 Deferred Cost-Sharing through Title IV of the 1990 Clean Air Act Amendments

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**I. INTRODUCTION**

TITLE IV of the 1990 Clean Air Act Amendments¹ (CAAA) contains a promising, but untested, approach for distributing the social and economic costs of acid rain control among the

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states and sources contributing sulfur and nitrogen oxide emissions to the atmosphere. Incorporating a system of marketable emission “allowances” for sulfur dioxide (SO2) emissions with incentives for the early use of emission control technologies, Title IV centralizes regulatory control of emission allowance transactions at the United States Environmental Protection Agency (EPA), but provides individual states and polluters broad discretion in the choice of emission reduction compliance options.

The emission allowance trading program proposed by the Bush Administration in June 1989 engrafted market-based incentives for pollution control onto the traditional command-and-control regulatory framework of the Clean Air Act. The Administration’s proposal for a two-phase reduction of ten million annual tons of SO2 emissions was modified in the course of congressional deliberations over the 1990 CAAA. Both the United States Senate and House of Representatives added provisions to the Clean Air Act to ensure a more equitable distribution of control costs among the regions affected by the program. These amendments were intended to avoid undue disruption of national coal markets as electric utilities comply with Title IV, to moderate the effect of acid rain compliance costs on utility rate-payers, and to provide a margin for future economic growth in states assigned relatively few emission allowances.2

The “Byrd-Bond Amendment”3 to the Senate bill, approved by the House-Senate conference committee, created a reserve of 3.5 million tons of SO2 emission allowances available to utilities that employ emission control technologies during Phase I of the pollution reduction program.4 Phase I of Title IV targets 111 fossil-fired power plants for emissions reductions by January 1, 1995. The incentives for technological controls added to Title IV through the Byrd-Bond Amendment should serve to concentrate Phase I emission reductions at a smaller number of sources with relatively cost-effective opportunities, avoiding the need to reduce emissions at all 111 targeted plants.5 Control costs at these sources can later be recouped in part by the sale of emission

2. See generally, infra section II.
5. Id.
allowances to plants with higher emission reduction costs. This deferred cost-sharing, as well as other economic efficiencies claimed for the emission allowance program, will result only if a robust market for emission allowances develops as envisioned by the architects of the Title IV program. 6

This article describes the legislative antecedents of Title IV's provisions for deferred cost-sharing, and assesses early federal and state regulatory experience with the technology incentive provisions added by the Byrd-Bond Amendment. The additional emission allowances available for the use of technological emission controls during Phase I already have led state public regulatory commissions to encourage utilities affected by Phase I to employ retrofit flue gas "scrubber" technologies7 in lieu of fuel-switching. By focusing Phase I emission reductions on large baseload plants, the incentives for early use of control technology added by the Byrd-Bond Amendment will reduce the socioeconomic impacts of job losses in the coal mining industry and the regional economies it supports. 8

A. Legislative Antecedents of Deferred Cost-Sharing

Enactment of a national acid rain control program required a full decade of congressional debate. Senator George J. Mitchell (D-ME) introduced the first major acid rain control bill in 1981. 9 The original Mitchell bill required a ten million ton annual reduction of SO2 emissions from 1980 levels to be achieved within ten

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We managed to keep the costs down by relying on a system of market incentives. One of the truly innovative parts of this legislation, I believe, is its commitment to the free market.

We want to build on the best strengths of that market to try and get the gains in the most cost effective way. We believe the cost of doing it that way will be to reduce the costs of acid rain cleanup by about 20%, or roughly [one] billion [dollars] a year.

Id. (testimony of William K. Reilly, Administrator, EPA).

7. "Scrubbers" or "retrofitting scrubbers" are pollution control devices used in the process of desulfurization.

8. Estimates prepared for EPA indicate that, under Phase I of the Administration's acid rain proposal, the two-year time extension and two-to-one bonus allowance provisions of the Byrd-Bond Amendment would reduce expected coal production losses in the Midwest and northern Appalachia from 50-70 million tons in 1996-98 to 35-60 million tons. Memorandum from Bruce Braine, Dina Kruger & Richard Stuebi, ICF Resources, Inc., to Rob Brenner, EPA at Table 2 (Nov. 30, 1989) (on file with author) [hereinafter Nov. 30, 1989 Memorandum].

years of enactment. Emission reductions were allocated among thirty-one eastern states based on each state's contribution to 1980 electric utility SO2 emissions in excess of 1.2 pounds of SO2 per million British Thermal Units (BTU) of heat input.\textsuperscript{10}

Senator Mitchell's "excess emissions" formula was copied in dozens of acid rain control bills introduced in Congress during the 1980's.\textsuperscript{11} Industries and states assigned large emission reduction requirements under these proposals were able to prevent their enactment by drawing attention to their high social and economic costs, and the apparent inequities of the excess emissions allocation formula. For example, the states of Kentucky and New York each emitted roughly one million tons of SO2 in 1980.\textsuperscript{12} However, under an excess emissions allocation formula, New York would need to reduce its SO2 emissions by twenty-one percent while Kentucky would have to cut its emissions by more than sixty percent.\textsuperscript{13} The emission allowance program established by Title IV of the 1990 CAAA is based, in principle, upon an excess emissions allocation of 2.5 pounds of SO2 per million BTU in Phase I, and 1.2 pounds of SO2 per million BTU in Phase II.\textsuperscript{14}

