VIRGINIA CENTER FOR COAL
AND ENERGY RESEARCH

THE CLEAN AIR ACT ACID RAIN PROGRAM: IMPLICATIONS FOR VIRGINIA'S COAL PRODUCERS

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VCCER REPORT NO. 97-01

Virginia Tech
VIRGINIA POLYTECHNIC INSTITUTE
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REPORT NO. 97-01
May 1997

Virginia Tech Publication No.
VT/176/0597/100/973568

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EXECUTIVE SUMMARY

The Clean Air Act Amendments of 1990 (CAAA90) established a national program to control sulfur dioxide (SO_2) air emissions that contribute to acid rain formation. The program takes a market-based approach that includes trading and banking of emissions allowances. We have analyzed data describing electric utility compliance strategies for 1995, the program's first year. Results show that fuel switching and flue-gas desulfurization were the dominant means used by affected plants to achieve compliance. Over three million allowance credits (tons of SO_2 emissions) were banked by affected utilities in 1995, as emissions by the 261 original Phase I-affected units totaled 4.4 million tons. Projection of current trends to the year 1999, the conclusion of Phase I, indicate that 14 to 15 million allowance credits will have been banked by utilities for use during the program's Phase II, which will require stricter controls beginning in the year 2000. Factors contributing to the accumulation of a sizable allowance bank include increased use of western coal, falling prices for eastern low-sulfur coal and desulfurization equipment, and a presumed desire by utility planners to minimize financial risks inherent in CAAA90's more-stringent Phase II requirements. Cumulative consumption of allowances during the first decade of Phase II is forecast by EPA at less than 10 million tons.

The reduction of SO_2 emissions well beyond expectations, combined with falling prices for allowance credits, can be viewed as a success for market-based environmental controls. The implications for Virginia's low-sulfur coal producers, however, are more mixed. On one hand, the principal southeastern markets for low-sulfur Virginia coals have not experienced major inroads by low-sulfur western coal, or by installation of flue-gas desulfurization scrubbers that make high-sulfur coal purchases possible. On the other hand, central Appalachian coal price differentials based on sulfur contents have declined noticeably since initiation of CAAA90 Phase I in early 1995, and prospects for improved

pricing of low-sulfur coals appear poor. Under CAAA90, coal purchasers can link SO_2 emissions allowances with high-sulfur coals as a substitute for compliance-grade low-sulfur coals, such as those produced by many Virginia mines. Wide availability of allowance credits make it unlikely that Virginia coal producers will be able to increase the "price premiums" commanded by low-sulfur products any time soon. Scrubbers and low-price western coal sales effectively remove low-sulfur Appalachian producers from consideration as coal suppliers at a number of midwestern generating units, which has the effect of intensifying competition in the southeast. Electric utilities in states that are major purchasers of Virginia coal have been among the heaviest purchasers of allowances in the open markets.

INTRODUCTION

Economists have long argued that market-based, incentive approaches to pollution control would be less costly and more effective than the traditional, "command and control" regulatory approach. "Command and control" regulation is characterized by static emissions limits which do not take into account the costs of compliance by individual pollution sources. The U.S. Clean Air Act Amendments of 1990 (CAAA90) established a sulfur dioxide (SO_2) control program which aims to reduce acid rain while minimizing pollution control costs. Title IV of the CAAA90 established what has become known as the Acid Rain Program, which applies a flexible, market-based approach to achieve pollution abatement through the issuance of tradable SO_2 emissions permits (called "allowances").

Phase I of the CAAA90 program became operational in 1995. In this paper, we provide the results of an empirical assessment of electric utility compliance strategies during the program's first year of full implementation, and we analyze these results with respect to their implications for producers of Virginia coal.

METHODS

During the first phase of this study, we reviewed and analyzed available information on Phase I compliance practices by electric utilities during 1995. Items referenced during this study phase included Phase I compliance strategies declared by the owners of affected units (DOE, 1994), SO_2 emissions (EPA, 1996d) and fuel purchases (DOE, 1989-95; 1996a) by the affected units, SO_2 emission allowance trading data (EPA, 1996b), and other information distributed by EPA to describe the Acid Rain Program.

During the study's second phase, we used the results of our 1995 analysis as a basis for projecting allowance banking behavior during the remaining years of Phase I, and interpreted these results with reference to their implications for purchasers of Virginia coal.

REVIEW OF THE ACID RAIN PROGRAM

The Acid Rain Program, established by Title IV of the CAAA90, represents the largest-scale application of a marketable permit approach to pollution control in the United States. The goal of the Acid Rain Program is to reduce acid deposition by reducing SO_2 and NO_x emissions from electric power generation units. The centerpiece of the Acid Rain Program is its SO_2 control program. It aims to reduce annual electric utility SO_2 emissions by 10 million tons from the 1980 level (18.9 million tons) by the year 2010. The CAAA90 requires a two-phase tightening of the restrictions on SO_2 emissions placed on fossil fuel-fired power plants [Title IV, Sections 403 - 406].

Phase I of the Acid Rain Program began on January 1, 1995. The original legislation identified 261 electric generating units at 110 plants operated by electric utilities in 21 eastern and midwestern states. The original Phase I units are mostly coal-fired, generally older, and include the nation's highest SO_2 emitters. Phase I seeks to reduce SO_2 emissions at these plants to below 2.5 pounds SO_2 per million Btu of fuel input during the years 1995 to 1999. Phase II, which begins on January 1, 2000, will seek to reduce the rate of SO_2 emissions to below 1.2 pounds per million Btu at all fossil fuel-fired electric generating plants with a nameplate capacity of 25 megawatts or greater, and will apply a nationwide annual SO_2 emissions cap. Since 1990, all newly constructed generating units larger than 25 MW have been required to comply with the Phase II SO_2 emission rate.

EPA issued utilities limited authorizations to emit SO_2 in the form of "allowances"; each allowance is equivalent to one ton of SO_2 emissions. Each allowance has a "use year" attached to it, which identifies the first year in which the allowance can be used for compliance purposes. EPA has issued allowances for the years 1995 through 2025. At the end of each calendar year, a utility must hold allowances in an amount equal to or greater than its SO_2 emissions for that year. Utilities whose annual SO_2 emissions do not exceed their allotment of allowances may either sell their extra allowances or "bank" them for future use. However, allowances cannot be transferred "backwards"; for example, 1996 allowances cannot be used to cover 1995 emissions.

Utilities whose Phase I SO_2 emissions during a given year exceed held allowances must acquire additional allowances or face fines and emissions-offset requirements. Allowances may be bought, sold, or transferred between utilities and other interested parties. Those utilities whose annual SO_2 emissions are likely to exceed their allotment of allowances are able to choose from among several compliance options, such as installing pollution control technologies, switching to lower-sulfur fuels, or obtaining additional allowances on the open market.

The EPA tracks generating plant emissions through the use of Continuous Emission Monitoring systems (CEMs) which measure and record every ton of SO_2, NO_x, and CO_2 emitted. Utilities are required to record these measurements and report them to EPA.

EPA has developed the Emission Tracking System (ETS) database to monitor utility SO_2, NO_x, and CO_2 emissions over time (EPA, 1994; EPA, 1996d). EPA has also developed the Allowance Tracking System (ATS) database which tracks the allowances held by utilities and other affected organizations or individuals (EPA, 1994; EPA, 1996b). The ATS records the issuance of all allowances, the holdings of allowances in accounts, the holdings of allowances in EPA reserves, the annual deduction of allowances for compliance purposes, and any transfers of allowances between accounts.

At the end of each calendar year, utilities report the annual SO_2, NO_x, and CO_2 emissions from their Phase I units to EPA. Utilities are given the month of January to acquire additional allowances (if necessary) to cover any excess SO_2 emissions for the previous year. After the January 31 deadline, EPA deducts allowances from each unit's accounts in an amount that corresponds with that unit's SO_2 emissions for that year.

Electric utilities were chosen as the focus of the Acid Rain Program because, although utilities account for a relatively small proportion of the total number of SO_2 sources, they produce a relatively high proportion of total SO_2 emissions. Another factor which may have contributed to the focus on utilities is the fact that this industry is already heavily regulated (Rico, 1995).

The Acid Rain Program seeks to achieve environmental quality goals while providing regulated facilities with a great deal of flexibility in finding least-cost strategies to meet those goals. Mostaghel (1995) listed several other potential benefits of SO_2 allowance trading. In areas where compliance costs are high, the revenues from SO_2 allowance sales can help to offset costs; in areas that are witnessing high population and/or economic growth rates, allowances enable utilities to meet the increased demand for electricity while avoiding large investments into "cleaner" technologies. Also, since emissions reductions translate into tradable allowances, utilities have an incentive to control SO_2 emissions beyond minimum standards.

