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Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990

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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, *Electric Utility Phase I Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990*. The purpose of this report is to provide information on strategies utilities are using to comply with Phase I of the Clean Air Act Amendments of 1990 and estimates of the costs of selected utilities for compliance. Compliance strategies are discussed including technological considerations and costs for the six main strategies: (1) fuel switching and/or blending, (2) obtaining additional allowances, (3) installing flue gas desulfurization equipment (scrubbers), (4) using previously implemented controls, (5) retiring facilities, and (6) boiler repowering. Impacts on coal demand and supply are also examined.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's 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 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 (CAAA90)—Public Law 101-549—are the latest revisions to the Clean Air Act. Among the numerous provisions of the 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 (acid rain). Acid rain is formed largely from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) which are emitted primarily by fossil-fueled electric power plants, other industrial sources, and transportation sources. The SO_2 reduction provisions of CAAA90 are noteworthy and controversial, because they represent the first large-scale attempt to set overall emissions levels using marketable licenses (allowances) to control emissions, as opposed to regulations that specify what actions must be undertaken by those affected (command and control). An allowance permits the emission of one ton of SO_2. The use of allowances leaves electric utilities with several options for compliance strategies and, thus, introduces flexibility into compliance plans. Many utilities, because they have several compliance options, have alternative plans that can be used to comply with Phase I, depending on the circumstances.

The Acid Rain Program is divided into two time periods; Phase I, from 1995 through 1999, and Phase II, starting in 2000. Phase I mostly affects power plants that are the largest sources of SO_2 and NO_x. Phase II affects virtually all electric power producers, including utilities and nonutilities. This report is a study of the effects of compliance with Phase I regulations on the costs and operations of electric utilities, but does not address any Phase II impacts.

The CAAA90 specifies 261 generating units[1] (mostly coal-burning) at 110 utility plants that are affected by Phase I. These units, located in 21 eastern and midwestern States, are high emitters of SO_2 and NO_x. However, because of provisions in the CAAA90 that allow utilities to use other units to substitute or compensate for those originally specified, additional

In the CAAA90, 261 units were targeted for emissions reductions before 1995, including 4 units at the 953-megawatt Hammond facility operated by Georgia Power.

[1]Table A of the CAAA90 specified 261 electric power generators that were affected by Phase I. These generators are attached to 263 boilers at 261 boiler/generator units. See Appendix A for an individual listing of the 261 generators.

generator units may be affected by Phase I.[2] This report focuses on the original 261 Phase I affected units specified in Table A of the CAAA90. During Phase I, those 261 units will receive an annual allocation of allowances for SO_2 emissions equal to approximately 2.5 pounds of SO_2 per million Btu of heat input during the historic baseline period (the average for 1985 through 1987). For most of the units, the allowances are lower than historical emission levels. Phase I also specifies maximum levels of NO_x emissions that affected units may emit.

Options to comply with the SO_2 limitations of Phase I are grouped into six categories: (1) fuel switching and/or blending, (2) obtaining additional allowances, (3) installing flue gas desulfurization equipment (scrubbers), (4) using previously implemented controls, (5) retiring facilities, and (6) boiler repowering (Table ES1). Fuel switching consists of either switching to lower sulfur coal, blending lower sulfur coal with higher sulfur coal, or co-firing with another fuel, usually natural gas. Obtaining additional allowances entails obtaining a sufficient number of allowances in addition to the initial allocation so that no other action needs to be taken.[3] The use of scrubbers involves installing equipment that removes sulfur dioxide from the boiler flue gas. Previously implemented controls are actions already taken, usually because of State requirements, that have already reduced emissions. Boiler repowering involves replacing an existing boiler with one using a different fuel or technology that may emit less SO_2. Permanently retiring a facility is also an option. Several additional strategies are available: energy conservation (including supply-side and demand-side management), reduced utilization, and substitution of units. Most Phase I affected utilities are using one or more of these in conjunction with their main method of compliance.

The main strategy planned for compliance with the SO_2 requirements of Phase I is fuel switching. Utilities currently plan to change fuels at more than half (about 62 percent) of the affected units. Fuel switching is

Table ES1. Compliance Methods for the 261 Generators Affected by Phase I of the CAAA90

Compliance Method[a]	Number of Generators[b]	Affected Nameplate Capacity (megawatts)	Allowances[c] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[d]
Fuel Switching and/or Blending	162	53,203	3,315,554	5,455,734	499,202
Obtaining Additional Allowances	39	14,137	917,573	1,496,406	817,023
Installing Flue Gas Desulfurization Equipment (Scrubbers)	27	14,101	923,467	1,637,783	2,178,324
Using Previously Implemented Controls[e]	25	6,092	333,061	584,307	0
Retiring Facilities	7	1,342	56,781	121,039	0
Boiler Repowering	1	113	4,385	6,713	5,451
Total	**261**	**88,989**	**5,550,821**	**9,301,982**	**3,500,000**

[a]These compliance methods are based on information obtained in late 1993.

[b]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 affected boilers is 263 and the number of affected generators is 261.

[c]One SO_2 allowance permits one ton of SO_2 emissions.

[d]Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Extension allowances were awarded for 1995 through 1999.

[e]Using previously implemented controls includes facilities that have already met required reductions due to existing State regulations or other reasons.

CAAA90 = Clean Air Act Amendments of 1990. SO_2 = Sulfur dioxide.

Source: **Compliance Method**: U.S. Environmental Protection Agency, *Coal Week*, *Compliance Strategies Review*, Georgia Public Utility Commission, *Utility Environment Report*, and *McIlvaine Utility Forecast*. **List of Affected 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). **Phase I Extension Allowances:** Facsimile from the U.S. Environmental Protection Agency (February 7, 1994).

[2]The number of additional units affected by Phase I is not clear for two reasons: (1) on March 12, 1993, petitions for review of the EPA rules covering substitution and compensating units were filed in the U.S. Court of Appeals; and (2) EPA currently is proposing to revise these rules for the years 1996 through 1999.

[3]Publicly announced Phase I allowance transaction prices have ranged from $178 to $276. "Publicly Announced Phase I Allowance Transactions," *Compliance Strategies Review* 4, 24 (December 20, 1993), p. 4.

favored not only because of the low cost of low-sulfur coal but also because its usually smaller capital expenditures make it a more cost-effective compliance method given the uncertainty associated with compliance costs. The second most frequently chosen strategy is allowance acquisition. For about 15 percent of the affected units, the operating utilities plan to comply by acquiring enough SO_2 allowances, largely from other utilities that have reduced their allowance requirements below their annual allocation of allowances, to cover their emissions. About 10 percent of the affected units will install scrubbers to reduce emissions. While this percentage is small compared to the percentage of utilities switching fuels or acquiring additional allowances, it should be noted that scrubbers will account for a large share of the required SO_2 emissions reduction in Phase I. At another 10 percent of the affected units, emissions have already been reduced below the number of allowances that have been allotted. Phase I affected utilities plan to repower only one unit.

Utilities switching to low-sulfur coal are expected to obtain two-thirds of the low-sulfur coal (approximately 24 million tons) from central Appalachia, located in eastern Kentucky, western Virginia, and southern West Virginia and the remainder (approximately 12 million tons) from the Powder River Basin, located in southwestern Montana and northwestern Wyoming. An electric utility that switches to burning a subbituminous western low-sulfur coal may need to modify its plant, including the coal handling system, fuel preparation and firing system, steam generator, particulate removal system, ash and waste disposal system, and building structures. These modifications are necessary because of the higher moisture content and different ash properties of western coal, and may cost between $25 and $119 per kilowatt (1992 dollars).[4]

The responses of electric utilities to Phase I SO_2 emissions limits, however, have been evolving since the CAAA90 was enacted. Two trends in this development are evident. One is that an increasing number of utilities are purchasing allowances from others who own them. Prices for allowances have been lower than many expected. As a result, fewer scrubbers are being installed at affected plants than originally planned. For example, Illinois Power originally began installing scrubbers at its Baldwin plant, but has since stopped construction and announced that it will buy allowances to comply with Phase I. The other trend is that the price of low-sulfur coal has not risen as much as expected, resulting in lower costs to switch to low-sulfur coal. Several utilities report that they are not paying any premium for low-sulfur coal. Both trends have reduced the expected cost of compliance with Phase I for many utilities.

There are two other basic requirements of Phase I: NO_x emission performance standards for certain types of boilers, and installation of continuous emission monitors (CEMs).[5] The NO_x performance standards limit each affected unit to specific maximum emission rates. CEMs measure emissions in the flue gas from a boiler. Although these requirements are more straightforward than the SO_2 requirements, NO_x control and CEM requirements will be costly to Phase I affected utilities in part because of their less flexible compliance options.

The costs of complying with Phase I of the Acid Rain Program, while relatively small, vary substantially among utilities. For a small sample of six utilities, total capital costs for SO_2 and NO_x controls and CEMs range from $10 to $216 per kilowatt (1993 dollars) of affected capacity (Table ES2). Annual operation and maintenance and fuel expenses range up to over $14 per kilowatt per year. Depreciating Phase I capital expenditures over 15 years results in annual total costs ranging from less than $1 to more than $14 per kilowatt. The effect of these costs on electricity rates is small, ranging from 0.3 to 1.9 mills per kilowatthour; the additional electricity sales revenue requirements range between 0.4 and 3.8 percent for an entire utility.

Table ES2. Utility Costs for Complying with Phase I of the Acid Rain Program

Range of Cost	Lowest	Highest
Total Capital (1993 dollars per kilowatt)	10.5	216.4
Annual Capital (1993 dollars per kilowatt)	0.7	14.4
Annual Operations & Maintenance (1993 dollars per kilowatt)	0.2	14.1
Annual Fuel (1993 dollars per kilowatt)	0.0	3.8
Annual Total (1993 dollars per kilowatt)	2.6	17.2
Required Rate Increase (1993 mills per kilowatthour)	0.3	1.9
Required Rate Increase (percent)	0.4	3.8

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels (November 1993 through March 1994).

[4]Romas L. Rupinskas and Paul A. Hiller, “Considerations for Switching from High-Sulfur to Low-Sulfur Coal,” Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Atlanta, GA, October 18-22, 1992).

[5]Any alternative to CEMs must be explicitly approved by EPA.

1. Introduction

Title IV of the Clean Air Act Amendments of 1990 (CAAA90) requires the Environmental Protection Agency (EPA) to establish the Acid Rain Program which in turn requires electric utilities to substantially reduce their emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), the primary air pollutants that contribute to acid rain. Fossil-fired electric utility plants are the main source of SO_2 emissions and a major source of NO_x emissions in the United States. Because NO_x reductions rely on more traditional controls, this report places special emphasis on the unique, market-based approach to SO_2 reduction strategies. The Acid Rain Program for both pollutants is split into two periods—Phase I, which runs from 1995 through 1999, and Phase II, which starts in 2000. In complying with Phase I, affected utilities have considerable flexibility in deciding how to reduce their SO_2 emissions and can design a compliance plan utilizing one or more strategies best suited to their individual needs.

Units Affected by Phase I

SO_2 and, to a lesser extent, NO_x emissions from fossil-fired facilities are concentrated in the eastern and midwestern portions of the United States (Table 1). Many of the utility coal-fired power plants in those regions emit more SO_2 per million British thermal units (Btu) than the standards set by EPA in 1971 because they were constructed prior to the issuance of those standards. They are also located in States that have coal deposits with higher sulfur content and frequently use such coal. These areas therefore account for the largest emissions reductions and have the most generating capacity affected by Phase I.

Table A of the CAAA90 specifies 261 generating units, associated with 261 generators and 263 boilers,[1] located in 110 plants in 21 States, that are affected by the SO_2 requirements of Phase I.[2] All 110 plants are located in the eastern and midwestern parts of the United States (Table 2). Of the 21 States in which affected units are located, 3 States have more than 40 percent of their total nameplate capacity affected by Phase I: Ohio, Indiana, and West Virginia. Another three States—Georgia, Missouri, and Tennessee—have at least one-third of their total nameplate generating capacity affected by Phase I (Figure 1). In absolute terms, 8 of the 21 States have more than 5 gigawatts of capacity affected by Phase I (Figure 2). Ohio has the largest amount of Phase I affected capacity with 14.3 gigawatts representing 48.7 percent of its total capacity and 57.3 percent of its coal-fired capacity.

Sulfur Dioxide Compliance Strategies

The CAAA90 allows affected units to choose their SO_2 compliance strategies, allowing several options for utilities. To meet CAAA90 requirements, all Phase I utilities must have allowances to cover their SO_2 emissions—each allowance permits the utility to emit one ton of SO_2. Each of the 261 Phase I units initially receive annual allowances for emissions of approximately 2.5 pounds of SO_2 per million Btu of heat input during the baseline period (the average for 1985 through 1987). Beginning in the year 2000, the act places a cap on the number of allowances issued to all utility generating units, 25 megawatts and larger, each year at 8.95 million. This effectively permanently caps emissions and ensures that the mandated emissions reductions will be maintained over time. Each utility generally has chosen a specific strategy in addition to the use of allowances for compliance with Phase I. These specific strategies can be grouped into six categories (Table 3):

- Fuel switching and/or blending
- Obtaining additional allowances
- Installing flue gas desulfurization equipment (scrubbers)
- Using previously implemented controls
- Retiring facilities
- Boiler repowering.

[1]Table A of the CAAA90 specified 261 electric power generators that were affected by Phase I. These generators are attached to 263 boilers at 261 boiler/generator units. See Appendix A for an individual listing of the 261 generators.

[2]All coal-fired boilers in this group also must meet NO_x emissions limits. Dry bottom wall-fired and tangentially-fired boilers must meet NO_x standards by January 1, 1995, while all other Phase I coal-fired boilers must meet NO_x standards by January 1, 1997.

Table 1. Emissions from Fossil-Fueled Steam-Electric Generating Units at Utilities by Census Division and State, 1992
(Thousand Short Tons)

Census Division State	Sulfur Dioxide	Nitrogen Oxides
New England	**302**	**117**
Connecticut	34	16
Maine	7	3
Massachusetts	203	75
New Hampshire	57	23
Rhode Island	*	*
Vermont	*	*
Middle Atlantic	**1,599**	**558**
New Jersey	61	45
New York	342	154
Pennsylvania	1,197	358
East North Central	**4,869**	**1,868**
Illinois	842	306
Indiana	1,182	539
Michigan	353	313
Ohio	2,228	552
Wisconsin	264	158
West North Central	**1,215**	**913**
Iowa	175	155
Kansas	67	129
Minnesota	78	151
Missouri	681	284
Nebraska	52	82
North Dakota	130	94
South Dakota	32	18
South Atlantic	**3,456**	**1,345**
Delaware	40	19
District of Columbia	1	*
Florida	745	394
Georgia	787	194
Maryland	259	96
North Carolina	378	195
South Carolina	154	80
Virginia	177	72
West Virginia	916	295
East South Central	**2,210**	**820**
Alabama	537	229
Kentucky	767	358
Mississippi	102	42
Tennessee	803	192
West South Central	**756**	**1,264**
Arkansas	66	102
Louisiana	110	189
Oklahoma	108	168
Texas	473	804
Mountain	**464**	**786**
Arizona	128	144
Colorado	87	136
Idaho	--	--
Montana	22	80
Nevada	59	71
New Mexico	59	152
Utah	31	77
Wyoming	78	126
Pacific Contiguous	**85**	**205**
California	1	137
Oregon	14	21
Washington	70	47
Pacific Noncontiguous	**23**	**12**
Alaska	1	*
Hawaii	23	12
U.S. Total	**14,981**	**7,889**

*Value less than 0.5.

Notes: • Total may not equal sum of components because of independent rounding. • These data are estimates derived from Form EIA-767, "Steam-Electric Plant Operation and Design Report." • Data include facilities of 10 megawatts or greater capacity. • Data are preliminary.

Source: Energy Information Administration, *Electric Power Annual 1992,* DOE/EIA-0348(92) (Washington, DC, January 1994), p. 73.

Kentucky Utilities is installing flue gas desulfurization equipment (top) at its 557-megawatt Ghent unit 1 (bottom) to meet compliance with Phase I, which will yield excess allowances at Ghent that can be distributed to the utility's other affected facilities.

Table 2. Phase I Affected Coal-Fired Nameplate Capacity and Total Nameplate Capacity by State, 1992

State	Nameplate Capacity Affected by Phase I (gigawatts)	Number of Genera-tors	Total Nameplate Capacity (gigawatts)	Percentage of Total Nameplate Capacity Affected by Phase I	Coal-Fired Nameplate Capacity (gigawatts)	Percentage of Coal-Fired Nameplate Capacity Affected by Phase I	Percentage of Coal-Fired Nameplate Capacity
Alabama	3.4	10	21.4	15.7	12.6	26.6	59.1
Florida	2.3	5	36.9	6.2	10.9	21.1	29.4
Georgia	8.4	19	23.2	36.4	14.5	58.0	62.7
Illinois	6.0	17	36.9	16.3	17.2	34.9	46.7
Indiana	11.2	37	23.1	48.4	21.6	51.8	93.5
Iowa	1.0	6	8.8	11.2	6.3	15.6	71.4
Kansas	0.2	1	10.6	1.5	5.6	2.8	53.3
Kentucky	4.7	17	17.4	26.8	16.1	28.9	92.8
Maryland	2.4	6	11.8	20.2	4.9	48.1	42.0
Michigan	0.7	2	24.0	2.7	12.9	5.0	53.8
Minnesota	0.2	1	9.3	1.8	5.8	2.8	63.0
Mississippi	0.8	2	7.2	10.4	2.2	34.9	29.9
Missouri	6.5	16	16.8	38.4	11.7	55.3	69.4
New Hampshire	0.5	2	2.6	17.6	0.6	75.4	23.4
New Jersey	0.3	2	14.6	2.1	1.7	17.3	11.9
New York	2.4	10	33.4	7.2	4.1	59.1	12.2
Ohio	14.3	41	29.3	48.7	24.9	57.3	85.0
Pennsylvania	7.7	21	36.9	20.8	19.3	39.8	52.2
Tennessee	6.3	19	18.2	34.7	10.0	63.2	55.0
West Virginia	7.4	14	15.1	48.8	15.0	49.1	99.2
Wisconsin	2.7	13	10.9	24.8	7.3	37.0	67.0
Total United States	**89.0**	**261**	**741.7**	**12.0**	**325.1**	**27.4**	**43.8**

Source: **Capacity**: Energy Information Administration, *Inventory of Power Plants 1992,* DOE/EIA-0095(92) (Washington, DC, October 1993). **List of Affected Units**: *Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691.

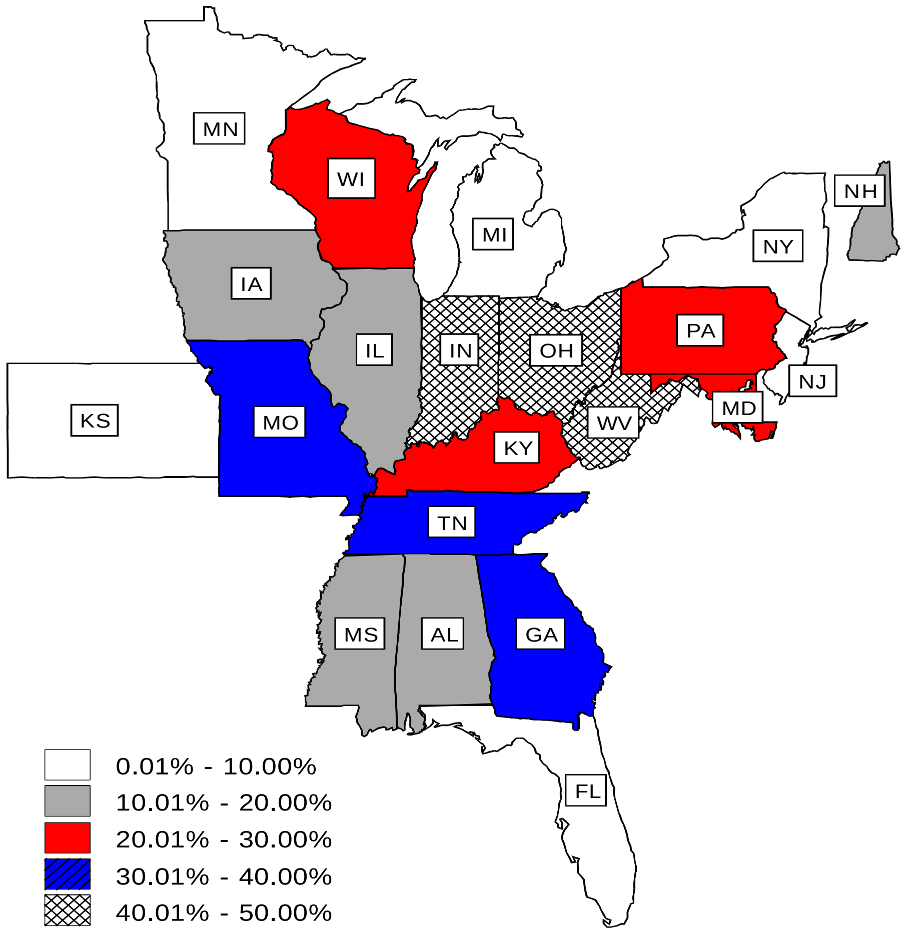
Over half of the compliance strategies involve fuel switching and/or blending (including cofiring). Fuel switching and/or blending is not capital intensive, and as such is a low fixed-cost strategy that allows utilities to comply with the CAAA90 for a few years at relatively low cost. Therefore, utility planners have additional time for resolving uncertainties in strategy costs. Kovy A. Bailey, an economist with the Technology and Environmental Policy Section of Argonne National Laboratory, states that, “Maintaining flexibility is probably the most important thing utilities can do right now in terms of environmental air-emission compliance. The view seems to be, when in doubt, fuel switch.”[3]

Currently 162 Phase-I affected units are planning to switch fuels. The use of lower sulfur coal, as well as a complete switching and blending, are the two major types of fuel switching being utilized. Other options are mixing in-State coal with various low-sulfur coals and switching or blending fuels, as well as some other temporary fuel change, such as a seasonal switch to gas or cofiring with gas. A few units have also indicated that they will blend coal with another energy source, such as tires.

Another 39 units will comply by obtaining emission allowances from other units as their main strategy. For example, Illinois Power will buy approximately 550,000 allowances for its Baldwin, Hennepin, and Vermilion plants to comply with Phase I.[4] Illinois Power considered fuel blending and scrubbers for Baldwin, but announced in mid-1993 that it would use allowances to comply. The lower-than-expected allowance prices may have played a significant role in Illinois Power’s decision.

[3]“Phase I Compliance Plans Emphasize Flexibility,” *Electric Light and Power* (August 1993), p. 8.
[4]“Illinois Power Fishes for Credits,” *Coal Outlook* (October 11, 1993), p. 3.

Figure 1. Percentage of Nameplate Capacity Affected by Phase I by State, 1992



Source: **Capacity**: Energy Information Administration, *Inventory of Power Plants 1992,* DOE/EIA-0095(92) (Washington, DC, October 1993). **List of Affected Units**: *Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691.

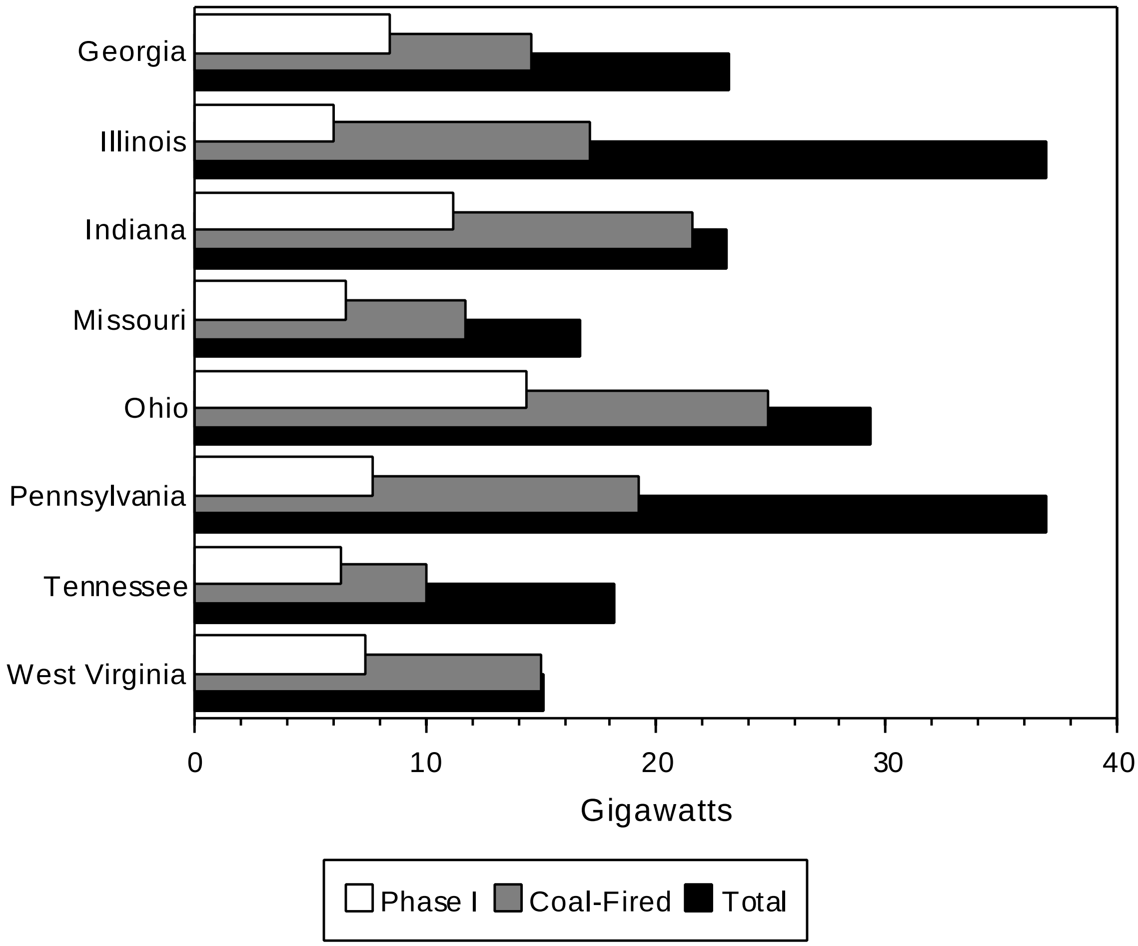
Allowances also may be obtained from other units within the same utility system. For example, Kentucky Utilities will scrub the flue gas of its Phase I unit at Ghent, resulting in Ghent needing fewer allowances than the EPA allotted to it. This allows Kentucky Utilities to transfer allowances from Ghent to its other Phase I plants, Brown and Green River, to bring them into compliance.

Scrubber equipment (primarily wet-limestone or wet-lime) will be installed or retrofitted on flue stacks associated with 27 units, principally in Indiana, Kentucky, and West Virginia (Table 4). Some have chosen to scrub in order to receive additional allowances from EPA which were set aside for utilities that would be installing scrubbers. The number of generating units estimated to install scrubbers has fallen since early 1993. This can be attributed to allowance prices that are lower than had been expected.

A number of Phase I affected units are already in compliance so their owners do not have to take action. Some plants have already undertaken steps that will ensure that, by continuing their current generation practices, they will have sufficient allowances from the initial allowance distribution. Often these reductions in emissions have resulted from State regulations. In Wisconsin, excluding four units that have already been retired, all affected units already meet Phase I requirements. Currently, 25 units fall into the category of using previously implemented controls.

One unit, Wabash River unit 1, owned and operated by PSI Energy, will comply through boiler repowering. This utility will replace its Phase I coal-fired generating unit with a coal-gasification/combined-cycle unit. The remaining seven Phase I units will meet compliance by being retired.

Figure 2. Phase I Affected Nameplate Capacity, Coal-Fired Nameplate Capacity, and Total Nameplate Capacity for States with More than 5 Gigawatts of Affected Capacity by State, 1992



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Contents of the Report

The remaining chapters of this report provide analyses of the effects of compliance strategies for Phase I of the Acid Rain Program on electric utilities. Chapter 2 provides detailed information about the CAAA90 and their antecedents. Chapter 3 gives detailed descriptions, including engineering considerations and cost estimates, of the six specific strategies utilities are using to meet compliance with the Acid Rain Program. Chapter 4 discusses the effects of the Acid Rain Program on the largest affected plants, and also looks at the effects of the amendments on six individual utilities, including cost estimates for the compliance method being followed, plus the conclusion of this study.

Following the analyses in the chapters, several appendices are provided that include data, methodologies, and more extensive background information. Appendix A presents the list of 261 generators that are affected by Phase I, along with data about the individual units. Appendix B includes a technical description of the characteristics of scrubbers reported since 1985. An econometric analysis of costs and operating characteristics is presented in Appendix C for the 32 retrofitted scrubbers. The capital and operations and maintenance costs for the current scrubber technology for new units along with a technical description of the technology are presented in Appendix D. Appendices E and F present cost analyses for the installation of NO_x controls and continuous emission monitors. These appendices also include descriptions of the technical aspects of the equipment. Appendix G presents the methodology used for cost estimates of the six utilities presented in the latter part of Chapter 4. Finally, a glossary of technical terms is included.

Table 3. Profile of Phase I Compliance Methods

Compliance Method[a]	Number of Generators[b]	Average Age[c] (years)	Affected Nameplate Capacity (megawatts)	Average Nameplate Capacity (megawatts)	Allowances[d] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[e]
Fuel Switching and/or Blending	162	29	53,203	328	3,315,554	5,455,734	499,202
Obtaining Additional Allowances	39	30	14,137	362	917,573	1,496,406	817,023
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[a]These compliance methods are based on information obtained in late 1993.

[b]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 affected boilers is 263 and the number of affected generators is 261.

[c]Base year of 1992 was used to calculate average age.

[d]One SO_2 allowance permits one ton of SO_2 emissions.

[e]Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Extension allowances were awarded for 1995 through 1999.

[f]Using previously implemented controls includes facilities that have already met required reductions due to existing State regulations or other reasons.

SO_2 = Sulfur dioxide.

Source: **Compliance Method**: U.S. Environmental Protection Agency, *Coal Week*, *Compliance Strategies Review*, Georgia Public Utility Commission, *Utility Environment Report*, and *McIlvaine Utility Forecast*. **List of Affected Units**: *Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691. **Age and 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). **Phase I Extension Allowances:** Facsimile from U.S. Environmental Protection Agency (February 7, 1994).

Table 4. Scrubber Retrofits for Compliance with Phase I

Year	State	Units	Plant	Utility
1993	Georgia	Y1BR	Yates	Georgia Power
	Indiana	7,8	Bailly	Northern Indiana Public Service
1995	Indiana	2,3	F.B. Cully	Southern Indiana Gas & Electric
	Indiana	4	Gibson	PSI Energy
	Kentucky	1,2	Elmer Smith	City of Owensboro
	Kentucky	1	Ghent	Kentucky Utilities
	New York	1,2	Milliken	New York State Gas & Electric
	Pennsylvania	1	Conemaugh	Pennsylvania Electric Company
	Tennessee	1,2	Cumberland	Tennessee Valley Authority
	West Virginia	1,2,3	Harrison	Monongahela Power Company
	West Virginia	3	Mt. Storm	Virginia Electric & Power Company
1996	Ohio	1,2	General J.M. Gavin	Ohio Power
	Pennsylvania	2	Conemaugh	Pennsylvania Electric Company
	Indiana	1,2	Petersburg	Indianapolis Power & Light
1997	Kentucky	H1,H2	Henderson MP&L Station	Big Rivers Electric
	New Jersey	2	B.L. England	Atlantic City Electric Company

Note: The scrubbing retrofits should go up substantially in the year 2000 and after due to Phase II requirements of the Acid Rain Program.

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

2. The Acid Rain Provisions of the Clean Air Act Amendments of 1990 and Their Antecedents

The Clean Air Act Amendments of 1990 (CAAA90)—Public Law 101-549—are the most recent in a progression of legislative measures to control air pollution. The CAAA90 were preceded by An Act to Provide Research and Technical Assistance Relating to Air Pollution Control (Public Law 84-159) (the original clean air legislation), the Clean Air Act of 1963 (Public Law 88-206), the Air Quality Act of 1967 (Public Law 90-148), the Clean Air Amendments of 1970 (Public Law 91-604), and the Clean Air Act Amendments of 1977—Public Law 95-95—(Table 5).

The Clean Air Act Before 1990[5]

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

An Act to Provide Research and Technical Assistance Relating to Air Pollution Control was passed in 1955 partially in response to the growing concentration of the U.S. population in urban areas. Many urban areas were spread over more than one State (e.g., New York, Chicago, and Washington, DC). 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."[6]

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. There was no direct regulatory role for the Federal Government.

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 which "endanger[ed] 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, since 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 that were consistent with these criteria.

The Clean Air Act Amendments of 1970

The Clean Air Act Amendments of 1970 substantially enlarged the Federal role in air pollution control. Because only a limited amount of action had been taken by State and local governments (with the exception of California) to control air pollution, Congress decided

[5]The following discussion of the 1955 Act and the 1963 Act is based on David P. Currie, *Air Pollution, Federal Law and Analysis* (Wilmette, IL: Callaghan and Company, 1981), pp. 1-10. The remaining discussion of the progression of the Clean Air Act is based on Energy Information Administration, *Impacts of the Proposed Clean Air Act Amendments of 1982 on the Coal and Electric Utility Industries*, DOE/EIA-0407 (Washington, DC, June 1983), pp. 3-4, Lester B. Lave and Gilbert S. Omenn, *Clearing the Air: Reforming the Clean Air Act* (Washington, DC: Brookings Institution, 1981), pp. 7-9, and 40 CFR Part 60.

[6]The Clean Air Act (42 U.S.C. 7401-7626), consisting of Public Law 159 (July 14, 1955; 69 Stat. 322) and the amendments made by subsequent enactments.

Table 5. Chronology of Historic Federal Legislation to Control Air Pollution

Legislation and Date	Federal Role	State Role
An act to provide research and technical assistance relating to air pollution control (1955)	Research, technical and financial aid to States	All responsibility for control
Clean Air Act of 1963	Mediate among States, if requested	Form regional commissions
Air Quality Act of 1967	Create air quality control regions; establish criteria for health protection; recommend control techniques; set national emissions standards for vehicles	Must adopt ambient air quality standards (Federal review and approval)
Clean Air 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	Design State implementation plans and enforce, if approved by EPA; right to impose more stringent standards
Amendments and extensions of Clean Air Act (1971, 1973, 1974, 1976)	Waivers and extensions of motor vehicle emissions standards	
Clean Air Act Amendments of 1977	Classification of air quality control regions as attainment or nonattainment; program for prevention of significant deterioration; special treatment for eastern coal; new source performance standards and hazardous pollutant sections strengthened; motor vehicle emissions standards tightened further	Modification of State implementation plans for nonattainment areas, to avoid major sanctions; cost-benefit analysis and offset policy for new sources

Source: Lester B. Lave and Gilbert S. Omenn, *Clearing the Air: Reforming the Clean Air Act* (Washington, DC: Brookings Institution, 1981), p. 6.

that 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 six criteria pollutants: particulate matter, sulfur oxides, carbon monoxide, nitrogen dioxide, ozone,[7] 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." In nonattainment areas, the 1970 amendments mandated that States establish State Implementation Plans to ensure that the minimum standards set by EPA would be met and maintained. Accordingly, new and modified sources within non-attainment areas were required to attain the "lowest achievable emission reduction." Consistent with Congress' directive concerning setting the standards for NAAQS, cost was again not to be considered in achieving this reduction.

Distinct from ambient standards, the 1970 amendments also introduced national emissions standards for new stationary sources of air pollution, limiting the amounts

[7]Ozone at lower levels in the atmosphere is a pollutant; at higher levels, it forms a layer that protects the earth from ultraviolet radiation.

Some Phase I affected facilities have been around longer than much of the clean air legislation, including five of Yates' seven affected units that were built prior to the original Clean Air Act of 1963.

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 1971 New Source Performance Standards issued by EPA under the authority of the 1970 amendments required that utility coal-fired boilers of 73-megawatt output or greater, on which construction or modification had begun after August 17, 1971, could not emit more than 1.2 pounds of SO_2 per million British thermal units (Btu) of heat input. Plant operators were required to use "continuous emission monitoring" to measure the SO_2 emission levels in the flue gas outlets of coal-fired boilers. If the average emission level exceeded the new standard for more than 3 hours, the plant could be cited for violation.[8]

The 1971 New Source Performance Standards also issued requirements for NO_x and particulate emissions. NO_x emissions from bituminous coal-fired units were limited to 0.7 pounds per million Btu; subbituminous-fired units and lignite-fired units were limited to 0.6 pounds per million Btu; except for those units fired by lignite mined in North Dakota, South Dakota, or Montana which were limited to 0.8 pounds per million Btu. Particulate emissions were limited to 0.1 pounds per million Btu. Additionally, plants were prohibited from producing emissions that exhibited greater than 20 percent opacity except for one 6-minute period per hour of not more than 27 percent opacity.[9]

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. Whereas, sources in attainment areas were directed to use the "best available control technology" in order to

[8]The continuous emission monitoring (CEM) equipment required in the CAAA90 acid rain regulations is more accurate than that required in the New Source Performance Standards of 1971. The standards required plants to emit below a certain level, so older CEMs only needed to accurately measure emissions up to that level. For the CAAA90 rules, the CEM equipment must be able to accumulate total emissions over a given period of time. Thus the new CEMs need to be accurate for any level of emissions that an electric power generating plant may produce.

[9]Opacity is the percentage of incident light that does not pass through the flue gas, and gives an indication of the amount of particulate matter being emitted.

"prevent significant deterioration" of the clean air within the control region.

In 1979, EPA issued Revised New Source Performance Standards. These standards were more stringent than the original standards and applied to all coal-fired utility plants capable of producing more than 73 megawatts of generating capacity, and on which construction or modification began after September 12, 1978. The new standards retained the 1971 standard of 1.2 pounds of SO_2 per million Btu of energy input as a ceiling for emissions, but additionally required that SO_2 emissions from all new or modified boilers be reduced on a sliding scale of percentages based on the sulfur content of the coal burned. All coal burned was required to have at least 90 percent of the SO_2 removed from its emissions, unless 90-percent removal reduced emissions to less than 0.6 pounds per million Btu, in which case reductions between 70 and 90 percent were permitted, depending on the sulfur content of the coal. Utilities were required to monitor SO_2 emissions from these new sources continuously, both at the flue gas inlet and at the outlet, to determine whether the required removal was attained on a 24-hour rolling average.

The Revised New Source Performance Standards also included new requirements for NO_x and particulate emissions that were sometimes more stringent than the requirements of the 1971 standards. NO_x emissions from bituminous coal-fired units were lowered to 0.6 pounds per million Btu, subbituminous-fired units were lowered to 0.5 pounds per million Btu, and the limit for units fired by lignite mined in North Dakota, South Dakota, or Montana remained at 0.8 pounds per million Btu. The limit for other lignite-fired plants remained at 0.6 pounds per million Btu. Particulate emissions were limited to 0.03 pounds per million Btu. The prohibition against emissions exhibiting greater than 20 percent opacity was retained under the revised standards, but there was no mention of the 6-minute period per hour of not more than 27 percent opacity.

The Acid Rain Program of the Clean Air Act Amendments of 1990[10]

Title IV of the CAAA90 established the Acid Rain Program, which is designed to reduce the adverse effects of acid deposition. This will be achieved primarily through domestic 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 Title IV is the reduction of annual SO_2 emissions from electric utilities by 10 million tons below their 1980 level by the year 2010.

The legislation also calls for a reduction of 2 million tons in NO_x emissions from utility boilers. Utilities will 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. NO_x limits for wall dry-fired and tangential-fired boilers affected in Phase I have been selected as 0.50 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 wall- and tangential-fired boilers can be revised, if allowed by improved technology. An emissions averaging provision allows individual utilities to average NO_x over multiple units, if the same or lower emissions result.

To achieve these reductions, the law requires a two-phase tightening of the restrictions placed on fossil-fuel-fired utility power plants. Phase I begins in 1995 with specified limitations for 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern States. Phase II, which begins in the year 2000, tightens the total annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller and cleaner plants fired by coal, oil, and gas. Approximately 2,500 boiler units within approximately 1,000 utility plants will be affected in Phase II. New nonutility boilers that produce electricity for sale to end users will also be affected in Phase II.

Emission Allowances

The Acid Rain Program represents a legislative breakthrough in environmental protection. The approach to controlling SO_2 embodied in the new provisions represents a radical departure from the traditional "command-and-control" approach to environmental regulation. Instead, it introduces an innovative allowance system that harnesses the incentives of the free market to reduce pollution. The acid rain provisions

[10]The discussion in this summary is based primarily on the series of documents regarding the Acid Rain Program published by the U.S. Environmental Protection Agency, Office of Air and Radiation, beginning in 1991.

of the CAAA90 may become the prototype for tackling emerging environmental issues in a more cost-effective manner.

An “allowance” is defined in the CAAA90 as the authorization, allocated to an electricity producer, to emit 1 ton of SO_2 during or after a specified calendar year.[11] The EPA, which will maintain the system for issuing, recording, and tracking allowances, will allocate allowances to affected utilities each calendar year during Phase I based on a standard formula: the product of a 2.5 pound sulfur dioxide per million Btu emission rate multiplied by the unit’s average fuel consumption for 1985 through 1987. In Phase II, all Phase I plants, as well as all remaining utility generating units greater than 25 megawatts in size, must constrain annual emissions to a permanent cap totaling 8.95 million tons of SO_2.[12] Included in the basic allocation of 8.95 million allowances are three reserves: (1) 50,000 allowances for the use of clean coal technologies, (2) 50,000 allowances for conservation and renewable energy initiatives, and (3) 250,000 allowances for auctions and sales. In addition, there will be 500,000 bonus allowances and 50,000 allowances allocated to utilities in certain midwestern States.

The primary requirement for electric power generators to be in compliance with the law is that a generator may not emit more sulfur dioxide than it holds allowances for; therefore, electricity producers will have to either reduce emissions to the level of allowances given to them or obtain additional allowances to cover their emissions above their initial allocation. Sources whose emissions exceed allowances held will be required to pay $2,000 per excess ton, and will be required to offset excess emissions with allowances the following year. Allowances may not be used prior to the calendar year for which they are allocated.

Electric power producers that reduce their emissions below the number of allowances they hold may elect to trade allowances within their systems, bank allowances for future use, or sell them to other utilities. This flexibility provides an incentive for power producers to achieve total emissions limits as cheaply as possible. Anyone may hold allowances—including brokers, environmental groups, and private citizens—and trading will be conducted nationwide. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate Federal or State limits set under Title I or other provisions of the act and its previous amendments to protect public health.

Electricity generating units that began operating after November 15, 1990, will not receive any allowances. Instead, they will have to purchase allowances that were initially allocated to other units, which will limit emissions even more as plants are built and the combustion of fossil fuels to generate electricity increases.

In addition to the initial allocation, allowances are available in three different reserves. In Phase I, units can apply for and receive additional allowances by: (1) installing a qualifying Phase I technology (a technology that can be demonstrated to remove at least 90 percent of the unit’s SO_2 emissions), (2) by reassigning their reduction requirements among other units employing such a technology, or (3) by replacing boilers with new, cleaner and more efficient technologies. EPA has created 3.5 million allowances to stock this reserve. A second reserve provides allowances as incentives for units achieving SO_2 emissions reductions through customer-oriented conservation measures or renewable energy generation.

For the third reserve, EPA has set aside allowances for auctions and direct sales in a Special Allowance Reserve, which is approximately 2.8 percent of the total

On November 15, 1990, President George Bush signed the new Clean Air Act Amendments into law.