The disproportionate impact of electric utility "excess emissions" allocations results from differences in statewide average SO2 emission rates and the geographic distribution of industries nationwide. For example, a major part of New York's SO2 emissions in 1980 came from the industrial sector, and its electric utility emission rate in pounds of SO2 per million BTU was lower

\begin{footnotesize}
\begin{enumerate}
\item Id.
\item See E. Yanarella & R. Ihara, \textit{The Acid Rain Debate - Scientific, Economic and Political Dimensions} (1985) \[hereinafter Yanarella \& Ihara, Acid Rain Debate\].
\item Id. at 222, Table 8.1.
\item Id. at 141, Table 6.3. If all 31 eastern states were required to reduce total emissions of sulfur dioxide (SO2) by a uniform percent reduction to achieve a 10 million ton annual reduction of SO2 emissions below 1980 levels, each state would reduce emissions by 44%. \textit{Id.}
\item Section 404(a) of the 1990 Clean Air Act Amendments (CAAA) requires that after Jan. 1, 1995, emissions at 111 specific power plants not exceed the SO2 allowances stated in Table A of that section. 42 U.S.C.S. § 7651c(a) (Law. Co-op Supp. 1991). Phase I emission limits are determined by multiplying each unit's 1985-87 baseline heat input in British Thermal Units (BTU) by an emissions rate equal to 2.5 pounds of SO2 per million BTU, divided by 2000. 42 U.S.C.S. § 7651c(a)(2) (Law. Co-op. Supp. 1991). Section 405 establishes Phase II emission limits. Phase II limits affect all generating units larger than 75 megawatts capacity. After January 1, 2000, all such units are limited to emission allowances equal to the product of the unit's 1985-87 baseline heat input multiplied by 1.2 pounds of SO2 per million BTU, divided by 2000. 42 U.S.C.S. § 7651d(b) (Law. Co-op. Supp. 1991).
\end{enumerate}
\end{footnotesize}
than Kentucky's emission rate. In theory, any state with a high proportion of SO2 emissions concentrated in the industrial sector, or with electric utility emissions below a rate of 1.2 pounds of SO2 per million BTU, could largely escape regulation under an excess emissions allocation formula regardless of the total tons of SO2 emitted within the state.

Congressional advocates of the excess emissions approach argued that "clean" states in the Northeast and West which had already cleaned up their emissions should not bear the same control burden as "dirty" states in the Midwest and Southeast with higher emission rates. The "clean state/dirty state" dichotomy defined the entire course of the acid rain control debate, and prevented acid rain control legislation from reaching a floor vote in either house of Congress for a decade. Interregional cost-sharing proposals were developed early in the debate in an effort to reduce the social and economic impacts of acid rain control legislation on high-emitting states.

The objective of interregional cost-sharing is to require relatively clean states to share part of the control costs of high-emitting states without further reducing their own emissions. Cost-sharing also protects the employment of tens of thousands of eastern coal miners and the regional economies dependent on the high-sulfur coal industry. By collecting fees or taxes through a national acid rain control trust fund or similar device, funds could be disbursed to defray the costs of installing pollution control devices, such as flue gas desulfurization "scrubbers" at midwestern power plants targeted for large emission reductions. Targeting these plants for emission controls, with a national trust fund to cover a portion of their control costs, would serve the dual objectives of minimizing electric rate increases for industry and con-

15. See Yanarella & Ihara, Acid Rain Debate, supra note 11.
17. See id. at 27-37.
18. The United Mine Workers of America estimates that a 10 million ton SO2 emission reduction, with 50% to 70% of reductions achieved through fuel-switching, could cause 40,000 to 60,000 coal mining job losses in high-sulfur producing regions of northern Appalachia and the Midwest, with direct annual income losses of $1.1 to $1.6 billion and total annual economic losses ranging from $3 to $4.6 billion, including income multiplier effects. Id. at 198-99. The Congressional Office of Technology Assessment has estimated these direct income losses at $600 to $800 million annually with total annual economic losses of $1.6 to $2.3 billion, taking into account potential increases in mining employment associated with the construction of new power plants. Id.
sumers while protecting the employment base of traditional coal-producing areas.

B. Direct Cost-Sharing Through Electric Generation Fees

Representative Henry Waxman (D-CA) co-sponsored the introduction of the first national cost-sharing bill on June 23, 1983. House Bill 3400 required the fifty highest emitting power plants to reduce SO2 emissions by meeting an emission limitation equivalent to EPA's 1979 Revised New Source Performance Standards for steam-electric fossil-fired sources, and provided for an Acid Deposition Control Fund to pay for ninety percent of the capital costs of compliance. Funds would be collected from all non-nuclear sources of electric utility generation at a rate of one mill ($0.001) per kilowatt-hour.

The co-sponsors of House Bill 3400 recognized that cost-sharing was necessary to mitigate the employment and economic impacts of acid rain control legislation:

The Congress finds that ... [t]he installation of additional control technology for a number of existing electric utility plants would provide an effective and verifiable means to reduce emissions of sulfur dioxides; and ... [a] nationwide fee system is necessary to provide funding for a portion of the capital cost of the required technology so as to lessen utility rate increases and avoid economic disruption or increased unemployment.

Despite support from the United Mine Workers of America (UMWA), industry groups, and midwestern states in favor of the regional cost-sharing concept advanced by House Bill 3400, the bill was criticized on three grounds: (1) that the top fifty emitting power plants included several plants whose design characteristics or age made it technically impossible or uneconomic to retrofit

20. The 1979 Revised New Source Performance Standards for Steam-Electric Power Plants require newly constructed units to meet a sliding-scale emission rate equivalent to 0.6 to 1.2 pounds of SO2 per million BTU by the use of continuous emission reduction technology achieving a percentage reduction of emissions not less than 70%.
pollution control technology;\(^\text{24}\) (2) that the electric generation fee would impose undue costs on northeastern states with relatively low SO2 emission rates;\(^\text{25}\) and (3) that an excess emissions formula, with unacceptable impacts on states with relatively high rates of emissions, would be used to make up an estimated three million ton annual shortfall between the emission reductions achieved at the fifty largest plants and a ten million ton annual SO2 reduction from 1980 emission levels.\(^\text{26}\)

In addition, environmental groups criticized House Bill 3400 on the grounds that an annual ten million ton SO2 emission reduction was insufficient to meet environmental protection needs.\(^\text{27}\) Despite its technical deficiencies, however, by drawing attention to the social welfare costs of proposed emission reduction legislation, and the need to minimize employment and community dislocation through direct or indirect forms of interregional cost-sharing, House Bill 3400 played a pivotal role in the acid rain debate.