Experience to date has seen market prices for allowances decline dramatically, relative to prior expectations. Whereas EPA forecasts prepared in 1989 were based on presumed allowance prices of $1000 to $1500 1988-dollars per ton over the 2001 - 2010 period (Ellman et al., 1990), allowance prices in early 1996 were below 100 current-dollars per ton (Figure 1).

COMPLIANCE OPTIONS

Under Title IV of the CAAA90, Phase I-affected electric utilities can make choices between compliance strategies based on evaluations of comparative costs across their systems. To the extent that inter-utility trading is not restricted, utilities can compare their marginal costs of SO_2 reduction with the market price of allowances. Compliance will no longer be the sole concern of a utility's environmental division; increasingly, it will become the domain of financial officers, operating officers, and executive officers (Lock and Harkawik, 1991). Complying with SO_2 standards via a market-based system will require the integration of compliance decisions with every other aspect of utility planning, necessitating an inter-departmental, multi-disciplinary decision-making process. In other words, compliance planning cannot be performed "in a vacuum"; it must be performed

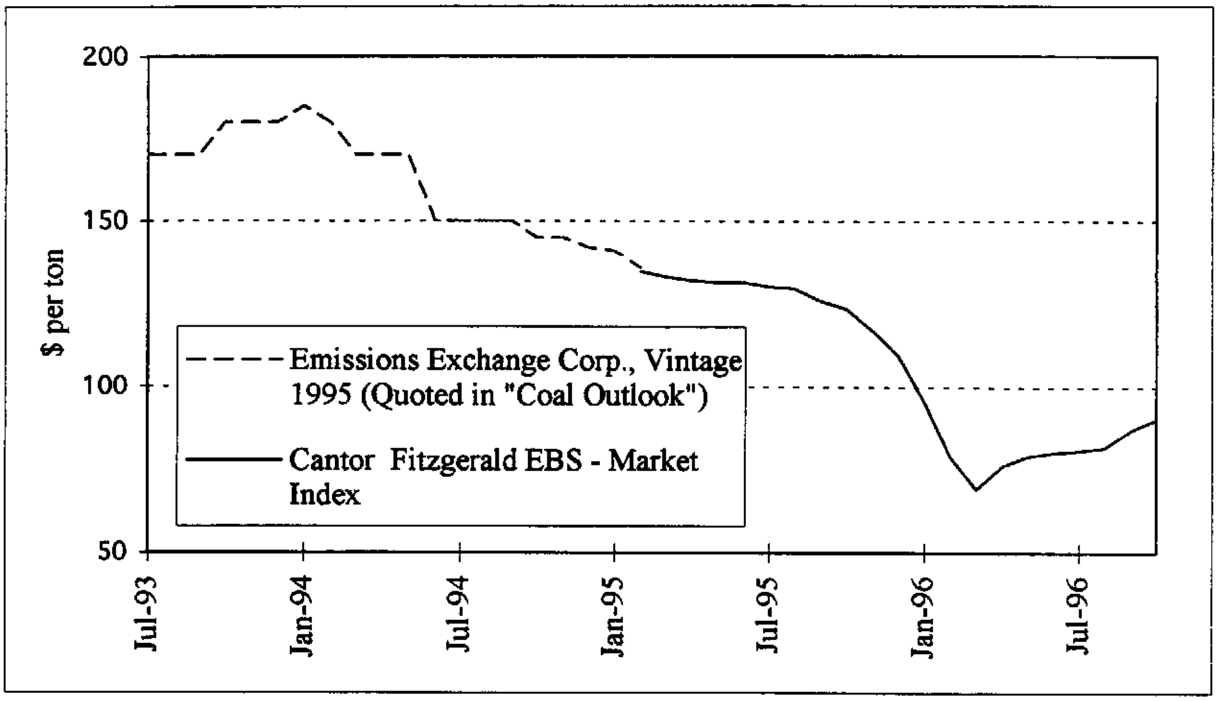

Figure 1. Sulfur dioxide emission allowance market prices, monthly averages.

within the context of more general utility objectives.

Utilities can choose between a variety of options to achieve compliance with Title IV. These basic compliance options (Table 1) are described below (DOE, 1994).

Fuel Switching/Blending

By far, the most popular compliance option for utilities has been fuel switching and/or blending. Fuel switching involves a change to either coal of a lower sulfur content or a low-sulfur fuel other than coal, typically natural gas. Fuel blending involves the blending of high- and low- sulfur coals to achieve SO_2 emissions reductions. Cofiring is another type of fuel blending which involves burning a combination of coal and another type of fuel (typically natural gas) in the boiler. Of the 261 original Phase I units, operators of 162 submitted plans to achieve compliance primarily by fuel switching or blending (including cofiring). Forty of those 162 units (mostly in Illinois, Indiana, and Pennsylvania) submitted plans to blend local high-sulfur coal with coals of lower sulfur content, while most of the other 122 units planned to switch entirely to low-sulfur coal.

Table 1. Sulfur dioxide emissions at 261 original Phase 1 generating units by compliance strategy, 1990 and 1995.

Compliance Strategy	Number of Units	Affected Nameplate Capacity (MW)	1990 SO_2 Emissions (tons)	1995 SO_2 Emissions (tons)	Emissions Reduction 1990-1995 (tons)
Fuel Switching/Blending	162	53,203	5,259,851	2,690,426	2,569,425
Obtaining Allowances	39	14,137	1,422,557	1,322,144	100,413
Installing FGD Equipment	27	14,101	1,630,753	264,270	1,366,483
Using Previous Controls	25	6,092	277,476	147,358	130,118
Retiring Facilities	7	1,342	32,895	0	32,895
Boiler Repowering	1	113	59,698	197	59,501
Total	261	88,988	8,683,230	4,424,395	4,258,835

Sources: DOE , 1994; EPA, 1995b; EPA, 1996d.

The fuel switching/blending option requires less capital investment than other compliance options. Hence, utilities opting for this strategy would maintain greater flexibility in developing future compliance strategies. Also, utilities were given little time to design compliance plans; roughly two years elapsed between the time that the CAAA90 was passed (November, 1990) and EPA's initial deadline for compliance-plan submission (February, 1993); some utilities chose the fuel switching/blending option because it could be implemented quickly. Choosing this strategy allowed utilities to achieve Phase I compliance while giving them time to evaluate the allowance market, and relative costs of Phase II compliance options, more thoroughly.

There are some considerations that are unique to the fuel switching/blending option. Power plants are usually designed to burn a certain type of coal; changes in the type of coal burned can affect plant performance. Eastern lower-sulfur coals (found primarily in southern West Virginia, southwestern Virginia, and eastern Kentucky) can generally be burned in boilers designed for high-sulfur coals from the east and midwest without major problems. The U.S. Department of Energy (DOE, 1994) estimates that the Central Appalachian region holds approximately 13% of U.S. recoverable reserves of coals containing less than 0.6 pounds of sulfur per million Btu ("low-sulfur coals").

The western United States contains over 85% of the country's recoverable low-sulfur coal reserves (DOE, 1994); most of this is located in Wyoming's Powder River Basin. However, western coals have properties which are quite different from those of eastern coals, making direct substitution in boilers designed to burn eastern and mid-western coals more difficult. First, western coals tend to have lower per-ton heat values than eastern coals. Next, some western coals have a higher moisture content than midwestern and eastern coals, making combustion less efficient. Also, western coals tend to be more brittle and dusty than eastern coals. Western coals are also more prone to spontaneous combustion, necessitating more elaborate fire control equipment and procedures. Finally, many western coals tend to have higher ash contents than eastern coals.

Acquiring Additional Allowances

Utilities can also comply with the CAAA90 by acquiring additional SO_2 emission allowances. Phase I allowances were allocated to Phase I-affected generating units based on their average fuel consumption during the years 1985 to 1987 and a 2.5-pounds-SO_2-per-million-Btu emission rate. Most of these units did not receive enough allowances to enable continuation of emissions at 1985 - 1990 levels. Additional allowances can be acquired in a variety of ways, including intra-utility reallocations, inter-utility transactions, purchases from brokerages, purchases from EPA allowance auctions, and purchases from an EPA allowance reserve. Of the 261 Phase I-affected generating units, a total of 39 planned to acquire additional allowances as their main compliance tool.

Installing FGD Equipment

Phase I-affected utilities submitted plans to install flue-gas desulfurization (FGD) equipment (generally called "scrubbers") on 27 generating units representing over 14,000 megawatts of generating capacity. Factors which prevent more widespread adoption of scrubbers include high capital-investment requirements, high operating costs, and the large volumes of solid waste generated. Units adopting scrubbers are able to remain in compliance while using lower-cost high-sulfur coals. An advantage of a scrubber investment is that it allows the generating unit to achieve SO_2 emission levels well below the scrubbed unit's emissions limits. A scrubber operating at 92 percent efficiency on a unit burning 2.5 % sulfur, 12,000 Btu per lb. coal would reduce SO_2 emissions to about 0.33 lbs sulfur per million Btu, well below both the Phase I and Phase II emissions limits. Emissions reductions beyond the scrubbed unit's Phase I limit can be used to compensate for excess emissions by other units on the scrubbing utility's system, or they can be banked for sale or later use. A scrubber installation also reduces a utility's uncertainty regarding Phase II compliance.