[11]U.S. Environmental Protection Agency, “Acid Rain Program Allowance System,” EPA 430/F-92/018 (December 1992), p. 2.
[12]This annual limit averages out to approximately 1.2 pounds per million Btu for all units existing before 1990.

annual allowances allocated to all units. The auctions, the first of which has already occurred, are intended to send the market an allowance price signal along with furnishing affected units and others with an additional source for purchasing allowances. Auction results will be made public by EPA. The sales offer allowances at a fixed price of $1,500. Anyone can buy allowances in the direct sale, but independent power producers can obtain written guarantees from EPA stating that they will have first priority. These guarantees, which are awarded on a first-come, first-served basis, secure the option for qualified independent power producers to purchase a yearly amount of allowances over a 30-year span, and enables them to assure lenders that they will have access to the allowances they need to operate new generating units.

Operating Permits

The Acid Rain Program is implemented through operating permits. Each plant that houses an affected unit must submit a standard permit application form when applying for an Acid Rain Permit. The form must include general plant information, information about the Designated Representative, specific unit information, and a compliance plan for each affected unit. The plan must describe the actions taken to ensure compliance with the Acid Rain Program and must indicate that the unit will hold enough allowances to cover its annual SO_2 emissions and will be operated in compliance with the applicable NO_x emissions limitations. The plan may comprise one or more of the following options: (1) hold allowances, (2) substitution plan, (3) extension plan, and (4) reduced utilization plan. Each of these options and the permitting process are discussed in more detail in Chapter 3. Applications are submitted for approval to EPA in Phase I and to an EPA-approved State or local permitting authority in Phase II. Those States that do not have EPA approval permit programs by July 1, 1996, will have their sources' Phase II permits processed by EPA.

Continuous Emission Monitoring

Affected units also are required to install systems that continuously monitor emissions of pollutants discharged into the atmosphere in exhaust gases. This "continuous emission monitoring" (CEM) is required to ensure that the mandated reductions of pollutants are achieved. EPA has established requirements for the continuous monitoring of SO_2, NO_x, volumetric flow, opacity, and diluent gas (carbon dioxide (CO_2) or oxygen) for units regulated under Phase I and Phase II. In addition, if a utility uses a CEM system to monitor emissions, a CO_2 diluent monitor plus a flow monitor would be used to compute emissions. The rule also contains requirements for equipment performance specifications, certification procedures, and recordkeeping and reporting, which plants must do on a quarterly basis to EPA. All required CEM equipment must be installed, certified, and operational by November 15, 1993, for Phase I units, and by January 1, 1995, for Phase II units (Appendix F). A new unit (a unit that begins commercial operation on or after November 15, 1990) must meet all requirements no later than 90 days after commencing commercial operation.

Phase I Implementation Issues

Two substantial issues have arisen in the implementation of Phase I of the CAAA90. EPA has approved some of the Phase I permits for only 1 year, although it had initially planned to approve them for the entire 5 years of Phase I. EPA estimates that some substitution compliance plans and reduced utilization compliance plans specified by utilities under the initial EPA rules will generate approximately 1 million more allowances for Phase I than they expected. As a result, EPA has proposed that it revise the Phase I rules for substitution plans and reduced utilization plans, and that it issue permits for these two plans for 1995 only under the old compliance rules. Permits for 1996 through 1999 for these units will be subject to the revised rules, which are expected to be promulgated in early 1994.

Previous to the proposal to only partially approve some permits, several environmental advocate groups and the State of New York petitioned the U.S. Court of Appeals for review of the initial compliance rules. These petitions are currently being considered by the court.

3. Compliance Strategies for Control of Sulfur Dioxide Emissions

Most utilities affected by Phase I of the Acid Rain Program need to take some action to meet sulfur dioxide (SO_2) emissions limitations. The majority will switch or blend fuels, obtain additional allowances, or install flue gas desulfurization equipment (scrubbers). Some affected units will not need to take any action because previously implemented controls will enable them to meet compliance using their basic allotment of allowances. Others will retire affected units, and one unit will use boiler repowering. In addition to the six main methods of compliance discussed in this report, there are further strategies available which most utilities plan to use in conjunction with their main method. They include energy conservation (including supply-side and demand-side management), reduced utilization plans, and substitution plans. Chapter 3 discusses each of these strategies and several other directly related issues.

Fuel Switching/Blending

More than half of the compliance methods chosen for Phase I affected units involve fuel switching, blending, or cofiring.[11] Fuel switching usually involves changing to a coal with a lower sulfur content, although it may include switching to another type of fuel entirely. Fuel blending is the blending of high- and low-sulfur coals to reduce SO_2 emissions, while cofiring usually involves combining another type of fuel, commonly natural gas, with coal in the boiler to reduce emissions. Of the 110 Phase I targeted plants, with a total of 261 affected generating units, more than 60 plants housing 162 affected units have chosen fuel switching, blending, or cofiring. About 40 of those 162 units, primarily in Illinois, Pennsylvania, and Indiana, are planning to blend in-State coal with coals of lower sulfur content. Another four to six plants have submitted plans to cofire with, or switch to, natural gas.

While some utilities have stated where they intend to purchase low-sulfur coal for compliance with Phase I, relatively few utilities have signed contracts confirming these intentions. However, the Central Appalachian Region is mentioned most often as a possible source for low-sulfur coal, followed by the Powder River Basin.

Switching to Low-Sulfur Coal

Compared to scrubbing and repowering, the fuel switching/blending method has lower capital costs, which will result in lower sunk costs in case a different compliance method later becomes preferred. Coal switching also offers the utility more time to look at the issues involved, including coal quality in total switching versus blending, transportation and fuel costs, and boiler performance, because switching may require less lead time to implement. This is particularly important for Phase I, since the amendments were passed in November 1990 and will take effect January 1995. However, switching to a low-sulfur coal carries with it a different set of costs and requirements to assess the characteristics of the low-sulfur coal and its impacts on the operation of existing power plants and the performance of boiler units and related components.

It has been estimated that potentially up to 60 percent of unscheduled outages at a power plant are associated with equipment that contacts either coal or coal combustion products.[12] In general, power plants are designed for a particular type of coal, with which initial performance guarantees are met. Plants also have an allowable range for the most important coal properties, within which it is expected that a full load may be produced, although possibly at reduced efficiencies. Deviations in one or more of the properties beyond the allowable range may result in impaired plant performance or even serious operating and maintenance

[11]Phase I units may use coal of any sulfur content that will meet their allowances to emit no more than 2.5 pounds of SO_2 per million Btu. SO_2 emissions are expressed as a function of the heating content of the coal and the sulfur content of the coal.

[12]IEA Coal Research, *Coal Specifications—Impact on Power Station Performance*, IEACR/52 (London, England, January 1993), p. 13.

Around 62 percent of the affected units will meet compliance by fuel switching and/or blending, including Ohio Edison's Edgewater facility.

problems.[13] Thus, a good coal switching plan requires significant cost analysis and could take as long as 2 years to implement, allowing time for study and design, test burns, equipment procurement and delivery, construction, and outages during construction.[14]

Low-Sulfur Coal Characteristics

There are an estimated 100 billion short tons of low-sulfur recoverable reserves in the United States. About 12 percent of those reserves are in the Appalachian Region, which includes Alabama, Georgia, eastern Kentucky, Maryland, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Eighty-seven percent are in the West, which includes Alaska, Arizona, Colorado, Idaho, Montana, New Mexico, North Dakota, South Dakota, Wyoming, Oregon, and Washington. Less than 1 percent are in the Interior Region which includes Oklahoma, Texas, Arkansas, Louisiana, Missouri, western Kentucky, Iowa, Kansas, Indiana, and Illinois.[15]

Low-sulfur coals in the West are found mostly in the Powder River Basin (Wyoming and Montana), Colorado, Utah, Arizona, and Washington (Figure 3). In the East, low-sulfur coals are found in the Central Appalachian Region, primarily in southern West Virginia, eastern Kentucky, and western Virginia. Low-sulfur coal from the East generally has a higher heating value and lower moisture content than low-sulfur coal from the West. These differences can greatly affect plant operation, from coal handling, storage, and pulverization to boiler design and ash handling.

Eastern Low-Sulfur Coal

The Effects of Eastern Low-Sulfur Coal on Boiler Performance

A typical eastern low-sulfur coal has a heating value of 13,000 British thermal units (Btu) per pound, moisture content of 6.9 percent, ash content of 4.5 percent, Hardgrove Grindability Index (HGI) of 45 to 55, and sulfur content of 0.7 percent by weight (Table 6).[16]

Little has been written about burning eastern low-sulfur coals, probably because of the relatively small impact of eastern low-sulfur coal on boiler performance or because of the economic attractiveness of low-sulfur coal from the Powder River Basin. It may be that central Appalachian low-sulfur coals will have little impact on boiler performance because most plants in Illinois and Ohio, where much switching will occur, can easily accommodate eastern low-sulfur coals with its high ash fusion temperatures.[17] The transition from bituminous high-sulfur coal to bituminous low-sulfur coal has few equipment impacts. The grindability of eastern low-sulfur coals from southern West Virginia is usually around 55, a favorable HGI for pulverizers. (The lower the HGI, the more difficult the coal is to grind.)

In a study of one plant switching to low-sulfur eastern coal, the low-sulfur eastern coal that was tested produced more favorable results in some equipment

[13]IEA Coal Research, *Coal Specifications—Impact on Power Station Performance*, IEACR/52 (London, England, January 1993), p. 13.

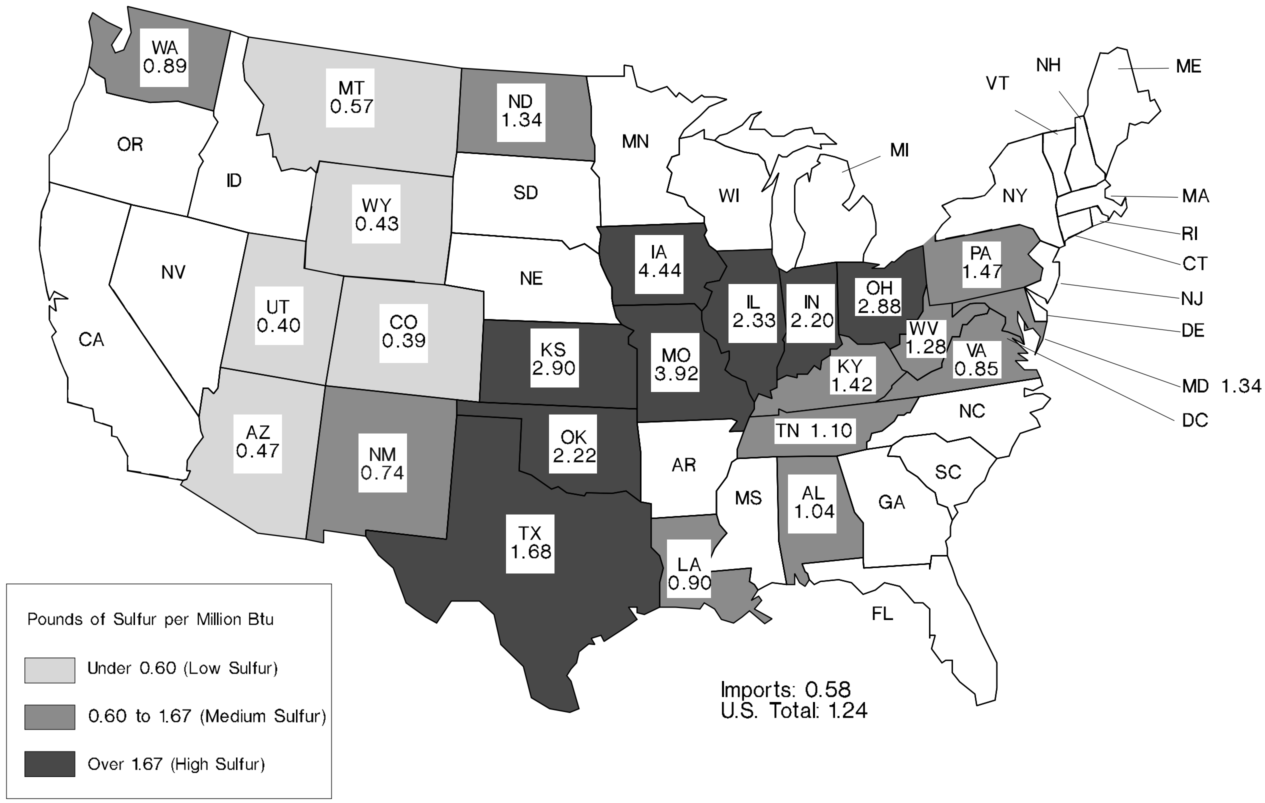
[14]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).

[15]Energy Information Administration, *U.S.Coal Reserves: An Update by Heat and Sulfur Content*, DOE/EIA-0529(92) (Washington, DC, February 1993), p. ix.

[16]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).

[17]Verbal communication with Edward T. McHale, Science Applications International Corporation.

Figure 3. Average Sulfur Content of Coal Shipped to U.S. Power Plants by State of Origin, 1992
(Pounds of Sulfur per Million Btu)



Source: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1992*, DOE/EIA-0191(92) (Washington, DC, August 1993), p. 30.

Table 6. Comparison of Typical Coal Characteristics and Ash Properties

	High-Sulfur Coal	Eastern Low-Sulfur Coal	Western Low-Sulfur Coal
Heating Value (Btus per pound)	10,500	13,000	8,000
Moisture Content (percent)	11.7	6.9	30.4
Ash Content (percent)	11.8	4.5	6.4
Hardgrove Grindability Index (HGI)	55	45-55	40-65
Sulfur Content (percent)	3.2	0.7	0.5
Ash Properties			
Sodium Content (percent)	0.5	0.8	1.6
Calcium Content (percent)	4.8	1.0	21.8
Slag Temperature (T_{250} in °F)[a]	2,400	2,900	2,900

[a]T_{250} is the maximum temperature for which molten ash or slag will flow easily, and is characteristic of the slag constituents. The notation 250 refers to a measure of the viscosity of the slag (specifically, at temperature T_{250}, the slag will have a viscosity of 250 poise).

Note: All values are typical of "as-received" coal.

Source: Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low Sulfur Coal," Sargent & Lundy, presented at the 1992 International Joint Power Generation Conference and Exposition (Atlanta, GA, October 18-22, 1992).

performance areas than the higher-sulfur coal that the boiler was designed to burn. Boiler efficiency was expected to increase by 2 percent, primarily because of lower moisture content. The higher heating value of the eastern low sulfur coal improved boiler efficiency and resulted in 26 percent less pulverizer capacity required. The higher HGI and the lower moisture content also contributed to an increase in available pulverizer capacity. However, installation of a flue gas conditioning system was required to improve precipitator performance. No change was required for the forced draft fans or for the fly ash handling system. The estimated cost for these plant modifications amounted to $25.5 per kilowatt of plant capacity (1992 dollars).[18]

Production and Distribution in Central Appalachia

Since the Central Appalachian Region has been chosen as a new source of coal by more of the plants switching to a lower sulfur coal, the present production and end use of coal from this region may be affected when plants make the final implementation of their compliance plans.

Production in the Central Appalachian Region in 1992 was 273.6 million short tons; 118.7 million short tons from eastern Kentucky, 112.0 million short tons from southern West Virginia, and 42.9 million short tons from Virginia.[19] The eastern Kentucky coalfield covers 10,500 square miles, with more than 80 named coal seams and eight widespread, relatively thick beds of low-sulfur coal.[20] In 1992, 69 percent of eastern Kentucky coal distributed was used by electric utilities; 18 percent was used by coke plants and industrial, residential, and commercial users; and 12 percent was exported.[21]

The southern coalfield of West Virginia is more homogeneous than its northern counterpart, with 43 minable seams and many high-quality (low-sulfur, low-ash, and high-Btu) coals. The average sulfur content is consistently below 1.5 percent. In 1992, southern West Virginia coal was distributed as follows: 43 percent went to electric utilities, 39 percent was exported, and 17 percent went to coke plants and industrial, residential and commercial users.

All of Virginia's 1992 coal production, totaling 42.9 million short tons, came from the Southwest Virginia coalfield in the western part of Virginia. The coals vary from high to low volatile bituminous in rank and are typically low sulfur (less than 1 percent). Thirty-eight percent of the coal distributed from this coalfield was exported, 33 percent went to electric utilities, and 27 percent went to coke plants, industrial, residential, and commercial users.

Powder River Basin Coal

As previously mentioned, of the estimated U.S. total of 100 billion short tons of low-sulfur recoverable coal reserves, 87 percent is in the West.[22] Western coals have several characteristics that differentiate them from eastern coals and will have an impact on plant operations (Table 7):

- They are more brittle, which means that they are very dusty. The brittleness of Powder River Basin coals is caused by the presence of intact plant materials (vitrain bands). This characteristic requires more aggressive dust suppression and dust collection procedures and more diligent housekeeping in coal handling areas.[23]

- They have a higher tendency for spontaneous combustion than eastern coals, creating a fire and explosion hazard and requiring more extensive fire protection equipment and procedures. The risk of fire is greater for cyclone boilers than for pulverized coal boilers because the coal for cyclone boilers is crushed in the coal handling areas. This means that the crushed coal receives an increased amount of handling in a more ignitable form as it is brought over an extended distance by a conveyor system to coal bunkers

[18]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).

[19]Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, November 1993), Table 3.

[20]*1992 Keystone Coal Industry Manual*, Maclean Hunter Publishing Company (Chicago, Illinois, 1992).

[21]Energy Information Administration, *Quarterly Coal Report*, DOE/EIA-0121(92/4Q) (Washington, DC, May 1993), pp. 20-22.

[22]Energy Information Administration, *U.S. Coal Reserves: An Update by Heat and Sulfur Content*, DOE/EIA-0529(92) (Washington, DC, February 1993), p. ix. The West includes Alaska, Arizona, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

[23]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).

Table 7. Impact of Coal Characteristics on Coal Switching

Change in Coal Characteristics	Resulting Potential Operating Problems	Possible Solutions
Lower heating value	Insufficient coal-handling capacity Unable to achieve design steam output	Enlarge coal-handling equipment Derate capacity
Higher moisture	Longer/cooler flames Lower furnace exit temperature Higher gas flow	Derate capacity Increase/modify boiler heat transfer surface area Increase fan capacity
Higher ash	Increased particulate in flue gas Increased solid waste	Increase soot blowing Modify boiler convective section heat transfer area Increase electrostatic precipitator plate area Modify ash-handling and disposal systems
Lower sulfur	Lower particulate collection efficiency	Increase electrostatic precipitator plate area Install flue gas conditioning
Higher ash fusion	Incompatible with cyclone and wet-bottom furnaces	Use different coal
Higher sodium and iron content in ash	Increased slagging and fouling	Increase soot blowing Use ash additives Accept higher forced-outage rates
Higher volatility	Changed heat transfer characteristics Heating and potential fires in coal-handling equipment	Change boiler tube distribution in furnace and convective sections Modify pulverizers, silos, and other coal-handling equipment
Harder grindability	Insufficient pulverizer capacity	Increase pulverizer capacity Derate boiler capacity

Source: Radian Corporation, "Analysis of Low NO_x Burners Technology Costs," unpublished draft report prepared for the U.S. Environmental Protection Agency (Research Triangle Park, NC, November 1992).

and silos. Pulverizers for low-sulfur coals may require enclosed conveyors and explosion venting and procedures to remove hot coals from bunkers and silos.[24]

- They generally have a lower heat value, requiring a higher firing rate to produce the same heat rate. Lower heat values force the utility to decide between derating the capacity of the boiler and increasing the size of the boiler combustion zone.

- Some Powder River Basin coals have a higher moisture content than high-sulfur coals. A higher moisture content increases the drying requirements in the pulverization process,[25] and may decrease boiler efficiency because combustion heat must be used to evaporate the water in the coal.

- They are more difficult to pulverize, with HGI in the range of 40 to 50. Utilities are using a variety of measures to maintain pulverizer capacity and performance when firing blends of western coal with eastern coal. A recent survey reports that 5 of 11 pulverizer units blending eastern and western coals reported lowering the pulverizer exit temperature control point to reduce the incidence

[24]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).

[25]These results were obtained from a pulverization pilot plant program to determine the effect of moisture differences on mill performance, using a blend of 40/60 Illinois low-sulfur with Powder River Basin coal containing 21.7 percent moisture by weight. R.E. Douglas and C.L. Krcil, "The Effect of HGI and Coal Moisture Differences on Mill Performance for Coals and Coal Blends," paper presented at the Engineering Foundation Conference on Coal Blending and Switching of Western Low-Sulfur Coals (Salt Lake City, UT, September 26, 1993).

Amax Coal, owned by Amax Incorporated who recently merged with the Cyprus Minerals Company, has been producing low-sulfur coal in Wyoming for a number of years, and demand for low-sulfur coal is expected to rise due to the passage of the CAAA90.

> of mill "puffs" or pyrite trap fires. Four of the units added mill inerting or flooding capabilities, while two of the same units altered startup and shutdown procedures to promote safe operation. Two units reported efforts to improve pulverizer maintenance, and two units added pulverizer air flow and/or temperature instrumentation where none had existed before.[26]

In addition, the different ash properties of western low-sulfur coal have a significant effect on the components of a steam generator. Ash resulting from the combustion of coal can occur in several forms in the furnace: as solid fly ash passing through the furnace, as molten ash particles in the gas stream, or as an accumulation of very hot, but not molten, ash in the convective passes of the superheater. Each of these leads to different problems: decreased effectiveness of the electrostatic precipitator,[27] a lower heat transfer rate because of the formation of slag deposits on the water wall tubes, and less efficient heat transfer because ash builds up and plugs convection passes (fouling). While theories vary as to which constituents of western coal are related to ash problems, there is general agreement that the tendency to foul and slag increases with western coals. These ash problems may require upgrades or modifications to boiler components, including additional soot blowers, mechanisms to control steam temperature, conversion or replacement of fans, adjustments to air heaters, and modifications or upgrades to electrostatic precipitators.

Equipment Problems Resulting from Fuel Switching

The extent of the impact of fuel switching on plant operation depends on the original plant design and the specific coal considered for the fuel switch. Although potential equipment problems vary on a case-by-case basis, there are several common problems for a typical unit switching to a subbituminous western coal. The following discussion identifies some of the major problems and the methods for addressing them.

Coal Handling System: Depending on the origin and delivery route of the western coal, it could arrive frozen, causing problems during coal unloading. Unloading facilities may have to be modified if the current system is not capable of handling frozen coal. These modifications could range from the addition of coal car rappers to the construction of a coal car preheating facility.

[26]J.R. Gunderson, S.J. Selle, and N.S. Harding, "Utility Experience Blending Western and Eastern Coals—Survey Results," paper presented at the Engineering Foundation Conference on Coal Switching and Blending of Western Low Sulfur Coals (Salt Lake City, UT, September 26, 1993).

[27]This occurs because the reduction in sulfur content lowers the sulfur oxidation process in which sulfuric acid is formed and condenses on the fly ash particles and produces an electrically conducive film that makes the electrostatic precipitator process effective.

Western coal brittleness and dust-forming characteristics require additional dust suppression equipment to reduce the potential of explosions. Higher coal volatility, accumulation of coal dust on surfaces, and exposure of coal dust to electrical contacts increases the possibility of fire. It may be necessary to reduce conveyor speeds to control coal spillage and coal dust release to surrounding areas. Transfer points, bins, and bunkers may need to be enclosed or equipped with additional skirting structures and belt wipers. Also a fabric filter collecting the dry particulate matter as the cooled flue-gas passes through or wet dust suppression system may be required.

The lower Btu content of the coal will require greater volumes of fuel and will affect long-term and short-term storage requirements. The high moisture content and increased fineness reduce movement on the conveyor and may require additional conveyor capacity. Western coals also become more cohesive when wet, causing plugging in crushers, feeders, chutes, and coal silos. Required modifications can include replacement of or lining existing equipment.

Fuel Preparation and Firing System: The lower HGI, higher moisture content, and increased inlet feed size typical of western coal increase time requirements in the fuel preparation stage, thereby decreasing coal throughput capacity. High-moisture western coals require more drying than low-moisture bituminous coals. This may be offset to a slight degree by a reduction in the required fineness. Reduced throughput may necessitate bringing an additional mill into service, installing an additional mill, or replacing all mills.

Western coal brittleness and dust-forming characteristics, coupled with the higher inlet temperatures required for drying the coal, increase the chance of mill explosions. Inerting systems, explosion venting, and additional water hoses and fire extinguishers may be required.

Primary Air System: The high moisture and increased fuel burn rate of western coals require larger volume and higher temperature primary air, increasing the requirements on primary air fans and air heaters. If primary air flow is insufficient to convey and dry the coal, modifications to primary air fan blades, wheels, or motors may be needed, or fan replacement may be required. If temperatures cannot be maintained at higher flows, air heater performance can be upgraded by replacing existing air heater baskets with high-density baskets or adding in-duct air heaters (Figure 4).

Steam Generator: Western coals typically have a higher propensity to slag and foul, increasing the difficulty of removing deposits on water wall surfaces. If tube cleanliness cannot be maintained because of ash deposits that are difficult to remove, heat transfer to the walls decreases, increasing heat input requirements and thereby decreasing boiler efficiency. Higher furnace temperatures may lead to further slagging or fouling problems. Increased fouling may reduce heat transfer to the convective surfaces, thereby increasing the economizer (a counterflow heat exchanger for recovering energy from the flue gas) gas outlet temperature and decreasing boiler efficiency.

Ash deposits caused by western coals may also increase the difficulty of removing the slag or foul deposits. Additional steam or air soot blowers and water cleaning may maintain cleanliness; however, tube erosion problems resulting from additional soot blowing or cleaning will also increase. Boiler unit availability will be reduced if unit load must be decreased for slag shed or if additional tube failures cause more outages.

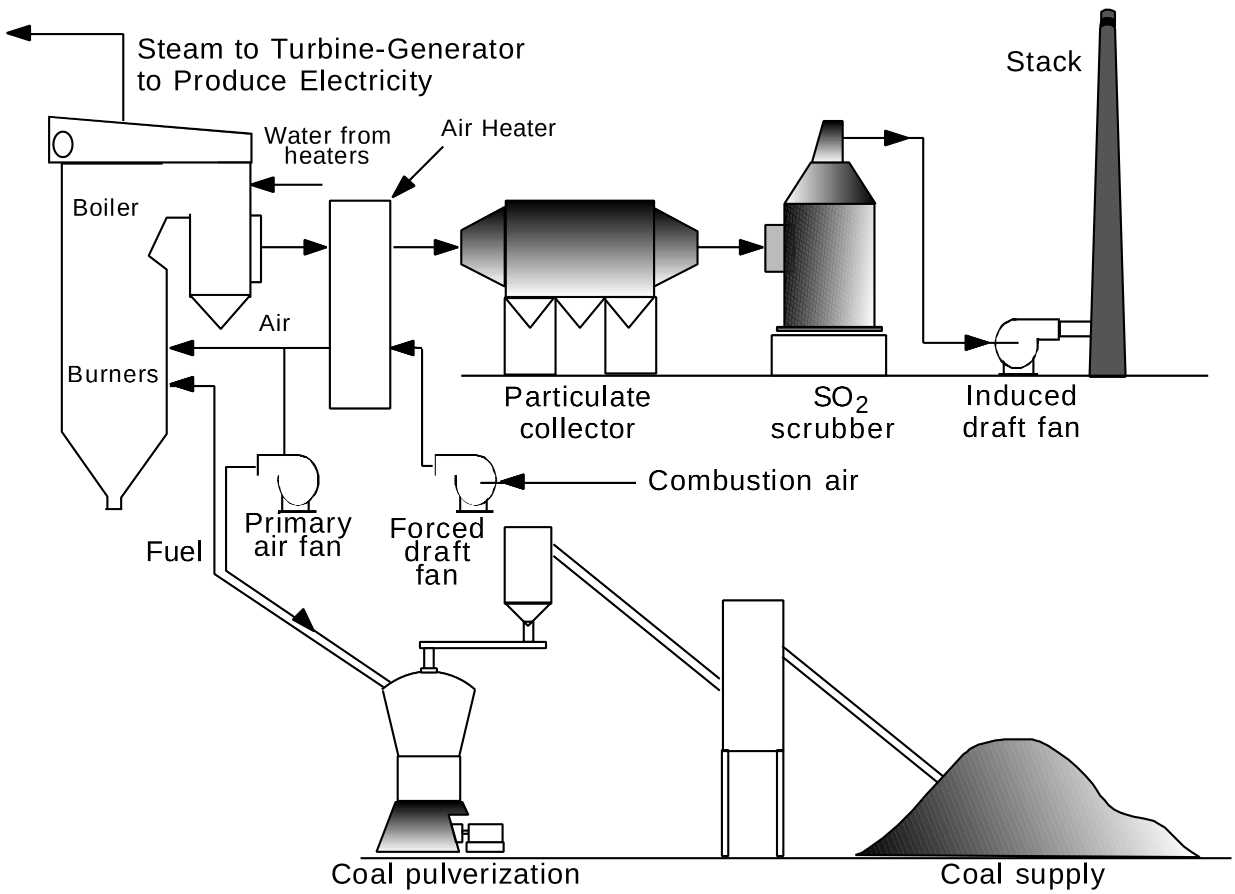
Higher gas volumes and temperatures entering the convective pass (the horizontal and vertical downflow sections of the boiler enclosure) may also reduce net turbine efficiency. Higher moisture content increases latent heat losses, decreasing boiler efficiency. Higher fuel burn rate due to larger volume causes higher duty requirements in several systems and increases auxiliary power requirements. Increased spray treatment may increase net turbine heat rate. These all decrease the efficiency of the power plant.

Particulate Removal System: Sodium, an essential chemical for charging particulate matter for capture by the electrostatic precipitator is more easily depleted from western coals. 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.

Ash and Waste Disposal: The low ash content typical of western coal will have little impact on the typical ash and waste disposal system; however, the high calcium oxide content of some western coals can cause ash to harden when wet. Avoiding these buildups may require conversion from a wet to a dry ash disposal system.

Building and Structural Support: The brittleness and dust-forming characteristics of western coals may

Figure 4. Coal-Fired Utility Steam Generator Schematic



Source: Steven C. Stultz and John B. Kito, eds., *Steam: Its Generation and Use*, 40th ed. (Barberton, OH: Babcock and Wilcox Co., 1992), p. 1-4.

require modifications to the boiler building, as well as to coal handling and other coal contact areas and structures, to prevent dust buildup and reduce explosion potential. Since dust collects on horizontal surfaces, exterior wall panels may have to be moved inside the supporting structure to prevent coal dust from accumulating on the structural beams. Additional ventilation may be necessary to supply makeup air, especially if a dry dust bag house collection system is installed. Some areas may need to be pressurized to prevent infiltration of coal dust. Electrical systems such as junction boxes, conduits, and plug receptacles may require modification to be dust ignition-proof. Cable trays may need to be moved or covered, and motors and control systems may need to be upgraded or enclosed. Expansion of the existing fire protection system may also be necessary.

Plant Cleanup and Maintenance: Proper plant cleanup schedules reduce the presence of stray coal, which reduces the chance of fires and explosions. Necessary equipment upgrades for cleanup could include the addition of water hoses and runoff drains or the installation of a vacuum system. In addition to good housekeeping practices, maintenance procedures may need modification to ensure a safe working environment.[28]

The Effects of Fuel Switching on Power Plant Costs, Coal Distribution, and Production

A wide range of capital costs can be incurred in converting a power plant from high-sulfur to low-sulfur

[28]John H. Pavlish, April Anderson, and Neil C. Craig, "Using the CQIM to Evaluate Switching to Western Low-Sulfur Coals," Black & Veatch, paper presented at the Engineering Foundation Conference on Coal Switching and Blending of Western Low Sulfur Coals (Salt Lake City, UT, September 26, 1993).

Another study has reviewed the capital costs of the coal handling system modifications required to switch to low-sulfur blends for three electric utilities in the Midwest.[30] One plant made several modifications to the conveyor system and added ventilation fans, dust suppression systems at conveyors, and some house-keeping equipment. The installation was completed over an 11-month period and cost $8 per kilowatt.

Another plant installed a new blending system, requiring 18 months for the modification and costing $14 per kilowatt. A third plant made extensive modifications to the reclaim belt conveyor system, including new electronically controlled belt feeders, new dust suppression and collection systems, and a new programmable logic control system for the entire coal-handling process at a cost of $30 per kilowatt.[31]

Compliance with Phase I may result in changes in coal distribution patterns and transportation rates; however, because of the variety of compliance strategies, the impacts of the law on coal and coal transportation markets are highly uncertain.

coals. Information compiled from eight case studies to assess the potential effects of coal switching indicates that the costs may vary from $25 to $119 per kilowatt of capacity (Table 8).[29] The studies included two conversions to eastern low-sulfur coal and six to western low-sulfur coal. The two plants changing to eastern coals had capital costs of $25 and $31 per kilowatt, both for electrostatic precipitators. All six western coal cases had higher costs, and only western coal cases required modifications to reduce fire and explosion hazards. Dust control capital costs ranged from $6 to $28 per kilowatt. The capital costs for modifications for fire protection ranged from $12 to $33 per kilowatt. The capital costs for modifications to reduce or eliminate facility and performance shortcomings such as modifications to pulverizers and electrostatic precipitators ranged from $18 to $86 per kilowatt. The highest capital costs to modify plants changing to western coal were also for modifications to electrostatic precipitators.

Fuel costs may change when a plant switches to low-sulfur coal. In 1992, the coal receipts of the plants planning to switch to low-sulfur coal totaled 133.2 million short tons. The five States from which the largest amounts of coal originated were Illinois, Kentucky, West Virginia, Ohio, and Pennsylvania. Other States from which coal originated were Alabama, Colorado, Indiana, Iowa, Maryland, Missouri, Tennessee, Utah, Virginia, and Wyoming. (Appendix A contains a listing of the origin of the coal received in 1992 at plants planning to switch or blend). Their average Btu content was 11,739 Btu per pound, average sulfur content was 2.22 percent by weight and average delivered coal cost was $35 per short ton.

The average fuel costs of all plants planning to switch to a low-sulfur coal are not expected to increase significantly because of two factors:

- The potential excess productive capacity of the regions selected as new sources of coal
- It is expected that fuel costs for some plants may increase and others decrease as plants switch to coal from the Central Appalachian Region and the Powder River Basin.

Fuel switching will have some effects on production and distribution of low-sulfur coal. Over the last 3 years (from 1989 to 1992), receipts of low-sulfur coal

[29]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).
[30]Romas L. Rupinskas and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low-Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Altanta, GA, October 18-22, 1992).
[31]Some of these costs were for new electrical work that was not related to coal blending.

Table 8. Capital Expenditures for Modifications Associated with Switching to Low-Sulfur Eastern and Western Coal
(1992 Dollars per Kilowatt)

Issues	Case Study[a] Eastern Coal Region 1	2	Western Coal Region 3	4	5	6	7	8
Fire and Explosion Issues								
Dust Control								
Dust Suppression	0.0	0.0	0.2	2.1	2.5	1.9	2.1	1.4
Dust Collection	0.0	0.0	1.1	3.0	4.5	9.3	3.4	3.3
Ventilation	0.0	0.0	0.7	1.2	3.2	3.6	5.7	4.1
Housekeeping	0.0	0.0	3.3	0.6	3.1	0.9	0.6	0.9
Electrical Component Replacement or Relocation	0.0	0.0	0.2	2.6	0.0	12.3	2.5	3.4
Subtotal	0.0	0.0	5.5	9.5	13.3	28.0	14.3	13.1
Fire Protection								
Additional Coverage	0.0	0.0	5.4	0.6	4.9	0.9	3.0	2.8
Explosion Venting	0.0	0.0	0.0	0.6	0.0	1.0	0.8	0.8
Bunker/Silo/Pulverizer Inerting	0.0	0.0	1.1	0.6	3.1	1.7	2.0	0.9
Emergency Bunker/Silo Unloading	0.0	0.0	1.1	0.4	1.4	0.8	2.2	1.2
Conveyor Modifications	0.0	0.0	0.2	0.0	0.0	0.0	0.4	0.0
Subtotal	0.0	0.0	7.8	2.2	9.4	4.4	8.4	5.7
Total Fire and Explosion	0.0	0.0	13.3	11.7	22.7	32.4	22.7	18.8
Facilities and Performance Issues								
Steam Generator	0.0	0.0	10.1	0.0	0.0	0.0	0.0	10.3
Pulverizers	0.0	0.0	2.2	0.0	0.0	0.0	10.7	0.5
Sootblowers	0.0	0.0	3.2	0.0	2.1	0.0	0.0	0.0
Fans	0.0	0.0	1.3	0.0	0.0	0.0	5.4	0.0
Precipitators	24.9	31.0	0.0	46.4	24.9	74.4	12.8	5.3
Coal Handling	0.0	0.0	1.5	2.0	3.7	1.9	9.7	11.2
Ash Handling	0.0	0.0	0.0	7.8	0.0	9.9	8.3	5.7
Auxiliary Power	0.0	0.0	0.0	1.0	0.9	0.0	2.4	1.5
Total Facilities and Performance	24.9	31.0	18.3	57.2	31.6	86.2	49.3	34.5
Grand Total	24.9	31.0	31.6	68.9	54.3	118.6	72.0	53.3
Derating (percent)	0.0	0.0	15.0	0.0	7.5	0.0	0.0	0.0

[a]Eight case studies were presented in the report considering eight unnamed plants.

Note: Costs include equipment, material, labor, and contingency.

Source: Romas L. Rupinskas and Paul A. Hiller, “Considerations for Switching from High-Sulfur Coal to Low Sulfur Coal,” Sargent & Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition (Atlanta, GA, October 18-22, 1992).

show slight regional increases in anticipation of acid rain legislation as indicated by receipts at U.S. electric utilities from the Central Appalachian Region in 1989 of 131.9 million short tons of low-to-medium sulfur coal, compared with 135.9 million short tons of low-to-medium sulfur coal from the Central Appalachian Region in 1992. Likewise, U.S. electric utilities received 215.8 million short tons of low-to-medium sulfur coal from Wyoming, Montana, and Colorado in 1989 and 235.2 million short tons of low-to-medium sulfur coal from this region in 1992 (Table 9).

About 34 of the plants planning to switch to low-sulfur coal have already decided where they will obtain the low-sulfur coal. Thus far, two-thirds have chosen the Central Appalachian Region and one-third have chosen the Powder River Basin as the new source of coal. It is estimated that these plants will require about 24 million

Table 9. Coal Receipts at Electric Utility Plants by Supply Region and Sulfur Dioxide Level, 1989 and 1992
(Thousand short tons)

Supply Region	1989			1992		
	Low to Medium SO_2[a]	High SO_2[b]	Total	Low to Medium SO_2[a]	High SO_2[b]	Total
Central Appalachia	131,889	12,213	144,102	135,853	4,349	140,202
Eastern Kentucky	76,031	9,451	85,482	74,521	2,321	76,842
Virginia	16,192	1,807	17,999	15,178	1,370	16,548
Southern West Virginia	39,666	955	40,621	46,154	658	46,812
Mountain	215,835	27	215,862	235,182	184	235,366
Wyoming	165,633	--	165,633	181,368	184	181,552
Montana	36,063	18	36,081	37,309	--	37,309
Colorado	14,139	9	14,148	16,505	--	16,505
Illinois Basin	9,478	106,462	115,940	7,136	112,870	120,006
Illinois	7,598	46,220	53,818	4,236	50,268	54,504
Indiana	1,734	25,431	27,165	2,454	22,472	24,926
Western Kentucky	146	34,811	34,957	446	40,130	40,576

[a]Low to Medium SO_2 level is less than or equal to 2.5 pounds of sulfur dioxide per million Btu.
[b]High SO_2 level is greater than 2.5 pounds of sulfur dioxide per million Btu.
SO_2 = Sulfur dioxide.
Source: Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants*, DOE/EIA-0191 (Washington, DC, 1989 and 1992).

tons of coal from the Central Appalachian Region in order to reach the Phase I emission level goal of 2.5 pounds SO_2 per million Btu in 1995 and about 12 million tons from the Powder River Basin.[32]

Both the Central Appalachian Region and the Powder River Basin potentially have the productive capacity to meet the demands of complying with the Clean Air Act Amendments of 1990 (CAAA90). In 1992, mines east of the Mississippi River operated with an excess capacity of about 20 percent, implying that southern West Virginia, Virginia and the eastern Kentucky region could produce an additional 65 million tons of coal without a significant increase in mine cost or minemouth price. In the West, mines in the Powder River Basin operated with an excess capacity of about 22 percent in 1992, implying that the States of Montana and Wyoming could produce an additional 78 million tons of coal without significant increases in mine cost or minemouth price.[33]

Obtaining Additional Allowances

Another option for complying with the CAAA90 is for an affected unit to acquire additional SO_2 allowances that will cover its emissions. Every Phase I affected unit, as well as Phase II affected units in the year 2000, must possess a number of allowances equal to its emissions. Thus, every affected unit must use allowances to comply with the Acid Rain Program. Units are given an initial quantity of allowances, based on their average fuel consumption in 1985 through 1987 times a 2.5 pound SO_2 per million Btu emission rate for Phase I. In most cases, this initial distribution is not sufficient to meet the amount of SO_2 that the unit is expected to emit starting in 1995.

For each individual unit, a sufficient strategy to meet the clean air requirements is to acquire enough additional allowances to cover their expected emissions.

[32]See Appendix A for the methodology used to calculate these estimates.
[33]Energy Information Administration, *Coal Production 1992*, DOE/EIA-0118(92) (Washington, DC, November 1993), p. 68.

Ohio Edison's Niles facility will use allowances for compliance on unit 1 and a flue gas desulfurization technology on unit 2.

Notwithstanding the small number of supplemental allowances allocated by the EPA, utilities must obtain additional allowances from other utilities that have reduced their emissions below their annual allocation. Because the total number of allowances for any one year is fixed, and is less than the emissions expected to be produced by all of the affected units, not all utilities may choose the strategy of acquiring additional allowances. Thus, there are not enough allowances for every unit to purchase allowances to cover its expected emissions.

One way for utilities to acquire additional emission allowances is to purchase them from a current allowance owner. This process constitutes the private allowance market. In addition, there are two institutions specified by the CAAA90 to foster the exchange of allowances—an allowance auction and an allowance sale.

Private Allowance Market

As of December 20, 1993, nine private market Phase I allowance sales have been announced. This number includes only firm purchases; there have also been several options to purchase allowances and to barter allowances between utilities. These sales in 1992 and 1993 have exchanged more than 350,000 allowances; for those where the cost was reported, the average amount paid for each allowance was between $178 and $276 (current dollars).[34]

Many observers have been disappointed in the small number of private sales that have been announced. Several factors may be restricting the private allowance market. One may be the adverse publicity surrounding one of the early sales of allowances. Wisconsin Power and Light was criticized for limiting future economic growth in the State of Wisconsin due to its sale of allowances to the Tennessee Valley Authority, while the Tennessee Valley Authority was criticized for importing pollution into its service area. These problems for both sides of the sale have decreased the enthusiasm of other utilities to trade allowances.

Another inhibiting factor may be the uncertainty associated with a sale or purchase of allowances. Utilities are often unsure how a sale of allowances would be treated by the State Public Utility Commissions, because many State commissions have not specified how they will treat allowance sales and purchases. Of course, not selling or purchasing allowances could also be received unfavorably by a State commission; apparently, omitted actions are considered less risky by many utilities than committed actions. Another uncertainty rests with how much of the savings that a utility gains by trading allowances will the State commissions allow the utility to keep and how much must be returned to share holders.

The novelty of emissions allowance markets may be inhibiting utilities from trading. The allowance market system specified by CAAA90 has not been used before on such a wide scale and may be unfamiliar to many utilities; they have become comfortable with the command and control systems specified by earlier clean air legislation.

Finally, individual utilities may be trading allowances among their own plants, but not with another utility. This would occur if individual utilities had a broad range of compliance costs among their plants, so that efficient trading could occur within individual utilities. These intra-utility trades may not have been announced yet. In fact, even some inter-utility trades that have been negotiated may not have been announced.