C. Freedom-of-Choice Measures

In late 1983, a new group of acid rain control proposals called for two-phase emission reduction strategies to be achieved through statewide average electric utility emission rates of 2.0 pounds of SO2 per million BTU in the first phase and 1.2 pounds of SO2 per million BTU in the second phase.\(^\text{28}\) Proponents of these so-called "freedom-of-choice" or "least-cost" bills ignored the proposals' potential adverse employment impacts and heralded the direct cost savings utilities could realize by avoiding capital outlays for technological controls at existing power plants.\(^\text{29}\)


\(^{25}\) Id. pt. 1, at 31-35 (testimony of Mario M. Cuomo, Governor, State of New York); pt. 1 at 42-46 (statement of United States Senator Daniel P. Moynihan, D-NY).

\(^{26}\) Id. pt. 2, at 758-66 (statement of Gerald Hawkins, International COM-PAC Coordinator, Illinois, on behalf of the United Mine Workers of America).

\(^{27}\) Id. pt. 1, at 110-12 (testimony of Dr. Michael Oppenheimer, Environmental Defense Fund).


\(^{29}\) See, e.g., Paul R. Portney, High-Price Cure for Acid Rain, THE WASHINGTON POST, August 12, 1983.

But while the two means of sulfur removal are expensive, they are not equally so. If forced to reduce sulfur dioxide emissions by a fixed amount, some power plants would voluntarily choose scrubbers. But
Indeed, estimates of the direct utility compliance costs of meeting statewide average emission rates were somewhat lower than those associated with Senator Mitchell or Representative Waxman's proposals of 1981-83. However, the impacts of "freedom-of-choice" bills on coal production and job dislocation were severe for the Midwest and for other high-emitting regions. These socioeconomic costs were not included in estimates of the comparative utility costs of scrubbing and fuel-switching approaches to acid rain control. One study that evaluated both the direct utility costs and indirect socioeconomic costs of technological and fuel-switching approaches to acid rain control concluded:

The direct compliance costs to electric utilities would be somewhat higher under technology based controls, but these higher costs are likely to be more than offset by the lower indirect costs associated with shifts in economic activity. Technology based controls also are likely to have less of an adverse effect on the mining industry, on shifts in employment and population migration, on worker productivity and training costs, and on public and private community investment requirements. The total present value of compliance costs would be approximately $39 billion under technology based controls as compared with $44 billion under fuel-switching approaches to acid rain control concluded:

the overwhelming majority would find it more economical to shift to lower-sulfur coal.

Since each plant would choose the least expensive alternative, the total costs of the sulfur reduction program would be minimized. This "least-cost" approach would be good regulatory policy by either Republican or Democratic lights.

Id. at A17.

30. See YANARELIA & IHARA, ACID RAIN DEBATE, supra note 11, at 188, Table 7.2 (estimating direct annual utility control costs of "least-cost" Udall-Cheney Bill, H.R. 5370, 98th Cong., 2d Sess., at $3.26-$3.72 billion compared with $4.22 billion for H.R. 3400).

31. See id. The net present value utility costs of 10 million ton SO2 reduction are estimated at $34.5 billion for "least-cost" polluter-pays program during the period 1986-2015, compared with $35.5 billion for technology subsidy program with 90% of capital costs paid through electric generation fee of 0.5 mills per kilowatt-hour. The 1995 coal mining job losses in Ohio, Indiana, Illinois and Pennsylvania under these proposals were estimated at 21,900 jobs for "least-cost" proposal and 12,600 jobs for technology subsidy approach.
switching.33

D. Targeted Emission Controls with Cost-Sharing

In 1985, EPA evaluated the engineering characteristics of 200 power plants, and ranked 120 plants based on the relative ease of retrofitting scrubbers at each.34 This analysis led to comparative economic studies of “targeted” scrubber retrofit strategies focusing on plants with the lowest costs of SO2 removal.35 These studies indicated that a targeted control strategy could reduce three to four million annual tons of SO2 emissions by 1995 at costs comparable to freedom-of-choice proposals, but without the large-scale job dislocations associated with fuel-switching. Coupled with a form of direct cost-sharing, such as a modest fee on national electric power generation, a targeted scrubber retrofit strategy also would diminish the direct utility rate impacts of compliance.36

During the summer of 1988, I met with Senator George J. Mitchell and negotiated the first compromise acid rain control agreement incorporating targeted scrubbing and direct cost-sharing. My primary objective, which Senator Mitchell agreed to, was that any agreement we reached must be coal-market neutral — acid rain legislation should not cause regional coal production to depart from expected future production in the absence of acid rain control legislation. Senator Mitchell’s primary objective, with which I concurred, was that any compromise must achieve a true ten million ton annual reduction of SO2 emissions from 1980 levels.

We met our objectives. The Mitchell-UMWA compromise reached on September 22, 1988, would have required thirty-two listed power plants to retrofit SO2 emission control technologies by January 1, 1995. These plants were considered by EPA to be the most likely to retrofit scrubbers to comply with any form of acid rain control legislation due to their age, size, emissions and site-specific characteristics. In the first phase of the compromise,

34. ENERGY VENTURES ANALYSIS, INC., EVALUATION OF SO2 EMISSIONS AND FGD RETROFIT FEASIBILITY AT THE 200 TOP EMITTING GENERATING STATIONS (1985).
36. Id.
capital cost payments of $200 per kilowatt of capacity would be provided to the owners of the listed plants through a fee of one mill ($0.001) per kilowatt-hour on the electric generation of plants emitting at a rate in excess of 1.0 pound of SO2 per million BTU. This emission-based generation fee meant that very low-emitting plants, such as those in "clean" states of the West, would not contribute to midwestern cleanup costs.

The second phase of the compromise required electric generating units larger than 100 megawatts to meet an emission rate limit of 1.0 pound of SO2 per million BTU by January 1, 2003. These units would have discretion in the means selected for compliance, but would be entitled to capital cost subsidies if conventional or advanced clean coal technologies were employed.