In an effort to encourage utilities to invest in high-efficiency SO_2-control technologies such as scrubbers, the CAAA90 set aside a pool of 3.5 million allowances (called Phase I Extension allowances) that were available to "either control units that install a technology that removes 90% or more of their SO_2 emissions and begin operation by January 1, 1997, or control units or other units that use a different compliance strategy but which are associated with the control unit in the extension allowance application." (DOE, 1994). This mechanism allocated additional allowances to scrubbing utilities, providing an incentive for scrubber installation and providing the utilities with a mechanism for compliance in the event that scrubber construction was not complete at the onset of Phase I. Extension allowances were intended to reduce compliance costs (and their effect on electricity rates) for utilities that rely on high-sulfur coal, and to preserve jobs in high-sulfur coal mining communities (Norris, 1992). These allowances can be banked in order to offset future emissions reduction requirements, redistributed to other units within the firm, or sold to recover a portion of the investment in the control technology.

A total of 17 utilities applied for extension allowances, requesting over four million allowances. EPA used a lottery to determine which utilities would receive these allowances. However, all but one of the 17 utilities (Potomac Electric Power Company) entered into a pooling agreement whereby the extension allowances would be shared between all of the applicants on a pro-rata basis. This guaranteed that each utility would get a percentage of their requested allowances. The largest recipients of these extension allowances were American Electric Power (with approximately 570,000 allowances) and the Tennessee Valley Authority (with approximately 510,000 allowances).

The actual cost of scrubber operation varies widely. Based on a DOE estimate compiled from a 1992 survey of electric utilities (DOE, 1995), coal-quality characteristics that are typical of scrubbing units, and capital recovery methods and rates of return typical of regulated utilities, we calculated a scrubber cost estimate of $400 to $500 per ton of SO_2 removed. Experience in technology utilization and financing since that time has allowed some utilities to reduce costs. Today, utility sources cite representative costs of SO_2 removal with new scrubbers in the range of $200 to $300 per ton of SO_2 removed.

Using Previously Implemented Controls

Prior to the Phase I compliance plan deadline in early 1993, several plants had already taken steps to ensure that their Phase I allowance allocation will be sufficient to cover their Phase I emissions. This was largely due to emissions reduction mandates enacted by several states (including Kansas, Michigan, New Hampshire, New York, and Wisconsin) prior to 1993. Where state laws had required utilities to bear costs of SO_2 control over and above those required by federal law prior to CAAA90, this factor was considered by the EPA in establishing baseline emission levels which determine Phase I allowance allocations (DOE, 1994).

Retiring Facilities

The owners of seven Phase I-affected generating units plan to achieve compliance by retiring these facilities. Each of the operating utilities will be required to surrender the allowances allocated to the retired units unless they can show compensating generation at other units. The retired units consist of Wisconsin Electric Power's North Oak Creek units 1 through 4, Cleveland Electric Illuminating Company's Avon Lake unit 8, American Electric Power's Breed unit 1, and Iowa Power's Des Moines unit 7.

Repowering Boilers

Repowering is the use of a new technology in refurbishing an existing power plant. The ability to upgrade generation while maintaining use of an existing power plant site, as opposed to acquiring permits to use a new site, is a major advantage of this option. Repowering older boilers can increase the generating capacity of a site by as much as 200%, improve efficiency, and reduce SO_2 emissions (DOE, 1994). Because potential repowering technologies, such as integrated gasification combined cycle, are still under development, this option has not been widely utilized. Only one of the 261 Phase I- affected generating units (PSI Energy's Wabash River unit 1) has chosen repowering as a compliance strategy.

Other Compliance Strategies

Although all of the 261 Phase I-affected generating units chose to implement one of the six control options presented above, there are a variety of other mechanisms that could be used to achieve compliance. Some Phase II-affected units are choosing to implement energy conservation measures to help achieve compliance. The CAAA90 set aside a pool of 300,000 allowances (called the Conservation and Renewable Energy Reserve) which have been awarded to several utilities for implementing demand-side management (DSM) measures or for utilizing renewable energy sources such as solar, geothermal, wind, and biomass.

Another method of achieving compliance is reduced utilization. A utility can choose to adopt conservation measures (on both the supply- and demand-side) to reduce utilization of a given generating unit without having to surrender allocated allowances. The CAAA90 specifies that a Phase I unit that meets its emissions requirements through reduced utilization must surrender allowances unless it can demonstrate that a shift of generation to a non-Phase-I unit was not the factor responsible for reduced emissions.

Another EPA program allows a Phase I unit to reassign its Phase I emissions reduction requirements to one or more Phase II units (called "substitution" units). This would only be allowed if the substitution units were able to meet the Phase I unit's emissions reduction requirements. The intent of this provision is to allow utilities that operate Phase I units to reduce emissions at other plants as a substitute for reductions at the original Phase I plant, if doing so allows them to meet the SO_2 emissions-reduction requirements of CAAA90 more cost effectively.

Finally, utilities can choose to reduce their generation requirements (and, hence, their SO_2 emissions) by purchasing power from other firms. In order to get the maximum benefits from a wholesale power purchase, both parties must be aware of the other's allowance position. In wholesale power agreements, provisions are made to compensate the "seller" utility for the emissions associated with the purchased power either in monetary terms or through the transfer of allowances from the "buyer" to the "seller". In the case where power is purchased from utilities not regulated by the acid rain provisions of the CAAA90 (such as nuclear facilities), the seller may take into account the value to the buyer of not using allowances. By purchasing power from utilities with lower marginal costs of SO_2 control, the cost of CAAA90 compliance can be reduced.

PHASE I COMPLIANCE STRATEGIES

A striking aspect of Phase I implementation so far has been the dramatic reduction in SO_2 emissions at Phase I-affected generating units in 1995. Figure 2 displays SO_2 emissions at original Phase I-affected units (categorized by compliance strategy) for 1985, 1990, 1994, and 1995 (EPA, 1996d). Total SO_2 emissions at these units declined by more than 50 percent over the 11-year period since 1985. The 261 original Phase I units were responsible for 95 percent of total emissions reductions at the 441 original, substitution, and compensating units affected by Phase I (EPA, 1996a). Fuel switching and scrubbing were the two strategies responsible for the bulk of the reduced emissions.

Emissions Reductions Since 1990

The 261 original Phase I units have reduced SO_2 emissions by over 4.26 million tons since 1990, representing a 49 percent decline (Table 1). Over 90% of this emission reduction can be attributed to units opting to either switch or blend fuels or install scrubbers. The 162 units that have opted to switch/blend fuels account for emission reductions of 2.57 million tons, or roughly 60% of the total. Phase I units located at plants that purchased substantial amounts of western coal were responsible for about 1 million tons of SO_2 reductions (Table 2). Our analysis of 1990 and 1995 coal purchases by the fuel-switching units (DOE, 1989-95; DOE, 1996a) yielded an estimate of about 90 percent of the reduction of incoming coals' sulfur contents resulting from substitution of coals mined in Wyoming, Montana, Colorado, and Utah ("western coal") for coals formerly procured from midwestern or eastern sources. By assuming the sources of reduced SO_2 emissions by the fuel-switching Phase I units to be roughly in proportion to the plants' incoming fuel-sulfur contents, we estimated that approximately 900,000 tons (or 35%) of the 2.6-million-ton fuel switching/blending SO_2-emission reduction has occurred due to substitution of western coals. This assumption is necessary because fuel-purchase data are available only on a plant-wide basis, and no data are available on actual burn by individual