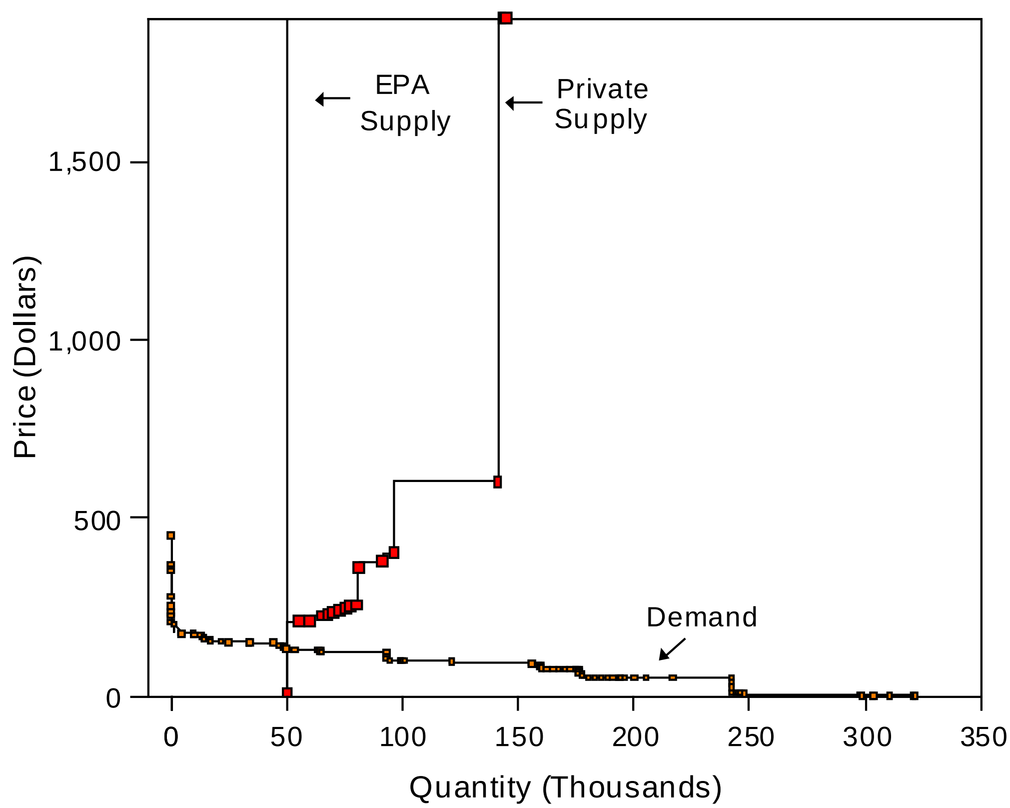
[34]"Publicly Announced Phase I Allowance Transactions," *Compliance Strategies Review* 4, 24 (December 20, 1993), p. 4.

Sulfur Dioxide Allowance Auctions and Sales

The EPA was required by the CAAA90 to hold annual emission allowance auctions and sales for a small portion of the total allowances distributed each year. The auctions and sales are intended to provide a limited source of additional allowances for affected units, including independent power producers in Phase II. The auctions also are expected to provide some information to market participants about allowance prices, although this purpose has to some extent been thwarted by the design of the auction.

The EPA offered 150,000 allowances for sale at the first auction, conducted by the Chicago Board of Trade for the EPA on March 29, 1993, and will do so again in 1994 and 1995; it will offer 250,000 allowances annually from 1996 through 1999 and 200,000 annually starting in 2000 from a special reserve of allowances that otherwise would have been allocated to affected units. The revenue raised at these auctions is returned to the affected units on a pro-rata basis. The auctions use sealed bids and award allowances to the highest bidders at their bid price. Allowances also can be offered for sale by private (non-EPA) holders at an EPA auction; they are traded after the allowances from EPA are sold, in order, from lowest to highest. Each auction is separated into two markets, spot and advance. The spot market trades allowances that can be used in the same year (for 1993 and 1994, the "same" year is 1995) as the auction, and the advance market trades

Figure 5. 1995 SO_2 Emission Allowance (Spot Market) Supply and Demand at the EPA Auction, March 29, 1993



SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

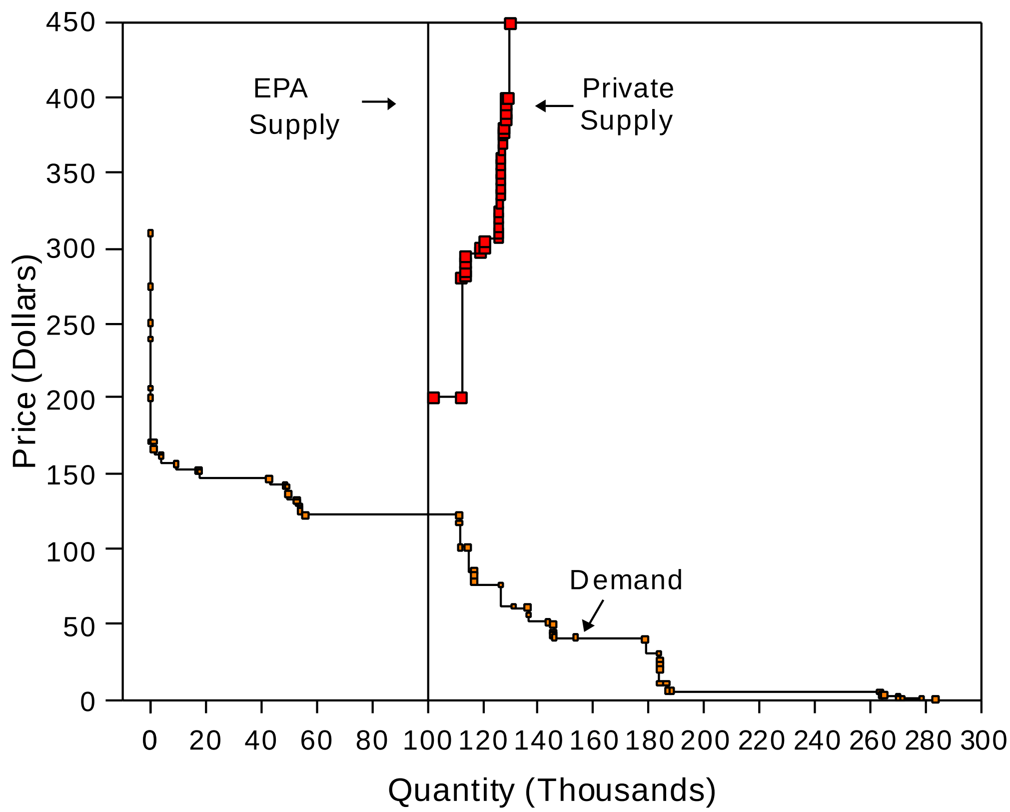
allowances that cannot be used until 7 years after the auction.

In the March 1993 spot market, for allowances usable beginning in 1995, 50,000 allowances were sold by EPA, with successful bids ranging from $450 to $131. In addition, 10 allowances offered by a private holder were sold for $131. For the 100,000 allowances offered by EPA in the advance market, for allowances usable beginning in 2000, successful bids ranged from $310 to $122; no privately-held allowances were traded in this market.

Carolina Power and Light purchased the majority of the allowances—85,103 in both markets—for a total of $11.5 million or a price that averaged $135 each. Brokerage firms, businesses, public interest groups, and private investors made up a small portion of the bidders. The largest number of allowances purchased by a bidder that was not an electric utility—Cantor Fitzgerald, a New York broker—was 2,572.

The winning price ranges show only a fraction of the bids and offers. Many more bids were submitted at lower prices, and most offers were submitted at higher prices; because most of these bids and offers did not match, they were not executed. The full range of activity in the markets included bids for more than 321,000 allowances for 1995 (Figure 5), and more than 283,000 allowances for 2000 (Figure 6). Because the auction rules specify that the EPA-offered allowances are to be sold first, the supply of allowances offered by private sources is shown added to the right of the EPA supply, which is a vertical line (perfectly inelastic) because there is no reserve price for them.

Figure 6. 2000 SO_2 Emission Allowance (Advance Market) Supply and Demand at the EPA Auction, March 29, 1993



SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

Table 10. 1995 SO_2 Emission Allowance (Spot Market) Bids at the EPA Auction, March 29, 1993

Bid Price	Bid Quantity	Bid Price	Bid Quantity	Bid Price	Bid Quantity	Bid Price	Bid Quantity
450	1	150	1	100	20,000	51	80
369	1	150	69	96	142	51	133
350	1	150	500	92	35,400	50	1
280	1	150	10,000	90	3	50	100
251	1	142	2,914	88	2,750	50	2,000
234	1	141	48	85	851	50	4,000
225	1	138	972	81	20	50	5,000
208	2	132	1,567	80	500	50	11,750
201	1,000	131	3,800	78	5	50	25,000
200	1	130	1	77	2,500	38	50
200	1	130	10,000	77	2,500	26	10
200	1	128	3	77	2,500	11	100
200	500	128	729	77	2,500	11	2,272
176	3,000	126	81	77	2,500	10	1,000
175	1	122	848	77	2,500	10	1,000
175	5,000	122	27,709	76	134	6	1,000
173	70	120	100	76	1,000	5	50,000
171	604	108	3	66	103	3	300
170	2,572	106	128	65	4	2.6	100
162	1,277	101	1,000	60	1,400	2	200
158	3	101	5,000	58	10	2	5,000
157	2,636	100	2	52	2,665	1	250
156	446	100	10	52	2,665	1	7,000
152	45	100	50	52	2,665	1	10,000
152	4,085	100	200	52	2,665	0.26	1,000
151	3,300	100	500	52	2,665		
151	8,900	100	1,000	52	2,675		

SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Note: Bids outlined with thick lines were winning bids; the lowest winning bid was only partially filled.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

In the auction for 1995 allowances, bids for more than 242,000 allowances were submitted at $50 or more, but bids for only 1,512 allowances were submitted at $200 or more (Tables 10 through 13). Of the more than 91,000 private offers at $600 and below, only 10 allowances were offered at $200 and below. Similarly, in the auction for 2000 allowances, bids for more than 145,000 allowances were submitted at $50 or more, but bids for only 106 allowances were submitted at $200 or more. Of the 30,500 private offers at $449 and below, no allowances were offered at prices below $200, although 12,000 were offered at $200. Many of the offers in both auctions were part of an ordered series, suggesting that there may have been only a few private suppliers making many of the offers in the two auctions. Without the supply of allowances offered by EPA, only 10 of the 1995 allowances would have been traded, with a market-clearing price of $201, and only 106 of the 2000 allowances would have been traded, with a market-clearing price of $200.

There are two complications to interpreting the results of the EPA auction. One is the price discrimination (exchange of different units of the same good at price differentials not related to differences in their cost of supply) that was specified in CAAA90.[35] The lowest winning bids in each market, $131 for 1995 allowances and $122 for 2000 allowances, are the market-clearing prices. If there had been no price discrimination in the auctions so that a single price was determined for each market, these two prices, $131 and $122, would have equilibrated demand and supply. The price discrimination that did occur in the auctions did not affect the quantity of allowances exchanged. It did increase the prices paid by those buyers willing to pay more than the market-clearing price. In doing so it redistributed

[35]For an analysis of price discriminating auctions, see James C. Cox, Vernon L. Smith, and James M. Walker, "Theory and Behavior of Multiple-unit Discriminative Auctions," *Journal of Finance* 39,4 (September 1984), pp. 983-1010.

Table 11. 2000 SO_2 Emission Allowance (Advance Market) Bids at the EPA Auction, March 29, 1993

Bid Price	Bid Quantity	Bid Price	Bid Quantity	Bid Price	Bid Quantity
310	1	136	87	43	10
275	1	132	3,135	41	117
251	1	131	100	41	8,000
240	100	128	1,234	40	25,000
207	1	126	114	31	5,000
200	1	125	1	26	138
200	1	122	1,696	23	50
171	24	122	55,416	20	1
171	1,209	117	41	11	100
166	30	101	500	11	2,272
162	2,554	101	2,500	6	830
161	37	85	2,282	6	1,000
157	5,272	82	58	5	75,000
156	45	78	5	3	500
152	8,170	76	10,000	3	1,000
151	54	62	5,000	2	5,000
151	300	61	5,000	1	250
147	25,000	56	128	1	250
146	64	52	7,000	1	1,010
142	5,830	51	100	1	7,000
141	75	50	2,000	0.01	5,000
141	709	45	2		

SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Note: Bids outlined with thick lines were winning bids; the lowest winning bid was only partially filled.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

more money from buyers to sellers than a single-price auction would have.

More importantly, discriminatory pricing schemes encourage strategic bidding behavior (not revealing their true demand for allowances) by market participants, because the bid prices and not the market-clearing price become the prices at which allowances are exchanged. Strategic behavior by participants may, in general, distort the results and efficiency of a market. In particular, since bidders knew they would pay their bid price and not the market clearing price, they would be expected to "under-reveal" their "true" demand for allowances by bidding less than they would have had the price discrimination not occurred.[36] Concurrently, since sellers knew that private allowance offers were to be executed in order, from lowest to highest, they would be expected to price their offers strategically and not correctly reveal their "true" supply of allowances.

An extreme manifestation of strategic behavior may have been the offer of 10 allowances in the 1995 auction at $10 each. The auction rules, stipulated by Congress, require that privately offered allowances be exchanged at the bid price (not the offer price) and sold in ascending order, starting with the allowances which have the lowest minimum price requirements. Given these rules, this lowest minimum price offer may have been a strategic one to ensure that the corresponding allowances would be the first, and therefore the highest-priced, privately held allowances sold at the auction. No other allowances were offered at either auction by private holders for less than $200.

One less ambiguous result of the auction was the confirmation that allowances will be more valuable in 2000 (Phase II) than in 1995. When viewed solely as financial instruments, with everything else held constant, the prices of the 1995 and 2000 allowances should be quite different because of the time value of money. If 1995 and 2000 allowances are viewed as providing the same stream of benefits (avoiding the same stream of costs), then the 1995 allowances are more valuable than the 2000 allowances, because they potentially begin

[36]For a general analysis of auctions, see Paul Milgram and Robert Weber, "A Theory of Auctions and Competition Bidding," *Econometrica* 50, 5 (September 1992), pp. 1089-1122.

Table 12. 1995 SO_2 Emission Allowance (Spot Market) Offers at the EPA Auction, March 29, 1993

Offer Price	Offer Quantity	Offer Price	Offer Quantity
10	10	250	2,500
210	5,000	255	2,500
210	5,000	361	1,000
225	5,000	375	10,000
230	2,500	400	5,000
235	2,500	600	45,000
240	2,500	1,900	1,900
245	2,500	1,900	2,100

SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Note: Offer outlined with thick lines was only accepted offer.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

Table 13. 2000 SO_2 Emission Allowance (Advance Market) Offers at the EPA Auction, March 29, 1993

Offer Price	Offer Quantity	Offer Price	Offer Quantity
200	2,000	340	100
200	10,000	345	105
280	40	350	110
282	1,500	355	115
285	45	360	120
290	50	365	125
295	55	370	130
297	5,000	375	135
300	60	377	1,000
300	2,000	380	140
305	65	385	145
307	5,000	390	150
310	70	395	155
315	75	400	160
320	80	400	1,000
325	85	449	250
330	90	449	250
335	95		

SO_2 = Sulfur dioxide.
EPA = U.S. Environmental Protection Agency.
Note: No offers were accepted.
Source: U.S. Environmental Protection Agency, Information Package on First Acid Rain Allowance Auctions (April 1993).

providing benefits 5 years earlier than 2000 allowances. In present value terms, assuming a discount rate of 15 percent,[37] a stream of benefits beginning in 2000 is worth only about 50 percent of the same benefits beginning in 1995. This calculation suggests that, if 1995 and 2000 allowances were equally valuable to their holder at the time each could first be used, 1995 allowances would have twice the market value of 2000 allowances in 1993. However, in the auctions, 2000 allowances had a market-clearing price only 7 percent below 1995 allowances. Therefore, given the time value of money, the auctions valued an allowance useable in 2000 more highly than one useable in 1995. An alternative way to reach a similar conclusion is to calculate the future value of 2000 allowances in the year 2000 and the future value of 1995 allowances in the year 1995, assuming a particular rate of return and the 1993 auction relative prices. Using a (riskless) rate of return of 3 percent, 2000 allowances in 2000 were valued at 25 percent more than 1995 allowances in 1995 by the auction. Using a rate of return of 10.8 percent,[38] 2000 allowances are valued at 80 percent more than 1995 allowances, and, using a rate of return of 15 percent, 2000 allowances are valued at 116 percent more than 1995 allowances. Of course, 2000 is the year when the more stringent and extensive limits of Phase II of CAAA90 take effect.

Flue Gas Desulfurization Retrofits

Installing flue gas desulfurization equipment (scrubbers) is a capital-intensive strategy for complying with Phase I SO_2 limitations. As such, the initial cost of this strategy is greater than the initial cost for other responses, although the operating costs may be less. In addition, the utility industry has had substantial experience with scrubbers, which were required on some electric power generating plants by earlier environmental regulations and have been installed on some utility boilers for several decades. It is estimated that scrubbers will account for a large share of the required SO_2 emissions reduction in Phase I of the CAAA90.

The initial cost of retrofitting a plant with a scrubber varies dramatically, depending on the characteristics of

[37]Discount rates used by businesses are often much higher than their cost of capital. Fifteen percent was the median discount rate found in a recent study. See Lawrence H. Summers, "Investment Incentives and the Discounting of Depreciation Allowances," in Martin Feldstein, ed., *The Effects of Taxation on Capital Accumulation* (University of Chicago Press, Chicago, IL, 1987), p. 300. For a possible explanation of this high discount rate, see Avinash Dixit, "Investment and Hysteresis," *Journal of Economic Perspectives* 6, 1 (Winter 1992), pp. 107-132.

[38]For an estimate of the investor-owned electric utility cost of capital, see Energy Information Administration, *Assumptions for the Annual Energy Outlook 1993*, DOE/EIA-0527(93) (Washington, DC, January 1993), p. 94.

the electricity generating plant where they are installed as well as the characteristics of the scrubbers themselves. This report presents two methods to estimate these costs which were developed in two separate studies sponsored by the Energy Information Administration (EIA).[39] One is based on historical accounting records of costs. The historical cost approach uses econometric techniques to analyze the recorded costs and their statistical relationship to other scrubber characteristics. For example, these techniques estimate how much the cost of a scrubber increases as the size of the electricity generator associated with it increases. The other method used in this report is based on recent engineering design and cost estimates. Expert engineers use currently available technology to design a scrubber and estimate its cost based on the components of the design.

These two estimating methodologies offer distinct advantages and disadvantages. The most important distinction is that historical cost estimates are based on actual recorded costs, while engineering costs are estimated by the expert engineer. Engineering cost estimates may differ from the actual costs that would be incurred if the designed scrubber were built. However, engineering cost estimates use currently available technology, which would be available to future builders, for their design. Historical cost estimates are based on the technology existing at the time they were built; they do not take into account current design technologies or current costs.

Estimates Based on Historic Costs

The historical cost estimating methodology uses econometric techniques to analyze data regarding scrubbers that are collected by EIA on Form EIA-767, "Steam-Electric Plant Operation and Design Report." This form has been used to collect plant operations and equipment design information on all fossil-fueled steam-electric generating plants in the United States with a nameplate capacity of 10 or more megawatts since 1986. The form pays particular attention to the scrubber units at those plants.

Sample Characteristics

This sample contains 32 flue gas desulfurization units that have been installed for normal production use after the boilers were initially built (retrofit) and were operating between 1985 and 1991. These units have 12 gigawatts of electricity generating nameplate capacity.

Extension Allowances for Units Installing High-Efficiency Control Technologies

An additional incentive to install high-efficiency control technologies has resulted from the creation of extension allowances. The CAAA90 specify that a pool of 3.5 million allowances, called "Phase I extension allowances," be made available to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions and begin operation by January 1, 1997, or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. The extension allowances do not extend the dates by which qualifying units must acquire allowances for their emissions. They do allocate, at no charge, additional allowances to utilities so that they may emit SO_2 above their annual allocation of allowances.

Seventeen utilities submitted final requests for extension allowances. Since the total number of requests was for more than 4 million allowances, EPA used a lottery to distribute the extension allowances. The number of allowances awarded to the winning applicants becomes final when EPA issues an Acid Rain Permit to the utility.

However, all utilities in the lottery, except for Potomac Electric Power, voluntarily joined a pool that agreed to share any extension allowances received by its members. Potomac Electric Power was ranked third in the lottery, but its request for allowances was denied by the EPA. That leaves the entire 3.5 million extension allowances for the 16 utilities in the pool, which agreed to share them on a pro-rata basis, with those that won in the lottery receiving a slightly higher pro-rata share than those that lost. Based on the 88 percent pro-rata share, the largest recipients of extension allowances, conditional on EPA approval, are American Electric Power, with approximately 750,000 allowances, and the Tennessee Valley Authority, with approximately 710,000.

[39]United Engineers & Constructors, Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant, UE&C/EIA: 921005 (Philadelphia, PA, October 1992) and Decision Analysis Corporation of Virginia, "Regression Models for Analysis of Retrofit Flue Gas Desulfurization Unit Cost and Performance" (Vienna, VA, May 28, 1993).

This capacity represents 17 percent of all generators associated with scrubbers in service at electric utilities in 1991. The average size of the generators which have retrofit scrubbers is 365 megawatts; they range from 114 to 818 megawatts. Because some of the observations contained problematic information, fewer units remain in the cost estimating sample.[40] Only retrofit scrubbers are included in the sample because they are substantially more expensive than scrubbers designed and built with the plant, and because all the plants installing scrubbers to comply with Phase I will be retrofitting scrubbers. Retrofit scrubbers are more expensive to install than original equipment scrubbers because the plant was not designed to include them, and therefore they may present difficult design and construction problems (for example, a lack of physical space for building the scrubber). It is also important that the units in the sample be designed for normal production use. Experimental or prototype units may have anomalous costs.

On average, the scrubbers in the sample were installed 13 years after the boilers to which they are connected were built, with 28 years as the longest gap between boiler and scrubber installation. Retrofit scrubbers in the sample were installed beginning in the early 1970's. The retrofit scrubber units in the sample are located in 8 States, with 5 or more units in each of 4 States, Kentucky, New Mexico, Pennsylvania, and Wyoming. Many of the western scrubbers were installed to meet previous Clean Air Act requirements for "prevention of signification deterioration" in air quality.

Design Characteristics

Scrubber designs can be characterized by the method that they bring into contact the flue gas containing the SO_2 and the absorbent (which absorbs the SO_2 from the flue gas). Some absorbers spray the absorbent into the flue gas, while others pass the gas over or through a bed of the absorbent. In some, the waste from the process is a dry solid; in others, a liquid. The most common absorbent in the sample is limestone; lime is second.

The sulfur dioxide removal efficiency is another important design parameter for describing a scrubber. It specifies the proportion of sulfur dioxide removed from the flue gas. Most of the current generation of scrubbers are designed to remove 85 to 95 percent of the SO_2. The average removal efficiency for the sample studied was 83 percent; however, efficiencies ranged down to only 26 percent.

Scrubbers also are characterized by their energy requirements. Electricity is needed to power the fans that force the flue gas through the scrubber and to power other electromechanical equipment. The design electricity requirements for the sample of retrofit scrubbers averaged 7 megawatts, with a range from 0.4 to 18 megawatts. In addition, thermal energy is sometimes needed to reheat the flue gas as it leaves the absorber so it will be less corrosive.

Performance Characteristics

One of the most important performance characteristics for a scrubber is its actual SO_2 removal efficiency—that is, the actual percentage of SO_2 removed from the flue gas during operation. The actual removal rate often differs from the design removal rate. For the average scrubber, the actual removal rate has been about 2 percent less than the design removal rate. However, many scrubbers in the sample perform above their design

One method of compliance is scrubber installation, such as the one being installed at Conemaugh. The average scrubber can remove up to 95 percent of the SO_2 in the flue gas.

[40]There were several estimating samples, depending on the information necessary for the estimation being performed. For a more extensive discussion of the data and editing procedures, see Appendix C.

efficiency. There are several possible explanations for design efficiency to exceed actual efficiency: the design rate of SO_2 removal may be greater than the rate that is actually required; the scrubber may be more costly to operate at its design efficiency than at a lower rate; or the potential efficiency of the scrubber may decline over time.

Costs of Scrubbers

Costs are generally broken down into two categories: (1) capital costs, the total cost of installing the physical equipment, and (2) operation and maintenance costs (operating costs), the annual cost of running the scrubber.[41] In general, the most important factors affecting retrofit scrubber capital costs are size, efficiency, type, and the difficulty of incorporating the scrubber into the existing structure of the generating plant.

The statistical analysis of the sample of retrofit scrubbers identified four characteristics that were important in estimating capital costs:

- Capacity of the associated electric generators
- Number of absorber modules in the scrubber
- Design efficiency of the scrubber (percentage of SO_2 it was designed to remove)
- Type of absorber technology.

The capital cost estimated by an econometric model from the sample of retrofit scrubbers was $227 per kilowatt of installed generating capacity (1992 dollars).[42] There is some ambiguity as to whether the installed capital costs include overhead costs. The *Accounting and Reporting Requirements for Public Utilities and Licensees* require that overhead construction costs be included in the capital costs of each unit as reported to the Federal Energy Regulatory Commission (FERC).[43] However, these requirements do not specifically apply to Form EIA-767, and some utilities reporting on the form do not report information to FERC. An informal survey of several reporting utilities found that some may not include overhead costs in capital costs for scrubbers. Excluding overhead costs understates total capital costs. One engineering estimate of the overhead costs for scrubbers is 21 percent of their total installed capital costs.[44]

The largest cost in operating a scrubber is the cost of the absorbent.[45] For the sample of retrofit scrubbers examined, operation and maintenance costs averaged 4.2 mills per kilowatthour, excluding the electricity used by the scrubber.

Estimates Based on Engineering Studies

The current engineering cost estimate for scrubbers is based on a 488-megawatt (net) high-sulfur pulverized coal-fired power generating station. The cost estimate reflects the best available control technology that is being applied in currently built plants, with an adjustment for the additional retrofit costs.[46]

Description of Scrubber

The scrubber system is designed to remove SO_2 from the essentially particulate-free flue gas exiting the electrostatic precipitator from a coal-fired plant and produce a co-mixed fly ash waste product suitable for landfill disposal. The system design is a nonrecovery forced-oxidation wet limestone process consisting of a limestone unloading and storage facility; a limestone slurry preparation system; an SO_2 absorber system; a waste slurry thickening system; a scrubber waste product system; and a water distribution system. The performance criterion for this design is 95 percent SO_2

[41]The operating expenses recorded on the Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report," do not include the cost of the electricity consumed by the scrubber; the physical quantity of electricity consumed is recorded separately on the form. Scrubber operating costs on the form are broken down into feed materials and chemicals, labor and supervision, waste disposal, and other costs.

[42]This cost is calculated by evaluating the regression estimating equation at the sample means of the independent variables. Heteroscedasticity was encountered in estimating the econometric model. Remedial measures were attempted to eliminate it, but they were unsuccessful.

[43]Federal Energy Regulatory Commission, FERC-0114, (Washington, DC, January 17, 1989), ¶15,054. Installed capital costs do include the cost of major modifications, which are defined as physical changes which result in a change in the amount of pollutants emitted. They are broken down into structures and equipment, sludge transportation and disposal system, and other capital costs.

[44]United Engineers & Constructors, Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant, UE&C/EIA: 921005 (Philadelphia, PA, October 1992).

[45]Oak Ridge National Laboratory, "Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants—1982," ORNL/TM-8324 (Oak Ridge, TN, September 1982).

[46]United Engineers & Constructors, Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant, UE&C/EIA: 921005 (Philadelphia, PA, October 1992).

removal efficiency for 3.2 percent sulfur coal. This system design provides a zero liquid discharge capability and the latest reliability features. The SO_2 absorber system brings the flue gas into direct contact with a recirculating slurry within an absorber vessel in order to remove SO_2 from the flue gas stream. The SO_2 absorber system is sized to treat 100 percent of the flue gas flow at valves wide open, 5 percent overpressure turbine operation.

The major components of the SO_2 absorber system include spray tower type absorber modules fabricated of rubber-lined carbon steel, recirculation pumps, mist eliminator wash pumps and blend tank, limestone slurry feed pumps and storage tank, dampers, agitators, piping, valves, instrumentation, and controls. The absorber system waste products are discharged via a bleed stream from the recirculating slurry. The waste slurry thickening system dewaters the bleed slurry from the absorber module to produce a concentrated underflow slurry and a high-quality (low suspended solids) overflow. The underflow slurry, which contains a minimum of 45 percent solids by weight, is pumped to the waste product system for treatment prior to disposal.

Costs of Scrubber

The capital costs, including direct and indirect costs, for retrofitting scrubber structures and equipment to an existing coal-fired plant with no spare module is estimated to be $266 per kilowatt (1992 dollars), including a scrubber retrofit multiplier of 1.25. The design criteria for this scrubber is 95 percent SO_2 removal efficiency which is higher than the historical sample for scrubbers. The amount of space available to install scrubbers is the main constraint.[47]

The additional nonfuel operation and maintenance (O&M) costs for a plant retrofitting a scrubber were determined by comparing a coal plant using bituminous 3.2 percent sulfur coal with and without a wet limestone scrubber.[48]

The additional nonfuel O&M costs for retrofitting a scrubber is $9.2 per kilowatt per year for fixed costs and 1.6 mills per kilowatthour for variable costs. The largest increase is in supplies and expenses (including fixed and variable costs of $4.5 million). The variable cost for limestone of $2.7 million and waste disposal of $1.3 million are the two major items. The additional onsite staff of 34 personnel is required to maintain and monitor the scrubbers, at a cost of $1.3 million.

Previously Implemented Controls

A number of plants have already taken steps to ensure that, by continuing their current generation practices they will have sufficient allowances from the initial allowance distribution to cover their emissions in Phase I. In most cases, States had already required emissions reductions for these Phase I plants. The States that had such regulations were Kansas, Michigan, New Hampshire, New York, and Wisconsin.

In most cases, the State-mandated actions were required either during or after the Phase I baseline period of 1985 through 1987. This overlap allowed the plants to have their higher emissions calculated into the Phase I allowance allocation equation.

In Kansas, the City of Kansas City's Quindaro plant has taken steps to meet State regulations that will put it in compliance with Phase I. Although the regulations addressed ambient air quality standards, and not just SO_2 emissions, they permitted reductions in SO_2 as one means of meeting the air quality regulations. Therefore, in 1989, Quindaro began blending the Southern Illinois coal that it had been using exclusively with a lower sulfur Hanna Basin coal.[49]

Consumers Power's J.H. Campbell plant was required to convert to 1 percent sulfur coal from 2 to 3 percent sulfur coal by the Emissions Limitations and Prohibitions—Sulfur-Bearing Compounds regulations as issued by the Michigan Air Pollution Control Commission. Campbell underwent this conversion at the end of 1987. The plant had been operating under extensions of the fuel sulfur limit compliance date (originally January 18, 1980). The mechanism for the extension was a consent order issued by the Air Pollution Control Commission. This explains why Campbell's baseline was higher than other Michigan plants.[50]

[47]United Engineers & Constructors, Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant, UE&C/EIA: 921005 (Philadelphia, PA, October 1992), Table 3, pp. 1-3.

[48]Oak Ridge National Laboratory, Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants - 1982, NUREG/CR-2844, ORNL/TM-8324 (Oak Ridge, Tennessee, September, 1982). This model was updated in 1987.

[49]Verbal communication with the Kansas City, Kansas Board of Public Utilities (October 6, 1993).

[50]Michigan Air Pollution Control Commission, General Rules, as amended April 20, 1989, Part 4, Emission Limitations and Prohibitions - Sulfur-Bearing Compounds.

The New Hampshire Acid Deposition Control Program required Public Service of New Hampshire's Merrimack plant to reduce its emissions to a level that has coincidentally placed the plant in compliance with Phase I of CAAA90. The effective date of this program was January 1, 1991. The program mandated large plants to reduce their emissions by 40 percent from a baseline established from 1979 through 1982.[51]

The New York State Acid Rain Deposition Control Act ensured that the Long Island Lighting Company's Northport and Port Jefferson plants (both oil-fired) would be in compliance with Phase I of CAAA90. The Act required both plants to reduce the sulfur content of the oil they burned from 2.8 percent to 1 percent. The act allowed a two-year phase-in period from 1986 until January 1, 1988.[52]

Wisconsin also required its plants to reduce their sulfur emissions prior to CAAA90 and has a number of plants that will find themselves in compliance with Phase I requirements simply by adhering to State regulations. These Phase I plants are South Oak Creek, operated by Wisconsin Electric Power; Genoa, operated by Dairyland Power Cooperative; Nelson Dewey and Edgewater, operated by Wisconsin Power and Light; and Pulliam, operated by Wisconsin Public Service. According to the Wisconsin Department of Natural Resources, Bureau of Air Management, Statute 144.386, paragraph 2, passed in 1989, lays out the requirements. The legislation requires that major utilities (those emitting more than 5,000 tons of SO_2 systemwide in any year after 1979) limit the average number of pounds of SO_2 emissions per million Btu of heat input from all boilers under their ownership or control to 1.2.

There is, however, a trading mechanism, whereby two major utilities may enter into an agreement for trading emissions unless the sum of the proposed traded emissions and the projected annual emissions of the grantor major utility for the year to which the agreement will apply would exceed the actual annual emissions of the grantor major utility in 1985. To determine whether the major utility that is the grantor in an agreement is in compliance, the Wisconsin Department of Natural Resources adds the traded emissions and the grantor's annual emissions and divides the sum by the annual heat input of the grantor.[53] (Note that this does not permit the same level of flexibility as CAAA90, where total emissions, regardless of heat input, are the only compliance issue.)

In addition to the plants that were required to reduce their emissions by State legislation, there are a number of plants that took action based on other factors. These plants are located in Minnesota, Iowa, and Missouri, which are three of the four westernmost States affected by Phase I of CAAA90.

In Minnesota, Northern States Power's High Bridge plant switched from bituminous to a western subbituminous fuel. The switch was completed in 1987. The utility gave three reasons for the switch: environmental benefits; economic considerations;[54] and the fact that stricter environmental legislation seemed imminent.

In Missouri, two plants, Empire District's Asbury[55] and Kansas City Power and Light's Montrose,[56] fuel switched after and during the CAAA90 baseline period, respectively. In both cases, low-sulfur western coal was chosen as the new fuel. Economic analyses led to the conclusion that western coal was cheaper than local Missouri coal, even though both plants are minemouth plants. In the case of the Montrose plant, one of the local supply mines had played out as well.

In Iowa, boiler 1 at Midwest Power's George Neal plant switched fuel for economic reasons. The plant had been burning both Hanna Basin coal and gas during the baseline period, when it was used predominantly as a peaking unit, and switched to a much lower sulfur Powder River Basin coal in 1989. The plant will need to take no further action to comply with Phase I requirements.[57]

In summary, 10 Phase I plants, by complying with relatively strict State regulations, will, in essence, find themselves in compliance with the requirements of Phase I. Additionally, four plants have taken action for other reasons that have also reduced their sulfur dioxide emissions to a level that will meet the requirements of Phase I.

[51]Verbal communication with the New Hampshire Air Resources Division (September 28, 1993).
[52]Verbal communication with the Long Island Lighting Company (September 29, 1993).
[53]91-92 Wisconsin Statutes, 144.386, Sulfur dioxide emission rates after 1992; major utilities, Section 2, paragraphs (a) and (b).
[54]Verbal communication with Patty Boyce of Northern States Power (October 1, 1993).
[55]Verbal communication with Bob Bromley of the Empire District Electric Company (October 4, 1993).
[56]Verbal communication with Jerry Bennett of Kansas City Power and Light (October 5, 1993).
[57]Verbal communication with Dave Dooley of Midwest Power (October 6, 1993).

Retiring Facilities

Retirement is also an available option for compliance with Phase I. There are seven units that have indicated that they will use retirement. Five of the seven units, Wisconsin Electric Power's North Oak Creek units 1 through 4 and Cleveland Electric Illuminating's Avon Lake unit 8, retired prior to the passage of the law. Two other units, Indiana Michigan Power's Breed unit 1 and Iowa Power's Des Moines unit 7 will retire in time to meet compliance with Phase I. These units will be required to show compensating generation elsewhere in their system or surrender the units' allowance allocation.

Boiler Repowering

Repowering is the integration of modern technology into an existing power plant site, thereby increasing the available capacity at the site by as much as 200 percent; improving efficiency; and lowering the plant's air emissions profile. Repowering typically involves a partial or complete replacement of the existing steam supply system and a more or less complete retention and refurbishment of the turbine-generator system. Refurbishment and reuse of the turbine-generator is the major area of cost savings over new construction. Other components and systems, including the fuel supply and storage (if the same fuel is used), roads and utilities, cooling towers, and nongeneration buildings, are almost always refurbished and used.

Repowering assumes the existence of a utility steam plant which through age or technological obsolescence is no longer viable. The ability to use the existing site and the extent to which existing equipment can be reused are important repowering considerations. These present the opportunity to save up to half the cost of a comparable new plant. Repowering represents the least-cost option for the utility in some cases.[58]

Many of these aging plants are without air pollution controls and are candidates for repowering including integrated gasification combined-cycle technology. Repowering technologies are still under development; however, it represents a potential for development, particularly after the year 2000 when more of the repowering technologies will be ready for commercial implementation.

Coal and Oil and Gas Repowering

Repowering options for coal include partial repowering and station repowering. Several different systems can be introduced in each of these groups. "Coal-for-coal boiler repowering" is partial repowering of the unit by replacing the bottom half of the existing boiler with bubbling bed atmospheric fluidized bed combustion. "Coal-for-coal station repowering" is complete repowering of the unit by replacing the entire boiler (and possibly the nonsteam supply systems as well) with any fluidized bed boiler (atmospheric, circulating, or pressurized), integrated gasification combined cycle coal, or some other clean coal technology.

Steam units can be repowered to fire partly or completely on oil or gas using combustion turbines and heat recovery steam generators. Several options are commercially proven, including combustion turbine repowering, gas-firing in addition to existing boiler firing (addition of a gas-fired combustion turbine to an existing gas-, oil-, or coal-fired boiler with the combustion turbine exhaust used for air or water preheating and retention of the existing boiler method and fuel); and heat recovery steam generator repowering (addition of a heat recovery steam generator with or without replacement of the existing boiler and without replacement of the steam turbine-generator).

Wabash River Coal Gasification Repowering Project

PSI Energy is repowering unit 1 of the Wabash River Generating Station in Vigo County, Indiana, for CAAA90 Phase I.[59] This is a 112.5-megawatt steam turbine-boiler generating station that burns bituminous coal. It was completed in 1953. The unit is being repowered with integrated gasification combined-cycle using a two-stage, entrained-flow gasification system. The plant capacity after repowering will be 268 megawatts (net), and the total project cost $396 million.

With the new technology to be used at the Wabash station, coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained-flow slagging first stage and non-slagging second stage), oxygen-blown, entrained-flow gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system that removes

[58]Energy Information Administration, "Performance Optimization and Repowering of Generating Units," *Electric Power Monthly*, DOE/EIA-0226(92/08) (Washington, DC, August 1992).

[59]U.S. Environmental Protection Agency, *SO_2 Phase 1 and 2 Boiler Compliance Methods* (July 12, 1993), p. 13.

particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-megawatt gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 110-megawatt steam turbine.

The repowered unit will use 2,544 tons of high-sulfur, Illinois Basin bituminous coal per day. The anticipated heat rate for the repowered unit is 8,974 Btu per kilowatthour (38 percent efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.2 pound per million Btu (98 percent reduction). Nitrogen oxide (NO_x) emissions are expected to be less than 0.1 pound per million Btu (90 percent reduction). Upon completion in 1995, the project, partially sponsored by the Department of Energy, will represent the largest single-train integrated gasification combined-cycle plant in operation in the United States.[60]

Additional Compliance Strategies

Many plants intend to supplement their main method of compliance with one or more of the additional strategies available: energy conservation, reduced utilization, and substitution of units. Each of these, along with issues that are directly related, are addressed in the following sections.[61]

Energy Conservation

Title IV of the CAAA90 required EPA to establish rules for the use of energy conservation as a compliance strategy. The allowance trading system contains an inherent incentive for utilities to conserve energy, since for each ton of SO_2 that a utility avoids emitting, one fewer allowance must be held at year end. There are also two explicit conservation incentives in the Acid Rain Program: (1) the Conservation and Renewable Energy Reserve, and (2) the reduced utilization provision.

The Conservation and Renewable Energy Reserve is a pool of 300,000 allowances that will be awarded to utilities for implementing demand-side conservation measures (actions taken to encourage a customer to modify the amount or timing of electricity use) or for using renewable energy sources (such as biomass, solar, geothermal, or wind). According to EPA, in order for an electric utility to qualify for the reserve, it must:

- Own or partly own an affected unit
- Pay or partially pay for the measure
- Implement least cost planning
- Have net income neutrality (if investor-owned).[62]

The reserve was established by reducing Phase II allowances by 30,000 annually over a 10-year period from 2000 to 2009. Twenty percent (or 60,000 allowances) of the reserve is set aside for renewables, with a maximum of 30,000 allowances for each renewable technology. The allowances will be granted to utilities on a first-come, first-served basis starting in 1995 for demand-side conservation activities initiated after 1992. The Department of Energy is responsible for certifying that States have net-income neutrality policies before a company can receive bonus allowances.

On November 17, 1993, EPA awarded the first 532 reserve bonus allowances to 6 non-Phase I affected companies during the annual meeting of the National Association of Regulatory Utility Commissioners in New York City. Puget Sound Power & Light received the largest award of the group, 245 allowances, for residential, commercial, and industrial conservation programs, followed by ESI Energy, the Florida Power & Light subsidiary, with 109 allowances attributable to geothermal generation, and 2 New England Electric System companies, which received a total of 103 allowances for conservation programs and a landfill gas project. In addition, Portland General Electric received 57 and the City of Austin, Texas, got 18 allowances, both for conservation projects.[63]

Demand-Side Management

While the Acid Rain Program provides incentives for utilities owning Phase I and/or Phase II plants to

[60]U.S. Department of Energy, Assistant Secretary for Fossil Energy, *Clean Coal Technology Demonstration Program: Program Update 1992 (As of December 31, 1992),* DOE/FE-0272 (Washington, DC, February 1993), pp. 7-96, 7-97.

[61]The discussion in this section is based primarily on the series of documents regarding the Acid Rain Program published by the U.S. Environmental Protection Agency, Office of Air and Radiation, beginning in 1991.

[62]Net income neutrality occurs when the State regulatory authority establishes rates and charges that are expected to keep the net income earned by the utility constant as it adopts conservation programs.

[63]"Six companies Earn Bonus Allowances from Conservation/Renewable Reserve," *Utility Environment Report* (November 26, 1993), pp. 1-2.

develop demand-side management (DSM) programs, nearly half of the Nation's utilities are electively establishing DSM programs, and interest in them continues to grow. DSM is the process, employed by utilities, of influencing customers directly or indirectly to modify and/or reduce energy consumption. DSM has entered the mainstream of utility planning options, and utility management has come to view DSM as a viable business strategy. Its popularity stems from three major factors: (1) DSM programs can provide cost-effective energy and capacity resources that can reduce the need to build new power plants and transmission lines; (2) they are strongly favored by public opinion over construction of new plants; and (3) they offer substantial environmental benefits over traditional utility supply resources. By emphasizing the various applications of energy efficiency, DSM programs can lead customers to use less electricity, alter the time when they use it, or substitute more efficient technologies for less efficient applications.

From 1989 through 1991, total energy savings attributable to DSM programs increased from 16,268 million kilowatthours to 23,343 million kilowatthours. By 1996, DSM energy savings are estimated to increase to 57,011 million kilowatthours, representing an average annual increase of nearly 20 percent for the period from 1991 through 1996. Most of the energy savings result from conservation programs that promote high-efficiency end-use equipment. Investor-owned utilities accounted for the major share of the DSM energy savings, with nearly 60 percent of the total in 1991. Total DSM energy savings represented nearly 1 percent of the 2,762 billion kilowatthours of total sales to ultimate customers.[64]

Utilities are obligated to meet the needs of their customers. Historically, the fundamental strategy used to meet increasing electricity needs has been to build more power plants. During the past several years, however, DSM has become one of the primary vehicles used to satisfy the Nation's increasing energy requirements.