EPA later confirmed that the Mitchell-UMWA compromise would achieve a ten million ton annual reduction of SO2 emissions from 1980 levels with virtually no disruption of expected future regional coal production or employment. Two weeks after Senator Mitchell and I reached agreement, The Washington Post observed that we had constructed "a package that perfectly balances the concerns of special interests." Unfortunately, not all of the "special interests" agreed. Faced with opposition from industry and environmental groups, Senator Mitchell withdrew our agreement along with other provisions of the Senate's clean air bill from floor consideration on October 4, 1988. In retrospect, this action was inevitable given the
lack of Senate consensus on other provisions of the proposed Clean Air Act Amendments of 1988. Ultimately, other affected industries and labor groups in the automotive, steel and chemical sectors had not effectively reached out to support the Mitchell-UMWA compromise.

II. Deferred Cost-Sharing Through Marketable Emission Allowances

The centerpiece of Title IV of the 1990 CAAA is a system of transferrable emission allowances limiting total SO2 emissions from electric utility plants.\textsuperscript{41} Each allowance represents a limited right to emit one ton of SO2 during a calendar year.\textsuperscript{42} Allowances may be transferred among plants within a utility system, banked for later use or sold.\textsuperscript{43} The cost-sharing potential of the emission allowance system depends on the development of a workable market for allowances in which utilities with cost-effective emission control opportunities choose to over-control their emissions and sell the resulting allowances to other utilities.

Title IV requires two phases of SO2 emission reductions. By January 1, 1995, 261 “affected units” at 111 listed power plants must reduce emissions to the equivalent of 2.5 pounds of SO2 per million BTU based on their historic consumption of BTU during the period 1985-87.\textsuperscript{44} Each of these high-emitting affected units is assigned a specific number of annual allowances during the 1995-99 Phase I period.\textsuperscript{45} Because allowances are transferrable within and among utility systems, individual unit emissions may exceed the statutory assignment of allowances provided that the unit owner holds allowances sufficient to cover the higher emissions.\textsuperscript{46}

In Phase II, commencing January 1, 2000, all electric utility units of seventy-five megawatts capacity or larger that emitted SO2 in 1985 at a rate in excess of 1.2 pounds of SO2 per million BTU will be limited to emission allowances equivalent to a 1.2 pound SO2 emission rate based on their 1985-87 BTU consumption.\textsuperscript{47} Similar constraints are imposed on smaller coal-fired and

\textit{Id.} at S14455-57.


\textsuperscript{42} Id.

\textsuperscript{43} Id.


\textsuperscript{45} Id.

\textsuperscript{46} Id.

oil-fired units that emitted SO2 at a rate in excess of 1.2 pounds per million BTU in 1985.48

With limited exceptions, all new utility units commencing operation after enactment of the 1990 CAAA must obtain allowances for the SO2 emissions of these units from existing units assigned allowances under Title IV.49 This new unit "cap" or emission offset requirement was developed by EPA to prevent total SO2 emissions from increasing following the Phase I and Phase II reductions, and to ensure that an active market in emission allowances would develop.50 Aggregate utility SO2 emissions are capped at a level of 8.9 million tons per year commencing January 1, 2000.51

A. Evolution of the Byrd-Bond Amendment

Prior to the Bush Administration’s June 1989 announcement of its acid rain control proposal, analysts at EPA evaluated alternative approaches for achieving Phase I emission reductions: the first required the twenty largest emitters of SO2 to meet the equivalent of an emission standard of 1.1 pounds per million BTU; the second required a group of 107 plants to reduce emissions to the equivalent of 2.5 pounds of SO2 per million BTU.52 In each case, marketable emission allowances would be assigned to these plants, which could be sold or transferred among themselves or other substitute plants.53

A draft Clean Air Act Options Paper circulated by EPA in May 1989 gave the following assessment of the alternative Phase I options :54

Option 1 (20 plants):

<table>
<thead>
<tr>
<th>Pros:</th>
<th>Cons:</th>
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<td>Easy to implement (in first phase), because the biggest emitters are known.</td>
<td>It seems unfair to subject some plants to one standard, other plants to another, less stringent standard.</td>
</tr>
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48. Id.
53. Id.
Politically more palatable, because this regime would only affect twenty plants in nine states - thus generating less widespread opposition.

These plants tend to be in regions whose electric rates are somewhat lower than certain other regions.

Option 2 (107 plants):

Pros:
- Fairest of all the options - requires all plants to meet the same standard.
- Does not force one region or set of utility companies to meet disproportionate share of burden of reductions.

Cons:
- More difficult to implement, since it requires regulation of many more plants.
- Will engender more widespread political opposition, since 107 plants in eighteen states would be affected.

Low cost, since it allows individual plants to meet requirements in any way they choose.

EPA was aware that the twenty plant Phase I option meant fewer job displacements than a large number of plants meeting a weaker emission standard through fuel-switching. Senator Robert C. Byrd (D-WV), among other congressional leaders, also recognized that the twenty plant option would provide more effective protection of coal mining jobs. Senator Byrd communicated his position on EPA’s alternative options to President Bush in a letter, which Senator George J. Mitchell delivered to the President at a meeting of congressional leaders, shortly before the President announced his acid rain plan:

I strongly support the position taken by both EPA Administrator William Reilly and Secretary of State Jim Baker regarding the need to target the twenty top sulfur dioxide emitting plants and requiring these plants to meet a 1.1 pound per million BTU standard by the end of 1995. . . .
Most importantly, however, this option which would target the twenty top emitting plants would encourage, but not mandate, the use of technology as a compliance strategy. As Administrator Reilly has pointed out, this has the important advantage of avoiding unnecessary disruptions of existing coal markets, which would have a devastating effect on local and regional economies.

The other option before you, which would require all generating units of 100 megawatts capacity or greater to meet a 2.5 pounds per million BTU standard by 1995, would literally wipe out the high sulfur coal industry. . . . EPA estimates that this would cause fifty-four existing coal contracts to be broken between now and 1995, engendering the loss, according to EPA, of 8,000 jobs throughout West Virginia, Kentucky, Illinois, Indiana, Ohio and Pennsylvania.55

Despite such warnings, the President announced his selection of EPA’s 107 plant Phase I acid rain plan on June 12, 1989.56 In doing so, the President set the stage for a year of political maneuvering to soften the impact of the 107 plant option on coal industry employment, coal-dependent communities and midwestern industrial states heavily impacted by the plan.