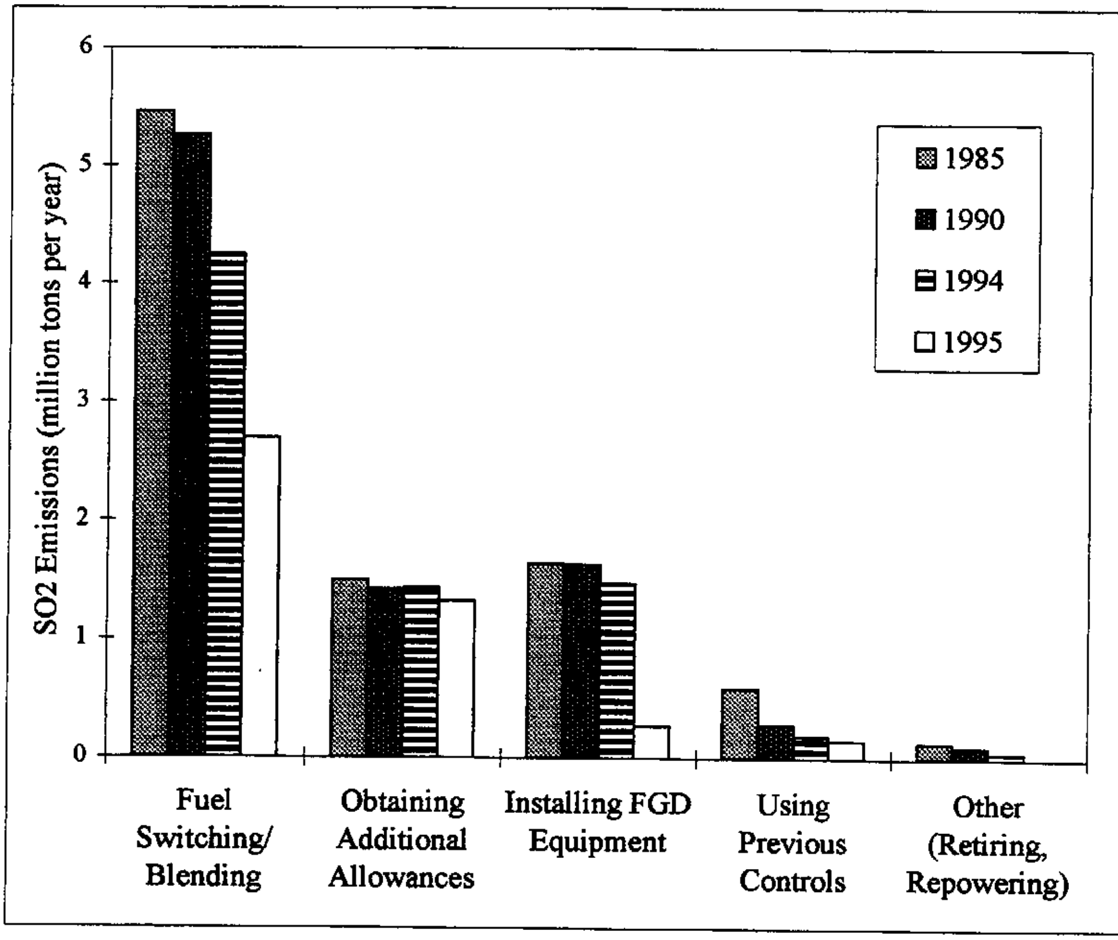

Figure 2. Sulfur dioxide emissions of 261 originial Phase I generating units, by compliance strategy, selected years.

units. Coal-fired generating plants typically stockpile on the order of 100 days' fuel supply. A large majority of the remaining 65% of the 2.57 million-ton reduction in SO_2 emissions by fuel switching/blending units can be attributed to substitution of lower-sulfur coals from midwestern and eastern sources.

The 27 generating units that opted to install FGD equipment (Table 3) reduced their 1995 emissions by over 1.36 million tons below 1990 levels, accounting for roughly 32% of the original Phase I unit SO_2-emission reductions. SO_2 emissions at these 27 units have declined by almost 85% from 1990 levels. SO_2 emissions at these units are expected to decline even further in 1996 and 1997 as the last 6 of the planned scrubber installations become operational.

Table 2. Estimated effects of western coal substitution on SO_2 emissions at 17 Phase I generating plants that purchased substantial amounts of western coal in 1995.

Plant Loca-tions	No. of Plants	Coal-fired Plant Capacity (MW)	Phase I Unit Capacity (% of (plant)	Plant Coal Purchase (1000 tons)	Plant Western Coal Purchases (% of total)	Unit Reduction in SO_2 Emissions (1000 tons)	Reduced SO_2 Due to Western Coal Substitution (% of total)
Florida	1	1821	73%	5388	15%	64	49%
Illinois	2	2420	100%	6156	98%	249	98%
Indiana	3	2944	82%	7762	58%	262	74%
Iowa	4	765	93%	2048	82%	37	100%
Kentucky	1	1750	10%	3821	47%	-2	na
Missouri	6	6601	86%	19671	87%	385	100%
Total	17	16301	78%	44846	71%	995	90%

Sources: DOE, 1989-1995; DOE, 1996a; and EPA, 1996d.

Notes: Incidental amounts of western coal also purchased by Phase I plants in Alabama, Mississippi, and Pennsylvania. Western coal substitution effect on SO_2 emissions estimated by authors based on sulfur contents of purchased coals.

Table 3. Locations of generating units using flue-gas desulfurization as a Phase I compliance strategy; quantity and quality of coal purchased by host plants in 1995.

State	No. of Host Plants	No. of Phase I FGD Units	Plant Capacity (MW)	P-I FGD Capacity (MW)	Coal Purchase (1000 tons)	Avg S Content (% by wt)
Georgia	1	1	1488	123	1235	0.90%
Indiana	4	7	6244	2377	14458	2.41%
Kentucky	3	5	3007	1337	6589	1.80%
New Jersey	1	1	299	163	594	2.43%
New York	1	2	323	323	716	2.00%
Ohio	2	3	2866	2733	6278	3.01%
Pennsylvania	1	2	1872	1872	4123	2.25%
Tennessee	1	2	2600	2600	8619	2.83%
West Virginia	2	4	3714	2574	9222	2.65%
Total	16	27	22412	14101	51834	2.47%

Sources: DOE, 1993; DOE, 1994; DOE, 1989-1995.

Note: Coal quantity and quality figures pertain to plants. FGD equipment was not yet operational on 6 Phase I units in 1995.

Table 4. 1995 SO_2 emissions and allowances, 261 original Phase I units.

Compliance Strategy	SO_2 Emissions (tons)	Allowance Allocation	Allowances Banked
Fuel Switching/Blending	2,690,426	3,315,554	625,128
Obtaining Additional Allowances	1,322,144	917,573	-404,571
Installing FGD Equipment	264,270	923,467	659,197
Using Previously Implemented Controls	147,358	333,061	185,703
Retiring Facilities	0	56,781	56,781
Boiler Repowering	197	4,385	4,188
TOTAL	4,424,395	5,550,821	1,126,426

Sources: EPA, 1995b; DOE, 1994.

Note: A negative number of allowances banked indicates allowances consumed.

Allowances Banked in 1995

Analysis of Phase I emissions data reveals that cumulative 1995 SO_2 emissions by the 261 original Phase I units are well below the CAAA90 limits (Table 4). Over 1.1 million allowances were banked by the original Phase I units in 1995 as a result of these emissions reductions.

The total emissions bank amassed by all 445 Phase-I-affected units (including the original Phase I units, and substitution and compensating units) far exceeds that 1.1 million tons (Figure 3; EPA, 1996a; EPA, 1996d). In addition to the 5.5 million allowances allocated to the original Phase I units, EPA awarded approximately 1.35 million Phase I Extension allowances for use in 1995. Also, utilities earned over 500,000 allowances from special EPA allowance reserves such as the Auction Reserve and the Conservation and Renewable Energy Reserve. Over 1.32 million 1995 allowances were allocated to 184 units opting into Phase I as substituting and compensating generation; these units only emitted roughly 880,000 tons of SO_2 in 1995, allowing an additional 445,000 allowances to be banked. In total, 8.74 million allowances were available for use in 1995, while Phase I-affected units only emitted 5.3 million tons of SO_2. The net result is an overcompliance "bank" of 3.44 million 1995 allowances.

Allowance Trading Activity

Gilroy (1996) analyzed allowance trading activity recorded by the EPA's Allowance Tracking System (EPA, 1996b). His analysis covered allowances issued for the