EPA Conservation Verification Protocols

Conservation measures that are used to qualify for the 300,000 Conservation and Renewable Energy Reserve bonus allowances or to contribute to the reduced utilization provision enable electric utilities to earn or save allowances, which can be banked for future use or sold. It is, therefore, essential to the credibility of the market approach for there to be procedures to verify and quantify energy savings. Accordingly, EPA set forth the Conservation Verification Protocols, which will be used primarily by public power utilities, while investor-owned utilities' energy savings will be verified by procedures specified by their State Public Utility Commissions. Due to the diversity of conservation technologies, programs, and activities, the Protocols give general guidelines, rather than specific requirements, for verifying energy savings. The Protocols are designed to ensure the cost effectiveness of conservation programs and SO_2 emission reduction measures, as well as the reliability of actual energy savings from these programs.[65]

Reduced Utilization

The second conservation incentive is contained in the reduced utilization provision where a utility can use conservation, both on the demand side and on the supply side (i.e., power generation, transmission, or distribution efficiency) to reduce utilization in Phase I without surrendering allowances.

To account for possible shifts in electricity generation from Phase I units to Phase II units, the CAAA90 specify that a Phase I unit that meets its emissions reduction requirements by decreasing electricity generation must either surrender allowances or account for the reduced generation in one of several ways: (1) by adopting verifiable energy conservation or improved unit efficiency measures, (2) by designating sulfur-free generators to provide generation, or (3) by designating one or more non Phase I SO_2-emitting unit or units (called compensating units) to increase generation. Compensating units are granted allowances based on 1985 SO_2 emissions rates and average annual fuel use from 1985 through 1987. Allowances may be transferred from the original unit to the compensating units in order to cover emissions beyond their granted allowances.

Substitution Units

EPA designed a plan that would allow a Phase I unit to reassign all or some of its Phase I SO_2 emissions reductions requirements to one or more existing units

[64]Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

[65]U.S. Environmental Protection Agency, "Conservation Verification Protocols: A Guidance Document for Electric Utilities Affected by the Acid Rain Program of the Clean Air Act Amendments of 1990," EPA 430/8/B-92-002 (March 1993).

(referred to as substitution units) that would otherwise not be regulated until Phase II, if these units met the Phase I unit's requirements. This plan was designed to allow Phase I units to cost-effectively reduce emissions at another plant, achieving the same overall emissions reductions that would have occurred without the plan.

EPA Revisions to Reduced Utilization and Substitution Rules

In the case of both the reduced utilization provision and the substitution provision, the original intent was that emissions would be no higher with the option than without. However, some substitution plans and reduced utilization plans rely on emissions reductions at Phase II units that—after 1985, but prior to passage of the CAAA90—had already reduced their emissions, or were required to reduce their emissions in response to State laws. Again, relying on these reductions does not achieve new emissions reductions in response to the CAAA90. In each case, new authorizations to emit sulfur dioxide were created, thereby making projected total emissions higher with such plans (including the allocated allowances) than without. As a result, EPA is taking two actions to address this issue: (1) revisions of the rules promulgated for substitution and reduced utilization plans, and (2) issuance of draft Phase I permits containing partial approval of such compliance plans. EPA has proposed revisions to the rules for substitution and reduced utilization in the fall of 1993, and expects final revisions to be promulgated in early 1994. Using its discretionary authority to approve compliance plans, EPA is proposing to approve most Phase I permits with substitution or reduced utilization plans for 1995 only, and to defer action for the remainder of Phase I until the rulemaking on the revised rules is complete. This action will allow Phase I utilities to count on their current plans for the first year of compliance and, where appropriate, provide time to revise plans. Compliance plans submitted after this action will be considered under the amended rules to be issued in 1994.[66]

Phase I Permit Applications

All Phase I plants must submit to the EPA a "Phase I Permit Application" specifying, by boiler, which compliance plan is intended for each unit. The choices listed on the application are as follows:

- Hold allowances
- Substitution plan
- Reduced utilization plan
- Phase I extension plan.

A plant which plans to comply by purchasing additional allowances or by switching, blending, or cofiring falls into the category of "holding allowances" because it intends to meet emissions limitations without substituting units, reducing utilization, or installing scrubber equipment. In this case, EPA takes into consideration that there are actions plants can take in order to comply by holding allowances (e.g., switching fuels), but it is left entirely up to the plant to decide which is the most feasible and cost-effective action.

Plant operators may choose one or more options. Many have applied to use a substitution plan and a reduced utilization plan designating the same non-Phase I unit or units as substitution and compensating units. After the review process, if all criteria are met, EPA will give a "conditional" approval to both, along with any appropriate allowance allocations for both, and the plant operators will decide at a later date which plan to activate. If the approval is for the year 1995, plant officials have until December 31, 1995, to notify EPA, in writing, which plan has been implemented.

Phase I unit operators who plan to comply by installing a scrubber or repowering would submit a Phase I extension plan. The time for compliance would then effectively be extended until 1997 because EPA would provide additional allowances for the unit.

Sample Compliance Plans

To demonstrate the variety and flexibility of Phase I compliance plans, it will be helpful to cite the following examples of permits which have received draft approval.

On August 9, 1993, EPA issued a Draft Phase I Acid Rain Permit to Ashtabula boiler unit 7 (generating unit 5) operated by Cleveland Electric Illuminating Company, approving 14 conditional substitution plans

[66]U.S. Environmental Protection Agency, "Acid Rain Program: EPA's Proposed Response to Substitution and Reduced Utilization Compliance Plan Litigation" (July 1993).

for 1995.[67] Each plan designates the following 14 substitution units individually:

- Ashtabula boiler units 8, 9, 10, and 11
- Bay Shore boiler units 1, 2, 3 and 4
- Acme boiler unit 16
- Lake Shore boiler units 18, 91, 92, 93, and 94.

EPA also gave draft approval for five active substitution plans, designating Acme boiler units 13, 14, 15, 91, and 92 individually as substitution units for calendar year 1995. Action on the conditional and active substitution plans for 1996 through 1999 was deferred pending the aforementioned revisions to the substitution and reduced utilization rules.

A reduced utilization plan was also given draft approval; the plan will result in the shift of generation from Ashtabula boiler unit 7 to the following nuclear (sulfur-free) generators:

- Perry unit 1
- David Besse unit 1
- Beaver Valley unit 2.

This reduced utilization plan will also result in the use of energy conservation and improved unit efficiency measures to account for underutilization of this unit. There is no allowance allocation for the use of these conservation compliance measures, nor is there an allocation for the use of sulfur-free generators.

Ashtabula boiler unit 7 also applied for an extension plan naming an Elmer Smith coal-fired unit as a transfer unit. It was not approved because unallocated allow-ances did not remain in the Phase I Extension Reserve at the time EPA acted on this plan. However, if Phase I extension reserve allowances become available in the future, the application will be eligible to receive 7,279 allowances.

Included in the same application were the plans for Ashtabula boiler units 8, 9, 10, and 11 to be substitution units for Ashtabula boiler unit 7. All four units received draft approval for a conditional substitution plan for 1995 in which they were designated as substitution units for Ashtabula boiler unit 7. If the plans are activated, they will receive the following allowance allocations for 1995:

- Ashtabula unit 8: 10,753 allowances
- Ashtabula unit 9: 9,173 allowances
- Ashtabula unit 10: 8,275 allowances
- Ashtabula unit 11: 8,706 allowances.

All four also received draft approval for a conditional reduced utilization plan, shifting generation to sulfur-free generators and resulting in the use of energy conservation and improved unit efficiency measures. Activation of the reduced utilization plan is contingent upon the activation of the substitution plans for these four units.

On August 11, 1993, EPA issued a Draft Phase I Acid Rain Permit to the Potomac River Plant operated by the Potomac Electric Power Company. It states that EPA gave draft approval for conditional substitution plans for Potomac River units 1, 2, 3, 4, and 5 in which they are designated as substitution units for Chalk Point units 1 and 2, and for Morgantown units 1 and 2 in 1995. It also states that Potomac units 1, 2, 3, 4, and 5 are approved for a conditional reduced utilization plan in which they are designated as compensating units for Chalk Point units 1 and 2, and for Morgantown units 1 and 2 in 1995. Although the Potomac River plants were not originally targeted as Phase I plants, they became Phase I plants and were allocated allowances at the time they were given draft approval as either substitution or compensating units.

These conditional plans can be activated only to the extent that none of the five Potomac River units is both a substitution unit and a compensating unit for the same year and that none is a substitution unit under more than one substitution plan for the same year. Because these plans were conditionally approved for the year 1995, EPA must be advised by December 31, 1995, as to which plans were activated.

[67]Where a generator and boiler do not have the same identification number, as in the case of the Ashtabula plant, the unit number is specified as either the boiler or the generator.

4. Individual Utility Compliance Plans

While the previous chapter presented an overview of the different types of possible responses to Phase I of the Clean Air Act Amendments of 1990 (CAAA90), this chapter discusses the responses of individual utilities. The specific responses, and their costs, of individual utilities affected by Phase I of the CAAA90 vary substantially. One way to appreciate this variation is to consider the individual compliance strategies. First, this chapter presents the compliance plans of the large plants that are affected by Phase I; then the more detailed plans, including their costs, of six separate utilities are discussed.

Large Plant Compliance Plans

Of 110 plants affected by Phase I, some are very large coal-fired facilities. There are 16 plants with more than 1,500 megawatts of nameplate capacity affected by the law, and 7 plants with more than 2,000 megawatts of capacity affected (Table 14). These plants are located in various States throughout the affected area. The largest is Georgia Power's Bowen facility. Of its 3,541 megawatts, 3,499 megawatts (98.8 percent) of its capacity (generators 1, 2, 3, and 4) are affected by Phase I. The remaining portion of the Bowen facility is a small petroleum-fired unit.

To comply with Phase I, Bowen plans to switch to low-sulfur coal or blend its current fuel with a low-sulfur coal. In October 1992, Georgia Power signed contracts with Transco Coal Company to receive low-sulfur coal primarily for its Bowen units,[68] and more contracts are expected to meet demand at the facility.

PSI Energy's Gibson plant in Indiana has 2,672 megawatts of affected capacity at generators 1, 2, 3, and 4. The main compliance strategy at Gibson is the

Table 14. Plants with More Than 1,500 Megawatts of Phase I Affected Capacity, 1992

Plant	Operating Utility	State	Affected Nameplate Capacity (megawatts)	Allowances[a]	1985 SO_2 Emissions (tons)
Bowen	Georgia Power	Georgia	3,499	247,881	305,302
Gibson	PSI Energy	Indiana	2,672	178,477	294,669
Cumberland	Tennessee Valley Authority	Tennessee	2,600	176,763	344,153
General J.M. Gavin	Ohio Power	Ohio	2,600	175,002	363,249
Labadie	Union	Missouri	2,390	150,016	269,642
Harrison	Monongahela Power	West Virginia	2,052	132,685	234,693
E.C. Gaston	Alabama Power	Alabama	2,013	130,542	159,288
Wansley	Georgia Power	Georgia	1,904	132,616	248,651
Baldwin	Illinois Power	Illinois	1,892	141,391	264,594
Conemaugh	Pennsylvania Electric	Pennsylvania	1,872	122,918	181,892
Hatfield's Ferry	West Pennsylvania Power	Pennsylvania	1,728	112,383	161,081
W.H. Sammis	Ohio Edison	Ohio	1,694	117,649	150,580
Mt. Storm	Virginia Electric & Power	West Virginia	1,662	118,528	128,310
Mitchell	Ohio Power	West Virginia	1,633	87,135	103,326
Brunner Island	Pennsylvania Power & Light	Pennsylvania	1,559	109,716	124,956
Muskingum River	Ohio Power	Ohio	1,530	104,416	253,435

[a]One SO_2 allowance permits one ton of SO_2 emissions.
SO_2 = Sulfur dioxide.
Source: **Capacity**: Energy Information Administration, *Inventory of Power Plants 1992*, DOE/EIA-0095(92) (Washington, DC, October 1993). **Number of Allowances**: *Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691. **1985 Emissions**: U.S. Environmental Protection Agency, National Allowance Data Base, Version 2.11 (January 1993).

[68]Feildston Company, Inc., *Compliance Strategies Review: Guide to Phase I Units*, 3rd edition (Washington, DC, October 1992), p. 23.

Union's Labadie plant is one of the largest Phase I affected facilities at 2,390 megawatts.

installation of a scrubber on unit 4. The other three units will blend low-sulfur eastern and Illinois Basin coals. PSI Energy has purchased five elemental coal analyzers for use at Gibson to assist in blending the coal.[69]

The Tennessee Valley Authority's (TVA) Cumberland facility and Ohio Power's General J.M. Gavin facility both have 2,600 megawatts of Phase I affected capacity, and both are planning to install scrubbers in order to comply with Phase I. For the Cumberland plant, the installation of scrubbers on its two affected units, 1 and 2, will allow the facility to continue burning Kentucky coal. The plant has historically received the majority of its coal from Kentucky mines. The scrubbers will also aid the other affected TVA units, since excess allowances from the Cumberland plant can be reallocated to other plants so that all of TVA's Phase I affected capacity can have a sufficient number of allowances.[70]

Similarly, the centerpiece of Ohio Power's compliance strategy is the installation of scrubbers at Gavin 1 and 2. Some opposition to this plan was raised on the basis that scrubber installation was not the least-cost option. American Electric Power, the holding company for Ohio Power, supported the scrubber installations, saying that the long-run cost of scrubbers would be less than that of fuel switching.[71] It has since been decided that Gavin 1 and 2 will scrub in order to meet Phase I compliance.

Three other large facilities—Monongahela Power's Harrison plant, Pennsylvania Electric's Conemaugh plant, and Virginia Electric & Power's Mt. Storm plant—also plan to install scrubbers as part of their Phase I compliance strategies.

Like Georgia Power's Bowen facility, Union's Labadie facility and Alabama Power's E.C. Gaston are planning to switch and / or blend fuels in order to comply. Both plants are currently looking at existing contracts and negotiating new contracts in order to meet coal demand at the facilities.

The majority of the other large plants affected by Phase I are also complying by switching or blending fuels, including Georgia Power's Wansley facility, Ohio Edison's W.H. Sammis facility, Pennsylvania Power & Light's Brunner Island facility, and Ohio Power's Mitchell and Muskingum River unit 5 facilities.

[69]Fieldston Company, Inc., *Compliance Strategies Review: Guide to Phase I Units*, 3rd edition (Washington, DC, October 1992), pp. 73-74.
[70]Fieldston Company, Inc., *Compliance Strategies Review: Guide to Phase I Units*, 3rd edition (Washington, DC, October 1992), p. 83.
[71]Fieldston Company, Inc., *Compliance Strategies Review: Guide to Phase I Units*, 3rd edition (Washington, DC, October 1992), p. 61.

The two remaining plants with more than 1,500 megawatts of affected capacity are West Penn Power's Hatfield's Ferry facility and Illinois Power's Baldwin facility. Plans at both of these plants are to use allowances in order to meet their reduction requirements for Phase I. West Penn Power is a subsidiary of Allegheny Power System and a joint owner of Monongahela Power Company. Allowances from Monongahela Power's Harrison plant, which is installing scrubbers on its three affected units, 1, 2, and 3, will be available for Hatfield's Ferry.[72] For Baldwin, allowances are being purchased from other owners.

Specific Utility Compliance Plans

To provide a more intensive look at the compliance plans of some utilities, this section discusses the plans to comply with Phase I of the CAAA90 for six utilities. These six include three of the utilities with large plants discussed above and three other affected utilities. This discussion provides some examples of the differences and similarities among utility compliance plans and the effects of these plans. To comply with the sulfur dioxide (SO_2) control requirements, only one utility will use a single compliance strategy; the others will use a combination of strategies.

Illinois Power: Illinois Power owns 5.0 gigawatts of electricity generating nameplate capacity at eight facilities.[73] Three (Baldwin, Hennepin, and Vermilion) are affected by Phase I of the Acid Rain Program of the CAAA90. The three plants total 2.2 gigawatts of capacity (Table 15).[74] For these plants, the SO_2 allowances received annually by Illinois Power during Phase I will be more than 150,000 tons below their base emissions in 1985.

In July 1991, the Illinois State legislature passed a law effectively requiring Illinois utilities to install scrubbers for CAAA90 compliance. The intent of the law was to protect the Illinois coal industry which supplied Illinois Power. As a result, the utility originally had planned to install scrubbers on two of the units at Baldwin. Subsequently, a group of western coal producers and railroads sued the Illinois Commerce Commission, charging that the law discriminates against out-of-State coal and, therefore, violates the Commerce Clause of

Table 15. Characteristics of Selected Phase I Utilities

Owning Utility[a]	Affected Nameplate Capacity (megawatts)	Total Nameplate Capacity[b] (megawatts)	Proportion Capacity Affected (percent)	Allowances[c] (per year)	1985 SO_2 Emissions (tons)	Difference Between Base Emissions & Allotment	Total Phase I Extension Allowances[d]	No. of Unit Low-NO_x Burners[e]	Number of CEMs[e]
Illinois Power	2,232	5,005	44.6	171,328	324,584	153,256	0	2.0	9.0
Pennsylvania P&L	2,343	8,704	26.9	168,205	198,554	30,349	58,900	7.2	5.2
Potomac Elec. Power	2,162	6,433	33.6	128,770	132,796	4,026	61,494	4.2	3.2
Cincinnati G&E	1,374	5,555	24.7	80,987	128,060	47,073	0	1.4	3.4
Georgia Power	8,087	15,995	50.6	540,768	744,563	203,795	102,258	16.1	17.1
Southern Indiana G&E . . .	530	1,359	39.0	38,095	84,224	46,129	0	2.0	2.5

[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]Total utility capacity.

[c]One SO_2 allowance permits one ton of SO_2 emissions.

[d]Extension allowances are as distributed by EPA before any redistribution by the extension allowance pool. Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Extension allowances were awarded for 1995 through 1999.

[e]Number of units retrofitted with low-NO_x burners and number of CEMs may be fractional because of partial unit ownership by utility. Also, number of CEMs may not equal number of units because of boiler exhaust duct and stack configuration.

SO_2 = Sulfur dioxide.

NO_x = Nitrogen oxides.

CEM = Continuous emission monitor.

Note: Several of these utilities are part owners of affected units. See Appendix G for details.

Source: Based on information from Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric (November 1993 through March 1994).

[72]Fieldston Company, Inc., *Compliance Strategies Review: Guide to Phase I Units*, 3rd edition (Washington, DC, October 1992), pp. 52 and 87.

[73]The Joppa Steam plant, which is jointly owned by Illinois Power, is not included because it is not in Illinois Power's ratebase.

[74]Unit-level details are provided in Appendix G.

Estimates of the annual total cost for compliance at the 1,892-megawatt Baldwin facility are just under $27 million. Baldwin will use allowances as its main compliance strategy.

the U.S. Constitution. However, Illinois Power decided to delay installation of the scrubbers at Baldwin until Phase II,[75] because cost estimates for compliance using scrubbers were higher than for other methods of compliance.

Several alternatives to scrubbers were considered to comply with Phase I. Fuel blending was one of them. Illinois Power tested coal from the Powder River Basin at Baldwin. The coal tested was subbituminous, low Btu content, with 28 percent moisture, and required special preparation and unloading arrangements. Several blends of Illinois coal and Powder River Basin coal were tested. The conclusions from the testing were that all three units at the Baldwin station could use the blended fuels, but some modifications to the plant would be necessary if they were to become the normal fuel at the facility.[76]

Another alternative considered was allowance purchases. This method is estimated to be slightly less expensive than fuel blending. As a result, Illinois Power's current compliance strategy is to purchase allowances. As of October 1993, they had purchased more than 80 percent of the allowances needed for Phase I. Enough allowances have already been purchased for Hennepin and Vermilion; they are still being purchased for Baldwin.

Based on its compliance plans, the approximate cost to Illinois Power of complying with Phase I of the CAAA90 can be estimated (Table 16). Assuming an average allowance price of $200 and estimates of the cost of installing low-nitrogen oxide (NO_x) burners and continuous emission monitors (CEMs), the annual out-of-pocket cost of compliance will be $33 million,[77] 93 percent of which will be used to purchase allowances.[78] The overnight capital costs for NO_x control and CEMs total more than $23 million, but they are allocated over the life of the capital equipment, which is assumed to be 15 years.

Forty-five percent of the capacity owned by Illinois Power is affected by Phase I of the CAAA90, and the effect of Phase I on utility costs, while relatively small, is the largest of the six utilities considered here. For the amount of electricity generated at the utility in 1992, compliance with Phase I comes to 1.9 mills per kilowatthour (Table 17). This is 3.6 percent of the electricity sales revenue the utility received in 1992.

Pennsylvania Power & Light: Pennsylvania Power & Light owns 8.7 gigawatts of generating nameplate capacity at 15 facilities. Four plants—Brunner Island (generators 1, 2, and 3), Martins Creek (generators 1 and 2), Sunbury (generators 3 and 4) and Conemaugh (generators 1 and 2)—have been designated Phase I plants. The total of the Phase I affected capacity is 2.3 gigawatts.

The foundation of this utility's compliance strategy is fuel switching. Pennsylvania Power & Light will, however, install scrubbers at its Conemaugh plant.[79]

Phase I affected generators at Brunner Island will be receiving coal with a rating of less than 2.35 pounds of SO_2 per million Btu from southwestern Pennsylvania (Somerset and Greene counties). Sunbury, on the other

[75]"Western Coal Group Sues Illinois Commission over State Law Requiring Scrubber Use," *Utility Environment Report* (August 6, 1993), pp. 1-2.

[76]R.W. Eimer, R.H. Hayes, K.B. Pollman, and D.J. Diewald, "Blending Illinois and Powder River Basin Coals for Testing on a 585 Megawatt Unit," paper presented at the Engineering Foundation Conference on Coal Switching and Blending of Western Low Sulfur Coals (Salt Lake City, UT, September 26, 1993).

[77]All costs in this chapter are in 1993 dollars.

[78]If Illinois Power had to purchase all of its allowances, annual allowance costs alone would be almost $65 million.

[79]Conemaugh is jointly owned by Pennsylvania Power & Light (11.4 percent), Potomac Electric Power (9.7 percent), and other utilities.

Table 16. Costs of Phase I Compliance of Selected Utilities

Owning Utility[a]	SO_2 Control			NO_x Control Capital Costs (million dollars)	CEMs		Total Capital Costs (million dollars)	Annual Capital Costs (million dollars)	Annual O&M and Fuel Costs (million dollars)	Annual Total Costs (million dollars)
	Capital Costs (million dollars)	O&M Costs (million dollars)	Fuel Premium (million dollars)		Capital Costs (million dollars)	O&M Costs (million dollars)				
Illinois Power[b]	0.0	30.7	0.0	13.5	9.8	0.9	23.4	1.6	31.6	33.1
Pennsylvania P&L . .	48.1	2.2	0.0	70.6	7.7	0.0	126.4	8.4	2.2	10.6
Potomac Elec. Power	62.4	1.7	0.0	149.0	9.4	0.0	220.9	14.7	1.7	16.5
Cincinnati G&E[c] . . .	17.5	3.6	5.3	8.1	2.8	0.0	28.4	1.9	8.8	10.7
Georgia Power	78.3	1.8	0.7	178.0	16.0	0.0	272.3	18.2	2.5	20.7
Southern Indiana G&E	107.0	1.3	0.0	5.0	2.8	0.2	114.8	7.7	1.5	9.1

[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]Costs do not include the Joppa Steam Plant, which is not included in Illinois Power's ratebase.

[c]Costs do not include East Bend Station as a substituting unit.

SO_2 = Sulfur dioxide.

NO_x = Nitrogen oxides.

CEM = Continuous emission monitor.

O&M = Operations and maintenance.

Notes: •These are contemporary estimates made by the individual utilities; most dollars are adjusted to 1993. •Capital equipment is depreciated over 15 years. •The estimates underestimate the cost of compliance to the extent that no cost estimate has been made in some cases. •For unit level data, see Appendix G.

Source: Based on information from Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric (November 1993 through March 1994).

Table 17. Effects of Phase I Compliance on Selected Utilities

Owning Utility[a]	Average Capital Costs (dollars per affected kilowatt)	Average Annual			Utility-Wide[b]		
		Capital Costs (dollars per affected kilowatt)	O&M & Fuel Costs (dollars per affected kilowatt)	Total Costs (dollars per affected kilowatt)	Average Costs (mills per kilowatt-hours)	Electric Operating Expense Increase (percent)	Sales Revenue Increase (percent)
Illinois Power	10.5	0.7	14.1	14.8	1.9	3.6	2.8
Pennsylvania P&L	53.9	3.6	0.9	4.5	0.3	0.5	0.4
Potomac Electric Power	102.2	6.8	0.8	7.6	0.9	1.2	1.0
Cincinnati G&E	20.7	1.4	6.4	7.8	0.5	1.2	1.0
Georgia Power	33.7	2.2	0.3	2.6	0.3	0.6	0.5
Southern Indiana G&E	216.4	14.4	2.8	17.2	1.7	4.7	3.8

[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]Average generation cost increase and revenue and electric operating expense percentage increase are based on 1992 generation, revenue, and electric operating expenses.

O&M = Operations and maintenance.

Notes: •For unit level data, see Appendix G.

Source: Based on information from Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric (November 1993 through March 1994).

hand, will receive its coal from central Pennsylvania (Clearfield County). The Clearfield County coal will be cleaned to 2.3 pounds of SO_2 per million Btu. It is expected that any fuel premiums that will be incurred by the utility in meeting its Phase I requirements will be negligible.

All four plants will install low-NO_x burners at a total cost estimated by the utility of $71 million. Additionally, precipitator modifications at Brunner Island generators 1, 2, and 3 will cost approximately $3 million. Dust collectors at Sunbury's generators 3 and 4 will be modified at a cost over $3 million, and the precipitators at Martins Creek's generators 1 and 2 will also be modified—at a cost of $4 million. The 5.2 Phase I CEM units will cost a total of $8 million.[80] Pennsylvania Power & Light's share of scrubber installation at Conemaugh is $38 million.

Pennsylvania Power & Light has the second smallest proportion of their total capacity affected by Phase I of the six utilities examined, and Phase I has the smallest proportional effect on its costs. Average costs increase by only 0.3 mills per kilowatthour. This cost increase is only 0.4 percent of their 1992 revenues.

Potomac Electric Power: Potomac Electric Power owns over 6.4 gigawatts of electricity generating nameplate capacity at five facilities. Three—Chalk Point, Morgantown, and Conemaugh[81]—have two units each that have been designated Phase I units in the CAAA90. The total of the Phase I affected capacity is 2.2 gigawatts.

Both Chalk Point and Morgantown units will comply through changing fuels. The current plan is to continue to receive coal from western Maryland and western Pennsylvania. However, with the onset of Phase I, the coal will be washed. Conemaugh will install scrubbers.

Chalk Point will also install the capability to burn natural gas at a cost of $30 million. At the present time, however, the utility is not planning to burn gas unless the price of gas falls dramatically or the prices of the designated western Maryland and western Pennsylvania coals rise in an equally dramatic manner.

As such, the total Phase I compliance capital cost at Chalk Point units 1 and 2 is $84 million ($30 million for gas-burning capability, $51 million for low-$NO_x$ burners and $2 million for CEMS). The total capital cost of emissions reductions for Morgantown units 1 and 2 is $101 million (most of which is for the installation of low-NO_x burners). The total capital cost for Potomac Electric at Conemaugh, even though it will install scrubbers, is only $32 million, because the utility owns less than 10 percent of the plant.[82]

Potomac Electric is one of the median utilities (of the six considered) in terms of the proportional effect of Phase I on its costs. Their costs will increase 1.2 percent as a result of Phase I, although they expect the most expensive NO_x control costs, relative to the amount of affected capacity, of any of the six utilities.

Cincinnati Gas and Electric: Cincinnati Gas and Electric owns 5.6 gigawatts of generating nameplate capacity at six facilities. Three—Walter C. Beckjord (units 5 and 6), Miami Fort (units 5, 6, and 7) and Conesville (unit 4), all partially owned by Cincinnati Gas and Electric—have units that have been designated Phase I units in the CAAA90. The Phase I units at both Beckjord and Miami Fort will comply through fuel changes. The most likely source of the lower sulfur coal is central Appalachia. Current estimates of fuel premiums at Beckjord and Miami Fort for Phase I units are about $5 million annually. Conesville will acquire additional allowances. Assuming an allowance cost of $200 each, Cincinnati Gas and Electric's share of allowance costs at Conesville will be less than $4 million per year.

Only the Beckjord plant will install low-NO_x burners. The total cost to Cincinnati Gas and Electric for their installation at the two Beckjord Phase I units is $8 million. Additionally, the Beckjord station's precipitators will be modified at a capital cost to the utility of $9 million. Finally, two CEMs will be installed at Beckjord, costing the utility less than $1 million.

At Miami Fort and Conesville, there will be no low-NO_x modifications. However, the precipitators will be modified at Miami Fort, and gas-conditioning equipment will be installed. The cost of installing this SO_2 reduction equipment to Cincinnati Gas and Electric is estimated at less than $9 million. Units 5 and 6 at Miami Fort will share a CEM, and Unit 7 will have its own. The capital cost to the utility of Miami Fort's CEMs will be more than $1 million. For the one CEM at Conesville, the utility will spend about half a million dollars.[83]

[80]Verbal communication with Pennsylvania Power & Light (November 5, 1993).
[81]Conemaugh is jointly owned by Pennsylvania Power & Light (11.4 percent), Potomac Electric Power (9.7 percent), and other utilities.
[82]Verbal communication with Potomac Electric Power Company (November 4, 1993).
[83]Verbal communication with Cincinnati Gas and Electric (November 19, 1993).

For Cincinnati Gas & Electric the costs of complying with Phase I are also relatively small. They expect a small increase in their fuel costs resulting from switching to low-sulfur coal, and their share of allowance costs at Conesville is small. Costs increase only 0.5 mills per kilowatthour, which amounts to 1.0 percent of their 1992 electricity sales revenues.

Georgia Power: Georgia Power is an operating company of the Southern Company. It owns 16.0 gigawatts of nameplate electricity generating capacity at 34 facilities, including several small hydro-power plants. Bowen (generators 1 through 4), Hammond (generators 1 through 4), Jack McDonough (generators 1 and 2), Wansley (generators 1 and 2), Yates (generators 1 through 7) and Gaston (generators 1 through 3 and ST4) have been designated Phase I plants. The total of the Phase I affected nameplate capacity is 8.1 gigawatts. Georgia Power is the largest utility of the six discussed in this report. It also has the largest amount and proportion of capacity affected by Phase I.

The cornerstone of its compliance strategy is fuel switching. All six Phase I plants will be switching coal. In addition, one unit, generator 1 at the Yates plant, will install scrubber equipment with an estimated cost of $34 million, one-half of which will be paid by the U.S. Department of Energy.

Georgia Power's new low-sulfur coal will be Eastern Appalachian coal with 1.0 to 1.5 pounds of SO_2 per million Btu. According to the utility, because of the current "soft" market for coal, there is no expected fuel premium.[84]

The total annual cost of compliance for Georgia Power is approximately $21 million. These costs include the 17.1 CEMs[85] required for the six plants by the CAAA90, the cost of installing low-NO_x burners at all six plants, and various capital equipment required for SO_2 reductions. Some of these cost adjustments include the installation of smokeless igniters, oil-gun upgrades, and flue gas conditioners.

The increase in Georgia Power's cost from the CAAA90 is small, 0.3 mills per kilowatthour; this is 0.5 percent of their electric revenues in 1992. These low costs are largely because fuel switching was chosen at most of the affected units, all except the small Yates 1 unit, and the utility expects to pay no premiums for the lower sulfur coal.

Southern Indiana Gas and Electric: Southern Indiana Gas and Electric is the smallest utility owning the smallest total amount of affected capacity of the six utilities. Southern Indiana owns electricity generating units at five plants with a total capacity of 1.4 gigawatts. Two units at Culley and the one (partially owned) unit at Warrick, totalling 0.5 gigawatts, are affected by Phase I. The affected units are 39 percent of the utility's capacity.

Southern Indiana is installing scrubbers on both of its affected units at Culley. These two units comprise almost 20 percent of the total generating capacity and 50 percent of the affected capacity owned by the utility, a much higher proportion installing scrubbers than any of the other five utilities discussed here. The Warrick plant is expected to reduce utilization and use allowances to comply with Phase I, although it may switch to low-sulfur coal if switching appears to cost less than using allowances.

Scrubbing at Culley and reducing utilization at Warrick results in Southern Indiana receiving more allowances from the EPA than it will use in Phase I. The utility plans to sell these allowances, which will substantially reduce their compliance costs. Of course, this is one kind of activity that a marketable emissions allowance system is expected to encourage.

The total annual cost of compliance for Southern Indiana is estimated to be over $9 million, mostly for capital costs.[86] The capital costs are largely for the two scrubbers, while the operating costs are reduced by $5 million per year because of the sale of unneeded emission allowances. The costs also include (1) installing low-NO_x burners on the two units at Culley, (2) installing and operating two CEMs at Culley, and (3) half of the CEM cost at Warrick.

While Southern Indiana's total compliance costs are not particularly large, the proportional costs to the utility on the basis of total revenue are larger than the other five utilities considered here. Per kilowatt of affected capacity, the average annual costs total over $17. This is an increase of less than 2 mills per kilowatt hour generated by the utility in 1992 or 3.8 percent of its 1992 revenues.

[84]Verbal communication with Georgia Power (November 5, 1993).
[85]Georgia Power owns only part of Gaston.
[86]Verbal communication with Southern Indiana Gas and Electric (February 17, 1993).

Summary

Electric utilities are preparing to comply with Phase I of the Acid Rain Program of the CAAA90. Their response to the SO_2 reduction requirements of the CAAA90 vary from utility to utility. More than half of the affected utilities are planning to switch to low-sulfur coal, blend with low-sulfur coal, and co-fire with natural gas to comply with the CAAA90 requirements. The second most popular option is to obtain SO_2 emission allowances in addition to the ones allocated to the affected utility by the Environmental Protection Agency. Installing scrubber equipment is planned for about 10 percent of the affected units. An equal percentage of units do not need to take any action, because they have already reduced their SO_2 emissions enough so that the allowances allotted to them by the Environmental Protection Agency (EPA) are sufficient for compliance. Acquiring allowances and switching fuels are usually the least capital intensive compliance strategy.

This report has discussed in depth the compliance strategies of 6 utilities owning 20 affected plants: Illinois Power plans to purchase additional allowances for all of its affected units; Pennsylvania Power and Light plans to switch to low-sulfur coal, clean the high-sulfur coal burned, or scrub its Phase I units; Potomac Electric Power also plans to clean the high-sulfur coal they burn or scrub its affected units, as well as install the capability for some of their boilers to co-fire with natural gas; Cincinnati Gas and Electric plans to switch to low-sulfur coal and purchase additional allowances; Georgia Power will switch to low-sulfur coal from eastern Appalachia or blend it with the high-sulfur they have been burning and install a scrubber on one unit to release some of its initially allotted allowances; and Southern Indiana Gas and Electric plans to use a combination of scrubbing and selling unneeded allowances for its affected units.

For the units of the six utilities profiled here, scrubbing is the most costly compliance strategy. The high annual total cost for units choosing scrubbing results from the very high capital cost of scrubbers. Crucial to this conclusion is the assumption to depreciate capital costs over 15 years in this study. For all five of the units adding scrubbers, estimated capital costs ranged from just under \$200 to over \$300 per kilowatt. This brackets the cost estimates cited in Chapter 3 of \$227 to \$266 per kilowatt. Obtaining additional allowances has the second highest average annual total costs. Crucial to this conclusion is the assumed cost of SO_2 allowances. While obtaining additional allowances is a low capital cost strategy, it is a high operating cost strategy. Finally, fuel switching is the least expensive strategy of the units profiled here. Crucial to this conclusion is the assumption by many utilities that lower-sulfur coal will cost little or no more than the coal that they have been burning.

A study estimating the overall costs of the Acid Rain Legislation has been prepared for EPA.[87] For the Phase I requirements, the report estimates the annualized cost of SO_2 reductions to the electric generating sector will range from \$600 million to \$1 billion (1992 dollars), compared to the case where the CAAA90 were not enacted. The study also estimates the cost imposed by mandatory reductions specified in the CAAA90 without allowance trading to range from \$1.1 to \$1.6 billion, resulting in the flexible tradeable allowance system reducing costs by \$400 to \$600 million.

Unlike with SO_2 compliance strategies, electric utilities affected by Phase I have little choice in how they comply with NO_x emission levels and install CEMs. However, because NO_x controls and CEMs are less expensive than SO_2 controls, the cost of the loss of flexibility in NO_x and CEM compliance strategies is less than it would have been for SO_2 strategies.

[87]ICF, "Regulatory Impact Analysis of the Final Acid Rain Implementation Regulations," a report prepared for the U.S. Environmental Protection Agency (October 19, 1992), pp. 4-6.

Appendix A

Phase I Affected Units of the Clean Air Act Amendments of 1990

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Phase I Affected Units of the Clean Air Act Amendments of 1990

Profile of Affected Units

This appendix provides detailed information concerning the 261 generating units (263 boilers) listed in the Clean Air Act Amendments of 1990 as being affected by Phase I of the Acid Rain Program (Table A1).[89] The data are presented alphabetically by State, operating utility, plant and then numerically and alphabetically by generator identification number. The data represent electric generating plants in 21 States, and involve 64 operating utilities.

The following information is presented for each unit separately: (1) generator nameplate capacity (given in megawatts); (2) initial Phase I allowance allocations; (3) base SO_2 emissions (given in tons); (4) Phase I extension allowance allocations; and (5) code of the method of compliance. A brief explanation of each of these categories follows.

First, the generator nameplate capacity provides the operating utility's nameplate capacity for each generator. This data is taken from the *Inventory of Power Plants in the United States 1992*.

Next, the initial Phase I allowance allocation totals were issued by the U.S. Environmental Protection Agency (EPA) as published in the Federal Register on January 11, 1993.[90] Each unit was allotted a certain number of allowances. For each allowance, the unit may emit one ton of SO_2 emissions.

Base SO_2 emissions are listed next. Base SO_2 emissions are estimates of 1985 coal and oil SO_2 emissions. These estimates are from EPA's National Allowance Data Base, version 2.11, dated January 1993. Phase I extension allowances are also presented in Appendix A. Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions, or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Those that requested, but did not receive, extension allowances are shown in the Phase I Extension Allowances column in Table A1 with zeroes.

Finally, the code for the method of compliance is presented. The compliance strategies have been compiled into six groupings with coded numbers associated with each strategy as follows: (1) fuel switching and/or blending; (2) obtaining additional allowances; (3) installing flue gas desulfurization equipment (scrubbers); (4) using previously implemented controls; (5) retiring facilities; and (6) boiler repowering.

Several sources were used to obtained compliance strategy information about each unit. These sources include EPA, *Coal Week*, *Compliance Strategies Review*, the Georgia Public Utility Commission, *Utility Environment Report*, and *McIlvaine Utility Forecast*. The method of compliance was updated as of October 22, 1993.

Methodology for Calculating Coal Requirements

Estimates of the additional requirements for low-sulfur coal from the Central Appalachian Region and the Powder River Basin were made for those utilities that have chosen to switch to a lower sulfur coal or blend a lower sulfur coal with their currently used coal. The new source for obtaining low-sulfur coal was based on utility plans as reported in news articles or through communications with the utility. The estimates were

[89]Table A of the CAAA90 specified 263 boiler units that were affected by Phase I. These boilers are attached to 261 electric power generators at 261 generating units. This report uses generators to present individual unit data.

[90]*Federal Register*, Vol. 58, No. 6 (January 11, 1993), pp. 3687-3691.

calculated using the consumption data for the targeted boilers only with the following procedure:

(1) The 1992 SO_2 emission levels of the targeted boilers were calculated using coal consumption in tons, sulfur content, and Btu content as reported on the Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

(2) An algorithm was derived to use the 1992 SO_2 emissions of the targeted boilers and the average Btu and sulfur content of coal from the Central Appalachian Region *or* the Powder River Basin depending on which new source of coal the utility had chosen. The algorithm was used to calculate for each targeted boiler, what combination of tonnage of high-sulfur coal from the existing source and the low-sulfur coal from the Central Appalachian Region or Powder River Basin would be required to supply the required Btu levels and reach the emission compliance level of 2.5 pounds of SO_2 per million Btu.

(3) From that calculation all tonnage from the Central Appalachian Region was totaled as well as all tonnage from the Powder River Basin, thus giving the additional future requirements from each region.

The 1992 coal receipts at plants that have indicated fuel switching and/or blending to meet compliance with Phase I are also listed (Table A2).

Table A1. Profile of the 261 Generators Affected by Phase I

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
Alabama	Alabama Power	E C Gaston	1	272.0	17,624	22,220	--	1
Alabama	Alabama Power	E C Gaston	2	272.0	18,052	21,862	--	1
Alabama	Alabama Power	E C Gaston	3	272.0	17,828	23,369	--	1
Alabama	Alabama Power	E C Gaston	ST4	244.8	18,773	23,485	--	1
Alabama	Alabama Power	E C Gaston	5	952.0	58,265	68,352	--	1
Alabama	TVA	Colbert	1	200.0	13,213	20,522	--	1
Alabama	TVA	Colbert	2	200.0	14,907	20,227	--	1
Alabama	TVA	Colbert	3	200.0	14,995	23,325	--	1
Alabama	TVA	Colbert	4	200.0	15,005	24,748	--	1
Alabama	TVA	Colbert	5	550.0	36,202	52,318	19,442	1
Florida	Gulf Power	Crist	6	369.8	18,695	27,469	0	1
Florida	Gulf Power	Crist	7	578.0	30,846	55,921	39,714	1
Florida	Tampa Electric	Big Bend	1	445.5	27,662	56,181	--	1
Florida	Tampa Electric	Big Bend	ST2	445.5	26,387	53,820	--	1
Florida	Tampa Electric	Big Bend	ST3	445.5	26,036	32,901	--	1
Georgia	Georgia Power	Bowen	1	805.8	54,838	71,428	--	1
Georgia	Georgia Power	Bowen	2	788.8	53,329	63,727	--	1
Georgia	Georgia Power	Bowen	3	952.0	69,862	82,488	--	1
Georgia	Georgia Power	Bowen	4	952.0	69,852	87,659	--	1
Georgia	Georgia Power	Hammond	1	125.0	8,549	9,830	--	1
Georgia	Georgia Power	Hammond	2	125.0	8,977	9,997	--	1
Georgia	Georgia Power	Hammond	3	125.0	8,676	9,068	--	1
Georgia	Georgia Power	Hammond	4	578.0	36,650	35,539	--	1
Georgia	Georgia Power	Jack McDonough	1	299.2	19,386	32,738	27,391	1
Georgia	Georgia Power	Jack McDonough	2	299.2	20,058	33,749	--	1
Georgia	Georgia Power	Wansley	1	952.0	68,908	128,505	--	1
Georgia	Georgia Power	Wansley	2	952.0	63,708	120,146	100,186	1
Georgia	Georgia Power	Yates	1	122.5	7,020	11,673	9,225	3
Georgia	Georgia Power	Yates	2	122.5	6,855	11,199	--	1
Georgia	Georgia Power	Yates	3	122.5	6,767	11,279	--	1
Georgia	Georgia Power	Yates	4	156.3	8,676	13,758	--	1
Georgia	Georgia Power	Yates	5	156.3	9,162	15,754	--	1
Georgia	Georgia Power	Yates	6	403.8	24,108	42,207	9,236	1
Georgia	Georgia Power	Yates	7	403.8	20,915	23,974	2,806	1
Illinois	Central Illinois Public Service	Coffeen	1	389.0	12,925	38,013	--	1
Illinois	Central Illinois Public Service	Coffeen	2	616.5	39,102	102,616	--	1
Illinois	Central Illinois Public Service	Grand Tower	4	113.6	6,479	9,754	--	2
Illinois	Central Illinois Public Service	Meredosia	3	239.4	15,227	27,015	--	1
Illinois	Commonwealth Edison	Kincaid	1	659.7	34,565	94,042	--	1
Illinois	Commonwealth Edison	Kincaid	2	659.7	37,063	79,919	--	1
Illinois	Electric Energy Inc.	Joppa Steam	1	183.4	12,259	18,354	--	1
Illinois	Electric Energy Inc.	Joppa Steam	2	183.4	10,487	16,585	--	1
Illinois	Electric Energy Inc.	Joppa Steam	3	183.4	11,947	18,839	--	1
Illinois	Electric Energy Inc.	Joppa Steam	4	183.4	11,061	18,843	--	1
Illinois	Electric Energy Inc.	Joppa Steam	5	183.4	11,119	19,415	--	1
Illinois	Electric Energy Inc.	Joppa Steam	6	183.4	10,341	16,348	--	1
Illinois	Illinois Power	Baldwin	1	623.1	46,052	89,277	--	2
Illinois	Illinois Power	Baldwin	2	634.5	48,695	78,477	--	2
Illinois	Illinois Power	Baldwin	3	634.5	46,644	96,840	0	2
Illinois	Illinois Power	Hennepin	2	231.3	20,182	39,436	0	2
Illinois	Illinois Power	Vermilion	2	108.8	9,735	18,600	--	2

See footnotes at end of table.