B. Senate and House Cost-Sharing Initiatives

Soon after President Bush’s announcement, members of the United States Senate and House of Representatives initiated efforts to incorporate cost-sharing within the Administration’s acid rain proposal. Senator Byrd, Chairman of the Senate Appropriations Committee, and Representative Philip R. Sharp (D-IN), Chairman of the House Subcommittee on Energy and Power, led the fight to improve the regional equity of the Administration’s 107 plant plan. Representative Sharp highlighted the key issues:

One gross inequity stands out in the [P]resident’s proposal. Several midwestern and southeastern states are being asked to make emission reductions above and beyond their proportional contribution to the problem -

56. White House Fact Sheet on the President’s Clean Air Plan, 25 WEEKLY COMP. PRES. DOC. 882 (June 12, 1989). The initial group of 107 plants targeted for Phase I controls was expanded subsequently to 111 plants after additional plant emission data became available.
being asked, in effect, to make reductions for both themselves and others.

The [P]resident would require nine states, which contribute only fifty-one percent of the nation's sulfur dioxide (SO2) emissions, to achieve and pay for sixty-seven percent of the SO2 reductions.

Even this vast discrepancy understates the unfairness, because states that are among the highest overall emitters of SO2 and NOx escape cleanup responsibility entirely in proposals that focus for cost-effectiveness reasons on emissions from utilities, which tend to be large single sources of these pollutants.

. . . .

. . . A pound of SO2 or NOx removed from the air is of equal benefit to the environment whether it is removed from a small industrial facility in Texas or a large power plant in the [M]idwest.

. . . .

There is a way to reconcile the conflict between cost-effectiveness and fairness: cost-sharing. The argument is emphatically not that all of America's citizens should pitch in to clean up a few states' emissions; it is almost the reverse: that a few states should not be cleaning up both their own and somebody else's portion. Through cost-sharing, Texas can "pay" the targeted states to clean up its fair share of emissions, but at a lower cost than if it actually had to clean up the emissions in Texas.57

The Senate and House of Representatives pursued different paths in their efforts to modify the Administration's Phase I plan. In the Senate, a bi-partisan group of fourteen midwestern members, led by Senator Byrd, proposed to reduce the number of plants included in Phase I, and to provide a direct capital cost subsidy for the use of emission control technologies at Phase I plants through a nationwide fee on fossil-fired electric power generation.58


58. The 20-plant proposal favored by Senator Byrd's group would have provided a 90% capital cost subsidy for plants electing to retrofit scrubbers to meet an emission limit of 1.1 pounds of SO2 per million BTU. The capital cost subsidy would have been paid through the proceeds of a nationwide fee of one-
Responding to Senator Byrd's initiatives, Senate Majority Leader Mitchell and Senator Max Baucus (D-MT), Chairman of the Senate Committee on Environment and Public Works, agreed to revise the Administration's acid rain proposal. The Mitchell-Baucus compromise would have required the twenty largest emitters of SO2 to reduce emissions to 1.1 pounds of SO2 per million BTU by 1995. If this approach had been adopted by the Senate, momentum could have developed for a nationwide fee on electric generation in order to defray the costs of controls at these specific plants. However, in its consideration of the Mitchell-Baucus compromise, the Senate Committee on Environment and Public Works chose to retain the Administration's 107 plant Phase I option in Title IV of Senate Bill 1630.

In the House, Representative Sharp and Representative John Dingell (D-MI), Chairman of the Committee on Energy and Commerce, developed a cost-sharing mechanism based on a user fee of fifty-five dollars per ton of SO2 emitted by industrial sources, with the proceeds earmarked for the 107 plants included in Phase I. The White House, concerned that such a "user fee" would constitute a new federal tax, strenuously opposed the plan. As a result, insufficient votes were committed to the plan, and it never reached the floor for consideration by the full House of Representatives.

C. Senate-Administration Negotiations

Final Senate agreement on the 1990 CAAA was preceded by a series of closed-door negotiations between representatives of the Executive Branch, and Democratic and Republican members of the Senate. In these negotiations, each of the major titles of Senate Bill 1630 as reported by the Senate Committee on Environment and Public Works was modified to conform to the Administration's reported clean air "budget" or the overall macroeconomic impact of clean air reforms that the Administration was prepared to support.

half a mill ($0.005) per kilowatt-hour on all U.S. fossil-fired generation. See Nov. 30, 1989 Memorandum, supra note 4, at 3.


62. Id.

As closed-door negotiations proceeded, Senator Byrd's group of midwestern senators agreed to a compromise proposal for enhancing the incentives for technological emission controls in the acid rain control provisions of Senate Bill 1630. The Byrd-Bond Amendment, co-sponsored by Senators Byrd and Christopher S. Bond (R-MO), modified Senate Bill 1630 by permitting a two-year time extension under Phase I for utilities that choose to use "qualifying technologies" to reduce emissions, and by creating a system of two-to-one bonus emission allowances for emission reductions achieved during 1997-99 through qualifying technologies.

As a condition for accepting the Byrd-Bond Amendment, the Senate and Executive Branch negotiators imposed a limit of 3.5 million tons on the total number of SO2 allowances that would be made available under the two-year extension and two-to-one bonus provisions of modified Senate Bill 1630. This ceiling translated to ten to fifteen gigawatts of retrofit scrubber capacity, or ten to fifteen large 1,000 megawatt plants that could take advantage of the two-year delay and bonus emission allowance program. The 3.5 million ton pool of Phase I allowances was created, in effect, by advancing the Phase I deadline of the Administration's initial acid rain proposal by one year, from December 31, 1995, to January 1, 1995, with the resulting additional SO2 reductions assigned to the pool.