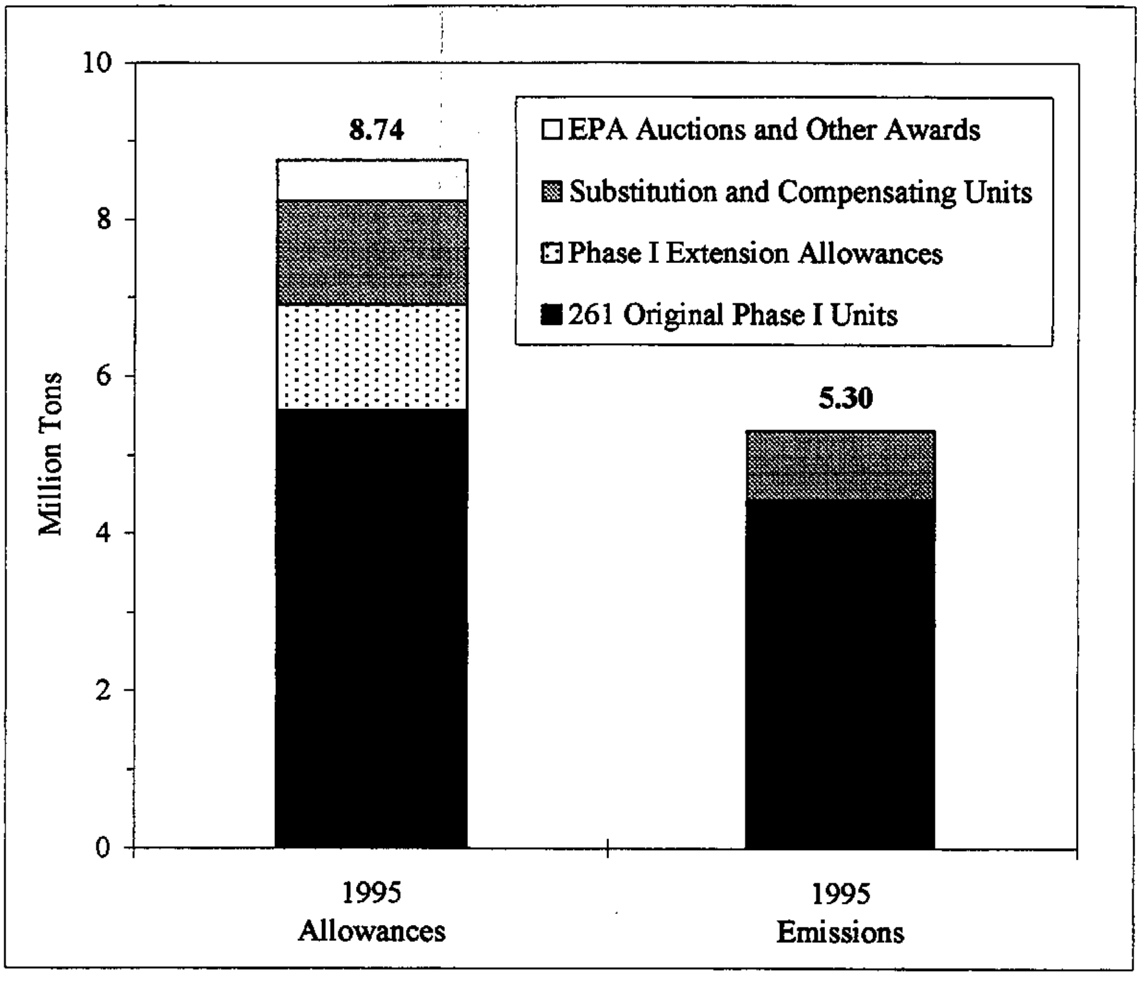

Figure 3. 1995 Phase I SO_2 emissions and allowances, by major source.

1995 - 2025 period, a total of 270 million (ICF, 1995). He found that transfers of 22 million allowances had been recorded prior to February, 1996. However, 85 percent of these represented "intra-utility" transactions, transfers among accounts held by individual utilities.

Approximately 3 million allowances, or slightly more than 1 percent of the total number issued, had been accounted for by the EPA as having been either bought or sold in market-based transactions such as interutility sales, transfers to and from brokers, and auctions. Approximately 700,000 of these represented allowances that were acquired by utilities in North Carolina and South Carolina (including Duke Power, Carolina Power and Light, and South Carolina Electric and Gas). No Phase I units are located in these states or are operated by these utilities. Therefore, Gilroy concluded that the allowances had been acquired for the purpose of assisting Phase II compliance.

Table 5. An estimate of Phase I SO_2 emissions, allowance allocations, and cumulative Phase I allowance bank, 1995 - 1999 (million tons).

Allowance Allocations:	
Allowance Allocation to Original Units	27.8
Estimated Allocation to Substitution Units	5.7
FGD Extension Allowances	3.5
Estimated Additional EPA Allowance Allocations	1.0
Phase I Allowances Sold at EPA Auctions (1993-1999)	0.8
Total Allowances	38.8
SO_2 Emissions:	
Original Phase I Units:	
Estimate w/ Constant Coal Sulfur Content	22.0
Adjust for Change in Coal Source, Quality	-1.0 to -1.5
Compensating and Substitution Units	4.4
Total Emissions	24.9 to 25.4
Total Phase I Bank	13.4 to 13.9

PHASE I PROJECTIONS

Based on our analysis of 1995 activity and data obtained from EPA, we projected CAAA90 compliance activity for the remainder of the Phase I period (Table 5).

Allowances

Total Phase I allowances are estimated at 39.5 million. This figure was calculated from data published by DOE (1994) and EPA (1996a). Some of the minor factors were estimated by the authors based on 1995 levels, with reference to personal communications with EPA officials.

Emissions

Emissions from the original Phase I units were projected through 1999 in two separate components. The first component of this analysis assumes constant coal sources and quality. Each non-scrubbed unit's emissions for 1996 through 1999 were estimated based on 1995 emissions data, assuming SO_2 emissions by each unit remain proportional to generation and that generation will change in proportion to average annual growth factors projected by DOE for the Electricity Market Module Region (DOE, 1995d) in which the unit resides. Coal utilization at units where planned scrubbers were not fully operational at the beginning of 1995 was assumed to increase in proportion to the same factors, and scrubbers were assumed to remove SO_2 from emissions at 90 percent efficiency beginning on the scheduled date of initial operation (DOE, 1994).

In the next component, we adjusted results of the above analysis to accommodate expected changes in coal-sulfur contents. In conducting this analysis, we concentrated on states east of the Mississippi, where 90 percent of the original Phase I generation is located. The geographic distribution of coal sources accessed by eastern coal has changed markedly during the past 10 years, and is expected to continue shifting westward (Figure 4; DOE, 1996d). Because coal-sulfur content varies with origin, changes in geographic distribution of coal sources will influence unscrubbed SO_2 emissions. The sulfur content of coal from western sources is typically well below that of interior- and Appalachian-origin coals. Thus, continuation of the trend toward increasing use of western coal by eastern utilities can be expected to reduce SO_2 emissions.

Sulfur contents of coal shipments from within each major coal-producing region have also been declining steadily since 1990. We projected the 1990-95 trends in average sulfur contents of coals produced within each of the major regions through 1999 using linear regression (Figure 5).

Based on the above two factors (Figures 4 and 5), we estimated the reduction in total sulfur carried in coal shipments to eastern U.S. buyers for each remaining Phase I year (1996 - 1999) and compared each to the 1995 level. If actual coal shipments occur in accord with these projections, the total quantity of sulfur in eastern U.S. coal shipments will be reduced by about 1.8 million tons over the 1996 - 1999 period, compared to the result that would occur if 1995 coal-sulfur contents were to be maintained through the period. If all 1.8 million tons of sulfur were emitted, 3.6 million tons of SO_2 would be released (the molecular weight of SO_2 is double that of elemental S).

However, the entire 1.8 million-ton-reduction of coal-S shipments cannot be factored into a projection of Phase I generating-unit SO_2 emissions. Factors which prevent direct projection include:

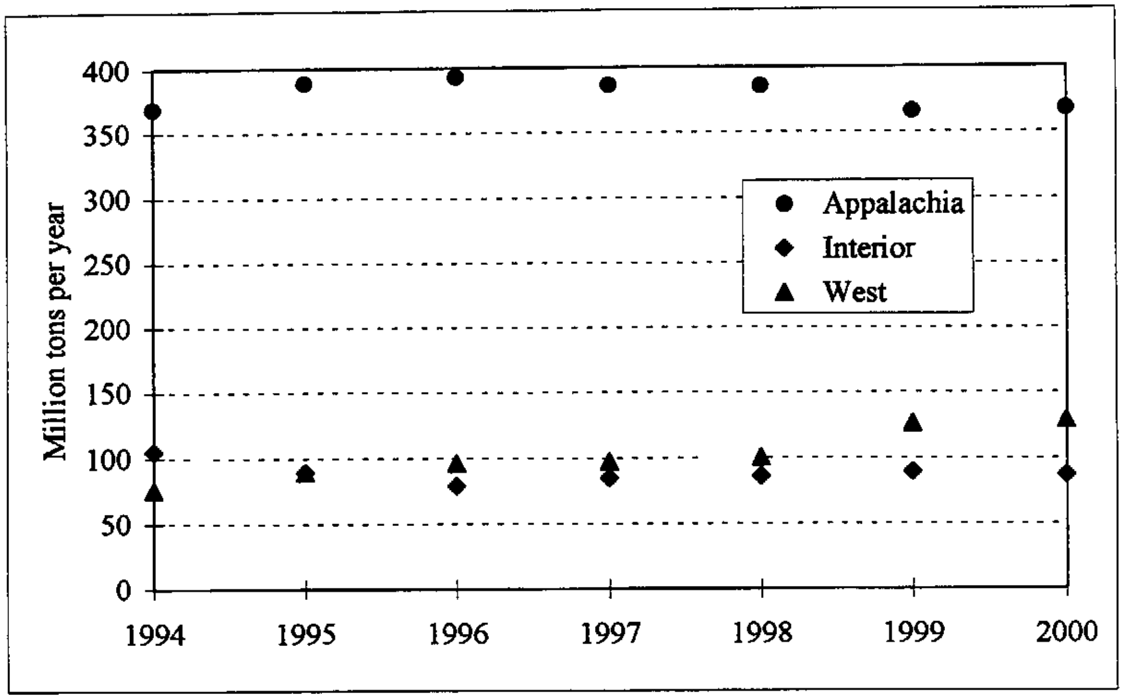

Figure 4. Coal shipments from major producing regions to eastern U.S., historical (1994 and 1995) and projected (1996 - 2000).