Table A1. Profile of the 261 Generators Affected by Phase I (Continued)

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
Indiana	Hoosier Energy REC Inc	Frank E. Ratts	1	116.6	9,131	19,069	--	1
Indiana	Hoosier Energy REC Inc	Frank E. Ratts	2	116.6	9,296	18,436	--	1
Indiana	Indiana Michigan Power	Breed	1	495.6	20,280	70,365	--	5
Indiana	Indiana Michigan Power	Tanners Creek	4	579.7	27,209	59,646	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	1	217.3	19,620	45,690	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	2	217.3	19,289	44,275	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	3	217.3	19,873	46,489	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	4	217.3	19,552	44,856	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	5	217.3	18,851	41,989	--	1
Indiana	Indiana-Kentucky Electric	Clifty Creek	6	217.3	19,844	45,563	--	1
Indiana	Indianapolis Power & Light	Elmer W. Stout	5	113.6	4,253	5,665	0	1
Indiana	Indianapolis Power & Light	Elmer W. Stout	6	113.6	5,229	7,743	--	1
Indiana	Indianapolis Power & Light	Elmer W. Stout	7	470.9	25,883	35,007	0	1
Indiana	Indianapolis Power & Light	HT Pritchard	6	113.6	6,325	7,586	0	1
Indiana	Indianapolis Power & Light	Petersburg	ST1	253.4	18,011	21,765	0	3
Indiana	Indianapolis Power & Light	Petersburg	ST2	471.0	35,496	53,110	0	3
Indiana	Northern Indiana Public Service	Bailly	7	194.0	12,256	26,874	46,521	3
Indiana	Northern Indiana Public Service	Bailly	8	421.6	17,134	12,312	59,014	3
Indiana	Northern Indiana Public Service	Michigan City	12	540.0	25,553	45,434	46,820	1
Indiana	PSI Energy	Cayuga	1	531.0	36,581	56,848	21,603	1
Indiana	PSI Energy	Cayuga	2	531.0	37,415	69,254	3,164	1
Indiana	PSI Energy	Gibson	1	668.0	44,288	71,467	--	1
Indiana	PSI Energy	Gibson	2	668.0	44,956	77,864	--	1
Indiana	PSI Energy	Gibson	3	668.0	45,033	67,787	--	1
Indiana	PSI Energy	Gibson	4	668.0	44,200	77,551	32,242	3
Indiana	PSI Energy	R Gallagher	1	150.0	7,115	1,770	13,586	1
Indiana	PSI Energy	R Gallagher	2	150.0	7,980	19,178	9,328	1
Indiana	PSI Energy	R Gallagher	3	150.0	7,159	20,883	11,936	1
Indiana	PSI Energy	R Gallagher	4	150.0	8,386	21,980	8,252	1
Indiana	PSI Energy	Wabash River	1	112.5	4,385	6,713	5,451	6
Indiana	PSI Energy	Wabash River	2	112.5	3,135	6,308	5,478	1
Indiana	PSI Energy	Wabash River	3	123.3	4,111	6,889	--	1
Indiana	PSI Energy	Wabash River	5	125.0	4,023	8,201	1,630	1
Indiana	PSI Energy	Wabash River	6	387.0	13,462	26,239	7,800	1
Indiana	Southern Indiana Gas & Electric	FB Culley	2	103.7	4,703	16,361	0	3
Indiana	Southern Indiana Gas & Electric	FB Culley	3	265.2	18,603	38,456	0	3
Indiana	Southern Indiana Gas & Electric	Warrick	[e]4	323.0	29,577	58,813	0	1
Iowa	Interstate Power	Milton L Kapp	2	218.5	13,437	31,379	--	1
Iowa	Iowa Electric Light & Power	Prairie Creek	4	148.8	7,965	12,466	--	1
Iowa	Iowa Power	Des Moines	7	113.6	2,259	2,490	--	5

See footnotes at end of table.

Table A1. Profile of the 261 Generators Affected by Phase I (Continued)

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
Iowa	Iowa Public Service	George Neal North	1	147.1	2,571	1,048	--	4
Iowa	Iowa Southern Utilities	Burlington	1	212.0	10,428	23,093	--	1
Iowa	Iowa-Illinois Gas & Electric	Riverside	5	136.0	3,885	4,707	--	1
Kansas	City of Kansas City	Quindaro	ST2	157.5	4,109	3,255	--	4
Kentucky	Big Rivers Electric	Coleman	1	174.3	10,954	18,537	19,916	1
Kentucky	Big Rivers Electric	Coleman	2	174.3	12,502	19,862	13,722	1
Kentucky	Big Rivers Electric	Coleman	3	172.8	12,015	19,007	8,380	1
Kentucky	Big Rivers Electric	HMP&L Station 2	1	180.0	12,989	22,040	27,828	3
Kentucky	Big Rivers Electric	HMP&L Station 2	2	184.5	11,986	22,831	29,044	3
Kentucky	City of Owensboro	Elmer Smith	1	151.0	6,348	10,176	0	3
Kentucky	City of Owensboro	Elmer Smith	2	265.0	14,031	26,755	0	3
Kentucky	East Kentucky Power	Cooper	1	100.0	7,254	8,605	--	1
Kentucky	East Kentucky Power	Cooper	2	220.9	14,917	14,870	--	1
Kentucky	East Kentucky Power	HL Spurlock	1	305.2	22,181	29,745	--	1
Kentucky	Kentucky Utilities	EW Brown	1	113.6	6,923	6,242	--	2
Kentucky	Kentucky Utilities	EW Brown	2	179.5	10,623	10,029	2,996	2
Kentucky	Kentucky Utilities	EW Brown	3	446.4	25,413	38,577	19,842	2
Kentucky	Kentucky Utilities	Ghent	1	556.9	27,662	71,102	89,689	3
Kentucky	Kentucky Utilities	Green River	4	113.6	7,614	12,939	15,966	2
Kentucky	TVA	Paradise	3	1,150.2	57,613	106,835	156,070	2
Kentucky	TVA	Shawnee	10	175.0	9,902	34,077	--	1
Maryland	Baltimore Gas & Electric	CP Crane	1	190.4	10,058	9,722	4,868	1
Maryland	Baltimore Gas & Electric	CP Crane	2	209.4	8,987	9,657	--	1
Maryland	Potomac Electric Power	Chalk Point	ST1	364.0	21,333	20,258	8,140	1
Maryland	Potomac Electric Power	Chalk Point	ST2	364.0	23,690	27,482	0	1
Maryland	Potomac Electric Power	Morgantown	ST1	626.0	34,332	29,388	11,064	1
Maryland	Potomac Electric Power	Morgantown	ST2	626.0	37,467	37,988	16,250	1
Michigan	Consumers Power	JH Campbell	1	265.0	18,773	27,180	--	4
Michigan	Consumers Power	JH Campbell	2	385.0	22,453	33,350	--	4
Minnesota	Northern States Power	High Bridge	6	163.2	4,158	2,176	--	4
Mississippi	Mississippi Power	Jack Watson	4	250.0	17,439	26,218	0	1
Mississippi	Mississippi Power	Jack Watson	5	500.0	35,734	46,401	0	1
Missouri	Associated Electric Coop	New Madrid	1	600.0	27,497	74,430	--	1
Missouri	Associated Electric Coop	New Madrid	2	600.0	31,625	77,895	--	1
Missouri	Associated Electric Coop	Thomas Hill	1	180.0	9,980	35,874	--	1
Missouri	Associated Electric Coop	Thomas Hill	2	285.0	18,880	56,866	--	1
Missouri	City of Springfield	James River	5	105.0	4,722	9,096	--	1
Missouri	Empire District Electric	Asbury	1	212.8	15,764	68,769	--	4
Missouri	Kansas City Power & Light	Montrose	1	187.5	7,196	28,740	--	4
Missouri	Kansas City Power & Light	Montrose	2	187.5	7,984	32,165	--	4
Missouri	Kansas City Power & Light	Montrose	3	188.1	9,824	35,192	--	4
Missouri	Union Electric	Labadie	1	573.8	39,055	72,811	--	1
Missouri	Union Electric	Labadie	2	573.8	36,718	63,653	--	1
Missouri	Union Electric	Labadie	3	621.0	39,249	67,587	--	1
Missouri	Union Electric	Labadie	4	621.0	34,994	65,591	--	1
Missouri	Union Electric	Sioux	1	549.8	21,976	42,688	--	1
Missouri	Union Electric	Sioux	2	549.8	23,067	14,504	--	1
Missouri	Utilcorp United	Sibley	3	418.5	15,170	26,812	--	1
New Hampshire	Public Service of New Hampshire	Merrimack	1	113.6	9,922	15,258	--	4

See footnotes at end of table.

Table A1. Profile of the 261 Generators Affected by Phase I (Continued)

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
New Hampshire	Public Service of New Hampshire	Merrimack	2	345.6	21,421	38,980	--	4
New Jersey	Atlantic City Electric	BL England	1	136.0	8,822	16,300	11,086	2
New Jersey	Atlantic City Electric	BL England	2	163.2	11,412	17,822	24,312	3
New York	Long Island Lighting	Northport	ST1	387.1	19,289	26,583	--	4
New York	Long Island Lighting	Northport	2	387.1	23,476	25,915	--	4
New York	Long Island Lighting	Northport	3	387.1	25,783	27,360	--	4
New York	Long Island Lighting	Port Jefferson	3	187.5	10,194	10,602	--	4
New York	Long Island Lighting	Port Jefferson	4	187.5	12,006	12,195	--	4
New York	New York State Gas & Electric	Greenidge	4	112.5	7,342	11,548	0	1
New York	New York State Gas & Electric	Milliken	1	155.3	10,876	9,400	0	3
New York	New York State Gas & Electric	Milliken	2	167.2	12,083	15,398	0	3
New York	Niagara Mohawk	Dunkirk	3	218.0	12,268	18,214	--	1
New York	Niagara Mohawk	Dunkirk	ST4	218.0	13,690	16,846	--	1
Ohio	Cardinal Operating Co.	Cardinal	1	615.2	37,568	69,012	93,076	2
Ohio	Cardinal Operating Co.	Cardinal	2	615.2	42,008	71,532	--	1
Ohio	Cincinnati Gas & Electric	Miami Fort	[f]5	100.0	834	262	--	1
Ohio	Cincinnati Gas & Electric	Miami Fort	6	163.2	12,475	21,111	--	1
Ohio	Cincinnati Gas & Electric	Miami Fort	7	557.1	42,216	62,456	--	1
Ohio	Cincinnati Gas & Electric	Walter C Beckjord	5	244.8	9,811	12,735	--	1
Ohio	Cincinnati Gas & Electric	Walter C Beckjord	6	460.8	25,235	39,140	--	1
Ohio	Cleveland Electric Illum.	Ashtabula	5	256.0	18,351	37,621	0	1
Ohio	Cleveland Electric Illum.	Avon Lake	8	233.0	12,771	16,952	--	5
Ohio	Cleveland Electric Illum.	Avon Lake	9	680.0	33,413	41,322	--	1
Ohio	Cleveland Electric Illum.	Eastlake	1	123.0	8,551	16,550	0	1
Ohio	Cleveland Electric Illum.	Eastlake	2	123.0	9,471	17,267	--	1
Ohio	Cleveland Electric Illum.	Eastlake	3	123.0	10,984	19,545	--	1
Ohio	Cleveland Electric Illum.	Eastlake	4	208.0	15,906	24,997	--	1
Ohio	Cleveland Electric Illum.	Eastlake	5	680.0	37,349	79,918	10,292	1
Ohio	Columbus Southern Power	Conesville	1	148.0	4,615	6,468	8,618	1
Ohio	Columbus Southern Power	Conesville	2	136.0	5,360	7,008	--	1
Ohio	Columbus Southern Power	Conesville	3	161.5	6,029	9,646	13,128	1
Ohio	Columbus Southern Power	Conesville	4	841.5	53,463	98,256	--	2
Ohio	Columbus Southern Power	Picway	5	106.3	5,404	13,671	13,126	1
Ohio	Ohio Edison	Edgewater	4	113.6	5,536	6,149	--	1
Ohio	Ohio Edison	Niles	1	132.8	7,608	14,054	21,528	2
Ohio	Ohio Edison	Niles	[g]2	132.8	9,975	16,264	9,177	3
Ohio	Ohio Edison	REBurger	[h]3	103.5	6,742	12,965	5,503	2
Ohio	Ohio Edison	REBurger	4	156.3	11,818	21,956	20,310	2
Ohio	Ohio Edison	REBurger	5	156.3	13,626	25,973	19,002	2
Ohio	Ohio Edison	WH Sammis	5	334.1	26,496	34,632	--	1
Ohio	Ohio Edison	WH Sammis	6	680.0	43,773	61,391	--	1
Ohio	Ohio Edison	WH Sammis	7	680.0	47,380	54,557	--	1
Ohio	Ohio Power	Gen JM Gavin	1	1,300.0	86,690	177,338	291,340	3
Ohio	Ohio Power	Gen JM Gavin	2	1,300.0	88,312	185,911	279,986	3
Ohio	Ohio Power	Muskingum River	1	219.7	16,312	41,429	43,378	2

See footnotes at end of table.

Table A1. Profile of the 261 Generators Affected by Phase I (Continued)

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
Ohio	Ohio Power	Muskingum River	2	219.7	15,533	41,796	36,986	2
Ohio	Ohio Power	Muskingum River	3	237.5	15,293	36,195	41,674	2
Ohio	Ohio Power	Muskingum River	4	237.5	12,914	35,108	42,478	2
Ohio	Ohio Power	Muskingum River	5	615.2	44,364	98,907	--	1
Ohio	Ohio Valley Electric	Kyger Creek	1	217.3	18,773	45,319	--	1
Ohio	Ohio Valley Electric	Kyger Creek	2	217.3	18,072	44,494	--	1
Ohio	Ohio Valley Electric	Kyger Creek	3	217.3	17,439	42,499	--	1
Ohio	Ohio Valley Electric	Kyger Creek	4	217.3	18,218	43,345	--	1
Ohio	Ohio Valley Electric	Kyger Creek	5	217.3	18,247	46,886	--	1
Pennsylvania	Duquesne Light	Cheswick	1	565.0	38,139	41,927	--	1
Pennsylvania	Metropolitan Edison Co.	Portland	1	171.7	5,784	6,436	7,178	1
Pennsylvania	Metropolitan Edison Co.	Portland	2	255.0	9,961	10,892	14,696	1
Pennsylvania	Pennsylvania Electric Co.	Conemaugh	1	936.0	58,217	92,088	145,727	3
Pennsylvania	Pennsylvania Electric Co.	Conemaugh	2	936.0	64,701	89,804	122,178	3
Pennsylvania	Pennsylvania Electric Co.	Shawville	1	125.0	10,048	13,485	--	1
Pennsylvania	Pennsylvania Electric Co.	Shawville	2	125.0	10,048	14,310	--	1
Pennsylvania	Pennsylvania Electric Co.	Shawville	3	187.5	13,846	18,692	--	1
Pennsylvania	Pennsylvania Electric Co.	Shawville	4	187.5	13,700	17,683	--	1
Pennsylvania	Pennsylvania Power & Light	Brunner Island	1	363.3	27,030	32,078	--	1
Pennsylvania	Pennsylvania Power & Light	Brunner Island	2	405.0	30,282	34,103	3,426	1
Pennsylvania	Pennsylvania Power & Light	Brunner Island	3	790.4	52,404	58,775	16,334	1
Pennsylvania	Pennsylvania Power & Light	Martin's Creek	1	156.3	12,327	14,627	--	1
Pennsylvania	Pennsylvania Power & Light	Martin's Creek	2	156.3	12,483	14,131	--	1
Pennsylvania	Pennsylvania Power & Light	Sunbury	3	103.5	8,530	10,046	1,206	1
Pennsylvania	Pennsylvania Power & Light	Sunbury	4	156.3	11,149	14,077	486	1
Pennsylvania	West Pennsylvania Power	Armstrong	1	163.2	14,031	16,434	7,414	2
Pennsylvania	West Pennsylvania Power	Armstrong	2	163.2	15,024	15,423	--	2
Pennsylvania	West Pennsylvania Power	Hatfield's Ferry	1	576.0	36,835	54,286	37,794	2
Pennsylvania	West Pennsylvania Power	Hatfield's Ferry	2	576.0	36,338	51,986	42,336	2
Pennsylvania	West Pennsylvania Power	Hatfield's Ferry	3	576.0	39,210	54,809	34,740	2
Tennessee	TVA	Allen	1	330.0	14,917	21,866	--	2
Tennessee	TVA	Allen	2	330.0	16,329	25,986	--	2
Tennessee	TVA	Allen	3	330.0	15,258	19,696	--	2
Tennessee	TVA	Cumberland	1	1,300.0	84,419	148,104	251,040	3
Tennessee	TVA	Cumberland	2	1,300.0	92,344	196,049	261,583	3
Tennessee	TVA	Gallatin	1	300.0	17,400	28,846	29,656	2
Tennessee	TVA	Gallatin	2	300.0	16,855	30,410	29,658	2
Tennessee	TVA	Gallatin	3	327.6	19,493	35,789	33,392	2
Tennessee	TVA	Gallatin	4	327.6	20,701	35,351	26,376	2
Tennessee	TVA	Johnsonville	1	125.0	7,585	11,123	--	1
Tennessee	TVA	Johnsonville	2	125.0	7,828	10,657	--	1
Tennessee	TVA	Johnsonville	3	125.0	8,189	9,712	--	1
Tennessee	TVA	Johnsonville	4	125.0	7,780	8,968	--	1
Tennessee	TVA	Johnsonville	5	147.0	8,023	8,544	--	1
Tennessee	TVA	Johnsonville	6	147.0	7,682	8,767	--	1
Tennessee	TVA	Johnsonville	7	172.8	8,744	10,389	--	1
Tennessee	TVA	Johnsonville	8	172.8	8,471	10,207	--	1

See footnotes at end of table.

Table A1. Profile of the 261 Generators Affected by Phase I (Continued)

State	Operating Utility	Plant	Generator Number[a]	Affected Nameplate Capacity (Megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	Total Phase I Extension Allowances[c]	Code of Compliance Method[d]
Tennessee	TVA	Johnsonville	9	172.8	6,894	8,922	--	1
Tennessee	TVA	Johnsonville	10	172.8	7,351	8,835	--	1
West Virginia	Monongahela Power	Albright	3	140.3	11,684	11,938	--	2
West Virginia	Monongahela Power	Fort Martin	1	576.0	40,496	44,309	2,818	2
West Virginia	Monongahela Power	Fort Martin	2	576.0	40,116	44,824	8,004	2
West Virginia	Monongahela Power	Harrison	1	684.0	47,341	78,231	132,755	3
West Virginia	Monongahela Power	Harrison	2	684.0	44,936	78,231	151,144	3
West Virginia	Monongahela Power	Harrison	3	684.0	40,408	78,231	152,604	3
West Virginia	Ohio Power	Kammer	1	237.5	18,247	48,863	--	1
West Virginia	Ohio Power	Kammer	2	237.5	18,948	57,963	--	1
West Virginia	Ohio Power	Kammer	3	237.5	16,932	50,208	--	1
West Virginia	Ohio Power	Mitchell	1	816.3	42,823	48,079	--	1
West Virginia	Ohio Power	Mitchell	2	816.3	44,312	55,247	--	1
West Virginia	Virginia Electric & Power	Mt. Storm	1	570.2	42,570	48,587	13,822	2
West Virginia	Virginia Electric & Power	Mt. Storm	2	570.2	34,644	35,817	21,118	2
West Virginia	Virginia Electric & Power	Mt. Storm	3	522.0	41,314	43,906	62,915	3
Wisconsin	Dairyland Power Coop.	Genoa	ST3	345.6	22,103	35,035	--	4
Wisconsin	Wisconsin Electric Power	North Oak Creek	1	120.0	5,083	6,810	--	5
Wisconsin	Wisconsin Electric Power	North Oak Creek	2	120.0	5,005	7,916	--	5
Wisconsin	Wisconsin Electric Power	North Oak Creek	3	130.0	5,229	7,184	--	5
Wisconsin	Wisconsin Electric Power	North Oak Creek	4	130.0	6,154	9,323	--	5
Wisconsin	Wisconsin Electric Power	South Oak Creek	5	275.0	9,416	16,586	--	4
Wisconsin	Wisconsin Electric Power	South Oak Creek	6	275.0	11,723	17,748	--	4
Wisconsin	Wisconsin Electric Power	South Oak Creek	7	317.6	15,754	27,888	--	4
Wisconsin	Wisconsin Electric Power	South Oak Creek	8	324.0	15,375	22,553	--	4
Wisconsin	Wisconsin Power & Light	Edgewater	4	330.0	24,099	39,722	--	4
Wisconsin	Wisconsin Power & Light	Nelson Dewey	1	100.0	5,852	13,289	--	4
Wisconsin	Wisconsin Power & Light	Nelson Dewey	2	100.0	6,504	12,273	--	4
Wisconsin	Wisconsin Public Service	Pulliam	8	136.0	7,312	10,446	--	4

[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 affected boilers is 263 and the number of affected generators is 261.

[b]One SO_2 allowance permits one ton of SO_2 emissions.

[c]Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Extension allowances were awarded for 1995 through 1999.

[d]The codes for the method of compliance are: (1) fuel switching and/or blending; (2) obtaining additional allowances; (3) installing flue gas desulfurization equipment (scrubbers); (4) using previously implemented controls; (5) retiring facilities; and (6) boiler repowering. Each plant is shown as using one primary compliance method. However, many plants intend to also use one or more of the other available options in conjunction with their primary method. These compliance methods are based on information obtained in late 1993.

[e]The compliance method for Warrick listed here is based upon information received in late 1993. Southern Indiana Gas and Electric, who owns 50 percent of Warrick's power, has since decided to use allowances to meet compliance at Warrick unit 4. Alcoa, who owns the other 50 percent, appears to have not yet finalized their compliance strategy.

[f]Miami Fort generator 5 has two boilers. Allowances and 1985 SO_2 emissions for the boilers were added to provide generator-level data.

[g]Niles unit 2 is using a flue gas desulfurization technology that is not considered a scrubber.

[h]R.E. Burger generator 3 has two boilers. Allowances and 1985 SO_2 emissions for the boilers were added to provide generator-level data.

SO_2 = Sulfur dioxide.

TVA = Tennessee Valley Authority.

Source: **Compliance Method**: U.S. Environmental Protection Agency, *Coal Week, Compliance Strategies Review*, Georgia Public Utility Commission, *Utility Environment Report*, and *McIlvaine Utility Forecast*. **List of Affected 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). **Phase I Extension Allowances:** Facsimile from the U.S. Environmental Protection Agency (February 7, 1994).

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Alabama Power Co Gaston	**3,840**	**12,059**	**1.67**	**11.93**	**174.7**	**42.14**
Alabama	2,642	12,126	2.08	12.46	185.2	44.92
Fayette	1,558	12,033	2.14	12.28	203.7	49.02
Jefferson	595	12,326	1.83	12.63	181.1	44.65
Tuscaloosa	58	12,055	1.92	12.24	113.3	27.31
Walker	431	12,194	2.22	12.88	134.7	32.86
West Virginia	1,198	11,911	.77	10.77	151.2	36.02
Lincoln	1,198	11,911	.77	10.77	151.2	36.02
Associated Electric Coop Inc Hill	**2,622**	**10,480**	**4.01**	**9.94**	**163.2**	**34.20**
Missouri	2,506	10,555	4.19	10.19	164.8	34.79
Randolph	2,506	10,555	4.19	10.19	164.8	34.79
Wyoming	116	8,844	.21	4.57	121.8	21.54
Campbell	116	8,844	.21	4.57	121.8	21.54
Associated Electric Coop Inc Madrid	**2,732**	**10,890**	**3.06**	**9.74**	**116.0**	**25.25**
Illinois	2,121	10,682	2.93	10.19	115.4	24.65
Randolph	2,121	10,682	2.93	10.19	115.4	24.65
Indiana	63	11,279	3.03	8.50	109.9	24.79
Warrick	63	11,279	3.03	8.50	109.9	24.79
Kentucky	548	11,651	3.56	8.15	118.7	27.66
Muhlenberg	548	11,651	3.56	8.15	118.7	27.66
Baltimore Gas & Electric Co Crane	**725**	**13,449**	**2.03**	**6.57**	**144.6**	**38.89**
Pennsylvania	234	13,309	2.14	7.26	140.8	37.47
Greene	234	13,309	2.14	7.26	140.8	37.47
Virginia	78	14,076	.80	5.05	169.9	47.84
Buchanan	78	14,076	.80	5.05	169.9	47.84
West Virginia	413	13,410	2.20	6.46	141.7	38.00
Barbour	7	13,232	2.12	8.00	138.6	36.68
Monongalia	406	13,413	2.20	6.43	141.7	38.03
Big Rivers Electric Corp Coleman	**1,133**	**11,267**	**2.54**	**8.08**	**97.4**	**21.95**
Indiana	221	11,258	2.40	8.69	113.1	25.47
Daviess	196	11,261	2.40	8.68	115.6	26.04
Gibson	24	11,232	2.44	8.80	92.8	20.86
Kentucky	912	11,269	2.57	7.93	93.6	21.10
Daviess	25	11,141	2.16	8.09	92.9	20.70
Henderson	888	11,273	2.58	7.92	93.6	21.11
Cardinal Operating Co Cardinal	**4,277**	**11,842**	**2.16**	**12.88**	**148.0**	**35.06**
Ohio	1,086	12,211	3.17	11.29	133.5	32.59
Belmont	123	11,614	3.16	13.31	106.6	24.75
Harrison	500	12,225	3.01	11.47	152.9	37.40
Jefferson	463	12,355	3.34	10.57	119.3	29.49
West Virginia	3,191	11,717	1.81	13.42	153.2	35.89
Brooke	1,548	12,116	2.87	10.40	143.4	34.75
Kanawha	1,400	11,219	.80	16.91	169.8	38.09
Logan	183	12,055	.70	12.52	131.0	31.59
Monongalia	25	12,082	1.10	12.47	108.7	26.28
Ohio	11	11,680	2.83	12.33	135.5	31.65
Preston	25	12,082	1.10	12.47	108.7	26.28
Central Illinois Pub Serv Co Coffeen	**1,755**	**10,562**	**3.00**	**8.53**	**155.6**	**32.87**
Illinois	1,755	10,562	3.00	8.53	155.6	32.87
Macoupin	1,755	10,562	3.00	8.53	155.6	32.87
Central Illinois Pub Serv Co Meredosia	**529**	**11,570**	**2.71**	**6.08**	**152.9**	**35.38**
Colorado	53	11,861	.46	8.80	155.7	36.94
Gunnison	53	11,861	.46	8.80	155.7	36.94
Illinois	476	11,537	2.96	5.78	152.6	35.21
McDonough	13	11,438	3.16	6.30	133.5	30.54
Schuyler	463	11,540	2.95	5.77	153.1	35.34
Cincinnati Gas & Electric Co Beckjord	**1,351**	**11,754**	**1.76**	**12.46**	**164.7**	**38.71**

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cincinnati Gas & Electric Co Beckjord						
Kentucky	829	11,955	1.25	12.30	161.7	38.67
Breathitt	2	11,139	.89	12.00	98.3	21.90
Floyd	48	12,320	.72	12.14	131.5	32.41
Greenup	10	11,471	2.22	14.17	181.7	41.69
Knott	28	11,540	1.12	14.26	98.3	22.69
Magoffin	255	12,063	1.27	12.49	176.7	42.62
Martin	357	12,033	.81	12.99	179.2	43.12
Muhlenberg	73	11,566	2.79	8.80	106.9	24.72
Ohio	33	11,563	2.81	8.67	107.3	24.80
Perry	18	11,338	1.14	14.42	95.7	21.70
Union	5	11,443	2.81	8.20	102.1	23.37
Ohio	442	11,430	2.64	12.58	168.2	38.45
Belmont	58	12,669	3.18	8.99	102.7	26.01
Jackson	6	10,993	4.37	13.10	78.3	17.22
Lawrence	377	11,247	2.53	13.12	181.1	40.73
West Virginia	80	11,454	2.27	13.52	177.1	40.56
Fayette	6	11,247	2.66	13.60	178.9	40.24
Kanawha	71	11,427	2.27	13.72	178.7	40.84
Mason	1	11,821	2.55	9.30	95.0	22.46
Mingo	2	13,112	.70	7.40	158.1	41.46
Cincinnati Gas & Electric Co Miami Fort	**2,501**	**12,166**	**1.32**	**11.04**	**163.5**	**39.79**
Kentucky	1,039	11,971	1.15	12.32	153.8	36.82
Floyd	276	12,283	.67	11.59	133.3	32.74
Knott	5	11,728	1.30	14.40	99.8	23.40
Magoffin	207	12,022	1.40	12.56	173.7	41.76
Martin	371	11,857	.81	14.04	182.0	43.16
Muhlenberg	73	11,634	2.80	8.53	104.3	24.28
Ohio	40	11,588	2.82	8.53	105.4	24.44
Perry	8	11,668	.92	12.92	106.8	24.92
Pike	35	12,003	.57	12.97	110.8	26.60
Union	23	11,425	2.84	8.16	100.6	22.99
Ohio	466	11,423	2.56	12.62	175.1	40.01
Belmont	43	12,635	3.17	8.98	104.6	26.44
Jackson	2	10,853	3.54	13.70	80.6	17.50
Lawrence	422	11,300	2.50	12.99	183.5	41.48
Pennsylvania	40	13,263	2.39	7.13	99.0	26.26
Greene	40	13,263	2.39	7.13	99.0	26.26
West Virginia	956	12,696	.85	9.04	171.2	43.48
Clay	13	12,104	.64	12.58	116.0	28.09
Fayette	8	11,216	2.61	12.99	181.5	40.72
Kanawha	606	12,546	.88	9.56	183.1	45.94
Logan	50	11,975	.64	12.45	119.0	28.49
Mason	11	11,784	2.60	9.31	96.7	22.78
Mingo	268	13,284	.68	6.92	159.6	42.41
Cleveland Electric Illum Co Ashtabula	**901**	**12,840**	**3.22**	**8.50**	**150.8**	**38.73**
Ohio	509	12,446	3.95	9.52	175.7	43.72
Belmont	509	12,446	3.95	9.52	175.7	43.72
West Virginia	392	13,353	2.28	7.18	120.8	32.25
Kanawha	32	12,397	.80	10.59	161.6	40.06
Monongalia	337	13,482	2.51	6.72	115.3	31.09
Nicholas	23	12,794	.84	9.20	150.3	38.46
Cleveland Electric Illum Co Avon Lake	**1,527**	**12,543**	**2.45**	**9.45**	**153.5**	**38.51**
Ohio	1,345	12,444	2.49	9.76	158.3	39.41
Belmont	262	12,420	3.15	9.54	214.4	53.26
Harrison	1,083	12,449	2.33	9.81	144.8	36.06
Pennsylvania	125	13,306	2.35	6.93	117.7	31.31
Greene	125	13,306	2.35	6.93	117.7	31.31
West Virginia	57	13,225	1.60	7.58	125.5	33.20
Mingo	30	13,079	.70	9.10	135.1	35.34
Monongalia	27	13,388	2.61	5.90	115.1	30.82
Cleveland Electric Illum Co Eastlake	**2,029**	**12,920**	**2.63**	**8.37**	**149.6**	**38.66**

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Cleveland Electric Illum Co Eastlake						
Ohio	987	12,591	3.46	9.34	170.0	42.80
Belmont	830	12,618	3.73	9.35	176.3	44.49
Columbiana	157	12,444	2.05	9.23	135.9	33.83
Pennsylvania	675	13,234	1.99	7.33	127.9	33.85
Greene	605	13,345	1.95	6.83	128.7	34.34
Westmoreland	70	12,275	2.34	11.66	120.5	29.57
West Virginia	367	13,227	1.58	7.70	137.4	36.36
Boone	72	13,450	.85	6.33	155.9	41.95
Monongalia	156	13,266	2.60	7.45	117.9	31.28
Nicholas	125	13,122	.83	8.78	149.7	39.28
Wayne	14	12,595	.78	8.00	152.0	38.29
Columbus & Southern Ohio El Co Conesville	**3,422**	**12,031**	**3.23**	**8.27**	**149.5**	**35.98**
Ohio	3,422	12,031	3.23	8.27	149.5	35.98
Coshocton	1,895	12,166	3.26	7.37	169.5	41.24
Guernsey	20	11,719	2.45	10.63	99.8	23.39
Harrison	195	12,462	2.92	8.97	122.4	30.52
Holmes	205	11,801	3.30	8.23	98.5	23.25
Jefferson	72	11,946	2.86	11.45	103.7	24.77
Muskingum	105	11,901	3.99	8.99	101.4	24.14
Noble	8	11,697	3.47	12.91	95.2	22.26
Perry	127	11,171	2.57	13.27	121.8	27.22
Tuscarawas	795	11,835	3.25	8.96	137.2	32.48
Columbus & Southern Ohio El Co Picway	**307**	**11,457**	**3.05**	**9.86**	**105.4**	**24.16**
Ohio	307	11,457	3.05	9.86	105.4	24.16
Hocking	16	11,487	3.15	9.55	100.8	23.15
Holmes	5	11,747	3.70	8.11	99.1	23.29
Jackson	20	11,554	3.24	10.14	104.0	24.04
Perry	98	11,375	3.25	9.64	99.6	22.67
Vinton	169	11,481	2.88	10.03	109.6	25.16
Commonwealth Edison Co Kincaid	**1,716**	**10,516**	**3.40**	**8.68**	**166.9**	**35.09**
Illinois	1,716	10,516	3.40	8.68	166.9	35.09
Christian	1,611	10,445	3.52	8.74	170.6	35.63
Franklin	105	11,611	1.46	7.77	115.7	26.87
Duquesne Light Co Cheswick	**1,320**	**12,975**	**1.75**	**9.39**	**128.1**	**33.23**
Pennsylvania	975	13,047	1.82	8.89	127.9	33.36
Allegheny	261	12,832	1.19	8.83	135.7	34.83
Armstrong	10	12,998	2.01	11.35	107.4	27.92
Fayette	121	12,854	1.16	9.46	133.5	34.32
Greene	551	13,181	2.27	8.82	123.6	32.59
Washington	32	13,235	1.51	7.64	123.6	32.70
West Virginia	345	12,771	1.56	10.79	128.7	32.87
Fayette	148	12,937	1.10	9.77	130.8	33.85
Monongalia	197	12,647	1.91	11.55	127.0	32.13
East Kentucky Power Coop Cooper	**732**	**12,361**	**1.62**	**10.09**	**113.1**	**27.95**
Kentucky	700	12,339	1.60	10.08	113.5	28.01
Clay	114	12,677	1.45	8.35	109.9	27.86
Jackson	8	11,566	2.19	11.96	103.4	23.92
Laurel	13	11,985	1.41	11.32	90.1	21.60
Leslie	46	12,661	1.95	9.16	110.9	28.08
Mccreary	25	13,250	.99	5.17	106.9	28.34
Perry	48	12,456	1.30	9.06	107.0	26.66
Pulaski	394	12,198	1.65	11.03	118.0	28.80
Whitley	34	12,131	1.62	9.95	107.1	25.98
Wolfe	18	11,876	1.98	10.58	105.5	25.06
Tennessee	32	12,837	2.02	10.31	103.8	26.64
Morgan	32	12,835	2.03	10.36	103.7	26.62
Scott	*	13,099	.82	4.80	109.6	28.71
East Kentucky Power Coop Spurlock	**1,542**	**12,273**	**1.35**	**10.74**	**116.7**	**28.64**

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
East Kentucky Power Coop Spurlock						
Kentucky	726	12,126	1.46	10.50	116.1	28.16
Boyd	205	12,666	.80	9.21	116.1	29.40
Floyd	159	11,980	1.45	11.26	122.1	29.26
Greenup	215	11,493	2.50	11.69	110.2	25.34
Johnson	3	11,205	2.47	12.70	100.4	22.50
Knott	121	12,617	.70	9.31	121.3	30.60
Martin	11	11,583	.80	11.73	106.5	24.68
Perry	3	11,758	1.84	15.00	76.7	18.04
Wolfe	9	11,995	2.16	10.27	100.4	24.08
Pennsylvania	33	12,939	2.52	8.02	101.0	26.13
Greene	19	13,273	2.26	6.94	98.9	26.26
Washington	14	12,487	2.87	9.49	103.9	25.96
West Virginia	783	12,382	1.20	11.08	117.9	29.19
Fayette	356	12,556	1.76	12.50	122.8	30.83
Harrison	13	12,330	2.67	12.48	101.6	25.06
Kanawha	27	12,293	.69	11.91	109.5	26.92
Logan	100	12,159	.67	11.07	115.2	28.01
Mingo	140	12,175	.66	9.56	114.3	27.84
Monongalia	3	11,295	1.86	15.70	96.2	21.73
Wayne	144	12,350	.63	8.66	114.2	28.21
Electric Energy Inc Joppa	**3,108**	**10,915**	**1.66**	**7.21**	**104.3**	**22.77**
Illinois	2,129	11,898	2.22	8.16	108.2	25.75
Franklin	431	11,703	1.79	7.60	107.9	25.26
Perry	401	11,023	3.01	9.36	99.5	21.93
Saline	1,283	12,241	2.11	7.93	110.7	27.11
Williamson	13	11,448	2.76	11.51	108.0	24.73
Indiana	40	11,230	1.93	7.68	121.7	27.33
Gibson	28	11,226	1.91	7.70	109.1	24.49
Pike	12	11,239	1.97	7.65	149.7	33.65
Wyoming	939	8,673	.38	5.03	91.2	15.82
Campbell	939	8,673	.38	5.03	91.2	15.82
Georgia Power Co Atkinson-Mcdonoug	**1,383**	**11,877**	**1.88**	**9.59**	**162.9**	**38.70**
Illinois	34	11,259	2.86	9.48	208.9	47.05
Franklin	34	11,259	2.86	9.48	208.9	47.05
Indiana	555	11,294	2.51	8.13	138.4	31.26
Pike	555	11,294	2.51	8.13	138.4	31.26
Kentucky	607	12,243	1.38	10.48	174.8	42.79
Leslie	170	12,642	1.30	9.59	174.7	44.18
Perry	434	12,103	1.42	10.74	174.9	42.33
Pike	3	9,595	.81	24.70	154.6	29.67
Virginia	187	12,537	1.42	11.07	183.3	45.96
Lee	159	12,439	1.38	11.33	185.3	46.09
Wise	28	13,097	1.69	9.55	172.7	45.24
Georgia Power Co Bowen	**8,082**	**12,186**	**1.54**	**10.47**	**162.0**	**39.47**
Illinois	82	11,793	2.49	7.67	215.8	50.90
Franklin	82	11,793	2.49	7.67	215.8	50.90
Kentucky	8,000	12,190	1.53	10.50	161.4	39.36
Bell	947	12,095	1.36	11.13	181.4	43.88
Clay	229	12,560	1.21	9.75	158.6	39.85
Hopkins	1,357	11,737	3.01	10.15	169.6	39.80
Knott	760	12,082	1.36	11.55	156.9	37.90
Leslie	2,713	12,325	1.28	10.48	158.9	39.17
Letcher	104	12,402	1.39	11.19	174.8	43.36
Perry	1,890	12,354	1.03	10.08	151.1	37.34
Georgia Power Co Hammond	**803**	**12,971**	**1.66**	**9.86**	**174.9**	**45.36**
Kentucky	5	12,594	1.04	9.01	152.0	38.29
Leslie	5	12,594	1.04	9.01	152.0	38.29
Virginia	798	12,973	1.67	9.86	175.0	45.40
Lee	137	12,722	1.39	10.60	179.5	45.68
Wise	661	13,025	1.72	9.71	174.1	45.35
Georgia Power Co Wansley	**4,719**	**11,192**	**2.65**	**10.36**	**202.8**	**45.39**

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Georgia Power Co Wansley						
Alabama	54	12,172	1.99	12.11	135.7	33.03
Fayette	54	12,172	1.99	12.11	135.7	33.03
Illinois	4,378	11,269	2.79	9.40	207.8	46.83
Franklin	3,224	11,409	2.67	8.94	213.9	48.81
Perry	1,077	10,879	3.11	10.77	194.0	42.21
Randolph	77	10,862	2.95	9.50	131.0	28.45
Kentucky	49	9,657	.68	23.87	147.9	28.57
Perry	3	8,980	.60	28.04	146.6	26.33
Pike	46	9,699	.68	23.61	148.0	28.71
West Virginia	227	9,918	.73	25.85	127.8	25.36
Fayette	53	10,504	.73	22.68	138.7	29.14
Kanawha	133	9,822	.78	26.71	125.3	24.62
Logan	41	9,476	.56	27.12	120.8	22.89
Wyoming	11	8,777	.38	4.59	127.5	22.38
Campbell	11	8,777	.38	4.59	127.5	22.38
Georgia Power Co Yates	**1,576**	**11,965**	**1.99**	**10.70**	**190.3**	**45.54**
Alabama	44	12,106	2.14	12.24	135.4	32.77
Fayette	44	12,106	2.14	12.24	135.4	32.77
Illinois	644	11,273	2.79	9.36	207.7	46.82
Franklin	470	11,423	2.67	8.90	213.7	48.81
Perry	164	10,867	3.09	10.67	194.3	42.23
Randolph	10	10,886	2.94	9.31	130.9	28.50
Kentucky	15	10,138	1.05	21.87	152.1	30.84
Harlan	3	12,493	2.37	9.43	148.5	37.10
Pike	13	9,637	.77	24.52	153.1	29.51
Virginia	843	12,596	1.44	10.91	183.5	46.21
Lee	632	12,458	1.39	11.30	187.2	46.65
Wise	210	13,009	1.60	9.71	172.6	44.91
West Virginia	30	9,875	.72	25.67	130.5	25.77
Fayette	9	10,323	.79	22.32	147.7	30.50
Kanawha	13	9,821	.77	26.91	124.5	24.45
Logan	8	9,485	.56	27.19	120.7	22.90
Wyoming	*	8,777	.38	4.59	127.5	22.38
Campbell	*	8,777	.38	4.59	127.5	22.38
Gulf Power Co Crist	**2,077**	**11,945**	**2.71**	**8.53**	**172.2**	**41.13**
Alabama	72	12,060	2.75	12.94	120.6	29.09
Walker	72	12,060	2.75	12.94	120.6	29.09
Illinois	1,780	11,926	2.70	8.37	180.8	43.12
Franklin	497	11,734	2.64	8.28	116.5	27.34
Gallatin	1,068	12,016	2.74	8.55	222.2	53.39
Saline	214	11,922	2.65	7.70	119.7	28.53
Kentucky	226	12,062	2.73	8.38	121.4	29.28
Ohio	10	11,687	2.83	7.80	117.7	27.51
Union	216	12,079	2.72	8.40	121.5	29.36
Hoosier Energy R E C Inc Frank E Ratts	**635**	**11,240**	**2.72**	**9.08**	**136.8**	**30.74**
Indiana	635	11,240	2.72	9.08	136.8	30.74
Pike	635	11,240	2.72	9.08	136.8	30.74
Indiana & Michigan Electric Co Tanners Creek	**1,323**	**11,609**	**1.88**	**9.22**	**154.1**	**35.78**
Indiana	499	11,163	2.44	8.38	143.7	32.08
Warrick	499	11,163	2.44	8.38	143.7	32.08
Kentucky	823	11,879	1.53	9.73	160.0	38.01
Hopkins	373	11,549	2.55	8.25	131.9	30.46
Unknown	450	12,154	.69	10.95	182.2	44.29
Indiana-Kentucky Electric Corp Clifty Creek	**3,765**	**11,205**	**2.90**	**10.01**	**109.3**	**24.50**
Indiana	306	10,892	3.23	10.34	94.6	20.61
Pike	61	11,463	3.45	8.29	98.3	22.54
Spencer	91	10,818	2.98	11.05	89.3	19.33
Warrick	154	10,710	3.29	10.74	96.2	20.61