The two-year extension and two-to-one bonus allowance provisions encourage technological emission reductions during Phase I by offering utilities an opportunity to earn substantial numbers of allowances that can either be used to delay compliance, or sold to defray the capital and operating costs of emission controls. If delayed compliance is chosen, generating units qualifying for a two-year time extension will receive sufficient allowances to cover each unit's emissions during 1995-96. If a unit achieves compliance with Phase I by January 1, 1995, the two-year extension allowances may be banked for later use or sold to other utilities.

64. "Qualifying Phase I technology" is defined as a technological system of continuous emission reduction which achieves a 90% reduction in sulfur dioxide emissions from the emissions which would have resulted from the use of fuels which were not subject to treatment prior to combustion. 42 U.S.C.S. § 7615(a)(19) (Law. Co-op. Supp. 1991).

65. 42 U.S.C.S. § 7651c(d)(6) (Law. Co-op. Supp. 1991). These two-to-one bonus allowances are to be awarded by EPA on the difference between a unit's controlled emissions and its tonnage emissions at a rate of 1.2 pounds of SO2 per million BTU.

66. See Nov. 30, 1989 Memorandum, supra note 8, at Table 2.
utilities. The two-to-one bonus allowances applicable during the period 1997-99 also may be banked or sold.

D. Conference Agreement

The acid rain title of Senate Bill 1630 formed the basis for the conference agreement creating Title IV. During the House-Senate conference, additional allocation provisions were agreed to for "clean" and "growth" states seeking allowances to ensure a margin for growth during Phase II, when the nationwide emissions cap of 8.9 million tons of SO2 becomes effective.67

Both the House and Senate committees contended with pressures from diverse interests seeking allowances for future emissions growth. In creating various allowance entitlements for "clean" and "growth" states, Congress may have diluted the value of the Phase I extension and bonus allowance pool by reducing the potential demand for the resale of these allowances to utilities in other states.68

Concerns about utility "hoarding" of allowances led the

67. Section 405(a)(2) of the CAAA creates a Phase II reserve of 5.3 million tons of allowances that are to be assigned at a rate of 530,000 tons per year during the period 2000-2009 to various categories of low-emitting plants. 42 U.S.C.S. § 7651d(a)(2) (Law. Co-op. Supp. 1991).

68. In the original Administration proposal, units emitting at a rate below 1.2 pounds of SO2 per million BTU in 1985 were exempted from the emission allowance program provided their emissions remained below this rate. Western and other low-emitting states recognized that as these clean units were retired, they would need to purchase emission allowances from the Midwest to cover emissions from new generating units. Concerns about the lack of emission allowances granted to clean states led these states to seek inclusion in the allowance program. See, e.g., Hearings Before the Subcomm. on Energy and Power, supra note 6, pt. 1, at 115-16:

Mr. Tauzin: So, in essence, after paying for 50% of the cleanup, and earning 50% of the credits, these utility plants in these nine States will have what we Cajuns call a lagniappe, for having paid their fair share of the cleanup.

Lagniappe may not be a term that you are familiar with, Mr. Reilly, but I know that Mr. Moore understands lagniappe. These States now have lagniappe that they can sell and make money from, or they can use to grow. Now, the States on the other hand, like mine, where many of our utilities . . . are now emitting at much lower rates.

. . . .

For our States to grow, we can increase our production, and I understand that, because we are below 1.2, and we can increase the production of that plant, as long as our rates stay the same.

But if we want to grow, and we are interested in growing in Louisiana . . . then we have to go pay somebody off to grow. Is that right?

Mr. Reilly: That's right. If you are talking about constructing new plants, yes, that is correct.

Id. (colloquy between Representative Billy Tauzin (D-LA) and William K. Reilly, Administrator, EPA).
House and Senate to provide for public auctions of allowances by EPA, with 2.8 percent of all regular allowances reserved by EPA for auction purposes. The conference committee blended the auction provisions of the House and Senate bills. The committee also adopted provisions from the House bill awarding up to 300,000 bonus emission allowances to utilities that reduce emissions through energy conservation.

The final language of the Byrd-Bond Amendment established an “order of receipt” priority for awarding the two-year extension allowances to units employing qualifying Phase I technology. Section 404(d)(3) of the CAAA states in part: “The Administrator shall review and take final action on each extension proposal in order of receipt, consistent with section 408 . . . and for an approved proposal shall designate the unit or units as an eligible [P]hase I extension unit.”

The “order of receipt” language in section 404 was added in contemplation of possible over-subscription of the 3.5 million ton Phase I extension and bonus allowance pool. The conference bill provided that EPA should award all of the two-year extension allowances to qualifying units before awarding any two-to-one bonus allowances. These limits were imposed because Congress recognized that there could be far more demand for Phase I extension and bonus allowances than the maximum supply fixed by the 3.5 million ton allowance pool.

III. EPA Implementation of the Byrd-Bond Amendment

Implementation of the Phase I extension and bonus allowance program created by the Byrd-Bond Amendment has proven more controversial than its sponsors may have envisioned. To assist in the development of regulations implementing Title IV, EPA established an Acid Rain Advisory Committee (ARAC) consisting of representatives of industry, labor, environmental and academic organizations. ARAC has conducted six public meetings to provide technical and policy input to EPA’s proposed


72. Id.
emission allowance trading regulations.\(^7\)

In ARAC's deliberations, some industry interests argued for a strict "first-come, first-served" interpretation of the "order of receipt" language of section 404(d)(3) of CAAA. This meant that utility applications for extension and bonus allowances would be processed by EPA based literally on the time of their receipt, as determined by a date and time stamp or similar procedure. In the event of a tie, or an over-subscription of the 3.5 million ton allowance pool, a lottery was proposed as a means for distributing allowances.\(^7\)

Recognizing that the Byrd-Bond extension and bonus allowance program was intended to encourage the use of control technologies for meeting Phase I requirements,\(^7\) utility and labor groups on ARAC endorsed an alternative pro rata method for distributing these allowances.\(^7\) EPA would accept all applications for extension and bonus allowances on a date certain and, in the event that total requested allowance awards exceeded the statutory 3.5 million ton pool, would issue each qualifying unit a percentage of its requested allowances.

