1.30	0.04	1.30	0.04	8.05
Total for Utility .			**2.0**	**2.5**	**1.0**	**103.00**	**4.00**	**5.00**	**2.80**	**0.16**	**110.80**	**4.16**	**208.90**

Note: Totals may not equal sum of individual components because of rounding.
[a]A fractional value indicates that ownership of equipment was allocated across more than 1 unit.
[b]Costs not estimated.
[c]Estimated to be negligible by utility.
[d]Includes only one-half of scrubber capital costs. The other half is paid by the Department of Energy as a demonstration project.
[e]Installation of the scrubber for the Baldwin 1 unit was suspended in 1992.
[f]Vermillion 1 is a substitution unit.
*Partially owned unit.
CEMS = Continuous emission monitoring systems.
NO_x = Nitrogen oxides.
SO_2 = Sulfur dioxide.
KW = Kilowatts.
Sources: Personal contact with Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas and Electric.

Glossary

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released into the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles, or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Allowance: One SO_2 allowance permits one ton of SO_2 emissions.

Anthracite: A hard, black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of fixed volatile matter.

Ash: Impurities consisting of silica, iron, alumina, and other noncombustible matter that are contained in coal. Ash increases the weight of the coal, adds to the cost of handling, and can affect its burning characteristics. Ash content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Ash Fusion Temperature: The temperature at which ash from coal melts.

Bituminous Coal: The most common coal. It is dense and black (often with well-defined bands of bright and dull material). Its moisture content usually is less than 20 percent. It is used for generating electricity, making coke, and space heating.

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature, and quality.

Bureau of Mines, District 1: Maryland - All mines in the State. **Pennsylvania -** All mines in the following counties: Bedford, Blair, Bradford, Cambria, Cameron, Centre, Clarion, Clearfield, Clinton, Elk, Forest, Fulton, Huntingdon, Jefferson, Lycoming, McKean, Mifflin, Potter, Somerset, and Tioga. Selected mines in the following counties: Armstrong County (part), all mines east of the Allegheny River, and those mines served by the Pittsburgh and Shawmut Railroad located on the west bank of the river; Fayette County (part), all mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad; Indiana County (part), all mines not served by the Saltsburg branch of the Consolidated Railroad Corporation; and Westmoreland County (part), all mines served by the Consolidated Rail Corporation from Torrance, east. **West Virginia -** All mines in the following counties: Grant, Mineral, and Tucker.

Bureau of Mines District 2: Pennsylvania - All mines in the following counties: Allegheny, Beaver, Butler, Greene, Lawrence, Mercer, Venango, and Washington. Selected mines in the following counties: Armstrong County (part), all mines west of the Allegheny river except those mines served by the Pittsburgh & Shawmutt Railroad; Fayette County (part), all mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad; Indiana County (part), all mines served by the Saltsburg branch of the Consolidated Rail Corporation; and Westmoreland County (part), all mines except those served by the Consolidated Rail Corporation from Torrance, east.

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

CAAA90: The Clean Air Act Amendments of 1990.

Capital Costs: The costs of the long-term productive assets of a utility including scrubbers and continuous emissions monitors.

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alternation from lignite to anthracite. Lignite contains approximately 9 million to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 million to 24 million Btu per ton and from 19 million to 30 million Btu per ton, respectively. Anthracite contains approximately 22 million to 28 million Btu per ton.

Low-sulfur coal: The EIA sulfur content category of coal with less than 0.60 pounds of sulfur per million Btu.

Medium-sulfur coal: The EIA sulfur content category of coal with 0.60 to 1.67 pounds of sulfur per million Btu.

High-sulfur coal: The EIA sulfur content category of coal with greater than 1.67 pounds of sulfur per million Btu.

Compensating Unit: A unit designated by a Table 1 unit that reduced its utilization below its baseline. The compensating unit provides compensating generation to account for the reduced utilization of the Table 1 unit.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service, start-up and/or flame stabilization.

Continuous Emission Monitor (CEM): A device that approximates a continuous measurement of certain characteristics of a gas by making separate measurements frequently. For compliance with the CAAA90, the measurements must be taken at least every 15 minutes.