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Indiana-Kentucky Electric Corp Clifty Creek						
Kentucky	2,987	11,419	3.26	10.77	106.5	24.32
Christian	121	11,319	3.08	10.27	101.4	22.97
Daviess	856	11,223	3.25	10.26	113.2	25.42
Hopkins	1,454	11,498	3.47	11.95	105.2	24.18
Letcher	44	13,037	1.47	6.14	124.0	32.33
Mclean	61	11,688	3.01	11.44	101.2	23.66
Ohio	451	11,372	2.85	8.41	98.2	22.34
Virginia	112	13,888	.73	5.28	160.0	44.44
Buchanan	112	13,888	.73	5.28	160.0	44.44
Wyoming	360	8,859	.27	4.89	130.5	23.12
Campbell	64	8,837	.33	4.82	126.1	22.29
Converse	296	8,864	.26	4.90	131.4	23.29
Indianapolis Power & Light Co Pritchard	**358**	**11,376**	**1.07**	**6.79**	**121.9**	**27.73**
Indiana	358	11,376	1.07	6.79	121.9	27.73
Greene	297	11,445	1.10	6.40	119.1	27.26
Knox	61	11,040	.95	8.69	136.1	30.04
Indianapolis Power & Light Co Stout	**1,069**	**11,213**	**1.60**	**8.06**	**128.0**	**28.70**
Indiana	1,069	11,213	1.60	8.06	128.0	28.70
Clay	297	11,273	1.56	7.04	115.9	26.14
Greene	534	11,287	1.43	7.94	120.2	27.14
Sullivan	238	10,973	2.02	9.59	161.4	35.42
Interstate Power Co Kapp	**501**	**11,381**	**2.02**	**7.98**	**138.1**	**31.44**
Illinois	250	11,593	2.03	7.62	141.3	32.76
Perry	250	11,593	2.03	7.62	141.3	32.76
Indiana	251	11,170	2.02	8.35	134.9	30.13
Pike	251	11,170	2.02	8.35	134.9	30.13
Iowa Electric Light & Power Prairie Creek 1-4	**439**	**9,763**	**1.47**	**7.15**	**129.1**	**25.21**
Illinois	153	11,605	2.08	7.90	136.6	31.72
Franklin	153	11,605	2.08	7.90	136.6	31.72
Iowa	55	9,811	4.37	13.56	172.4	33.84
Marion	55	9,811	4.37	13.56	172.4	33.84
Wyoming	231	8,531	.38	5.12	110.4	18.84
Campbell	231	8,531	.38	5.12	110.4	18.84
Iowa Southern Utilities Co Burlington	**476**	**9,489**	**1.95**	**7.86**	**104.0**	**19.74**
Indiana	179	11,439	3.09	8.94	123.3	28.20
Perry	3	10,149	1.19	11.85	84.9	17.23
Warrick	175	11,464	3.13	8.88	123.9	28.42
Wyoming	297	8,316	1.27	7.21	88.1	14.65
Campbell	297	8,316	1.27	7.21	88.1	14.65
Iowa-Illinois Gas&Electric Co Riverside	**281**	**11,162**	**1.85**	**7.93**	**110.9**	**24.76**
Illinois	237	11,686	2.12	8.28	109.6	25.62
Franklin	237	11,686	2.12	8.28	109.6	25.62
Wyoming	44	8,338	.40	6.05	120.7	20.12
Campbell	44	8,338	.40	6.05	120.7	20.12
Metropolitan Edison Co Portland	**723**	**13,188**	**1.70**	**6.97**	**140.6**	**37.08**
Pennsylvania	536	13,167	1.65	6.80	138.7	36.53
Armstrong	15	12,889	1.65	9.29	146.0	37.64
Clarion	24	12,838	2.17	8.68	138.2	35.49
Greene	497	13,191	1.63	6.63	138.5	36.55
West Virginia	187	13,250	1.84	7.45	145.9	38.66
Barbour	57	13,100	1.70	7.42	166.3	43.57
Monongalia	129	13,317	1.90	7.46	137.0	36.50
Mississippi Power Co Watson	**1,487**	**12,665**	**2.70**	**8.64**	**132.4**	**33.53**
Illinois	1,239	12,757	2.74	8.75	132.7	33.86
Gallatin	1,239	12,757	2.74	8.75	132.7	33.86

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality: Btu (per pound)	Average Quality: Sulfur (percent by weight)	Average Quality: Ash (percent by weight)	Average Delivered Cost: (cents per million Btu)	Average Delivered Cost: (dollars per short ton)
Mississippi Power Co Watson						
Kentucky	248	12,208	2.50	8.08	130.5	31.87
Greenup	26	12,047	1.85	8.28	140.0	33.73
Hopkins	143	12,102	2.66	8.51	129.3	31.30
Pike	19	12,090	1.62	8.06	141.9	34.31
Union	60	12,568	2.69	6.98	125.8	31.63
Missouri Public Service Comm Sibley	**985**	**11,097**	**2.63**	**9.29**	**133.7**	**29.68**
Colorado	9	10,964	1.21	4.07	141.0	30.92
Moffat	9	10,964	1.21	4.07	141.0	30.92
Illinois	929	11,131	2.75	9.45	134.1	29.85
Franklin	148	11,759	2.15	8.23	107.7	25.33
Perry	306	10,935	2.92	10.28	125.0	27.33
Randolph	476	11,062	2.83	9.30	148.6	32.87
Saline	*	11,875	2.60	7.50	106.0	25.17
Utah	27	11,606	.45	8.29	138.9	32.25
Carbon	27	11,606	.45	8.29	138.9	32.25
Wyoming	19	8,763	.46	5.39	96.0	16.82
Campbell	19	8,763	.46	5.39	96.0	16.82
New York State Gas & Elect Greenridge	**510**	**12,808**	**2.04**	**8.98**	**137.6**	**35.24**
Pennsylvania	391	12,661	1.94	9.81	139.8	35.39
Armstrong	12	12,735	1.68	9.41	143.6	36.57
Clarion	84	12,717	2.07	8.75	134.9	34.31
Clearfield	130	12,128	1.94	13.09	144.3	35.01
Elk	4	11,993	2.27	13.63	143.2	34.34
Greene	94	13,209	2.04	7.06	135.7	35.85
Jefferson	16	12,997	1.90	8.95	145.8	37.90
Washington	50	12,845	1.63	8.30	141.4	36.32
West Virginia	119	13,290	2.36	6.27	130.6	34.72
Monongalia	119	13,290	2.36	6.27	130.6	34.72
Niagara-Mohawk Power Corp Dunkirk	**1,531**	**13,178**	**2.06**	**6.96**	**136.0**	**35.84**
Pennsylvania	1,117	13,101	1.96	7.19	137.6	36.05
Armstrong	62	12,996	1.80	7.27	146.9	38.18
Clarion	302	12,686	2.06	8.59	143.6	36.44
Greene	483	13,281	1.75	6.42	140.8	37.41
Indiana	39	13,260	2.37	7.11	134.1	35.56
Mercer	71	13,143	2.46	7.08	129.3	33.98
Washington	160	13,323	2.10	6.87	117.9	31.42
West Virginia	414	13,385	2.36	6.34	131.8	35.27
Marion	16	13,550	2.65	7.19	139.0	37.67
Monongalia	398	13,379	2.35	6.31	131.5	35.18
Northern Indiana Pub Serv Co Michigan City	**1,022**	**11,232**	**2.41**	**8.34**	**135.9**	**30.54**
Illinois	472	11,198	2.97	9.67	128.0	28.67
Perry	366	10,987	3.07	10.31	135.3	29.72
Saline	106	11,929	2.61	7.46	104.9	25.02
Indiana	255	11,543	3.52	8.20	108.7	25.09
Pike	255	11,543	3.52	8.20	108.7	25.09
Virginia	20	13,835	.72	6.00	175.0	48.42
Buchanan	20	13,835	.72	6.00	175.0	48.42
Wyoming	276	10,815	.56	6.34	173.3	37.49
Campbell	40	8,584	.30	4.70	100.2	17.21
Carbon	235	11,199	.60	6.63	183.0	40.99
Ohio Edison Co Sammis	**5,531**	**12,343**	**1.67**	**10.52**	**132.3**	**32.65**
Kentucky	668	12,091	.86	10.57	125.6	30.37
Floyd	157	11,955	.84	10.99	114.2	27.32
Lawrence	72	11,889	.93	10.32	113.9	27.08
Martin	440	12,172	.86	10.47	131.5	32.00
Ohio	1,452	12,147	2.65	10.78	124.0	30.14
Belmont	3	12,154	3.37	10.60	98.7	23.99
Carroll	443	12,114	2.55	10.32	112.4	27.24
Harrison	399	12,343	3.37	10.82	106.2	26.22
Jefferson	607	12,042	2.25	11.09	144.7	34.86

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Ohio Edison Co Sammis						
Pennsylvania	1,707	12,532	1.80	10.36	141.6	35.49
Greene	1,505	12,602	1.71	10.16	141.2	35.59
Washington	176	11,998	2.37	11.93	151.3	36.31
Westmoreland	26	12,104	2.56	11.65	99.6	24.10
West Virginia	1,703	12,418	1.04	10.42	132.3	32.85
Fayette	47	12,679	.82	9.20	111.8	28.35
Kanawha	976	12,394	.75	10.44	132.8	32.93
Lincoln	103	12,006	.81	10.72	113.7	27.31
Logan	14	12,124	.65	11.20	111.4	27.01
Mingo	3	11,579	1.01	11.17	115.3	26.70
Monongalia	4	11,876	2.92	12.10	102.7	24.39
Nicholas	79	12,102	.90	11.93	112.1	27.13
Preston	475	12,602	1.72	10.16	141.2	35.59
Ohio Power Co Kammer	**1,912**	**12,250**	**4.07**	**12.39**	**118.3**	**28.98**
West Virginia	1,912	12,250	4.07	12.39	118.3	28.98
Marshall	1,912	12,250	4.07	12.39	118.3	28.98
Ohio Power Co Mitchell	**1,999**	**12,190**	**1.45**	**14.14**	**166.3**	**40.55**
West Virginia	1,999	12,190	1.45	14.14	166.3	40.55
Boone	14	12,361	.88	11.11	148.6	36.73
Clay	106	12,135	.81	12.68	144.9	35.16
Kanawha	40	12,185	.78	12.10	143.1	34.87
Marion	1,674	12,183	1.54	14.35	170.7	41.59
Monongalia	165	12,283	1.18	13.69	143.2	35.18
Ohio Power Co Muskingum	**3,238**	**11,504**	**4.17**	**12.65**	**166.3**	**38.25**
Kentucky	14	12,191	.60	11.30	150.4	36.67
Floyd	11	12,183	.60	11.30	149.3	36.38
Magoffin	1	12,222	.61	11.30	155.0	37.89
Martin	1	12,222	.61	11.30	155.0	37.89
Ohio	3,074	11,453	4.36	12.76	166.5	38.14
Muskingum	338	11,453	4.36	12.76	166.5	38.14
Noble	2,736	11,453	4.36	12.76	166.5	38.14
West Virginia	150	12,480	.64	10.39	163.5	40.81
Fayette	13	12,376	.66	9.57	146.1	36.15
Kanawha	6	12,380	.66	9.54	146.3	36.22
Logan	131	12,495	.64	10.51	166.0	41.49
Ohio Valley Electric Corp Kyger Creek	**3,464**	**12,041**	**3.73**	**10.82**	**122.0**	**29.39**
Kentucky	125	13,128	1.50	6.19	122.2	32.09
Floyd	37	12,998	1.63	6.77	118.7	30.84
Letcher	53	13,423	1.54	5.27	123.7	33.20
Pike	35	12,820	1.31	6.95	123.7	31.71
Ohio	1,097	11,569	3.65	11.01	95.9	22.20
Belmont	230	12,551	4.23	9.38	89.9	22.57
Hocking	448	11,396	3.52	11.34	97.7	22.27
Jackson	419	11,216	3.47	11.55	97.7	21.92
West Virginia	2,242	12,211	3.90	10.99	134.1	32.76
Marshall	2,192	12,192	3.95	11.08	134.4	32.77
Mingo	50	13,056	1.58	7.07	123.1	32.15
Pennsylvania Electric Co Shawville	**1,417**	**12,277**	**1.97**	**13.09**	**108.5**	**26.63**
Pennsylvania	1,417	12,277	1.97	13.09	108.5	26.63
Cambria	4	12,299	2.18	14.70	104.7	25.75
Clearfield	1,401	12,278	1.97	13.09	108.5	26.64
Jefferson	12	12,168	1.86	12.53	106.3	25.87
Pennsylvania Power & Light Co Brunner Island	**3,471**	**12,718**	**1.83**	**11.46**	**186.9**	**47.53**
Pennsylvania	3,471	12,718	1.83	11.46	186.9	47.53
Cambria	233	12,547	1.92	12.60	163.6	41.06
Clearfield	680	12,514	1.84	13.41	179.7	44.98
Greene	920	13,303	1.72	7.15	144.7	38.51
Indiana	1,638	12,498	1.88	12.91	218.4	54.59
Pennsylvania Power & Light Co Martins Creek	**603**	**12,954**	**1.91**	**9.80**	**186.5**	**48.32**

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Pennsylvania Power & Light Co Martins Creek						
Pennsylvania	603	12,954	1.91	9.80	186.5	48.32
Armstrong	10	12,569	2.28	11.60	138.4	34.79
Clarion	10	12,892	2.06	9.30	138.7	35.76
Clearfield	11	12,487	2.23	13.40	187.9	46.93
Greene	244	13,312	1.75	7.02	149.6	39.82
Indiana	288	12,641	2.06	12.18	229.4	57.99
Jefferson	20	13,201	1.58	9.80	136.6	36.07
Washington	20	13,320	1.61	6.75	145.5	38.77
Pennsylvania Power & Light Co Sunbury	**956**	**10,950**	**1.57**	**20.78**	**125.7**	**27.53**
Pennsylvania	956	10,950	1.57	20.78	125.7	27.53
Armstrong	12	12,835	1.71	9.89	129.4	33.23
Bedford	9	9,490	1.17	32.07	81.6	15.49
Centre	75	12,203	1.96	14.74	131.3	32.05
Clarion	14	12,758	2.15	9.16	134.0	34.19
Clearfield	454	12,154	1.98	15.05	145.0	35.26
Fulton	13	12,556	2.38	12.76	135.9	34.12
Jefferson	14	12,587	1.62	12.79	135.3	34.05
Lycoming	9	12,612	1.35	14.18	134.7	33.98
Northumberland	81	8,091	.96	30.03	75.8	12.27
Schuylkill	221	8,313	.63	34.74	78.4	13.03
Somerset	53	12,522	2.02	14.56	134.0	33.55
Sullivan	1	8,215	.61	37.00	71.0	11.67
Potomac Electric Power Co Chalk	**1,615**	**12,535**	**1.83**	**12.26**	**172.8**	**43.33**
Maryland	392	12,682	1.73	11.58	171.8	43.58
Garrett	392	12,682	1.73	11.58	171.8	43.58
Pennsylvania	1,200	12,477	1.88	12.53	173.5	43.29
Cambria	417	12,345	1.97	12.67	174.3	43.05
Clearfield	400	12,445	1.90	12.24	176.8	44.01
Jefferson	7	12,378	1.61	11.50	167.4	41.44
Somerset	375	12,659	1.75	12.71	169.2	42.84
West Virginia	23	13,044	1.53	9.98	156.2	40.75
Grant	23	13,044	1.53	9.98	156.2	40.75
Potomac Electric Power Co Morgantown	**2,165**	**12,645**	**1.77**	**12.33**	**171.4**	**43.34**
Maryland	660	12,803	1.65	11.51	170.4	43.64
Garrett	660	12,803	1.65	11.51	170.4	43.64
Pennsylvania	1,441	12,553	1.83	12.81	172.4	43.28
Cambria	466	12,482	1.88	12.62	175.7	43.85
Clearfield	433	12,504	1.86	12.87	177.3	44.33
Jefferson	16	12,051	1.84	14.10	173.8	41.89
Somerset	511	12,670	1.76	13.00	165.5	41.93
Westmoreland	14	12,697	1.99	8.80	166.1	42.18
West Virginia	64	13,101	1.52	9.88	159.5	41.80
Grant	64	13,101	1.52	9.88	159.5	41.80
Public Service Co of IN Inc Cayuga	**2,863**	**10,942**	**2.01**	**9.93**	**123.9**	**27.12**
Indiana	2,853	10,938	2.01	9.92	124.0	27.13
Clay	53	11,371	2.10	7.15	110.8	25.20
Daviess	147	11,110	1.72	8.38	122.4	27.19
Greene	122	11,124	2.15	9.41	121.0	26.91
Pike	312	11,143	2.18	9.22	117.7	26.24
Sullivan	1,982	10,891	1.99	10.18	127.5	27.77
Vermillion	227	10,749	2.09	10.62	108.2	23.27
Vigo	9	11,119	1.95	10.00	119.2	26.51
Kentucky	9	12,022	2.41	10.00	101.9	24.50
Webster	9	12,022	2.41	10.00	101.9	24.50
Public Service Co of IN Inc Gallagher	**1,144**	**11,240**	**2.04**	**8.82**	**137.2**	**30.84**
Illinois	51	10,841	3.41	7.97	185.5	40.21
Clinton	51	10,841	3.41	7.97	185.5	40.21
Indiana	827	10,901	2.26	8.78	142.3	31.01
Warrick	827	10,901	2.26	8.78	142.3	31.01

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Public Service Co of IN Inc Gallagher						
Kentucky	120	11,907	1.49	9.48	114.9	27.37
Bell	28	12,502	1.53	9.44	106.5	26.62
Daviess	27	10,766	2.27	10.29	109.9	23.66
Hopkins	5	11,469	2.25	9.50	112.0	25.69
Perry	59	12,191	1.03	9.12	121.4	29.59
West Virginia	146	12,744	.77	8.82	115.4	29.41
Kanawha	8	12,411	.70	13.06	119.4	29.64
Mingo	139	12,763	.78	8.58	115.2	29.40
Public Service Co of IN Inc Gibson Station	**8,297**	**11,106**	**2.01**	**10.14**	**157.2**	**34.91**
Illinois	6,082	10,761	2.45	10.47	169.2	36.41
Clinton	3,031	10,822	3.46	8.10	171.5	37.13
Jefferson	91	12,206	.81	4.89	119.9	29.26
Wabash	2,960	10,655	1.46	13.07	168.4	35.89
Indiana	862	11,435	.96	7.12	116.3	26.59
Clay	145	11,618	.63	6.44	128.5	29.85
Daviess	476	11,535	.84	6.54	114.5	26.42
Dubois	6	11,381	1.00	8.30	102.3	23.29
Perry	51	11,243	.89	7.94	118.2	26.59
Pike	53	11,503	3.51	7.90	89.4	20.57
Sullivan	130	10,912	.72	9.29	119.8	26.14
Kentucky	217	12,219	.80	11.06	123.5	30.18
Floyd	134	12,211	.82	11.41	123.9	30.26
Martin	25	12,568	.77	7.74	125.0	31.42
Perry	58	12,090	.77	11.66	121.9	29.48
West Virginia	1,136	12,489	.73	10.49	136.5	34.09
Boone	202	12,434	.73	11.15	130.1	32.35
Kanawha	377	12,357	.72	12.27	135.9	33.60
Mingo	434	12,766	.74	8.27	141.3	36.06
Wayne	123	12,013	.75	11.79	130.9	31.46
Public Service Co of IN Inc Wabash River	**1,430**	**11,036**	**2.00**	**9.33**	**117.2**	**25.87**
Indiana	1,430	11,036	2.00	9.33	117.2	25.87
Clay	35	11,354	2.08	6.92	107.7	24.46
Daviess	389	11,136	2.03	8.98	107.0	23.82
Greene	169	11,312	2.04	8.00	112.4	25.42
Sullivan	838	10,921	1.98	9.87	123.5	26.97
Southern Indiana Gas & Elec Co Warrick [b]	**475**	**11,132**	**2.47**	**8.64**	**115.1**	**25.63**
Indiana	422	11,109	2.45	8.75	116.7	25.92
Gibson	22	11,077	2.47	10.10	94.3	20.90
Pike	85	11,451	2.61	8.36	101.9	23.33
Warrick	315	11,019	2.41	8.77	122.4	26.97
Kentucky	53	11,315	2.60	7.71	103.2	23.35
Henderson	53	11,315	2.60	7.71	103.2	23.35
Springfield City of (MO) James River	**271**	**11,599**	**1.74**	**7.92**	**134.4**	**31.18**
Illinois	230	11,574	1.98	7.91	132.9	30.77
Franklin	230	11,574	1.98	7.91	132.9	30.77
Utah	41	11,737	.40	8.00	142.5	33.44
Carbon	41	11,737	.40	8.00	142.5	33.44
Tampa Electric Co Davant Transfer	**5,528**	**12,255**	**2.30**	**8.09**	**182.4**	**44.70**
Colorado	181	13,092	.45	10.01	146.5	38.37
Las Animas	181	13,092	.45	10.01	146.5	38.37
Illinois	1,224	11,287	2.87	8.89	181.0	40.86
Franklin	48	12,213	1.04	5.07	156.0	38.11
Gallatin	126	12,727	2.79	8.73	110.3	28.08
Perry	1,018	11,076	2.96	9.08	194.6	43.11
Randolph	33	10,945	2.92	9.10	108.9	23.84
Kentucky	3,359	12,415	2.30	7.91	178.7	44.37
Bell	51	12,909	.62	8.43	167.1	43.14
Daviess	90	11,629	2.82	9.47	115.4	26.83
Hopkins	104	11,973	3.05	10.25	111.2	26.63
Knott	19	12,923	.64	8.15	167.1	43.19
Knox	7	12,967	.57	8.80	167.1	43.34

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Tampa Electric Co Davant Transfer						
Kentucky						
Muhlenberg	488	11,767	2.75	8.51	115.1	27.09
Union	1,056	12,282	2.84	8.63	171.0	41.99
Webster	516	12,599	2.86	8.17	164.8	41.53
Whitley	1,029	12,842	1.27	6.36	232.9	59.83
Tennessee	269	12,861	1.19	6.20	217.6	55.98
Campbell	269	12,861	1.19	6.20	217.6	55.98
Utah	32	11,596	.39	8.20	163.8	37.99
Carbon	32	11,596	.39	8.20	163.8	37.99
West Virginia	452	13,137	2.38	7.64	207.1	54.41
Monongalia	452	13,137	2.38	7.64	207.1	54.41
Wyoming	12	8,887	.20	4.70	142.3	25.29
Campbell	12	8,887	.20	4.70	142.3	25.29
Tennessee Valley Authority Colbert	**2,742**	**11,970**	**1.32**	**10.93**	**129.6**	**31.01**
Illinois	850	11,577	1.88	9.26	123.7	28.65
Franklin	850	11,577	1.88	9.26	123.7	28.65
Kentucky	583	12,108	1.48	10.72	124.6	30.18
Breathitt	80	12,150	1.30	12.10	119.4	29.00
Daviess	44	12,200	1.04	12.50	122.5	29.89
Floyd	47	12,200	1.26	12.50	123.8	30.21
Johnson	324	12,102	1.40	9.26	131.1	31.74
Webster	88	12,000	2.30	13.00	106.9	25.65
Tennessee	363	12,377	.79	12.53	127.3	31.52
Sequatchie	363	12,377	.79	12.53	127.3	31.52
West Virginia	945	12,081	.93	11.94	138.5	33.46
Boone	50	12,287	.70	13.95	118.1	29.03
Kanawha	666	12,040	.94	12.34	140.8	33.91
Lincoln	26	12,000	.70	11.00	129.4	31.05
Mingo	204	12,174	.97	10.24	137.0	33.36
Tennessee Valley Authority Johnsonville	**2,326**	**11,992**	**1.75**	**9.12**	**130.8**	**31.37**
Illinois	1,203	11,681	1.71	8.99	132.9	31.06
Franklin	1,062	11,672	1.72	9.01	133.9	31.26
Jefferson	29	11,700	1.70	8.50	120.0	28.08
Kentucky	1,123	12,325	1.79	9.24	128.6	31.71
Webster	1,123	12,325	1.79	9.24	128.6	31.71
Tennessee Valley Authority Shawnee	**2,503**	**12,089**	**1.30**	**10.39**	**129.4**	**31.28**
Kentucky	1,775	12,017	1.54	9.90	129.7	31.16
Clay	13	12,000	.72	14.00	119.7	28.73
Floyd	10	12,100	.74	12.00	130.6	31.61
Hopkins	327	11,479	3.67	11.56	120.3	27.61
Johnson	48	11,300	.70	12.10	115.1	26.02
Magoffin	107	12,000	.71	12.11	118.9	28.53
Muhlenberg	272	11,613	2.52	9.40	123.8	28.75
Perry	18	12,296	.74	10.96	147.2	36.21
Pike	966	12,331	.70	9.08	135.7	33.46
Webster	14	13,000	2.25	7.00	138.2	35.94
Tennessee	13	12,500	.76	12.10	128.0	32.00
Sequatchie	13	12,500	.76	12.10	128.0	32.00
West Virginia	715	12,260	.73	11.57	128.7	31.56
Boone	347	12,314	.72	11.35	129.5	31.89
Kanawha	128	12,209	.76	13.00	125.4	30.62
Logan	142	12,240	.72	11.36	129.4	31.68
Mingo	79	12,203	.71	10.73	130.6	31.87
Wayne	20	12,000	.74	11.00	124.0	29.76
Union Electric Co Labadie	**5,468**	**10,151**	**1.55**	**7.50**	**116.0**	**23.54**
Colorado	487	11,750	.47	9.60	161.0	37.84
Gunnison	487	11,750	.47	9.60	161.0	37.84
Illinois	2,480	11,202	3.09	10.09	128.6	28.82
Jefferson	9	11,800	1.30	7.30	214.2	50.55
Perry	2,471	11,200	3.10	10.10	128.3	28.74

See footnotes at end of table.

Table A2. Profile of Coal Received at Plants Planning to Fuel Switch and/or Blend to Meet Compliance with Phase I, 1992 (Continued)

Operating Utility Plant [a] Origin State County	Receipts (thousand short tons)	Average Quality			Average Delivered Cost	
		Btu (per pound)	Sulfur (percent by weight)	Ash (percent by weight)	(cents per million Btu)	(dollars per short ton)
Union Electric Co Labadie						
Wyoming	2,501	8,798	0.22	4.52	88.3	15.53
Campbell	2,501	8,798	.22	4.52	88.3	15.53
Union Electric Co Sioux	**1,845**	**11,317**	**2.39**	**8.22**	**174.8**	**39.56**
Illinois	1,714	11,521	2.54	8.41	178.9	41.23
Perry	483	11,321	2.89	9.47	155.3	35.17
Saline	1,231	11,600	2.40	8.00	188.0	43.61
Wyoming	131	8,650	.52	5.70	102.0	17.65
Campbell	131	8,650	.52	5.70	102.0	17.65
Total	**133,245**	**11,739**	**2.22**	**10.02**	**148.4**	**34.84**

* = Number less than 0.5.

[a] The list of plants planning to fuel switch and/or blend is based upon information obtained late 1993.

[b] Based on information received in late 1993, the Warrick plant intended to use fuel switching as their method of compliance. Southern Indiana Gas and Electric, which owns 50 percent of the Warrick plant, has since decided to use allowances to meet compliance. Alcoa, which owns the other 50 percent appears to have not yet finalized their compliance strategy.

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

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

Appendix B

Engineering Characteristics of Retrofitted Flue Gas Desulfurization Units

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Engineering Characteristics of Retrofitted Flue Gas Desulfurization Units

The control of sulfur dioxide (SO_2) emissions resulting from burning coal can be accomplished in several different ways. Precombustion methods, which remove sulfur from coal before it is burned, include froth flotation, electrostatic precipitation, and magnetic separation. These methods rely on the difference between the physical characteristics of the coal and the sulfur compounds in the coal, including surface properties and susceptibility to magnetic or electric fields. Sulfur reduction can also be achieved during combustion, through the addition of chemical agents into the combustion chamber. However, the approach most commonly used for electric utility coal-fired power plants is a postcombustion method, flue gas desulfurization (scrubber) technology.[91]

In order to comply with clean air regulations and clean up their emissions, many utilities have installed scrubbers on their coal-burning plants. One or more scrubbers are placed in the plant so that flue gas exiting the boiler unit(s) passes through the scrubber(s). The flue gas undergoes a chemical reaction inside the scrubber which absorbs or "scrubs" the sulfur and sulfur compounds out of it. Once scrubbed, the gas is emitted into the atmosphere.

Scrubber systems differ widely throughout the industry. The scrubbing agent, or sorbent, which is responsible for the sulfur absorption, can vary and the structure by which the flue gas and sorbent are brought together in the reactor vessel varies. This appendix describes some of the more popular sorbents and reactor vessel types for scrubbers for coal-fired plants, as well as the characteristics of the scrubbers used to estimate historical retrofit scrubber costs in Appendix C.

Scrubber Sorbent Types

Any chemical reagent which, through a chemical process, can absorb SO_2 is a potential sorbent in a scrubber. Different sorbents vary by how the scrubber process is actuated, by their physical properties, and by the waste products that are left behind. Sorbents are used in a wet solution form or in a dry solid form in the scrubber. Nonregenerable sorbent systems produce wastes which must be disposed of in a landfill or in some other manner. Regenerable sorbents absorb SO_2 in the scrubber and then are subjected to other chemical processes which likewise absorb the sulfur products out of the sorbent, returning the sorbent to its original state, able to again absorb SO_2 in the scrubber. The list of sorbents presented here is by no means complete. These are some of the most predominant, which appear as classifications on the Energy Information Administration Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Of all sorbents, lime and limestone are the most popular.[92] They are used predominantly in nonregenerable processes. The chemical process employed involves the reaction of SO_2 with calcium carbonate ($CaCO_3$) present in the lime or limestone to produce calcium sulphite ($CaSO_3$) along with carbon dioxide (CO_2) and water (H_2O). Some of the calcium sulphite oxidizes to become calcium sulphate ($CaSO_4$), commonly known as gypsum. If the scrubber system is designed correctly, industrial-quality gypsum can be produced and sold. A common industrial use for gypsum is the production of wallboard. One reason for the popularity of lime and limestone systems is the relative inexpensiveness of these sorbents over other types.

[91]Steven C. Stultz and John B. Kitto, eds., *Steam, Its Generation and Use*, 40th ed. (Barberton, OH: Babcock and Wilcox Co., 1992), p. 35-1.
[92]Steven C. Stultz and John B. Kitto, eds., *Steam, Its Generation and Use*, 40th ed. (Barberton, OH: Babcock and Wilcox Co., 1992), p. 35-2.

Limestone, one of the most popular sorbents for scrubbers, is usually piped into the absorber module in the form of a slurry (right). Conemaugh uses limestone and stores gypsum, which is released as a by-product, in a nearby storage facility (left). It is possible to sell the gypsum for industrial use.

Sodium carbonate (Na_2CO_3), another nonregenerable sorbent, can be reacted with SO_2 to produce sodium sulphite (Na_2SO_3) and sodium hydrosulphite ($NaHSO_3$). It is fairly expensive but is easier to implement in the scrubber design due to the fact that all the reactants and products of the reaction stay in solution. The lime systems described above must use slurries (suspensions of solids in water), which tend to scale onto equipment surfaces, clogging valves and openings.

A solution of sodium sulphite can be used as a sorbent, and then treated in a lime or limestone process and used again. Although the sodium sulphite is reused, the lime or limestone is not, and therefore this process is still considered nonregenerable. This process has the advantage that the SO_2 has a greater affinity for the sorbent. However, sodium sulphite is expensive.

Magnesium hydroxide ($Mg(OH)_2$) is a very expensive but regenerable sorbent. The magnesium oxide reacts with SO_2 to produce magnesium sulphite ($MgSO_3$) and water. The magnesium sulphite is then oxidized to release the SO_2 in a relatively pure state which can be utilized in the production of sulfuric acid or sulfur. The magnesium oxide resulting from the oxidation is recycled to the scrubber.

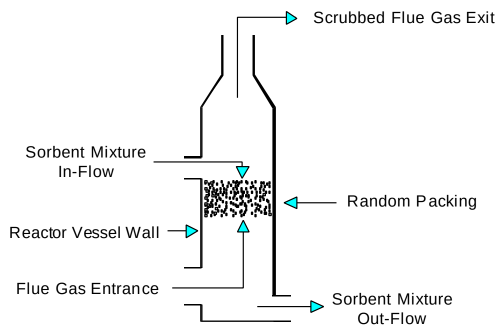
Reaction Vessel Types

Flue gas and sorbents are mixed in different types of reactor vessels. Reactor vessels are mass transfer mechanisms. For wet scrubbers, it is known that the type of absorption reactions occurring in scrubber systems between a liquid and gas occur at the surface of the liquid. For dry scrubbers, the reaction once again occurs at the surface of the sorbent, but the difference lies in the fact that a solid does not mix or diffuse like a fluid. This lack of diffusion implies that a solid particle of sorbent cannot absorb anymore once the surface has been saturated from the flue gas stream. A fluid particle, however, can replace surface sorbent with fresh sorbent from the interior of the particle and continue to absorb. In both cases, due to the surface nature of the reaction, there are two things that must be maximized for optimum absorption to occur: (1) the surface area of the sorbent exposed to the flue gas must be maximized, and (2) the sorbent must be renewed quickly to allow further absorption. The following reaction vessel arrangements tend to concentrate on one or both of these criteria to maximize absorption capability.

A packed column reactor vessel arrangement seeks to maximize the surface area criterion. A vertical tower is usually packed randomly with sorbent particles. The sorbent is sprayed down from the top of the column where it covers the packing particles, giving a large surface area. The flue gas enters the column at the bottom and rises up through the sorbent coated packing, allowing the absorption to occur (Figure B1).

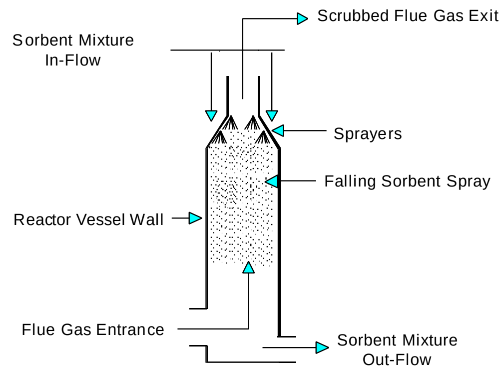
A tray column contains a tray with small perforations. The sorbent liquid flows continuously across this tray, thereby allowing the sorbent to be renewed quickly. The flue gas enters at the bottom of the column and rises up to the tray, where it bubbles through the

Figure B1. Packed-Type Scrubber



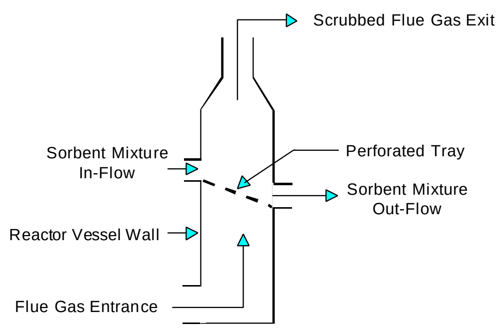
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Figure B3. Spray-Type Scrubber



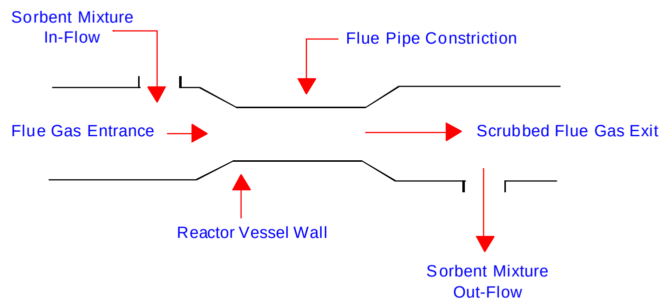
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Figure B2. Tray-Type Scrubber



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Figure B4. Venturi-Type Scrubber



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

perforations, gaining contact with the sorbent. This arrangement maximizes the renewal of the liquid surface since the sorbent flows continuously over the contact tray (Figure B2).

Spray towers are basically packed columns without any packing. The sorbent is sprayed down from the top of the column in fine droplets, giving a large surface area. The flue gas, having been introduced at the bottom, rises up through this spray where it reacts (Figure B3).

In a venturi arrangement, the liquid sorbent is injected into the flue gas just upstream of a constriction in the flue pipe Figure B4). In the constriction, conservation of mass requires that the velocity of the flue gas/sorbent mixture increase, thereby increasing the amount of mixing. Venturi scrubbers have also been shown to be efficient for particulate removal. The previously described systems usually will require some particle collector upstream of the unit (baghouses or electrostatic precipitators are common). Venturis require a higher energy input due to the constriction in the flue, however, and therefore are more costly to operate.

One example of a purely dry scrubbing process is the spray dryer scrubber system. Spray dryers are essentially the same as spray towers, except that sorbent is sprayed into the reactor vessel in a fine enough mist that water in the sorbent mix is evaporated by the hot flue gas at the same time that sulfur dioxide is absorbed from the flue gas. What is left is a dry powder which leaves the vessel with the exiting flue gas. To capture this dry waste, particulate collectors such as baghouses or electrostatic precipitators must be present downstream from the scrubber unit.

All of the above systems rely on natural processes for the mixing and absorption of the flue gas contaminants by the sorbent. Some systems use mechanical devices to enhance the mixing or absorption process, in order to optimize its effectiveness. These are the so-called "mechanically aided" scrubber systems.

There are of course systems which are hybrids of those mentioned above. Form EIA-767, "Steam-Electric Plant Operation and Design Report" allows scrubbers to be classified with up to four of the above types.

Characteristics of Retrofitted Scrubbers in Sample

Data from a sample of retrofit scrubbers were assembled for this report from the Form EIA-767, "Steam-Electric Plant Operation and Design Report" database. The sample includes some information on 32 retrofit scrubbers.[93] It includes all utility retrofit scrubbers on plants of 100 or more megawatts operating between 1985 and 1991. The sample includes data reported for each of these years; however, information is not available for all plants for all years.

The number of sample retrofit scrubbers installed in each State varies from one to seven (Table B1). The retrofit scrubbers are located in western as well as eastern States. The geographic distribution of the retrofit scrubbers in the sample (eastern and midwestern States) is different from the distribution of retrofits that will result from Phase I. This is a limiting factor in comparing the sample retrofits with those from Phase I.

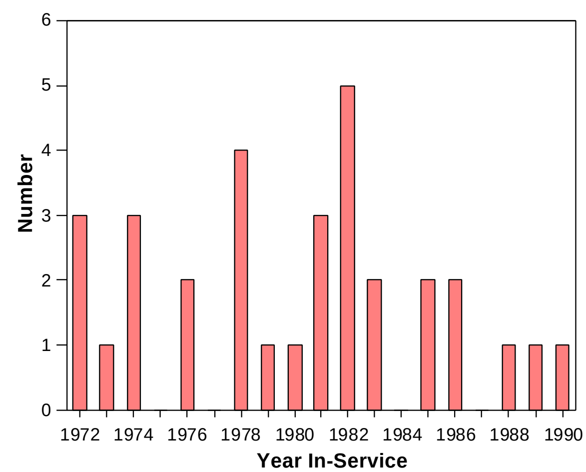
The scrubbers in the sample were placed into service from 1972 through 1990, with many coming on-line in the 5-year period from 1978 through 1982 (Figure B5). Another limitation for comparing the sample scrubbers and the Phase I scrubbers to be installed is the fact that all but three of the scrubbers in the sample went into service before 1988, and scrubber designs have evolved since then.

Table B1. Number of Retrofit Scrubbers in Sample by State

State	Number
Alabama	2
Arizona	1
Colorado	1
Kentucky	7
Nevada	2
New Mexico	7
Pennsylvania	7
Wyoming	5
Total	32

Source: Database created from Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1992) by Decision Analysis Corporation for the Energy Information Administration under contract #DE-AC01-92E121946.

Figure B5. Number of Retrofit Scrubbers in Sample by Year In-Service, 1972-1990

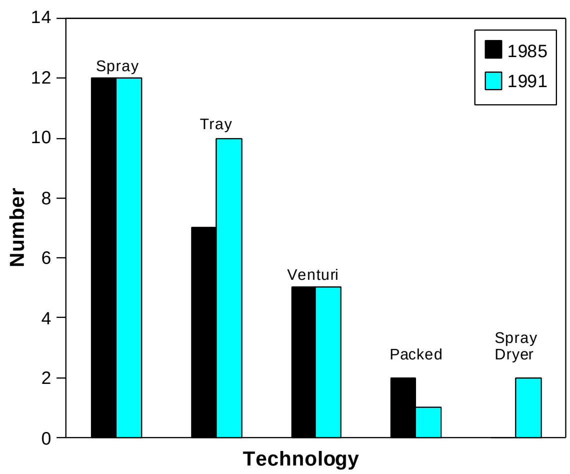


Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1991).

[93]The definition of a retrofit scrubber used here is one that went into service at least 1 year after its related boilers went into service. The number of units in the sample changed by year, depending on when they came into service and whether data were missing for a unit. For 1985, there were 26 units, while for 1991 this number was 30. For a more extensive discussion of the sample, see Decision Analysis Corporation of Virginia, "Analysis of Retrofit Flue Gas Desulfurization Unit Data," report to the Energy Information Administration (Vienna, VA, May 28, 1993). The data and analysis regarding the sample of retrofit flue gas desulfurization units discussed here are drawn from that report.

The 32 units in the sample mostly use spray or tray configurations for their reactor vessels. The spray-type scrubber was the most popular design in operation for this sample of units, but the tray and spray dryer designs were the only types that increased between 1985 and 1991 (Figure B6). Spray scrubbers are relatively easy to design as compared to the other configurations, and this fact may account for their earlier popularity.

Figure B6. Number of Scrubbers by Type of Technology, 1985 and 1991



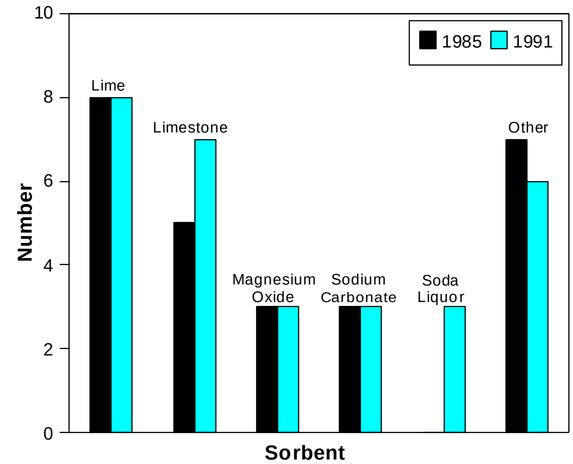
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1985 and 1991).