- 15 percent of coal consumed east of the Mississippi is used for purposes other than electrical generation (DOE, 1996b).
- Original Phase I units represent 39% of coal-fired generation east of the Mississippi.
- 18 percent of the original Phase I capacity is scrubbed.

Proportional application of these three factors to the 3.6 million-tons-SO_2 figure would yield an estimate of about 1 million tons of SO_2 reductions at Phase I units. However, Phase I generating units will have a greater incentive to reduce incoming coal-sulfur contents than will non-Phase-I units. Therefore, the Phase I units would be expected to attract a disproportionately large share of the reduced-S coals.

Another factor to be considered is the capability of coal reserves to sustain a continuation of the shifting coal source and quality trends. Increasing use of western coal and decreasing sulfur content in Appalachian coal account for 75 percent of the 3.6-million-tons-of-SO_2 estimate (Figure 6). Available data on coal reserves (DOE, 1995b) give no indication that both of these trends cannot be sustained at least through the end of Phase I.

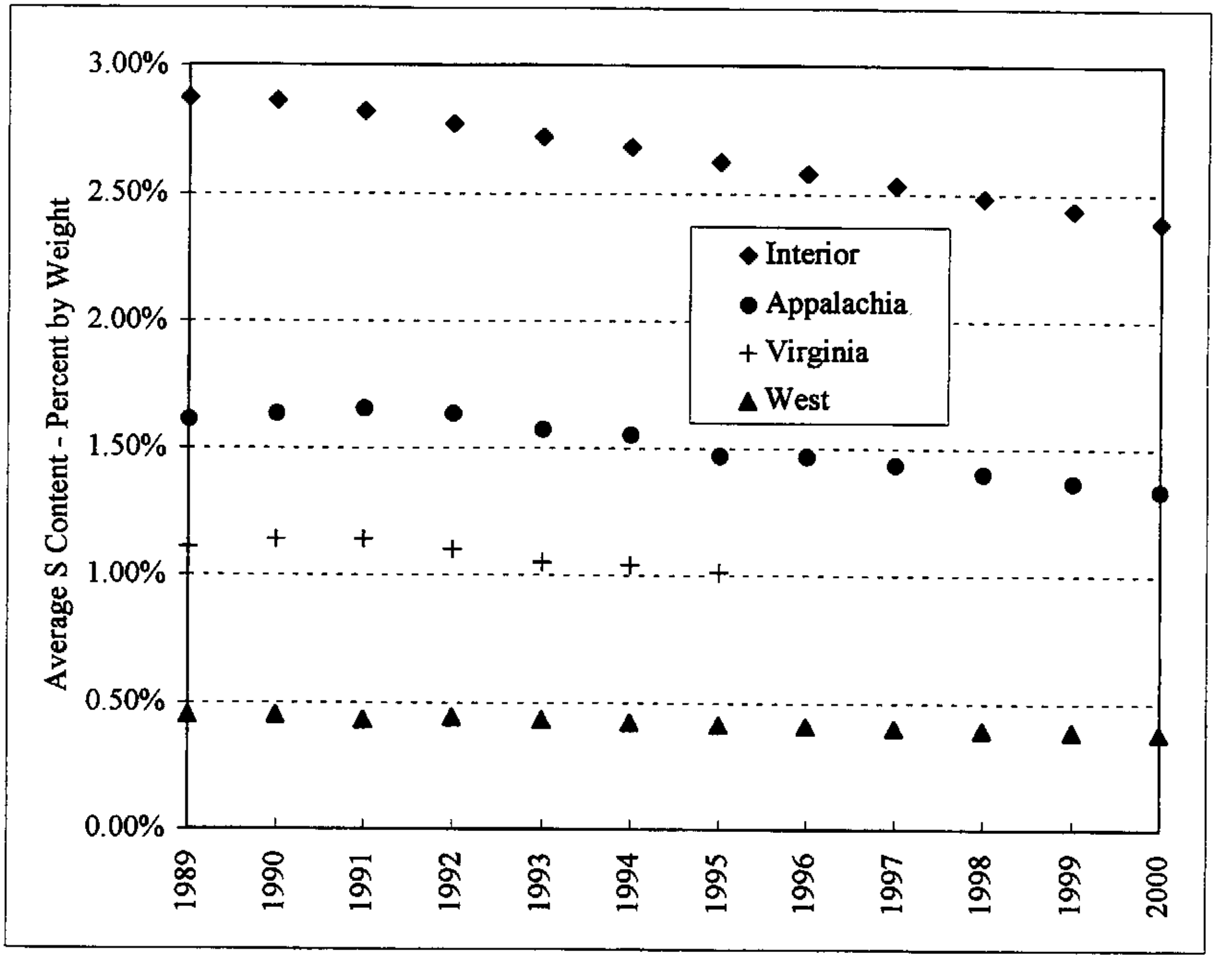

Figure 5. Average sulfur contents of coals shipped from major producing regions to U.S. electrical utility generating plants, historical (1989 - 1995) and projected (1996 - 2000), and average sulfur contents of Virginia-origin coal shipments to U.S. electrical utilities, historical.

Based on the above considerations, we estimate 1 to 1.5 million tons of SO_2 emission reductions by the original Phase I units will occur due to changing coal sources and quality (Table 5).

Emissions by compensating and substitution units were calculated by using average annual growth factors projected by DOE for each Electricity Market Module Region (DOE, 1995b), and the locations of those units within those regions, to calculate a weighted annual growth factor of 0.47 percent; this factor was applied to 1995 emissions.

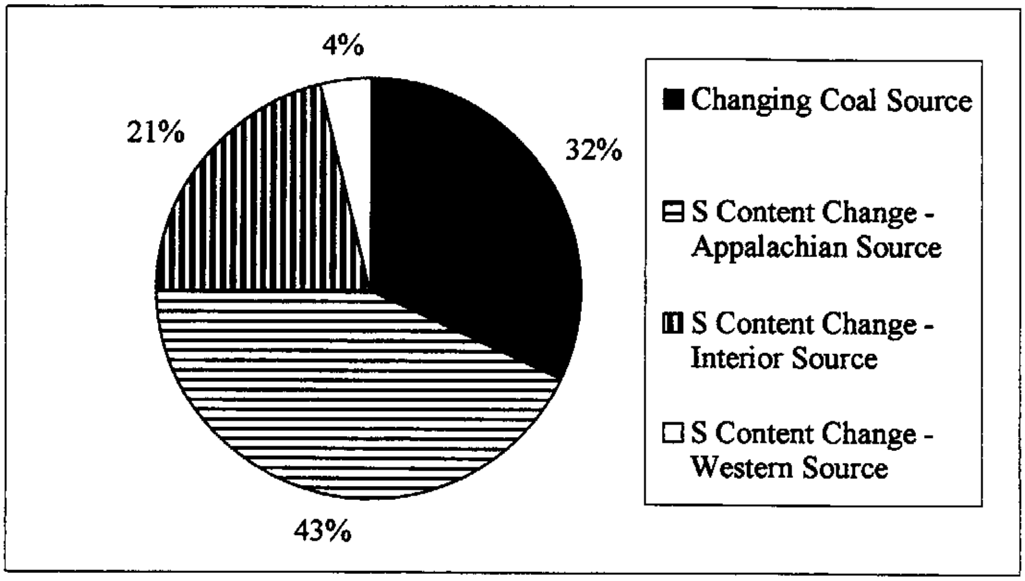

Figure 6. Major components of cumulative reduction of sulfur in coal shipped to eastern U.S. buyers, 1996 - 1999, compared to 1995, estimated.

Total Phase I Bank

Based on the above figures, the total number of banked SO_2 emission allowances is estimated at approximately 13.4 to 13.9 million tons (Table 5). This estimate is consistent with prior estimates: the Resource Data International estimate of 15 million tons, prepared in early 1995 (Coal Outlook, 1995), the 14-million-ton estimate prepared by EPA (1996c and 1996e) in early 1996, and the 12-million-ton estimate prepared by ICF (1995) in 1994 and early 1995.

The magnitude of this emissions bank is significant, given EPA (1996e) projections of Phase II allowance allocations (9.5 million tons per year) and emissions (9.9 to 10.7 million tons per year) during the 2000 - 2009 period (Figure 7). The emissions figures include generators less than 25 MW in size that are exempt from Phase II requirements. According to these estimates, total allowance consumption during the first 10 years of Phase II is not expected to exceed 10 million tons.

FACTORS INFLUENCING ALLOWANCE BANKING

The results of this analysis suggest that utilities are amassing a large stockpile of Phase I allowances. A number of factors can be considered as influencing this behavior.