In its proposed emission allowance regulations, EPA rejected a pro rata distribution and sought comment on an alternative method for awarding Phase I extension and bonus allowances employing a telephone-based queuing procedure.\(^7\) Under this approach, designated representatives of each utility unit seeking an award would dial an 800 telephone number at a specified time.

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73. 56 Fed. Reg. 63005 (1991) (to be codified at 40 C.F.R. pts. 72, 73, 75 & 77).
74. See Memorandum from Rachel Hopp, Chief, EPA Permits and Technologies Section, EPA, to Permits and Technology Subcommittee (Jan. 24, 1991) (on file with author).
75. See U.S. Senator Robert C. Byrd, *The Clean Air Act Amendments of 1990*, supra note 4, at 482:
All of the provisions regarding eligible Phase I extension units are intended to encourage utilities with affected Phase I units to incorporate the use of scrubbers in their overall compliance strategies, and thus help reduce, at least during Phase I, the potentially disruptive impact of the Clean Air Act Amendments of 1990 on existing coal markets. . . . While it is not yet possible to know precisely what impact the 1990 Amendments will have on the coal industry, it is my belief that the scrubber incentives incorporated into the law will have a significant positive effect in terms of minimizing the adverse impact of the Phase I emission reduction requirements on high-sulfur coal.
Electronic voice-mail measuring devices would determine the order of receipt of each incoming call:

Subpart L would provide the procedures for early ranking of Phase I Extension plans submitted under Section 72.42 of today’s proposal. Subpart L addresses two concerns: (1) the statutory mandate in Section 404 (d)(3) of the Act that submissions for Phase I extensions be considered by the Administrator “in order of receipt”, and (2) the need of the regulated community to know as early as possible whether they will be eligible for Phase I Extension allowances. Because of the economic benefits a source would derive from a Phase I Extension, some estimates indicate that the Phase I Extension reserve of up to 3.5 million tons may be oversubscribed.

The Agency is, thus, proposing an Early Ranking procedure for determining the order in which to act on Phase I Extension applications. The Agency proposes to use a voice-mail telephone queuing procedure followed by a written Phase I Extension Early Ranking application submission mailed not later than midnight of the same business day of the phone queue. In rejecting the proposed pro rata approach for distributing extension allowances, EPA acknowledged that such an approach “might potentially encourage the installation of more control technology.” However, EPA indicated that the “order of receipt” language controlled its interpretation of Section 404(d) of CAAA, requiring a sequential distribution of allowances to applicants rather than a share of allowances to all applicants. EPA also left open the possibility of a private allowance pool among applicants: “Nor would today’s proposal preclude side-bar pro rata agreements between applicants, should utilities wish to pursue such arrangements. EPA would have no involvement, however, with such agreements.”

Faced with this invitation, utilities are making arrangements among themselves to reallocate the 3.5 million ton pool of Phase I extension and bonus allowances, irrespective of the specific method chosen by EPA to determine the “order of receipt” of

78. Id. at 63039-40.
79. Id. at 63041.
80. Id.
81. Id.
applications or EPA’s actual award of extension allowances. A private reallocation of this type already has been endorsed by the National Association of Regulatory Utility Commissioners.

Thus, the congressional intent underlying Section 404(d) of CAAA may be effected by private contractual agreements among utilities notwithstanding the “order of receipt” language imposed on EPA by the statute itself. This should expand the number of utilities able to participate in the Phase I bonus allowance program, increase the number of Phase I units employing emission control technologies instead of fuel-switching, and reduce the number of coal mining jobs lost due to Phase I compliance. A private reallocation of these bonus allowances also would guard against the possibility that the entire 3.5 million ton pool could be awarded to a handful of very large, high-emitting units.

IV. EMISSION ALLOWANCE TRADING OUTLOOK

It is premature to speculate on the extent of the market for emission allowances that may develop under Title IV. If the emission allowance market functions efficiently, it should yield high degrees of emission reduction at many of the large baseload power plants that had been targeted for initial controls by the 1988 Mitchell-UMWA compromise. In the absence of any allowance trading, all 111 power plants affected during Phase I would be required to reduce emissions to the equivalent of 2.5 pounds of SO2 per million BTU, inducing a massive disruption of national coal markets.

The 1991 proposal by the Chicago Board of Trade (CBOT) to establish allowance cash and futures markets is an encouraging sign that market mechanisms will be in place to facilitate allowance trading. CBOT’s application to the Commodity Futures Trading Commission contemplates that firms reducing more pollution than their minimum statutory requirements will be reimbursed for doing so through the sale of excess allowances:

84. For American Electric Power Company’s estimate regarding one large unit, see infra note 95 and accompanying text.
85. For a discussion of the 1988 Mitchell-UMWA compromise, see supra Section I, part D.
It is widely agreed that a market approach to reducing pollution will help assure the total cost of the program, and the overall effect on electricity rates, is minimized.

Firms that can cut pollution at low cost are encouraged to provide relatively large amounts of the pollution reduction, and are compensated according to the amount of "clean air" they produce. Firms for which pollution reductions are more costly can choose not to cut pollution, but would have to compensate the plants that make disproportionately large cuts in pollution. By encouraging pollution reduction to come from those most efficient at doing so, a market approach leads to the use of lowest cost pollution control equipment first. The market approach uses the lowest possible amount of society's resources to achieve mandated pollution reductions, and thus leads to the smallest possible increase in product costs. 87

The economic value of the 3.5 million ton Phase I extension and bonus allowance pool, and the deferred cost-sharing potential it represents, will be determined by the market prices these allowances command. Conventional economic theory suggests that allowance prices will reflect the marginal costs of emission reductions. 88 The marginal costs of control should increase during the early stages of Phase II, when virtually all coal-fired and oil-fired electric utility units must hold SO2 allowances equivalent to a 1.2 pound per million BTU emission limit at their 1985-87 historic level of BTU consumption, and when the nationwide SO2 emissions cap of 8.9 million tons becomes effective. Later in Phase II, allowance prices may decline as existing generating units are retired and their allowances become available to lower-emitting new units. 89