Lime and limestone are the most common sorbent types for the sample (Figure B7). Their lower cost makes them attractive to utilities. The two scrubbers that were added from 1985 through 1991 used limestone as a sorbent. Limestone is easier to handle than lime. Lime must be safeguarded from moisture at all times, while limestone does not require such precautions. Such precautions increase the cost of lime systems, since extra waterproof structures must be erected for shipping and storage of the sorbent. Thus, although lime can be a more efficient SO_2 sorbent, limestone scrubbers have become almost as predominant as lime.

Engineering Performance of Scrubber Systems

Several key factors must be assessed to evaluate the engineering performance of an scrubber system in terms of its ability to meet SO_2 emission standards. One of the most important is the design SO_2 removal

Figure B7. Number of Scrubbers by Type of Sorbent, 1985 and 1991



Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1985 and 1991).

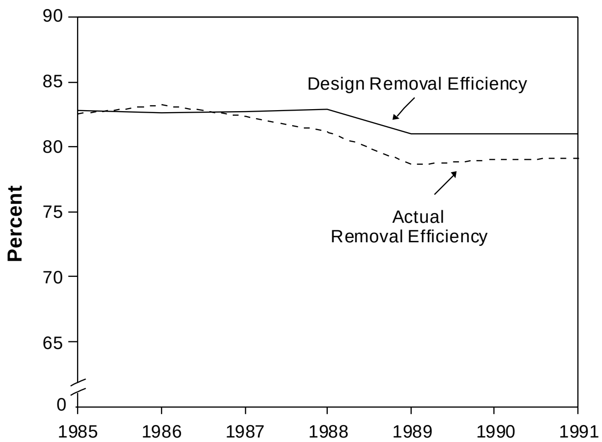
efficiency rate for the scrubber. The design removal efficiency for a scrubber is the percentage of SO_2 present in the flue gas which will be absorbed by the unit as estimated by the designing engineers before the scrubber is actually built. The engineers consider the scrubber design as well as plant and fuel characteristics to obtain this quantity. The weighted average design removal efficiency for this sample of units was never below 80 percent for any one year (Figure B8).

The actual removal efficiency is a measurement taken after the scrubber is in operation. The weighted average of the actual removal efficiency was less than the design removal efficiency in every year except 1986.

Another important factor in the evaluation of a scrubber is its reliability. A unit which consistently breaks down or requires large amounts of downtime for maintenance will not be effective in reducing plant emissions. The scrubber availability is the percentage of the whole year that the scrubber was operational. Weighted average scrubber availability increased 13 percentage points between 1985 and 1991 (Figure B9).

Scrubber systems may consist of several reactor vessels. Each of the vessels, called modules, can be operated independently. Modular scrubber design helps increase the availability and operability of scrubbers, since any one module which is forced off-line due to failure or required maintenance can be replaced by another module. Because older scrubbers, when engineers had less experience with them, are less reliable, they often

Figure B8. Weighted Average Design Removal Efficiency and Weighted Average Actual Removal Efficiency by Year, 1985-1991



Notes: •Removal Efficiency is the percentage of flue gas SO_2 removed by the scrubber unit. •Design Removal Efficiency is specified by the engineers who designed the scrubber unit. •Actual Removal Efficiency is measured at the plant when the scrubber unit is operating.

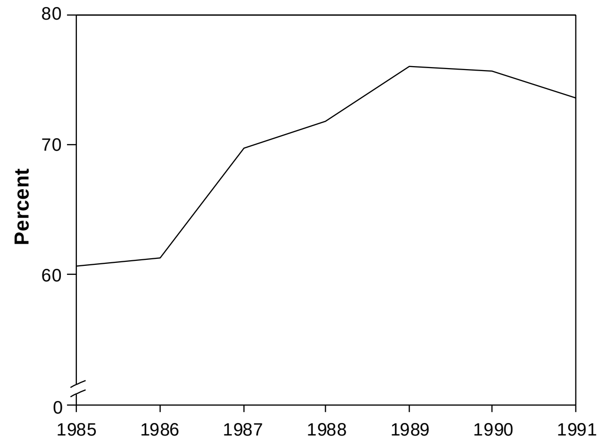
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1985-1991).

contain a "spare" module to substitute for non-operating modules. In contrast, newer scrubbers may be larger, requiring more modules, but the modules may be larger. The average number of modules in the sample of scrubbers increased overall for those units with in-service dates from 1971 through 1986. However, there has been some decrease in the average number of modules for units put in service after 1987 (Figure B10).

A predominant cost in the operation of a scrubber is the amount of sorbent it consumes. The average physical quantity of sorbent used increased from 1985 through 1991 (Figure B11), partially because of the switch from earlier lime scrubber designs to limestone scrubber systems. Limestone absorbs less sulfur per pound than lime, so more of it is needed to absorb the same amount of sulfur. In addition, the electricity output per unit and the amount of sulfur in the coal may have increased.

Finally, the operation of a scrubber requires electricity to run scrubber equipment. Usually the electricity is supplied by the power plant using the scrubber. This decreases the electricity output of the plant, by reducing the amount of electricity produced for sale from the same quantity of inputs. The weighted average electricity consumption of these scrubbers as a percentage of plant generation shows that scrubbers require a small percentage of a unit's electricity production, and that weighted averages have varied between 1.8 percent and 4.3 percent (Figure B12).

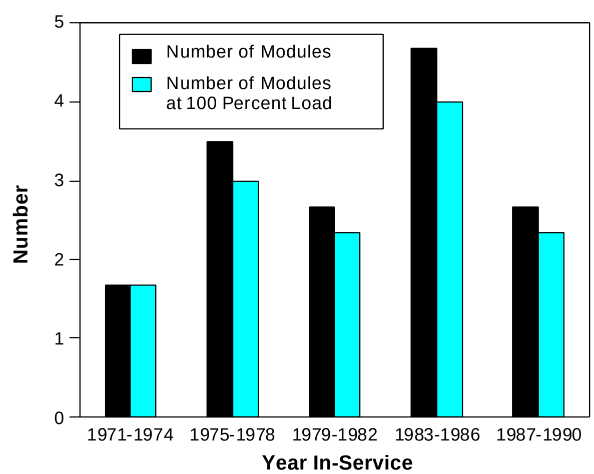
Figure B9. Weighted Average Availability of Scrubbers by Year, 1985-1991



Note: Availability is the number of hours the scrubber was operational during the year expressed as a percentage of the total number of hours in a year.

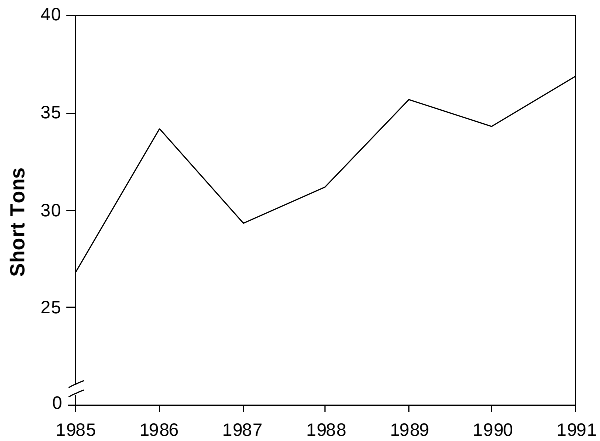
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1985-1991).

Figure B10. Average Number of Modules and Average Number of Modules Used at 100 Percent Load by Year In-Service, 1971-1990



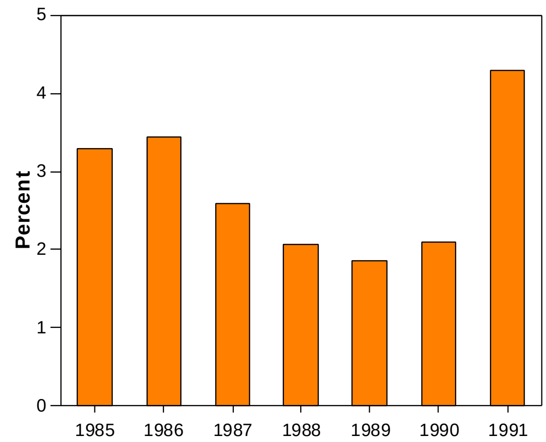
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1991).

Figure B11. Average Amount of Sorbent Used by Year, 1985-1991



Source: Energy Information Administration, Form EIA-767, “Steam-Electric Plant Operation and Design Report” (1985-1991).

Figure B12. Weighted Average Percent of Plant Generation Used by Retrofit Scrubbers, 1985-1991



Source: Energy Information Administration, Form EIA-767, “Steam-Electric Plant Operation and Design Report” (1985-1991).

Flue gas desulfurization is accomplished by many different methods and practices. As the electric utility industry becomes more experienced with scrubber processes and systems, scrubbers are expected to become more reliable and less expensive.

Appendix C

Econometric Estimates of Scrubber Retrofit Costs Based on Historical Costs

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Econometric Estimates of Scrubber Retrofit Costs Based on Historical Costs

Econometric analyses of the cost of scrubber retrofits was performed on a subset of all utility retrofit scrubbers for which data were available. The purpose of this analysis was to examine the effects of a number of variables on the cost and performance of the retrofitted units. In this analysis, scrubbers are classified as retrofits if they were installed at least 1 year after the installation of the boiler. The data base of scrubber retrofits analyzed here included 32 units located in 8 States. Cost data were obtained from Form EIA-767, "Steam-Electric Plant Operation and Design Report." Most units are located in the western or eastern United States (Table B1), where utilities, particularly in the Four Corners area,[94] chose scrubbers to meet strict Prevention of Significant Deterioration air quality regulations imposed by the States.

The location of a scrubber has an impact on many aspects of the retrofit decision, which is affected by the proximity to coal markets, the accessibility of water, land availability for waste pond storage, regional material and labor costs, and the State / regional regulatory environment.

Two different variables were estimated using econometric techniques: capital costs and operation and maintenance costs. In both cases, the ordinary least squares estimator was used to fit a linear model for each variable.[95] At least two important problems were encountered in the statistical analysis. One was that heteroskedasticity, when the disturbance term does not have uniform variance, was present. Heteroskedasticity has several consequences when using an ordinary least squares (OLS) estimator.

OLS is not the most efficient estimator, because it is not the estimator with the minimum variance; the variance of the parameter estimates is biased, so internal estimation and hypothesis testing are not dependable; and OLS is not the maximum likelihood estimator, so that the probability of obtaining the observed data is not maximized. However, the method to correct for this problem, using a generalized least squares estimator, is difficult to implement. For the scrubber models, attempts to correct for heteroskedasticity resulted in models of worse quality. Fortuitously, the OLS parameter estimates are unbiased even in the presence of heteroskedasticity and produce the highest coefficient of determination (R^2). Thus, the OLS parameter estimates have been accepted for this analysis.

The other data problem lies with some uncertainty regarding the definition of capital costs by respondents to the Energy Information Administration (EIA) Form EIA-767. The *Accounting and Reporting Requirements for Public Utilities and Licensees* require that overhead costs be included in reported capital costs.[96] Overhead includes such costs as engineering, supervision, general office salaries and expenses, insurance, and taxes. The requirement to include overhead cost does not apply specifically to the Form EIA-767; it applies directly to the bookkeeping and accounting practices of utilities regulated by the Federal Energy Regulatory Commission (FERC). Form EIA-767 instructions do not specify that the FERC regulations, called the Uniform System of Accounts, apply to the information reported there, and the instructions do not mention overhead costs. In addition, some utilities submitting information on the Form EIA-767 are not under the FERC's jurisdiction and thus are not bound by the Uniform System of Accounts. In an informal survey of five respondents to the Form EIA-767, at least one respondent was not able to confirm that overhead was included in capital costs. Overhead may be a substantial part of total capital

[94]Meeting point of Utah, Colorado, New Mexico, and Arizona.

[95]More detail regarding the econometric methods are available in the Decision Analysis Corporation of Virginia, "Regression Models for Analysis of Retrofit Flue Gas Desulfurization Unit Cost and Performance," a report prepared for the Energy Information Administration (Vienna, VA, May 28, 1993).

[96]Federal Energy Regulatory Commission, FERC-0114 (Washington, DC, January 17, 1989), ¶15,054.

costs. The engineering estimates used here (Appendix D) estimate that they are 21 percent of capital costs.[97] Thus the statistical estimates probably understate the capital cost of scrubbers.

Costs

Historical cost data were separated into operation and maintenance (O&M) costs and installed capital costs. Two models (equations) were developed to show the effects of a number of scrubber characteristics on the cost of the scrubbers. One of these models—the O&M cost model—employed time series/cross-sectional estimation procedures, incorporating both across-unit (cross-sectional) and serial within-unit (time-series) explanatory effects to estimate the dependent variable. For installed capital costs, which do not vary over time for individual units, one observation was used for each scrubber.

Installed Capital Costs

The installed capital cost model included engineering design and retrofit unit size variables. As with the O&M cost model, the engineering design variables served as cost parameter indicators. The major explanatory factor for installed capital costs was the size of the retrofit scrubber, which can be represented by scale variables such as the boiler firing rate, the generator nameplate capacity, annual coal consumption, and the number of absorber modules. Technology-specific factors that influence capital costs, include the design operating efficiency, the type of absorber module technology selected, and installation complex as indicated by design requirements associated with the existing boiler/generator/stack configuration.

The dependent variable, installed capital costs per kilowatt, was estimated with the standard cross-sectional ordinary least squares procedure. This dependent variable is expressed on a per-unit basis. Since capital costs for each unit can be incurred at different times, the costs were converted to real dollars with the use of the Gross Domestic Product Implicit Price Deflator.

The capital cost model was specified as follows:

$$\begin{aligned} CAPKW = {} & -\beta_0 + \beta_1 FGDMOD - \beta_2 MAXMW \\ & + \beta_3 BGYEAR + \beta_4 SULFDEFF \\ & + \beta_5 TYPE2 + \varepsilon , \end{aligned}$$

where

CAPKW	=	installed capital costs per kilowatt of nameplate electric capacity, expressed in real dollars,
FGDMOD	=	number of absorber modules,
MAXMW	=	generator nameplate capacity in megawatts,
BGYEAR	=	boiler in-service year,
SULFDEFF	=	percentage design sulfur removal efficiency,
TYPE2	=	absorber technology-type dummy variable (takes on a value of 1 if technology is a tray type, and 0 if otherwise),
ε	=	error.

The model provided the following results:

- For each absorber module added to the scrubber system, the mean value of the installed capital cost increases by $164 per kilowatt (1992 dollars) with all other influences held constant (Table C1).

- For each 1-megawatt increase in the generator nameplate capacity, the mean value of the installed capital cost decreases by $1.11 per kilowatt with all other influences held constant.

- For each incremental boiler in-service year, the mean value of installed capital cost increases by $5.2 per kilowatt with all other influences held constant.

- For each percentage-point increase in the design sulfur removal efficiency, the mean value of the installed capital cost increases by $3.0 per kilowatt with all other influences held constant.

- Selecting the tray type absorber module over other alternatives increases the mean value of the installed capital cost by $142 per kilowatt with all other influences held constant.

[97]United Engineers and Contractors, *Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High-Sulfur Coal-Fired Power Plants,* UE&C/EIA:921005 (Philadelphia, PA, October 1992).

Table C1. Retrofit Scrubber Installed Capital Cost Model Parameter Estimates and Model Performance Statistics

Variable	Parameter Estimate	t-Statistic
INTERCEPT	-475.561	-2.063
FGDMOD	164.223	5.836
MAXMW	-1.114	-4.977
BGYEAR	5.174	1.756
SULFDEFF	3.047	2.014
TYPE2	141.573	2.378
R_a^2	0.706	--
F Value	12.527	--

Source: Decision Analysis Corporation of Virginia, “Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance,” report prepared for the Energy Information Administration (Vienna, VA, May 1993), p. 28.

The level of sulfur removal for which the scrubber is designed is an important determinant of capital costs. Capital costs for different levels of design sulfur removal efficiency vary from $83 to $281 (Table C2).

Table C2. Retrofit Scrubber Installed Capital Costs by Design Sulfur Removal Efficiency

Design Sulfur Removal Efficiency (Percent)	Installed Capital Cost per Kilowatt (1992 dollars)
35	83
40	98
45	114
50	129
55	144
60	159
65	175
70	190
75	205
80	220
85	235
90	251
95	266
100	281

Notes: •Based on regression parameter estimates and mean sample values for variables FGDMOD, MAXMW, BGYEAR, and TYPE2. •Dollar values were converted to 1992 dollars using the Gross Domestic Product Implicit Price Deflator.

Source: Decision Analysis Corporation of Virginia, “Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance,” report prepared for the Energy Information Administration (Vienna, VA, May 1993), p. 30.

Operation and Maintenance Costs

The O&M cost model was based on a standard cost function model. Input prices, input quantities, production characteristics, and process activity levels are the key elements of the cost function that were included in the model. A linear cost equation that reflects the major input costs and engineering characteristics of the underlying scrubber technologies was constructed.[98]

The pooled modeling approach[99] allowed the inclusion of a per unit cost variable that represents the embedded price of inputs such as sorbent and associated chemical additives. This embedded cost variable allows input price variations to be included as an explanatory factor for changes in O&M costs over time. Since actual input prices for sorbent, water, and other chemical inputs were not known, the unit cost variable was constructed by dividing the “feed materials and chemicals” component of annual O&M costs by the quantity of sorbent consumed in the corresponding year. This variable, measured in dollars per pound of sorbent, captures the prices of sorbent and other feed materials, as well as average unit costs associated with materials preparation and handling.

The use of the pooled modeling approach also resulted in technology type becoming statistically significant—a benefit that was not possible with the cross-sectional modeling approach. An analysis of the pooled data matrix indicated that the venturi module configurations had a large across-unit impact on O&M costs: units with a venturi configuration had higher O&M costs relative to other technology types. Consequently, the venturi technology type was included in the pooled model as a dummy variable.

Also included in the model as an explanatory variable was the average percent sulfur content of the coal burned. This variable is a measure of the extent of scrubbing activity required. As the coal sulfur concentration increases, O&M costs are expected to increase as well, due to greater sorbent input requirements, higher waste generation, and elevated maintenance requirements stemming from higher flue gas sulfur dioxide (SO_2) concentrations (Table C3).

A variable representing the number of hours per year the boiler is under load was included to reflect the

[98]Testing of concave and linear cost curve models indicated that a linear model was superior to other forms.
[99]Cross-section / time series with the same number of observations for each period.

impact of plant system utilization on per-unit O&M costs. Higher boiler hours indicates greater fuel consumption and electric output (given a constant heat rate), which means that O&M costs are spread across a greater number of kilowatthours.

Table C3. Retrofit Scrubber Operations and Maintenance Costs by Coal Sulfur Content and Technology Type

Percent Coal Sulfur Content	Operations & Maintenance Cost (1992 mills per kilowatthour)	
	Venturi	Other
0.00	9.48	2.55
0.25	9.65	2.72
0.50	9.83	2.90
0.75	10.00	3.07
1.00	10.17	3.24
1.25	10.35	3.42
1.50	10.52	3.59
1.75	10.69	3.76
2.00	10.87	3.94
2.25	11.04	4.11
2.50	11.22	4.29
2.75	11.39	4.46
3.00	11.56	4.63
3.25	11.74	4.81
3.50	11.91	4.98
3.75	12.08	5.15
4.00	12.26	5.33
4.25	12.43	5.50
4.50	12.60	5.67

Note: • Based on regression parameter estimates and mean sample values for variables PSORB and LOADHOUR. • Mill values were converted to 1992 mills using the Gross Domestic Product Implicit Price Deflator.

Source: Decision Analysis Corporation of Virginia, "Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance," report prepared for the Energy Information Administration (Vienna, VA, May 1993), p. 7.

The model was specified as follows:

$$OMKWH = \beta_0 + \beta_1 PSORB + \beta_2 AVGSULF - \beta_3 LOADHOUR + \beta_4 VENTURI + (v_i + e_t + \varepsilon_{it}),$$

where

OMKWH = O&M costs per kilowatthour (excluding replacement electricity) in real mills,
PSORB = embedded price of sorbent and other chemical additives, in real dollars per pound of sorbent,
AVGSULF = average coal sulfur content in percent,
LOADHOUR = number of hours per year the boiler was under load,
VENTURI = venturi technology type (takes on a value of 1 for venturi technology type, and 0 for all other technology types),
v, e, ε = cross-section, time-series, and cross-section / time-series errors.

For this version of the O&M model, O&M costs are expressed in mills per kilowatthour. On average, use of the venturi technology type increased O&M costs by 6.9 mills per kilowatthour (Table C4).

Table C4. Pooled Retrofit Scrubber Operations and Maintenance Model Parameter Estimates

Variable	Parameter Estimate	t-Statistic
Intercept	3.082	1.642
PSORB	0.075	26.542
AVGSULF	0.694	3.138
LOADHOUR	-5.8E-4	-2.571
VENTURI	6.928	9.331
Model R_a^2	0.996	--
F Value	306.670	--

Source: Decision Analysis Corporation of Virginia, "Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance," report prepared for the Energy Information Administration (Vienna, VA, May 1993), p. 5.

Appendix D

Current Engineering Estimates of Scrubber Retrofit Costs

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Current Engineering Estimates of Scrubber Retrofit Costs

These engineering cost estimates use currently available technology, which would be available to future builders, for their design. Historical cost estimates are based on the technology existing at the time they were built; they do not take into account current design technologies or current costs (Appendix C). Two different methodologies are used to estimate scrubber retrofit costs. Each of these offers distinct advantages and disadvantages. The most important distinction is that historical cost estimates are based on actual recorded costs, while engineering costs are estimated by the expert engineer. Engineering cost estimates may differ from the actual costs that would be incurred if the designed scrubber were built.

The engineering cost estimate for flue gas desulfurization systems (scrubbers) presented in this appendix is based on retrofitting a scrubber to a 488-megawatt (net) high-sulfur pulverized coal-fired power generating station. This cost estimate is based on environmental regulations for coal-fired plants on January 1, 1992, and reflects the Best Available Control Technology for scrubber systems currently being used.[100] As of January 1, 1992, coal-fired plants were limited to sulfur dioxide (SO_2) emissions of 0.30 pounds per million British thermal units (Btu).[101]

Scrubber Description

Scrubber systems are designed to remove SO_2 from the flue gas exiting an electrostatic precipitator (which renders it essentially particulate-free) of a coal-fired power plant and to produce in the process a mixed fly ash and scrubber waste product suitable for landfill disposal. The SO_2 removal is accomplished by an absorbent, often lime or limestone. The system design considered here is a nonrecovery forced oxidation wet limestone process consisting of: a limestone unloading and storage facility; a limestone slurry preparation system; an SO_2 absorber system; a waste slurry thickening system; an scrubber waste product system; and a water distribution system. The performance criterion for a conventional limestone wet scrubbing system (Figure D1) is 95 percent SO_2 removal efficiency for 3.2-percent sulfur coal. The system design provides a zero liquid discharge capability.

The limestone unloading / storage facility is designed to receive the limestone shipments and to convey the limestone to storage silos for limestone slurry preparation. The limestone is usually delivered to the plant via railroad. The rail cars containing limestone are brought to the unloading shed, which houses the unloading hoppers. Limestone from the hoppers is crushed and pneumatically conveyed to the limestone storage silo.

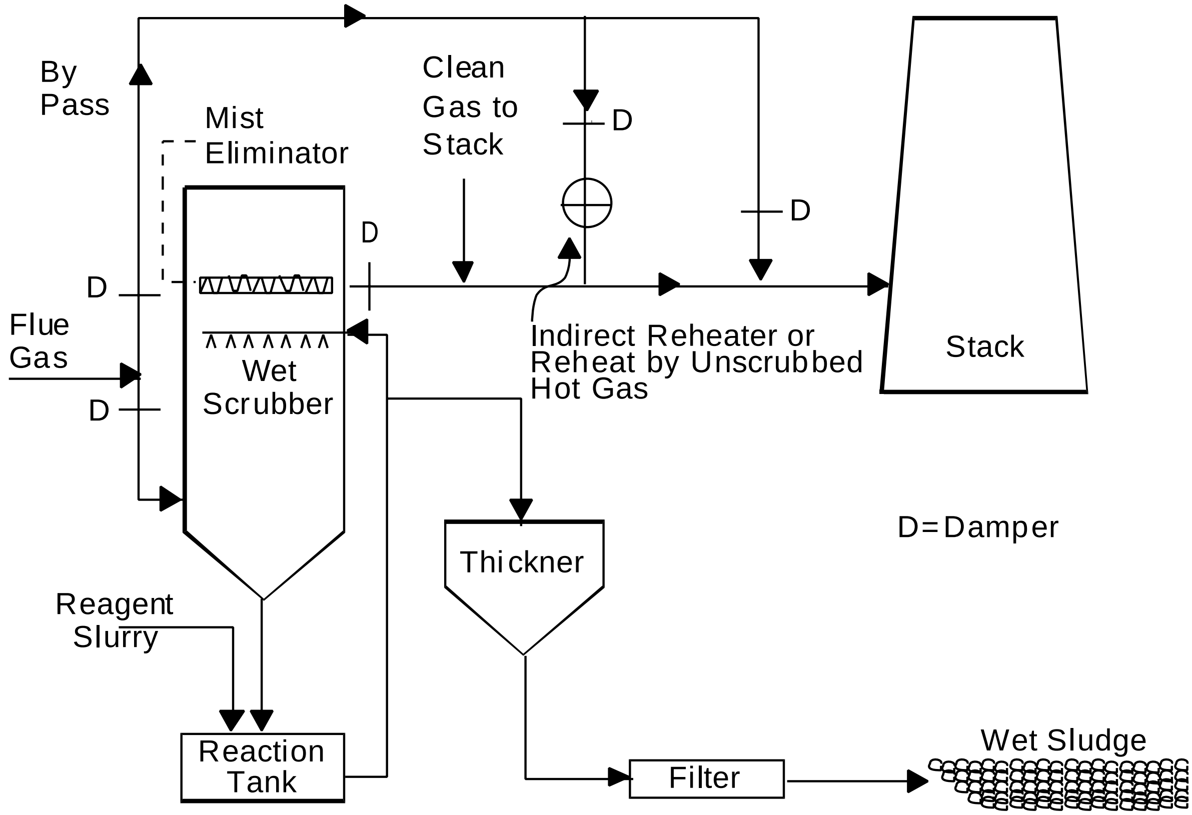
The limestone slurry preparation system receives limestone from the storage silo of the unloading / storage facility, grinds the limestone more finely, adds water, and stores the resultant slurry. The limestone slurry storage tank pumps transfer limestone slurry to the feed tanks in the absorber island. The slurry produced is used within the SO_2 absorber system.

The SO_2 absorber system brings the flue gas into direct contact with a recirculating slurry within an absorber vessel in order to remove SO_2 from the flue gas stream. The major components of the SO_2 absorber system include: spray tower absorber modules fabricated of rubber-lined carbon steel, recirculation pumps, mist

[100]United Engineers & Constructors, *Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant*, UE&C / EIA: 921005 (Philadelphia, PA, October 1992). The 488 megawatt (net) coal-fired generating station was selected as a typical plant for new construction.

[101]Under the current Best Available Control Technology approach, any lower limit technology permitted and installed anywhere for any reason becomes the benchmark limit for the next installation permit.

Figure D1. Conventional Limestone Wet Scrubbing Schematic



Source: Electric Power Research Institute, *Proceedings: Ninth Symposium on Flue Gas Desulfurization,* EPRI CS-4390, Volume 2 (Palo Alto, CA, January 1986), p.11-3.

eliminator, wash pumps and blend tank, limestone slurry feed pumps and storage tank, dampers, agitators, piping, valves, instrumentation, and controls.

One vertical spray absorber module is usually used. At valves wide open, 5 percent overpressure turbine operation with design coal, the absorber module treats 100 percent of the flue gas. The absorber module commonly contains five banks of sprays. Flue gas enters the absorber module with a slight downward direction and turns up through a bank of sprays where gas is scrubbed.

Rubber-lined casing centrifugal recirculation pumps are connected to each spray header, usually two at a time. The pumps are designed to produce a liquid-to-gas ratio with all 10 pumps in operation. These pumps take suction from the recirculation tank that is provided as an integral component of the absorber module.

Limestone slurry, as required to maintain the alkalinity within the absorber system, is added to the recirculation tank. The limestone slurry, prepared within the slurry preparation system, is pumped to the absorber from the limestone feed tank via a recirculating slurry feed loop.

The absorber is provided with a mist eliminator, which removes liquid droplets and particulates contained in the scrubbed flue gas. The absorber system waste products are discharged via a bleed stream from the recirculating slurry. The bleed stream is then directed to an agitated waste slurry sump. From this sump, the

Georgia Power installed a scrubber at Yates unit 1 for an estimated $34 million capital cost, half of which was paid by the Department of Energy as a demonstration project.

bleed stream is pumped to the waste slurry thickening system.

The waste slurry thickening system dewaters the bleed slurry from the absorber module to produce a concentrated underflow slurry and a high-quality (low suspended solids) overflow. The underflow slurry, which contains a minimum of 45 percent solids, by weight, is pumped to the waste product system for treatment prior to disposal. The overflow is returned for reuse within the scrubber system.

The waste product system is provided to process fly ash from the coal combustion process and scrubber waste product for co-disposal within a solid waste landfill. While the waste product system normally treats a combination of scrubber waste product and fly ash, it is also able to process fly ash alone. The primary influents to the waste product system are thickener underflow (from the waste slurry thickening system) and fly ash (from the fly ash system). The waste is normally loaded directly onto trucks for transport to the disposal areas.

The sulfur removal efficiency of 95 percent for the current engineering estimate yields an SO_2 emission of about 0.29 pounds per million Btu for 3.2-percent sulfur coal.

Capital Costs

The capital cost, including direct and indirect costs, for retrofitting scrubber equipment to an existing 488-megawatt (net) coal-fired plant with no spare module and 3.2-percent sulfur coal is estimated to be $266 per kilowatt (1992 dollars). This capital cost includes the scrubber structures and equipment.

This capital cost includes a scrubber retrofit multiplier of 1.25 times the cost of an original equipment scrubber. The multiplier is estimated to vary from 1.1 to 2.0 times the capital cost of an original equipment scrubber, depending on the conditions available for installing a scrubber. The amount of space available to install scrubbers is the main constraint.[102]

Spare Absorber Modules

Previously, scrubber systems usually included a spare absorber module to maintain low emission rates in the short term, when one absorber module was inoperative. However, under the Clean Air Act Amendments of 1990, a module or entire scrubber unit may be bypassed for a short period of time, as long as sufficient emissions allowances are acquired for the total emissions of the entire year. Therefore, a utility could

[102]United Engineers & Constructors, *Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant*, UE&C/EIA: 921005 (Philadelphia, PA, October 1992), Table 3, pp. 1-3.

overscrub for a period of time or acquire additional allowances to offset periods when one scrubber module is out of service. Furthermore, scrubber technology has advanced so that scrubber units have a high availability and efficiency without the use of a spare module.

Spare capacity for the auxiliary systems, such as thickeners and mills, is provided where required to support a single absorber module with a system availability of 99.5 percent. The cost of installing and maintaining a scrubber system would increase dramatically if there was a requirement for a spare module.[103] The current engineering capital cost estimate for scrubber systems for a 488-megawatt (net) coal-fired plant with 3.2-percent sulfur coal would increase by about one-third with a spare module.[104]

Operation and Maintenance Costs

The additional nonfuel operation and maintenance (O&M) costs for a retrofitted scrubber on a 488-megawatt (net) coal-fired plant with bituminous 3.2-percent sulfur coal are determined by comparing costs at plants with and without a wet limestone scrubber. A model based on engineering cost estimates developed by Oak Ridge National Laboratory is used in this report to determine the additional O&M costs for adding a scrubber.[105]

The largest increase in O&M costs for a wet limestone scrubber on a bituminous coal-fired plant is in supplies and expenses (including fixed and variable costs) of $4.5 million (Table D1). The variable costs for limestone of $2.7 million and waste disposal of $1.3 million are the largest items in supplies and expenses. The additional onsite staff is increased by 34 personnel to maintain and monitor the scrubbers at an additional cost of $1.3 million. Increased maintenance materials account for $1.4 million. Administrative and general costs, including benefits and worker's compensation and other general expenses, add $1.7 million or 19 percent of the total additional nonfuel O&M costs of $9.0 million. These costs can be divided into fixed and variable components. Additional nonfuel O&M fixed costs are $9.2 per kilowatt per year and variable costs are 1.6 mills per kilowatthour for the addition of scrubber equipment to the unit.

Table D1. Operations and Maintenance Costs for a Scrubber Retrofitting
(1992 Dollars)

Type of Cost	Cost (million dollars per year)
On-site Staff (34 persons)	1.3
Maintenance Materials	1.4
Fixed	1.1
Variable	0.3
Supplies and Expenses	4.5
Fixed	0.3
Variable—Plant	0.2
Variable—Limestone	2.7
Variable—Waste Disposal	1.3
Offsite Technical Support	0.2
Subtotal, Direct O&M Costs	7.3
Fixed	2.8
Variable	4.5
Administration and General Costs	1.7
Pensions, Benefits, and Worker's Compensation	0.3
Other General Expenses	1.5
Total Nonfuel O&M Costs	9.0
Energy (Electricity) Costs	1.5
Total O&M Costs (Including Electricity)	10.5
Fixed	4.5
Variable	5.9
Type of Cost	**Cost** (per unit)
Fixed O&M Costs (dollars per kilowatt per	9.2
Variable O&M Costs (Including Electricity) (mills per kilowatthour)	2.1
Variable Nonfuel O&M Costs (mills per kilowatthour)	1.6
Energy (Electricity) Costs (mills per kilowatthour)	0.5

O&M=Operations and Maintenance.

Notes: •Costs were calculated for a wet limestone scrubber retrofitted to a 488-megawatt (net) bituminous coal-fired power plant burning 3.2 percent sulfur coal. •Costs include direct costs and indirect costs (administrative and general costs). •Data estimated using a capacity factor of 65 percent. •Totals may not equal sum of individual elements because of independent rounding. •Dollar values were converted to 1992 dollars using the Gross Domestic Product Implicit Price Deflator.

Source: **Model**: Oak Ridge National Laboratory, "Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants—1982," ORNL/TM-8324 (September 1982). The model for estimating O&M costs for coal-fired power plants was updated in 1987. **Costs**: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

[103]Antonio J. DoVale, "Acid Rain Scrubber Retrofits May Cost Less than Anticipated," *Power Engineering* (February 1991), p. 38.

[104]United Engineers & Constructors, *Update of EEDB Phase X HS5 Base Construction Costs 500 MW (Nominal) High Sulfur Coal-Fired Power Plant*, UE&C/EIA:921005 (Philadelphia, PA, October 1992), Table 3, pp. 1-3. United Engineers & Constructors, *Phase IX Update (1987) Report For The Energy Economic Data Base Program EEDB—IX*, DOE/NE-0091 (Philadelphia, PA, July 1988), Table 5, pp. 5-13.

[105]Oak Ridge National Laboratory Report, "Nonfuel Operation and Maintenance Costs for Large Steam-Electric Power Plants—1982," ORNL/TM-8324 (September 1982).

In addition, the energy needed to operate a scrubber is estimated to be about 2.1 percent of the capacity of its associated generating unit(s). This is because when the retrofit scrubber is operating, it uses about 2.1 percent of the output of its associated generator(s) to power its fans and other electrical equipment.[106] For a 488-megawatt (net) plant, these costs amount to $1.5 million, or 0.5 mills per kilowatthour.[107] These electricity costs add 17 percent to the preceding estimates for total annual scrubber costs and 31 percent to the variable O&M costs.

[106]U.S. Environmental Protection Agency as quoted in a memo from Bruce Braine, Carl Leubsdorf, and Barry Kurland to Ann Watkins (July 14, 1993).

[107]Using a 65-percent capacity factor and a cost of replacement electricity of 2.5 cents per kilowatthour.

Appendix E

Nitrogen Oxide Controls

Appendix E

Nitrogen Oxide Controls

Nitrogen oxides (NO_x) are commonly emitted from combustion sources, predominantly transportation sources (e.g. automobiles), utilities, and other industrial sources.[108] One effect commonly attributed to NO_x emissions is acid rain. With the passage of the Clean Air Act Amendments of 1990 (CAAA90), affected electricity producers must comply with specified NO_x limits by using an approved and proven NO_x control technology. This appendix summarizes some of the predominant technologies available for controlling NO_x, the CAAA90 NO_x control regulations, and the costs of installing and using such control technologies.

The Formation of Nitrogen Oxides

NO_x is formed in high-temperature environments when nitrogen and oxygen are present together. In a combustion chamber, where temperatures can be very high, the nitrogen present in air can combine with oxygen to produce NO_x. This is called thermal NO_x and has no relation to the fuel used in the combustion process. Thermal NO_x production usually begins at temperatures above 1300° Celsius (or 2372° Fahrenheit).[109] A second NO_x production source is the nitrogen that may be present in the fuel, which when burned, is released and is able to react with any oxygen present. This is called fuel NO_x. Fuels with higher percentages of nitrogen are prone to higher emissions of fuel NO_x when they are combusted (Table E1).

NO_x Control Technologies

The current state of technology to control NO_x emissions can be grouped into three categories: combustion techniques, flue gas treatment techniques, and advanced techniques. Combustion techniques include the following methods of control: air staging, fuel staging (reburning), and flue gas recirculation. "Low-NO_x burners" are one example of an air staging combustion control technology. Flue gas treatment options include selective catalytic reduction, selective noncatalytic reduction, and some advanced techniques which simultaneously treat flue gas for NO_x and sulfur dioxide (SO_2) emissions. Advanced techniques include techniques used in fluidized-bed combustors, coal gasification processes, and slagging combustors. In many cases these techniques are still under investigation, and therefore they are not applicable to Phase I plants and will not be discussed here. Also, many of the projects selected in the Department of Energy's Clean Coal Technology program are advanced techniques for NO_x control.

Table E1. Typical Nitrogen Content of Selected Fuels from the United States

Fuel	**Nitrogen Content** (Weight Percent, Dry Ash-Free Basis)
Coal, Typical Eastern	1.3
Coal, Powder River Basin (Wyoming)	0.7
Coal, Powder River Basin (Montana)	0.8
Fuel Oil, No. 1	*
Fuel Oil, No. 2	*
Fuel Oil, No. 4	0.2
Fuel Oil, No. 6, Low Sulfur	0.3-0.5
Natural Gas (Pennsylvania)	[a]1.1
Crude Oil, Kern Co. (California)	0.5-0.8

[a]Molecular Nitrogen, N_2.

*Less than 0.05 weight percent.

Sources: **Coal—**John H. Pavlish, April A. Anderson, Neil C. Craig, and Arun K. Mehta, "Using the CQIM™ to Evaluate Switching to Western Low-Sulfur Coals," paper presented at the Engineering Foundation Conference on Coal Blending and Switching of Western Low-Sulfur Coals (Salt Lake City, UT, September 26-October 1, 1993), p. 7. **Fuel Oil, Natural Gas, Crude Oil—**Anna-Karin Hjalmarsson, *NO_x Control Technologies For Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 18.

[108]U.S. Environmental Protection Agency, "EPA Acid Rain Program Nitrogen Oxides Emission Reduction Program Proposed Rule for Group 1 Boilers," EPA430/F-92/014 (6204J) (October 1992), p. 1.

[109]Anna-Karin Hjalmarsson, *NO_x Control Technologies For Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 18.

In most cases, attempts to control NO_x emissions are first made during the combustion process.[110] These techniques are of the most interest for Phase I units for which NO_x control equipment retrofits are being considered.

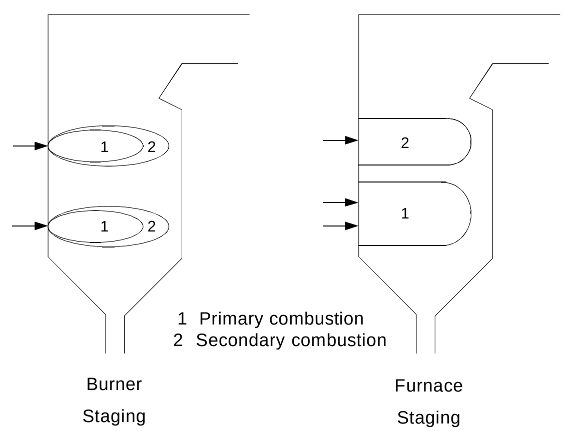
Combustion Techniques

Combustion techniques and many of the advanced techniques rely on the fact that NO_x formation in combustion processes is inhibited if less oxygen is present for the nitrogen to combine with. These techniques attempt to decrease oxygen levels by decreasing the amount of air present in combustion regions. Stoichiometry is a method for calculating the quantities of reactants and products in chemical reactions by use of simple weight ratios of the compounds as they appear in the chemical reaction equation. It can be used to calculate the amount of oxygen needed to entirely combust the fuel through the combustion chemical equation. Combustion NO_x control techniques provide less than this amount of oxygen to the combustion region, making the combustion a lean or fuel rich process (substoichiometric combustion). The combustion process then uses most or all of the oxygen present, leaving little for NO_x formation. Because of the oxygen limitation, substoichiometric combustion does not allow the fuel to burn entirely, so NO_x control technologies must allow for this by creating a second combustion zone where unburnt fuel can be combusted. This second process can be called the fuel burnout process. By separating the substoichiometric combustion and the fuel burnout process, the amount of NO_x production is reduced. Different combustion NO_x control techniques employ different methods for creating the substoichiometric combustion and fuel burnout processes.

Air staging is a NO_x combustion control method by which air to the combustion region in the burner or furnace is decreased to create the substoichiometric combustion condition, and the rest of the air needed for fuel burnout is supplied elsewhere. Air staging can be done in two ways: in the furnace, or in the burner (Figure E1). Furnace air staging supplies the burnout air away from the main combustion zone, creating a second combustion zone elsewhere in the furnace. Burner air staging creates different combustion zones in the flame of the burner, one being the substoichiometric region, the other the burnout region, by special placement of fuel and air nozzles in the burner. Burners with such nozzle arrangements and designs are called low-NO_x burners.

Fuel staging, which is commonly referred to as "reburning," stages fuel injection into the furnace to create a primary combustion zone, a secondary combustion zone which is substoichiometric, and a burnout zone to complete fuel combustion. The secondary combustion zone produces chemical compounds (hydrocarbon radicals) which take part in reactions to reduce NO_x formation in the primary combustion zone and increase the production of molecular nitrogen and other products. Since the primary zone is not substoichiometric, most of the fuel is burned, so secondary "staged" fuel must be added to create the secondary combustion zone. Burnout of the secondary fuel is completed in the burnout zone by staging air into this zone (Figure E2). The primary and secondary fuels need not be the same, although in most cases they are.

Figure E1. Air Staging in the Burner and the Furnace

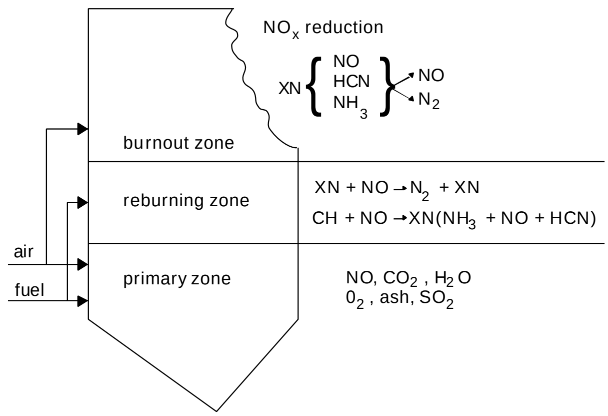


Source: Anna-Karin Hjalmarsson, *NO_x Control Technologies for Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 24.

Flue gas recirculation is another combustion NO_x control technique in which some of the flue gas is diverted back to the combustion zone. This dilutes the amount of oxygen available in the combustion zone, since the flue gas has been oxygen-depleted during the

[110]Anna-Karin Hjalmarsson, *NO_x Control Technologies For Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 15.

Figure E2. Principle of Fuel Staging (Reburning) in a Furnace



Source: Anna-Karin Hjalmarsson, *NO_x Control Technologies for Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 26.

combustion process, allowing less oxygen to be available for NO_x formation.