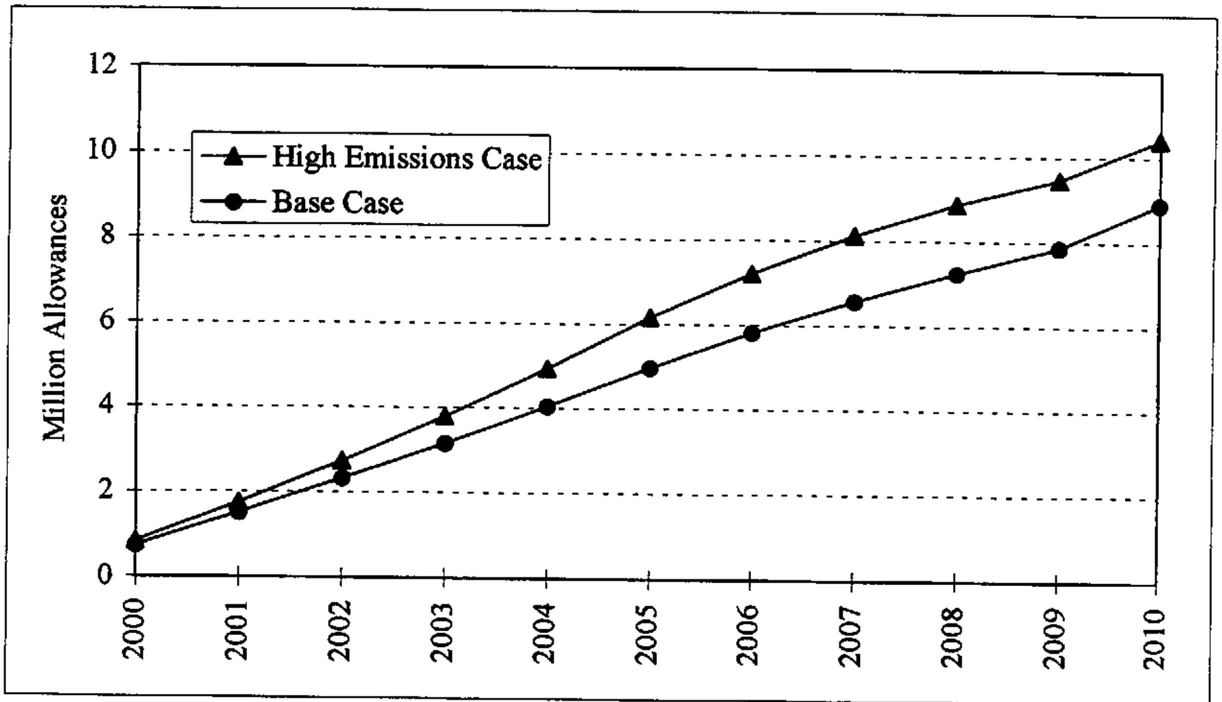

Figure 7. Estimated rate of SO_2 emission-allowance consumption during Phase II.

The Two-Phased Approach of Title IV

The original Phase I-affected generating units were chosen because they were among the highest SO_2 emitters in the nation and had not made substantial investments in SO_2 abatement prior to CAAA90. As such, these plants typically face lower marginal costs of SO_2 removal than Phase II-affected plants, which tend to be newer and to emit SO_2 at lower rates. In a perfect marketplace without phased implementation of controls, Phase I plants would be expected to become net sellers since it is relatively less expensive, on a per-ton basis, for them to reduce their emissions. Phase II units, on the other hand, generally will need to reduce emissions by only a small amount to meet the Phase II SO_2 limits and thus would be more likely to become net allowance buyers in a perfect market (GAO, 1994). By requiring SO_2 reductions in two phases, the Acid Rain Program effectively requires potential allowance sellers to reduce their emissions several years before potential allowance buyers are required to enter the market.

Reduced Pricing of Compliance Options

CAAA90 provided utilities a great deal of flexibility in determining how they will comply with SO_2 emission standards. This flexibility has led to competition between suppliers of compliance options, resulting in lower-than-expected prices for both low-sulfur coal and scrubbers.

Eastern low-sulfur coal prices have fallen in recent years in real terms for a variety of reasons, including increased mine productivity and greater competition for markets; significant quantities of low-sulfur Appalachian production have been displaced from eastern and midwestern utility markets by scrubber installations and by western coal. Burtraw (1995) discusses several innovations implemented by the rail industry to meet the increased demand for western coal, including laying double and triple tracks, increasing the size of car fleets, increasing the number of locomotives, increasing car dump speeds, and the use of aluminum cars. Rail competition for western coal has also resulted in lower coal-transport costs. Decreasing prices for low-sulfur coals have allowed fuel-switching units to reduce SO_2 emissions at costs that are lower than anticipated when the CAAA90 program began.

Scrubber vendors have also found ways to lower prices in response to increased competition, evidenced by the fact that scrubber prices have fallen by almost 50% since 1989 (Burtraw, 1995). Competition in the emerging deregulated electricity markets have caused utilities to develop lower-cost mechanisms to finance capital purchases such as scrubbers. The ability of generators to purchase extra SO_2 allowances to cover increased emissions during periods of scrubber maintenance or failure has allowed backup and redundancy equipment expenditures to be reduced. As utilities have gained experience in the use of scrubbers, operating efficiencies have improved.

Delaying Compliance with Phase II Emission Standards

One key factor influencing emissions banking by utilities in high-sulfur coal regions during Phase I is the incentive to allow delay of costly investments in FGD equipment until well into Phase II. This factor is directly related to the trend towards increased competition in the electric utility industry.

By delaying scrubber investments through use of allowance credits generated during the early years of Phase I, utilities will be able to maintain lower cost structures as the deregulated electricity marketplace emerges. Any generation-cost advantages will help generating firms establish market position during the early years of full competition. A scrubber investment delay also increases the odds that new, lower-cost SO_2 emissions-reduction technologies will emerge. There is also a possibility that, at some point in the future, either new scientific data or political change will cause the Acid Rain Program's emissions limits to be raised. By delaying scrubber investment, generating firms are increasing the probability that they will benefit as a result of such a change.

Utility Risk Aversion

For most of this century, electric utilities have been regulated by public utility commissions which control prices and profits. The General Accounting Office (GAO, 1994) notes that in recent decades, commissions have "increasingly denied or delayed" utility efforts to include certain costs in the rate base. This has resulted in an apprehension on the part of utilities to engage in untried and untested activities that risk denial of rate recovery in commission "prudency" hearings. Hence, utilities are commonly referred to as risk-averse; at least historically, utilities have tended to opt for low-risk approaches to problems such as compliance planning (U.S. General Accounting Office, 1994; Rose, 1995). With regard to the Acid Rain Program, the data reviewed here demonstrate that a number of utilities have chosen to generate allowance banks internally through overcompliance, a strategy that is considered to be less risky than purchasing allowances on the open market (Rose, 1995; Bohi, 1994).

Electric utilities experience several potential sources of risk and uncertainty related to market purchases of allowances. First, the 1990 Congress stopped short of attaching a property right to allowances (Dennis, 1993). This effectively precludes Fifth Amendment "takings" challenges in the event that EPA decides that allowances need to be confiscated in the future in order to meet the CAAA90's acid-rain-reduction goals. For an allowance market to fully develop, owner interests in allowances must be fully protected so as to merit investment over the long term.

The allowance market's slow rate of development contributes to perceptions of risk. Due to low volumes of allowance trading and a lack of reliable price information, utilities and brokerages have found it difficult to forecast future prices. For example, early 1996 allowance prices were on the order of one-half the level of late 1994 (EPA, 1996a). Because trading volumes have been so thin, information on market liquidity is lacking. Buying and selling of allowances by utilities at a given point in time would generally take place within the context of a longer-term strategy; the development of strategies that rely on market transactions has been hampered by the slow development of the market.

A related source of allowance-market risk occurs because it is possible for regulators to "second guess" the wisdom of transactions in the allowance market, especially if allowance prices were to change in a manner counter to expectations that prevail when a transaction is consummated (Bohi, 1994). Utilities may opt for "tried and true" compliance strategies (such as scrubbing and fuel switching) because of perceptions that they will be viewed more favorably by regulators.

The rules established by state utility regulators regarding cost recovery are another source of allowance-market risk. Most states treat allowances as current-period expenses, analogous to fuel costs, which are passed through to ratepayers. Burtraw (1995) notes that this exposes a regulated utility to risk for which there is little reward. While the gains from successful allowance market transactions are passed through to ratepayers, a portion of the investment risk remains with the utility. If an allowance trade proves ill-advised due to an unanticipated market shift, the utility bears the risk of regulatory disallowance.

AN ASSESSMENT: IMPLICATIONS FOR VIRGINIA COAL

The reduction of SO_2 emissions well beyond expectations, combined with falling prices for allowance credits, can be viewed as a success for market-based environmental controls. When viewed from the standpoint of Virginia's low-sulfur coal producers, however, the situation is not as positive.