Extractive Continuous Emission Monitor: A CEM that draws exhaust gas away from the combustion system to the measurement equipment through special ducts.

In Situ Continuous Emission Monitor: A CEM that makes measurements directly in the flue or exhaust pipe.

Cost: The amount paid to acquire resources, such as plant and equipment, fuel, or labor services.

Demand-Side Management: The planning, implementation, and monitoring of utility activities that are designed to influence consumer use of electricity in ways that will produce desired changes in a utility's load shape, including direct Load Control, Interruptible Load, and Conservation and Other Demand-Side Management categories. Demand-Side Management includes utility-administered programs that are designed to reduce load growth, and any other programs designed for strategic load growth.

Dry Dust Baghouse Collector: A fabric filter that collects the dry particulate matter as the cooled flue gas passes through the filter material.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Electrostatic Precipitator (ESP): A unit comprised of a series of parallel vertical plates through which the flue gas passes. It electrically charges the ash particles in the flue gas to collect and remove them.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units.

Facility: An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type.

Federal Energy Regulatory Commission (FERC): A quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particulate matter from coal ash in which the particle diameter is less than 1×10^{-4} meter. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fouling: The formation of high temperature bonded deposits on convective heat absorbing surfaces that are not exposed to radiant heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

> *Gross Generation*: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.
>
> *Net Generation*: Gross generation less the electric energy consumed at the generating station for station use.

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electric power production equipment under specific conditions as designated by the manufacturer. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Gigawatt (GW): One billion watts of capacity.

Greenfield Unit: A newly constructed generating unit.

Hardgrove Grindability Index (HGI): A measure of the relative ease with which coal can be pulverized or ground. Higher grindability indicates coal which are easier to grind.

Kilowatt (kW): One thousand watts of capacity.

Kilowatthour (kWh): One thousand watthours.

Lignite: A brownish-black coal of low rank with high inherent moisture and volatile matter (used almost exclusively for electric power generation). It is also referred to as brown coal.

Low-NO_x Burners: Burners that utilize special arrangements of fuel and air injection ports, which reduce the formation of NO_x during combustion.

Megawatt (MW): One million watts of capacity.

Megawatthour (MWh): One million watthours of electric energy.

NO_x: Nitrogen oxides.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Opacity: The degree of imperviousness to the passage of light.

Operations and Maintenance Costs: Operations costs are the components of power production that incur cost for operations that are directly related to producing electricity. The major item is almost always fuel that has to be burned to generate the electricity. Maintenance costs are the portion of operating expenses consisting of labor, materials, and other direct and indirect expenses incurred for preserving the operating efficiency and / or physical condition of utility plants used for power production, transmission, and distribution of energy.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes fuel oil No. 2, No. 4, No. 5, No. 6; topped crude; Kerosene; and jet fuel.

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Plant: A facility at which are located prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy. A plant may contain more than one type of prime mover. Electric utility plants exclude facilities that satisfy the definition of a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping-storage plants is, by definition, subtracted, and the energy production for these plants is then reported as a net figure.

Pulverizers: Mills of various designs used to finely grind the coal which is swept from the mills by air for pneumatic transport directly to the burners.

SO_2: Sulfur dioxide.

Slagging: The formation of molten, partially fused resolidified deposits on furnace walls or other surface exposed to radiant heat.

Subbituminous Coal: A dull black coal of rank intermediate between lignite and bituminous.

Substitution Unit: A unit brought into Phase I to assist a Table 1 unit in meeting emissions reduction obligations. Utilities may make cost-effective emissions reductions at the substitution unit instead of at the Table 1 unit by achieving the same overall emissions reductions that would have occurred without the participation of the substitution unit.

Sulfur: One of the elements present in varying quantities in coal which contributes to environmental degradation when coal is burned. In terms of sulfur content by weight, coal is generally classified as low (less than or equal to 1 percent), medium (greater than 1 percent and less than or equal to 3 percent), and high (greater than 3 percent). Sulfur content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.