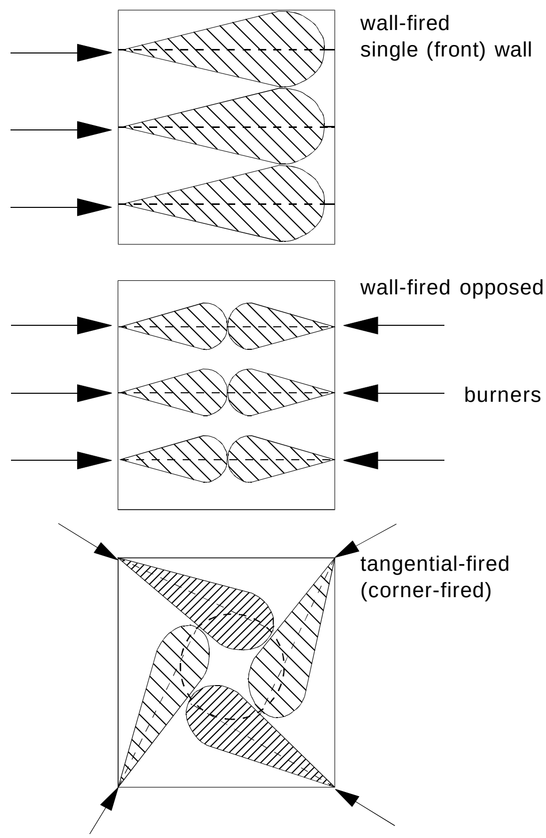
Costs For Retrofitting Low-NO_x Burners

The cost analysis provided in this section for retrofitted low-NO_x burners is obtained from two sources summarizing low-NO_x technology cost modeling efforts by the Department of Energy Clean Coal Technology program and the Environmental Protection Agency (EPA).[111] In each case, the only significant costs for low-NO_x burner retrofits are the capital costs. Operations and maintenance costs for low-NO_x burners are assumed to be the same as for regular burners.

These sources evaluate costs for the two types of boilers covered in Phase I of the CAAA90. These are dry-bottom wall-fired boilers, and dry-bottom tangentially-fired boilers. 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. Wall-fired boilers have burners facing 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 (Figure E3).

Model results for two different technologies for each boiler type show cost estimates for a 300-megawatt unit, which is in the approximate average size of Phase I units (Table E2). The two technologies applicable to wall-fired boilers are low-NO_x burners and low-NO_x burners with over fire air from a separate wind box. A wind box is the device in a boiler which distributes air to the air ports where it is injected into the combustion

Figure E3. Options for Burner Placement



Source: Anna-Karin Hjalmarsson, *NO_x Control Technologies for Coal Combustion*, IEACR/24 (London: IEA Coal Research, June 1990), p. 29.

[111]Radian Corporation, "Analysis of Low-NO_x Burner Technology Costs," draft report to the U.S. Environmental Protection Agency (November 1992), pp. 6-1 through 6-7.

Table E2. Comparison of Low-NO_x Burner Retrofit Cost Estimates for a 300-Megawatt Unit

Technology	Capital Cost (1992 Dollars per Kilowatt)		Average Cost (1992 Dollars per Kilowatt)
	Department of Energy Clean Coal Technology	Environmental Protection Agency	
Wall-fired:			
Low-NO_x Burner	19.0	22.9	--
Low-NO_x Burners plus Over Fire Air with a Separate Wind Box	26.0	28.0	--
Average	22.5	25.5	24.0
Tangentially-fired:			
Low-NO_x Concentric Firing System with Closely Coupled Over Fire Air	5.0	NA	--
Low-NO_x Concentric Firing System with Both Closely and Loosely Coupled Over Fire Air	23.0	20.9	--
Average	14.0	20.9	17.5

NA = Not available.
Source: Radian Corporation, "Analysis of Low-NO_x Burner Technology Costs," unpublished draft report to the U.S. Environmental Protection Agency (Research Triangle Park, NC, November 1992), p. 6-7.

A view from inside the boiler shows a low-NO_x burner being installed on Hammond unit 4.

chamber. The two technologies shown for tangentially-fired boilers are both low-NO_x concentric firing systems. The first type of system has closely spaced over fire air ports, while the second adds air ports spaced further from the burner unit.

The average capital cost for retrofitting low nitrogen oxide burners onto a wall-fired boiler is $24.0 per kilowatt (1992 dollars), whereas for tangentially-fired boilers, this cost is $17.5 per kilowatt. There are 95 tangentially fired units and 89 dry-bottom wall-fired units in Phase I.[112]

[112]*Federal Register*, Vol. 57, No. 228 (November 25, 1992), pp. 55679-55682.

Appendix F

Continuous Emission Monitoring

Appendix F

Continuous Emission Monitoring

The Clean Air Act Amendments of 1990 (CAAA90) require the installation of continuous emission monitors (CEMs) on the smokestacks of most Phase I and Phase II affected units. CEMs are devices which approximate a continuous measurement of certain characteristics of a gas by making separate measurements very frequently.[113] CEMs sample the exhaust or flue gas being emitted into the atmosphere from the burners / boiler of generating units fired by fossil fuels (coal, gas, or oil). Characteristics of the flue gas are recorded to allow calculations of the amount of pollutants being emitted into the atmosphere from the generating unit. CEM equipment technologies and configurations, particularly those that are retrofit, vary widely and are site-specific. The deadline for Phase I affected units to have operating CEMs is November 1993 and the deadline for Phase II units is January 1995. This appendix describes how the most popular CEMs work and their costs.

Technologies

CEM measurements can be based on any of several available technologies, each based on different physical processes depending upon the gas property of interest (Table F1). The constituents to which they can be applied include those specified by CAAA90 (Table F2).

CEM equipment is available in two broad types, extractive and *in situ* (Figures F1 and F2). Extractive systems draw exhaust gas away from the combustion system to the measurement equipment through special ducts. *In situ* systems make measurements directly in the flue or exhaust pipe. These two CEM technology types differ significantly not only in their configurations but in their costs.

Table F1. Continuous Emission Monitoring Technologies

Technology	Operating Characteristics
Infrared Radiation (IR)	An infrared beam passes through a measurement filter and is absorbed by the constituent gas. A light detector creates a signal which is used to monitor concentrations.
Ultraviolet Absorption (UV)	A split beam measures the difference in light beam absorption between a reference gas and the sample gas.
Chemiluminescence	Ozone (O_3) is injected into the sample to react with NO_x, generating light that is measured by a photocell.
Flame Ionization Detection	Hydrocarbons are ionized with strong light. The signals are received by a flame ionization detector.
Transmissometer	Light is passed through the stack, where it is reflected by a mirror on the opposite side. The quantity of light returning is proportional to particulate matter and aerosols in the flue gas.
Electrochemical Cells	The voltage measured when an oxygen (O_2) sample is injected into a solution with a strong base is compared to a reference voltage.
Chromatography	A sample, zero, and calibration gas are passed through a column where, due to chemical and physical considerations, constituents may be separately measured by such things as flame photometric or thermal conductivity detectors.

Source: Steven C. Stultz and John B. Kitto, eds., *Steam, Its Generation and Use*, 40th ed. (Barberton, OH: Babcock and Wilcox Co., 1992), p. 36-4.

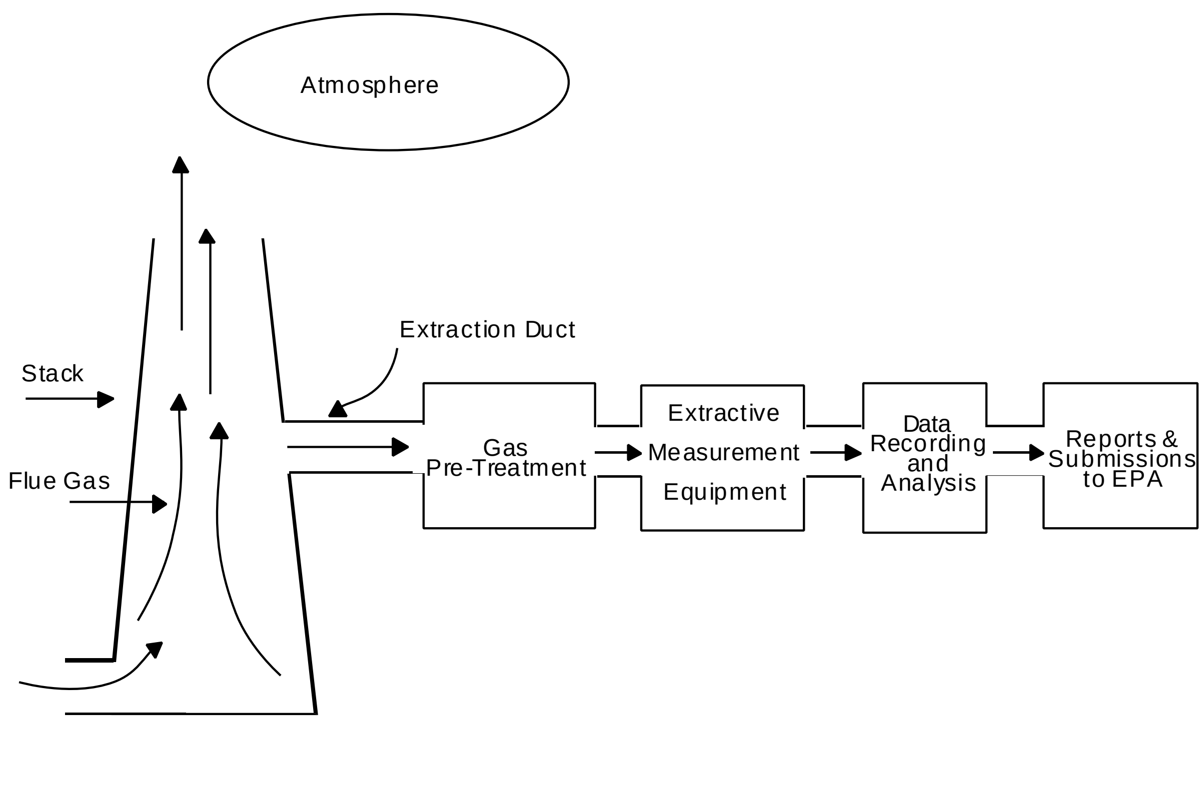
[113]For compliance with CAAA90, the measurements must be taken at least every 15 minutes.

Table F2. Continuous Emission Monitoring Measurement Techniques by Gas Constituent

Constituent	CEM Measurement Technologies
Particulate Matter (Opacity)	Transmissometer, beta ray absorption
Sulfur Dioxide (SO_2)	UV absorption, IR pulsed fluorescence
Nitrogen Oxides (NO_x)	Chemiluminescence, UV spectroscopy, IR
Hydrogen Chloride (Hcl)	IR with gas filter
Carbon Monoxide (CO)	IR
Carbon Dioxide (CO_2)	IR
Oxygen (O_2)	Electrochemical cell
Volatile Organic Compounds (VOC)	Flame ionization detection
Other Organic Air Toxics	Chromatography
Ammonia (NH_3)	Same as NO_x[a]

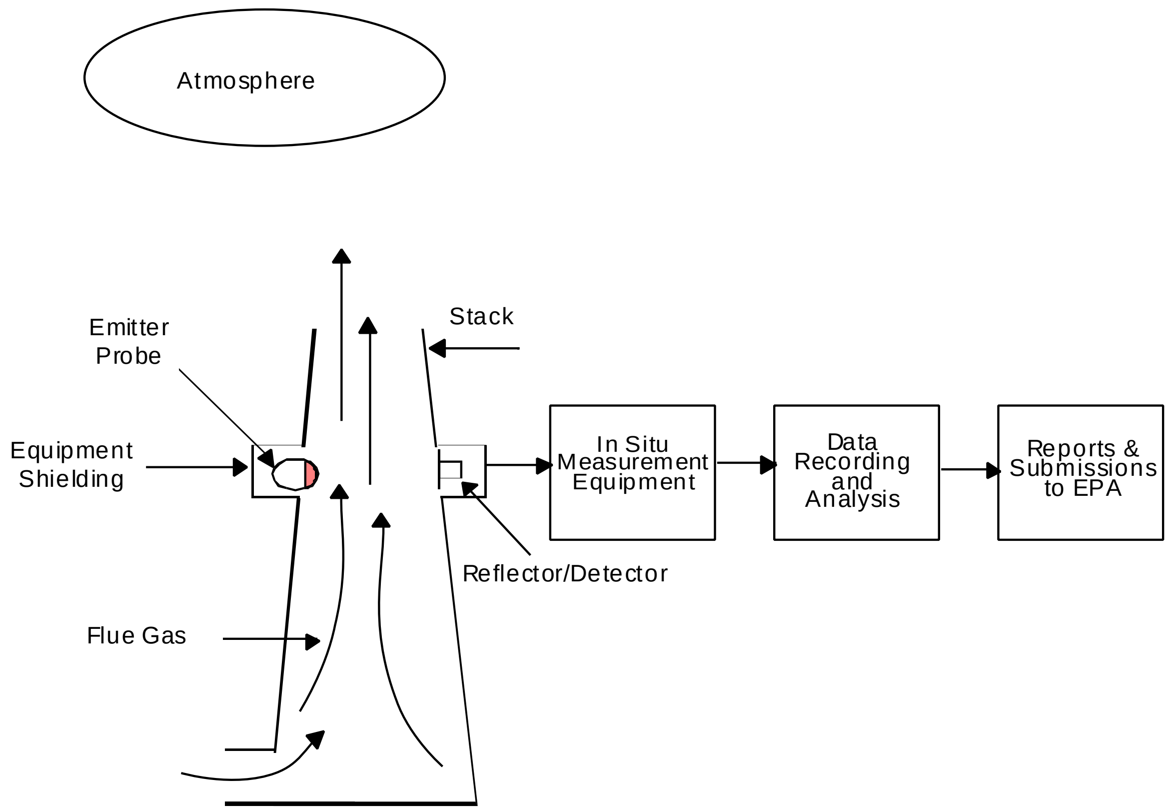
[a]NH_3 is converted to NO_x in one of two split streams. Both are analyzed for NO_x. NH_3 is determined as the difference.
CEM=Continuous emission monitoring.
IR=Infrared radiation.
UV=Ultraviolet absorption.
Source: Steven C. Stultz and John B. Kitto, eds., *Steam, Its Generation and Use*, 40th ed. (Barberton, OH: Babcock and Wilcox Co., 1992), p. 36-5.

Figure F1. Conceptual Extractive Continuous Emission Monitoring System Design



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Figure F2. Conceptual In Situ Continuous Emission Monitoring System Design



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Extractive CEM systems were the first to be developed. In early designs, ambient air measurement devices were modified to be used for combustion exhaust measurements.[114] Many times these devices could not tolerate the extreme conditions imposed by combustion exhausts, and therefore required pretreatment of the gases to make them more amenable to the measurement equipment; some modern extractive designs still need pretreatment. Examples of pretreatment include moisture removal to decrease the corrosiveness of the gas and dilution with other known gases to decrease the concentration of pollutants present.

As the design of extractive CEMs improved, techniques to handle exhaust gas in its original form were developed. These fully extractive systems do not need gas pretreatment equipment and are less costly. However, fully extractive systems do fall victim to some of the maintenance problems inherent in all extractive systems due to prolonged contact between equipment and exhaust gas. This drawback is mitigated by installing heating elements around the extraction lines to keep the exhaust gas above the temperature at which water vapor will condense. Condensation on equipment surfaces tends to increase the corrosiveness of the gas on those surfaces.

In situ CEM designs have become a popular alternative to extractive systems because of their lower equipment costs. These systems operate by emitting electromagnetic radiation (usually infrared light) or sound waves into the exhaust gas stream from a probe located

[114]Electric Power Research Institute, *Clean Air Act Response: Continuous Emissions Workshop*, EPRI TR-100510 Project 1961 (Palo Alto, CA, 1992), p. 5-8.

in the stack or exhaust pipe. In some systems there is a detector on the opposite side of the pipe which records the signal. In other systems, called multi-pass systems, there are reflecting devices which pass the signal back and forth across the pipe two or more times before it is recorded by a detector. In either case the pollutant concentrations can be calculated from the absorption of the signal by the gas. In one of the more recent *in situ* designs based on Fourier transform infrared spectroscopy, measurements of several pollutants can be made simultaneously. However, water vapor can interfere with this measurement technique. The extent of this interference and its effect upon the measurements are not well known.[115] Simultaneous measurement is a great cost advantage since one set of equipment will meet most or all of the requirements for pollution monitoring.

The relative merits of these two types of CEM systems are highly dependent upon the design specifications of the plant into which they are being installed. For instance, *in situ* equipment must be protected by special sheds or shielding if the environment around the plant is particularly hostile. In such cases, an extractive design, where only the sampling lines are exposed, can offer a less expensive alternative. Also, early *in situ* systems were subject to controversy concerning their calibration method, resulting in concern that they would not be able to pass the Environmental Protection Agency (EPA) standards tests. Later designs have allowed for easier calibration. Nonetheless, extractive systems require more periodic maintenance of filters and other similar equipment than do *in situ* systems.

Retrofit CEM Capital Costs, First Costs, and Operations and Maintenance Costs

The inherent uniqueness of retrofit CEM implementations makes retrofit CEM costing analysis a complex undertaking. In fact, most reports on the subject give only general cost characteristics for typical CEM designs. To comply with the CAAA90, systems must monitor levels of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and diluent gases (i.e., oxygen or carbon dioxide (CO_2), used in extractive systems to dilute the flue gases), as well as monitoring volumetric flow and opacity (Table F3). Volumetric flow is a measure of the volume of gas emitted from a unit in a specified time period. It is used in the calculation for percentages of other pollutants. Opacity is a measure of particulate matter being emitted from the unit, and is expressed as a percentage, this number being the proportion of incident light which passes through the gas. Most constituent measurements also require computer equipment for data handling and analysis. In addition, affected units must either monitor or estimate CO_2 emissions.

Table F3. Continuous Emission Monitoring Components Required for Acid Rain Regulations

Monitoring Requirement (Units Required)	Required Component					
	SO_2	NO_x	Flow	Opacity	Diluent Gas	Data Handling
Sulfur Dioxide (Pounds per Hour)	Yes	--	Yes	--	--	Yes
Nitrogen Oxide (Pounds per million Btu)[a]	--	Yes	--	--	Yes	Yes
Opacity (Percent)	--	--	--	Yes	--	Yes
Carbon Dioxide (Pounds per Hour)[b]	--	--	Yes	--	Yes	Yes

[a]A measured heat input rate in million Btu per hour would be multiplied by this nitrogen oxide (NO_x) continuous emission monitoring measurement in pounds per million Btu to obtain a NO_x emission rate in pounds per hour.
[b]Alternative methods may be used to monitor carbon dioxide (CO_2) (e.g. fuel analysis where constituent weights are used to calculate probable CO_2 emissions).
SO_2 = Sulfur dioxide.
NO_x = Nitrogen dioxide.
Source: U.S. Environmental Protection Agency, "Acid Rain Program Continuous Emission Monitoring," EPA430/F-92/021 (Washington, DC, December 1992), p. 2.

[115]Electric Power Research Institute, *Clean Air Act Response: Continuous Emissions Monitoring Workshop* (Palo Alto, CA, May 1992), pp. 12-1,2.

Generally, CEM costs can be categorized into capital costs and operations and maintenance (O&M) costs. Capital costs are the costs accrued to get the CEM system running for the first time, and include equipment, engineering, planning, installation, testing, and certification costs. The CAAA90 requires several certification tests for initial approval of a CEM system. O&M costs include all operation and maintenance costs. Included in this category are costs for periodic recertification pursuant to the CAAA90 regulations.[116] These cost categories were used in a 1991 CEM cost analysis model developed for EPA.[117] This model separately estimates costs of extractive and *in situ* systems. The following cost figures are based on this model as well as conversations with CEM vendors who offered cost data on the equipment they sell.

Several runs of the model were made using both types of systems designed to comply with the CAAA90 to estimate typical CEM costs. Equipment cost (cost of CEM hardware only, without other installation costs) estimates from the model for *in situ* systems were found to be roughly half those for extractive systems, with extractive equipment costs ranging from $300,000 to $410,000 (1992 dollars). The gas pretreatment and rerouting in extractive systems require extra equipment, increasing the equipment cost of these systems. Most vendors contacted offer extractive systems with equipment costs ranging from over $200,000 to over $600,000. Vendors offer most *in situ* systems for under $100,000 in equipment costs. A recent study cites average CEM equipment costs for both types of systems of $300,000.[118] Because extractive systems have been in use for a longer period of time and because their calibration procedures to meet EPA requirements are more easily met, this report assumes that most CEM systems will be extractive systems and that the average equipment costs for CEM systems are $500,000.

Continuous emission monitors consist of various components, including devices on the stacks (top) as well as computer equipment located inside the plant (bottom).

The EPA model results in the ratio of capital costs to equipment costs of 1:1.7.[119] It also finds that annual O&M costs, which include the cost of CAAA90

[116]Initial certification includes a 7-day calibration test, a linearity check for each pollutant monitor, a relative accuracy test (RATA) for each monitor, a bias test for each pollutant concentration and flow monitor, and a cycle time/response test for each pollutant concentration monitor. Periodic CEM testing requirements in CAAA90 include daily calibration error tests, daily interference tests for flow monitors, and semi-annual or annual RATA and bias tests. U.S. Environmental Protection Agency, "Continuous Emission Monitoring (CEM)," EPA430/F-92/021 (Washington, DC, December 1992), p. 4.

[117]Entropy Environmentalists, Inc., "Model for Estimates of CEMs and Annual O&M Costs for New and Existing Facilities," report to the U. S. Environmental Protection Agency (March 1991), p. 1.

[118]W.P. Coffey, J.C. Miller, Sr., M.A. Jones, H.S. Sawhney, "Upgrading Continuous Emissions Monitoring (CEM) Systems for Utility Units," paper presented at the Power-Gen '92 Conference (Orlando, FL, November 18, 1992).

[119]The previous study suggests that average capital costs of CEM systems are twice the equipment cost. W.P. Coffey, J.C. Miller, Sr., M.A. Jones, H.S. Sawhney, "Upgrading Continuous Emissions Monitoring (CEM) Systems for Utility Units," paper presented at the Power-Gen '92 Conference (Orlando, FL, November 18, 1992).

compliance, range from 40 to 50 percent of the total capital costs.[120]

Summary

The average capital cost of a CEM system is estimated at $850,000 of which the equipment cost is $500,000. The average annual operations and maintenance costs for a CEM system is estimated at $425,000. While CEM technology applications are relatively new, the lifetime of such equipment is not well known. They probably will have lifetimes shorter than most other plant components. There are approximately 170 stacks on the 263 units affected in Phase I.[121] Sometimes two or more units are connected to the same stack, which may necessitate a lesser or greater number of CEMs than units, depending on the configuration of ducts from the boilers to the stacks.

[120]Entropy Environmentalists, Inc., "Program Users Manual for Estimates of CEMs and Annual O&M Costs for New and Existing Combustion Facilities," report to the U.S. Environmental Protection Agency, (Research Triangle Park, NC, March 1991), p. 8-9; this report assumes 50 percent. Most vendors contacted offered annual maintenance contracts for their systems at about 5 percent of its capital costs. This figure includes only maintenance to the CEM hardware equipment provided by the vendor, not the other O&M costs for CAAA90 compliance.

[121]Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report" (1991), and verbal communications with various utilities owning Phase I affected units.

Appendix G

Selection Process and Data Collection for Individual Utility Compliance Costs and Effects for CAAA90 Phase I

Appendix G

Selection Process and Data Collection for Individual Utility Compliance Costs and Effects for CAAA90 Phase I

Selection Process

Six utilities were chosen for detailed investigation. Several characteristics were considered in choosing these utilities: generating capacity, coal consumption, sulfur dioxide (SO_2) emissions, location, and initial compliance strategy. The availability of information from the utility was crucial for inclusion. The intent of this sample is to provide information on compliance costs for several different types of compliance strategies and their effects on electricity generation and electricity prices. This appendix includes cost estimates for Phase I of the Clean Air Act Amendments of 1990 from the selected utilities by unit (Tables G1 and G2).

The six utilities chosen were Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas and Electric.

Data Collection

In general, the data collection involved contacting the individual utilities to confirm their strategy for compliance with Phase I and obtaining cost estimates from the utility for their compliance strategy. Unit data was aggregated to utility level for Chapter 4. After these estimates were received, the results were compiled and provided to the utilities, which were asked for any comments.

Georgia Power's Bowen facility has the largest Phase I affected capacity at 3,499 megawatts.

Table G1. Characteristics of Selected Phase I Affected Units by Utility

Unit	Plant	Owning Utility[a]	State[b]	Year On-line	Affected Nameplate Capacity[c] (megawatts)	Allowances[d] (per year)	1985 SO_2 Emissions (tons)	Difference Between Base Emissions & Allotment	Total Phase I Extension Allowances[e]	No. of Unit Low-NO_x Burners[f]	Number of CEMs[f]	Compliance Strategy
1	Baldwin	Illinois Power[g]	IL	1970	623	46,052	87,333	41,281	--	0	1.0	Allowances
2	Baldwin	Illinois Power[g]	IL	1973	635	48,695	92,715	44,020	--	0	1.0	Allowances
3	Baldwin	Illinois Power[g]	IL	1975	635	46,664	88,825	42,161	0	1	1.0	Allowances
2	Hennepin	Illinois Power[g]	IL	1959	231	20,182	38,635	18,453	0	0	3.0	Allowances
2	Vermilion	Illinois Power[g]	IL	1956	109	9,735	17,076	7,341	--	1	3.0	Allowances
1	Brunner Island	Pennsylvania P&L	PA	1961	363	27,030	32,078	5,048	--	1	0.5	Fuel Switch
2	Brunner Island	Pennsylvania P&L	PA	1965	405	30,282	34,103	3,821	3,426	1	0.5	Fuel Switch
3	Brunner Island	Pennsylvania P&L	PA	1968	790	52,404	58,775	6,371	16,334	1	1.0	Fuel Switch
1	Martins Creek	Pennsylvania P&L	PA	1954	156	12,327	14,627	2,300	--	1	1.0	Fuel Switch
2	Martins Creek	Pennsylvania P&L	PA	1956	156	12,483	14,131	1,648	--	1	1.0	Fuel Switch
3	Sunbury	Pennsylvania P&L	PA	1951	104	8,530	10,046	1,516	486	1	0.5	Fuel Switch
4	Sunbury	Pennsylvania P&L	PA	1953	156	11,149	14,077	2,928	8,140	1	0.5	Fuel Switch
1	Conemaugh*	Pennsylvania P&L	PA	1970	107	6,631	10,489	3,858	16,598	0.1	0.1	Scrub
2	Conemaugh*	Pennsylvania P&L	PA	1971	107	7,639	10,229	2,859	13,916	0.1	0.1	Scrub
ST1	Chalk Point	Potomac Elec. Power	MD	1964	364	21,333	20,258	-1,075	8,140	1	0.5	Fuel Switch
ST2	Chalk Point	Potomac Elec. Power	MD	1965	364	23,690	27,482	3,792	0	1	0.5	Fuel Switch
ST1	Morgantown	Potomac Elec. Power	MD	1970	626	34,332	29,388	-4,944	11,064	1	1.0	Fuel Switch
ST2	Morgantown	Potomac Elec. Power	MD	1971	626	37,467	37,988	521	16,250	1	1.0	Fuel Switch
1	Conemaugh*	Potomac Elec. Power	PA	1970	91	5,659	8,951	3,292	14,165	0.1	0.1	Scrub
2	Conemaugh*	Potomac Elec. Power	PA	1971	91	6,289	8,729	2,440	11,876	0.1	0.1	Scrub
5[h]	Miami Fort	Cincinnati G&E	OH	1949	100	834	262	-572	--	0	0.5	Fuel Switch
6	Miami Fort	Cincinnati G&E	OH	1960	163	12,475	21,111	8,636	--	0	0.5	Fuel Switch
7	Miami Fort*	Cincinnati G&E	OH	1975	357	27,018	39,972	12,954	--	0	0.6	Fuel Switch
5	Beckjord	Cincinnati G&E	OH	1962	245	9,811	12,735	2,924	--	1	1.0	Fuel Switch
6	Beckjord*	Cincinnati G&E	OH	1969	173	9,463	14,678	5,214	--	0.4	0.4	Fuel Switch
4	Conesville*	Cincinnati G&E	OH	1973	337	21,385	39,302	17,917	--	0	0.4	Allowance
1	Bowen	Georgia Power	GA	1971	806	54,838	71,428	16,590	--	1	1.0	Fuel Switch
2	Bowen	Georgia Power	GA	1972	789	53,329	63,727	10,398	--	1	1.0	Fuel Switch
3	Bowen	Georgia Power	GA	1974	952	69,862	82,488	12,626	--	1	1.0	Fuel Switch
4	Bowen	Georgia Power	GA	1975	952	69,852	87,659	17,807	--	1	1.0	Fuel Switch
1	Hammond	Georgia Power	GA	1954	125	8,549	9,830	1,281	--	0	0.5	Fuel Switch
2	Hammond	Georgia Power	GA	1954	125	8,977	9,997	1,020	--	0	0.5	Fuel Switch
3	Hammond	Georgia Power	GA	1955	125	8,676	9,068	392	--	0	0.5	Fuel Switch
4	Hammond	Georgia Power	GA	1970	578	36,650	35,539	-1,111	--	1	0.5	Fuel Switch
1	McDonough	Georgia Power	GA	1963	299	19,386	32,738	13,352	27,391	1	0.5	Fuel Switch
2	McDonough	Georgia Power	GA	1964	299	20,058	33,749	13,691	--	1	0.5	Fuel Switch
1	Wansley*	Georgia Power	GA	1976	509	36,866	68,750	31,884	--	0.5	0.5	Fuel Switch
2	Wansley*	Georgia Power	GA	1978	509	34,084	64,278	30,194	53,600	0.5	0.5	Fuel Switch

See footnotes at end of table.

Table G1. Characteristics of Selected Phase I Affected Units by Utility (Continued)

Unit	Plant	Owning Utility[a]	State[b]	Year On-line	Affected Nameplate Capacity[c] (megawatts)	Allowances[d] (per year)	1985 SO_2 Emissions (tons)	Difference Between Base Emissions & Allotment	Total Phase I Extension Allowances[e]	No. of Unit Low-NO_x Burners[f]	Number of CEMs[f]	Compliance Strategy
1	Yates[i]	Georgia Power	GA	1950	123	7,020	11,673	4,653	9,225	0	0.7	Scrub
2	Yates	Georgia Power	GA	1950	123	6,855	11,199	4,344	--	0	0.7	Fuel Switch
3	Yates	Georgia Power	GA	1952	123	6,767	11,279	4,512	--	0	0.7	Fuel Switch
4	Yates	Georgia Power	GA	1957	156	8,676	13,758	5,082	--	1	0.7	Fuel Switch
5	Yates	Georgia Power	GA	1958	156	9,162	15,754	6,592	--	1	0.7	Fuel Switch
6	Yates	Georgia Power	GA	1974	404	24,108	42,207	18,099	9,236	1	0.7	Fuel Switch
7	Yates	Georgia Power	GA	1974	404	20,915	23,974	3,059	2,806	1	0.7	Fuel Switch
1	Gaston*	Georgia Power	AL	1960	136	8,812	11,110	2,298	--	1	1.0	Fuel Switch
2	Gaston*	Georgia Power	AL	1960	136	9,026	10,931	1,905	--	1	1.0	Fuel Switch
3	Gaston*	Georgia Power	AL	1961	136	8,914	11,685	2,771	--	1	1.0	Fuel Switch
ST4	Gaston*	Georgia Power	AL	1962	122	9,387	11,743	2,356	--	1	1.0	Fuel Switch
2	Culley[j]	Southern Indiana G&E	IN	1966	104	4,703	16,361	11,658	0	1	1.0	Scrub
3	Culley[j]	Southern Indiana G&E	IN	1973	265	18,603	38,456	19,853	0	1	1.0	Scrub
4	Warrick*	Southern Indiana G&E	IN	1970	162	14,789	29,407	14,618	0	0	0.5	Allowances

[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]State codes are postal codes.

[c]Affected capacity at each unit is only that share owned by indicated utility.

[d]One SO_2 allowance permits one ton of SO_2 emissions.

[e]Phase I extension allowances were awarded to (1) control units that install a technology that removes 90 percent or more of their SO_2 emissions or (2) control units and other units that use a different compliance strategy but are associated with the control unit in the extension allowance application. Extension allowances were awarded for 1995 through 1999.

[f]Number of units retrofitted with low-NO_x burners and number of CEMs may be fractional because of partial unit ownership by utility. Also, number of CEMs may not equal number of units because of boiler exhaust duct and stack configuration.

[g]Illinois Power is also a part owner of Joppa Steam, an affected Phase I plant. Because Joppa Steam is not included in Illinois Power's ratebase, it is not included here.

[h]Miami Fort 5 has two boilers.

[i]Includes only one-half of scrubber capital costs. The other half is paid by the Department of Energy as a demonstration project.

[j]CEM operation and maintenance costs includes $30,000 of NO_x fuel costs.

SO_2 = Sulfur dioxide.

NO_x = Nitrogen oxides.

CEM = Continuous emission monitor.

* = Partially owned unit.

Note: All data are for the portion of the unit that is owned by the designated utility. Does not include substitution and compensating units.

Source: Based on information from Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric (November 1993 through March 1994).

Table G2. Costs and Effects of Phase I Compliance for Selected Affected Units by Utility

		SO_2 Control				CEMs							Average Annual		
Unit	Plant	Capital Costs (million dollars)	O&M Costs (million dollars)	Fuel Premium (million dollars)	**NO_x Control Capital Costs** (million dollars)	Capital Costs (million dollars)	O&M Costs (million dollars)	**Total Capital Costs** (million dollars)	**Annual Capital Costs** (million dollars)	**Annual O&M & Fuel Costs** (million dollars)	**Annual Total Costs** (million dollars)	**Average Capital Costs** (dollars per affected kilowatt)	Capital Costs (dollars per affected kilowatt)	O&M & Fuel Costs (dollars per affected kilowatt)	Total Costs (dollars per affected kilowatt)
1	Baldwin	0.0	8.3	0.0	0.0	1.4	0.1	1.4	0.1	8.4	8.5	2.3	0.2	13.4	13.6
2	Baldwin	0.0	8.8	0.0	0.0	1.3	0.1	1.3	0.1	8.9	9.0	2.1	0.1	14.0	14.2
3	Baldwin	0.0	8.4	0.0	7.8	1.1	0.1	8.9	0.6	8.5	9.1	14.1	0.9	13.4	14.4
2	Hennepin	0.0	3.7	0.0	1.6	4.1	0.3	5.7	0.4	4.0	4.4	24.7	1.6	17.3	18.9
2	Vermilion	0.0	1.5	0.0	4.1	1.9	0.3	6.0	0.4	1.8	2.2	55.1	3.7	16.3	19.9
1	Brunner Island	0.0	[a]	[b]	13.0	0.8	[a]	13.8	0.9	0.0	0.9	37.9	2.5	0.0	2.5
2	Brunner Island	3.0	[a]	[b]	15.0	0.8	[a]	18.8	1.3	0.0	1.3	46.3	3.1	0.0	3.1
3	Brunner Island	0.0	[a]	[b]	17.0	1.5	[a]	18.5	1.2	0.0	1.2	23.4	1.6	0.0	1.6
1	Martins Creek	2.0	[a]	[b]	6.0	0.8	[a]	8.8	0.6	0.0	0.6	56.4	3.8	0.0	3.8
2	Martins Creek	2.0	[a]	[b]	5.0	0.8	[a]	7.8	0.5	0.0	0.5	50.0	3.3	0.0	3.3
3	Sunbury	1.5	[a]	[a]	5.0	1.5	[a]	8.0	0.5	0.0	0.5	76.4	5.1	0.0	5.1
4	Sunbury	1.7	[a]	[a]	5.3	1.5	[a]	8.5	0.6	0.0	0.6	54.2	3.6	0.0	3.6
1	Conemaugh*	19.0	1.1	[b]	2.2	0.1	0.0	21.2	1.4	1.1	2.5	198.7	13.2	10.3	23.6
2	Conemaugh*	19.0	1.1	[b]	2.2	0.1	0.0	21.2	1.4	1.1	2.5	198.7	13.2	10.3	23.6
ST1	Chalk Point	15.0	[a]	0.0	25.3	1.6	[a]	41.9	2.8	0.0	2.8	115.0	7.7	0.0	7.7
ST2	Chalk Point	15.0	[a]	0.0	25.3	1.6	[a]	41.9	2.8	0.0	2.8	115.0	7.7	0.0	7.7
ST1	Morgantown	0.0	[a]	0.0	47.2	3.1	[a]	50.3	3.4	0.0	3.4	80.4	5.4	0.0	5.4
ST2	Morgantown	0.0	[a]	0.0	47.2	3.1	[a]	50.3	3.4	0.0	3.4	80.4	5.4	0.0	5.4
1	Conemaugh*	16.2	0.9	0.0	2.0	0.1	0.0	18.3	1.2	0.9	2.1	201.0	13.4	9.6	22.9
2	Conemaugh*	16.2	0.9	0.0	2.0	0.1	0.0	18.3	1.2	0.9	2.1	201.0	13.4	9.6	22.9
5	Miami Fort	1.4	[a]	0.5	0.0	0.4	[a]	1.8	0.1	0.5	0.6	18.0	1.2	5.1	6.3
6	Miami Fort	2.2	[a]	0.8	0.0	0.4	[a]	2.7	0.2	0.8	1.0	16.3	1.1	5.1	6.1
7	Miami Fort*	4.9	[a]	1.8	0.0	0.5	[a]	5.4	0.4	1.8	2.2	15.2	1.0	5.1	6.1
5	Beckjord	5.3	[a]	1.2	4.7	0.7	[a]	10.7	0.7	1.2	2.0	43.6	2.9	5.1	8.0
6	Beckjord*	3.7	[a]	0.9	3.4	0.2	[a]	7.3	0.5	0.9	1.4	42.4	2.8	5.1	7.9
4	Conesville*	0.0	3.6	0.0	0.0	0.5	[a]	0.5	0.0	3.6	3.6	1.4	0.1	10.6	10.7
1	Bowen	3.3	0.0	0.0	11.7	1.3	[a]	16.4	1.1	0.0	1.1	20.3	1.4	0.0	1.4
2	Bowen	3.2	0.0	0.0	11.5	1.3	[a]	16.1	1.1	0.0	1.1	20.4	1.4	0.0	1.4
3	Bowen	3.9	0.0	0.0	13.8	1.3	[a]	19.1	1.3	0.0	1.3	20.1	1.3	0.0	1.3
4	Bowen	3.9	0.0	0.0	13.8	1.3	[a]	19.1	1.3	0.0	1.3	20.1	1.3	0.0	1.3
1	Hammond	1.7	0.0	0.0	7.5	0.5	[a]	9.7	0.6	0.0	0.6	77.5	5.2	0.0	5.2
2	Hammond	1.7	0.0	0.0	7.5	0.5	[a]	9.7	0.6	0.0	0.6	77.5	5.2	0.0	5.2
3	Hammond	1.7	0.0	0.0	7.5	0.5	[a]	9.7	0.6	0.0	0.6	77.5	5.2	0.0	5.2
4	Hammond	7.7	0.0	0.0	34.9	0.5	[a]	43.1	2.9	0.0	2.9	74.5	5.0	0.0	5.0
1	McDonough	2.7	0.0	0.0	7.7	0.9	[a]	11.2	0.7	0.0	0.7	37.4	2.5	0.0	2.5
2	McDonough	2.7	0.0	0.0	7.7	0.9	[a]	11.2	0.7	0.0	0.7	37.4	2.5	0.0	2.5

See footnotes at end of table.

Table G2. Costs and Effects of Phase I Compliance for Selected Affected Units by Utility (Continued)

Unit	Plant	SO_2 Control: Capital Costs (million dollars)	SO_2 Control: O&M Costs (million dollars)	SO_2 Control: Fuel Premium (million dollars)	**NO_x Control Capital Costs** (million dollars)	CEMs: Capital Costs (million dollars)	CEMs: O&M Costs (million dollars)	**Total Capital Costs** (million dollars)	**Annual Capital Costs** (million dollars)	**Annual O&M & Fuel Costs** (million dollars)	**Annual Total Costs** (million dollars)	**Average Capital Costs** (dollars per affected kilowatt)	Average Annual: Capital Costs (dollars per affected kilowatt)	Average Annual: O&M & Fuel Costs (dollars per affected kilowatt)	Average Annual: Total Costs (dollars per affected kilowatt)
1	Wansley*	4.3	0.0	0.0	9.7	1.1	[a]	15.1	1.0	0.0	1.0	29.6	2.0	0.0	2.0
2	Wansley*	4.3	0.0	0.0	9.7	1.1	[a]	15.1	1.0	0.0	1.0	29.6	2.0	0.0	2.0
1	Yates[c]	17.0	1.8	0.7	1.6	0.6	[a]	19.3	1.3	2.5	3.8	157.4	10.5	20.7	31.2
2	Yates	1.8	0.0	0.0	1.6	0.6	[a]	4.1	0.3	0.0	0.3	33.5	2.2	0.0	2.2
3	Yates	1.8	0.0	0.0	1.6	0.6	[a]	4.1	0.3	0.0	0.3	33.5	2.2	0.0	2.2
4	Yates	2.3	0.0	0.0	2.1	0.6	[a]	5.1	0.3	0.0	0.3	32.4	2.2	0.0	2.2
5	Yates	2.3	0.0	0.0	2.1	0.6	[a]	5.1	0.3	0.0	0.3	32.4	2.2	0.0	2.2
6	Yates	6.0	0.0	0.0	5.4	0.6	[a]	12.1	0.8	0.0	0.8	29.9	2.0	0.0	2.0
7	Yates	6.0	0.0	0.0	5.4	0.6	[a]	12.1	0.8	0.0	0.8	29.9	2.0	0.0	2.0
1	Gaston*	0.0	0.0	0.0	1.9	0.1	[b]	2.0	0.1	0.0	0.1	14.9	1.0	0.0	1.0
2	Gaston*	0.0	0.0	0.0	2.9	0.1	[b]	3.0	0.2	0.0	0.2	21.8	1.5	0.0	1.5
3	Gaston*	0.0	0.0	0.0	6.5	0.1	[b]	6.6	0.4	0.0	0.4	48.6	3.2	0.0	3.2
ST4	Gaston*	0.0	0.0	0.0	3.5	0.1	[b]	3.6	0.2	0.0	0.2	29.1	1.9	0.0	1.9
2	Culley[d]	30.1	0.0	0.0	1.4	0.8	0.1	32.2	2.1	0.0	2.2	310.8	20.7	0.2	20.9
3	Culley[d]	76.9	-0.1	0.0	3.6	0.8	0.1	81.3	5.4	0.0	5.4	306.4	20.4	-0.1	20.3
4	Warrick*	0.0	1.4	0.0	0.0	1.3	0.0	1.3	0.1	1.5	1.6	8.0	0.5	9.2	9.7

[a]Cost not estimated by utility.
[b]Estimated to be negligible by utility.
[c]Includes only one-half of scrubber capital costs. The other half is paid by the Department of Energy as a demonstration project.
[d]CEM operations and maintenance costs include $30,000 of NO_x fuel costs.
SO_2 = Sulfur dioxide.
NO_x = Nitrogen oxides.
CEM = Continuous emission monitor.
O&M = Operations and maintenance.
* = Partially owned unit.

Notes: •These are contemporary estimates made by the individual utilities; most dollars are adjusted to 1993. •All data are for the portion of the unit that is owned by the designated utility. •Capital equipment is depreciated over 15 years. •The estimates underestimate the cost of compliance to the extent that no cost estimate has been made in some cases.

Source: Based on information from Illinois Power, Pennsylvania Power and Light, Potomac Electric Power, Cincinnati Gas and Electric, Georgia Power, and Southern Indiana Gas & Electric (November 1993 through March 1994).

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.

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.

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 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 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.

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 which 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 which 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: 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 as 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: Particule matter from coal ash in which the particle diameter is less that 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.

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.

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.