On the positive side, the core southeastern electrical-generation markets typically served by low-sulfur Virginia producers have not suffered major losses due to utilities Phase I compliance. Six southeastern states account for about 85 percent of electric utilities' Virginia coal purchases (Table 6). Flue-gas desulfurization has been installed as a Phase I compliance strategy on only one generating unit in this region (Table 3), and western coal purchases have not been utilized for Phase I compliance (Table 2). Looking beyond Phase I, scrubbers are less common in Virginia's southeastern markets than in most other areas of the country (Table 6). Tennessee's scrubbers are located at TVA's Cumberland plant, well west of the area typically accessed by Virginia suppliers. Only in Georgia have electric utilities begun using western coal to a significant extent.

On the negative side, it does not appear that Virginia's producers of premium-grade low-sulfur steam coals will be able to increase price premiums over higher-sulfur coals any time soon. Under the Acid Rain Program, coal purchasers can link SO_2 emissions allowances with high-sulfur coals as a substitute for CAAA90 compliance-grade low-sulfur coals, and the SO_2 allowance prices are far lower than originally expected (EPA, 1996a). The projections reviewed above indicate that allowance supply shortages are unlikely to develop any time soon.

Figure 8 shows spot-market price trends for central Appalachian steam coals since 1990, based on market prices published monthly in *Coal Outlook* (Pasha Publications). CAAA90 was passed by Congress and signed by President Bush in November of that year. The price spread between low- and mid-range sulfur coals increased markedly shortly thereafter, in early 1991. Expectations at that time were for improving markets for central Appalachian low-sulfur coal; one study conducted by a coal-industry consultant concluded that CAAA90 would "increase both utility demand and price for low-sulfur Virginia steam coals" (Hewson, 1991). As a result, coal producers were able to command an increased "price premium" for their low-sulfur coal products. This condition persisted until early 1995, when Phase I compliance data began to become available.

Unless there were to be a significant change in the CAAA90 legislation, price premiums received by producers of low-sulfur coals (*i.e.*, market-price increments over higher-sulfur coal products) are likely to remain linked to prices for SO_2-emissions allowances. Given the Acid Rain Program's success in bringing down SO_2 emissions, and its status as the nation's premier example of a "market incentive" regulatory approach, significant changes in the program over the next few years appear unlikely.

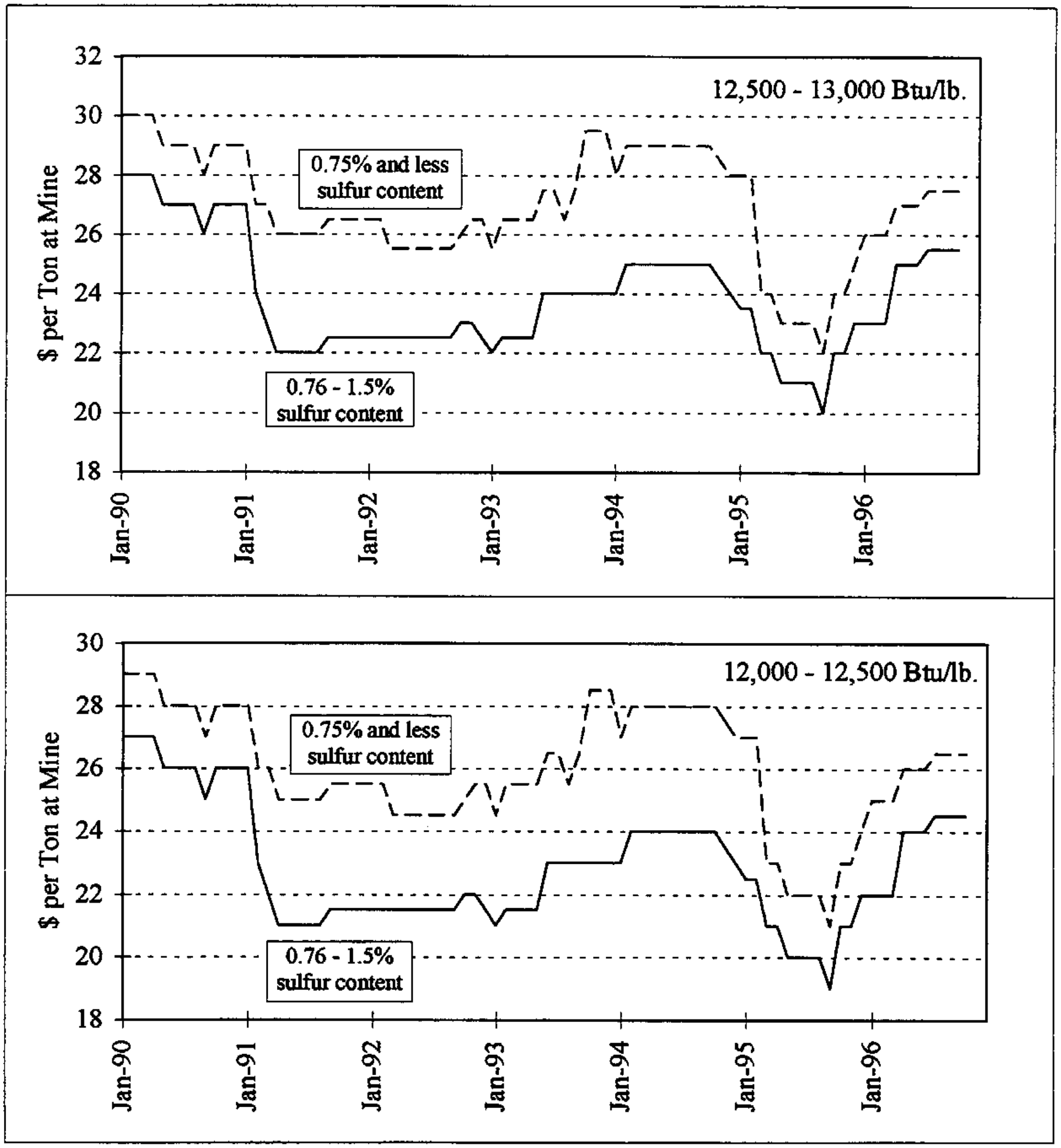

Figure 8. Monthly average spot-market prices for central Appalachian steam coals, eastern Kentucky and southwestern Virginia, January1990 - August 1996, by sulfur content.

Table 6. Total coal-fired electrical generation (total and scrubbed), 1995 western coal purchases, total allowance market transactions, and 1995 electric utility purchases of Virginia coal; southeastern states and U.S. totals.

State/ Region	Coal-fired Generation (MW)	Scrubbed Generation (% of total)	Western Coal Purchases (% of Total)	Allowance Market Transactions	Elec. Utilities Va Coal Purchases (1000 tons)
VA	5,331	15%	0%	16,397	4,423
NC	12,494	0%	0%	475,028	3,282
SC	5,915	39%	0%	237,488	1,096
GA	14,537	1%	24%	-16,572	1,987
TN	9,780	27%	0.1%	-39,999	658
FL	10,894	38%	3%	20,356	703
6 States Total	58,951	16%	7%	692,698	12,149
U.S. Total	319,600	25%	42%	0 (net)	14,453

Sources: DOE, 1995c; DOE, 1996a; Gilroy, 1996.

Note: Virginia generation totals include Clover plant. Allowance market transactions are net economic trades, exclude intra-utility transfers, through February 10, 1996. Florida utilities also purchased 14% of 1995 coal supplies from South American sources.

Although Virginia coal producers' core southeastern markets have not borne major, direct effects due to Phase I compliance actions, indirect effects have been profound. Low-sulfur coal producers that are able to compete more effectively in non-southeastern markets are in direct competition with western coal, while larger proportions of non-southeastern generation have been effectively removed from low-sulfur markets due to scrubber installations. Doubtless, this has resulted in more intense competition among low-sulfur coal suppliers in southeastern markets. In addition to eliminating the need to purchase low-sulfur coal at scrubbed units, scrubber installations generate additional allowances that can be sold or utilized by utilities at non-scrubbed units. In addition to competing with other low-sulfur coal producers, Virginia producers also have to compete with utilities' ability to link allowances with higher-sulfur coal products. Electric utilities in the states that are furthest from western coal sources and have not adopted scrubbers have been have been among the most aggressive allowance purchasers in the open markets (Table 6). When taken together, these factors provide no indication that the relative price position of Virginia's low-sulfur coal producers is likely to improve any time soon.

ACKNOWLEDGMENTS

Thanks to Ken McClevey of U.S. Department of Energy, Energy Information Administration; Kenon Smith, Sharon Saile, Mary Shellenbarger,Melanie Dean, and Janice Wagner of the Environmental Protection Agency; and Barry Solomon and Kennneth Rose for their assistance in this research. We also appreciate assistance received from individuals associated with several electric utilities.

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