Subsequent to enactment of the allowance program in November 1990, estimates of the market value of allowances have declined from EPA's initial estimates. Values as great as $700 per

87. Id. at 1-2.
88. See Hearings Before the Subcomm. on Energy and Power, supra note 6, at 227 (comments of Council on Economic Advisors, projecting marginal control costs ranging from $100 to $400 per ton in Phase I and approximately $700 per ton at beginning of Phase II).
ton by Phase II were cited by EPA when the Administration first proposed the allowance trading program. Surveys of potential allowance buyers and sellers conducted in 1991 by the Fieldston Company indicated the following estimates of allowance prices:

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<td>June/July 1991</td>
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<td>Best Estimate</td>
<td>$450</td>
<td>$320</td>
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<td>High</td>
<td>$725</td>
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The October/November 1991 survey’s “best estimates” suggest an overall value for the 3.5 million ton Phase I extension and bonus allowance pool of $1.1 billion in 1995 and $1.4 billion in 2000, with a “high” estimated value as great as $2.45 billion by 2000. If this pool were allocated among twenty power plants with an average capacity of 1,000 megawatts, and the allowances were sold at the best estimate prices, the potential benefits would be worth some $55 million per plant in 1995, or $70 million per plant in 2000. These benefits in turn could be passed through to utility ratepayers to defray the capital costs of emission control technologies. As discussed below, state public utility regulatory commissions already are moving in this direction.

V. RECENT STATE REGULATORY EXPERIENCE

The potential value of extension and bonus emission allowances has played an influential role in recent state regulatory proceedings concerning utility compliance with Phase I of the 1990 CAAA. Cases in Ohio, Pennsylvania and West Virginia illustrate the important financial advantages of the deferred cost-sharing that can result through the sale of extension and bonus allowances.

90. Hearings Before the Subcomm. on Energy and Power, supra note 6, at 255.
91. CSR Emissions Allowance Trading Index, 2 COMPLIANCE STRATEGIES REVIEW 3 (Nov. 25, 1991).
92. Id.
A. American Electric Power Company, Inc.

Electric utilities operating in the state of Ohio are periodically required to submit long-term forecast reports to the Ohio Public Utilities Commission (PUC). As part of its regular review of the long-term forecast reports of Ohio Power Company and Columbus Southern Power Company, two subsidiaries of American Electric Power Company (AEP), the Ohio PUC initiated a proceeding in 1991 concerning AEP's proposals for compliance with Phase I of the 1990 CAAA.

The issues in this proceeding were joined by an initial AEP study of the costs of scrubbing and fuel-switching at Ohio Power's 2,600-megawatt Gavin plant in Gallia County, Ohio. The Gavin plant is the largest single source of SO₂ emissions in the United States, and receives most of its coal from a nearby mine owned and operated by an AEP mining subsidiary. Based on preliminary estimates of the costs of scrubbing and fuel-switching at the Gavin plant, AEP proposed to close its captive mine and to purchase lower-sulfur coals from the West or from central Appalachia.

On May 14, 1991, the staff of the Ohio PUC issued a report critical of AEP's proposed compliance plan. The staff concluded "that the methodology employed by AEP to conduct its preliminary study was inappropriate and unreasonable, and that the results of its preliminary study are unfounded." The Ohio PUC entered an order the same day directing AEP to submit a complete system-wide CAAA compliance plan taking into consideration, inter alia, "the value of emission allowances produced by over-complying at Gavin, which may be used elsewhere in the AEP system to avoid compliance expenditures otherwise required by the Clean Air Act Amendments." AEP complied with PUC’s order and filed a preliminary system-wide compliance plan.

Following local public hearings and an adjudicatory hearing to review the reasonableness and adequacy of AEP's preliminary system-wide plan, the Ohio PUC issued an opinion and order on September 24, 1991. The commission concluded that:

The three most critical issues which have the greatest impact on a determination of least cost compliance at Gavin are the projected prices and supply reliability of low-sulfur coal, whether AEP will receive reserve allowances if it installs scrubbers at Gavin, and the market value of allowances to be earned. ... AEP's lack of a detailed fuel cost sensitivity analyses make[s] the fuel switch option at Gavin very risky. On the other hand, most parties agree that installing a scrubber at Gavin would not be cost effective unless AEP received its share of reserve allowances, which will not be known until March of 1992 or possibly later.100

The Ohio PUC's analysis indicated that emission allowance values in 1995 could range from a low of $429 per ton to a high of $989 per ton.101 AEP estimated that the Gavin plant alone could receive some 790,000 extension and bonus allowances, or nearly one-fourth of the total 3.5 million ton reserve pool.102 Using a value of $400 per ton, AEP determined that these allowances would be worth in excess of $300 million.103 Taking this into account, the Ohio PUC found that:

AEP should consider more seriously over-compliance in Phase I and the trading and banking of excess allowances as a compliance option. This could provide AEP with additional cost savings not only in Phase I but in Phase II as well. ... We would also encourage AEP to explore an overall allowance trading strategy and the possibility of allowance pooling arrangements apart from its power pooling agreement, possibly including plants in other systems.104

100. Opinion and Order, supra note 94, at 31.
101. Id. at 18.
102. Id. at 27.
103. Id.
104. Opinion and Order, supra note 94, at 18.
In addition, the commission encouraged AEP "to explore collaborating with other prospective bidders for reserve allowances and to determine the feasibility of a post-queue, pro-rata allocation of scrubber reserve allowances." By participating in such an after-the-fact reallocation of the extension and two-to-one bonus allowance pool, regardless of the outcome of EPA's telephone queue or other distribution method, AEP could assure itself of a substantial share of its estimated 790,000 ton entitlement.

In its findings of fact and conclusions of law, the commission determined that AEP "should keep both its fuel switching and scrubbing options open at Gavin until it can be determined whether AEP will receive reserve allowances." Specifically, the Ohio PUC recognized that the potential value of the extension and bonus allowances AEP could receive from EPA could tip the economic balance in favor of scrubbing: "The installation of scrubbers at Gavin can provide the lowest cost option consistent with the provision of adequate and reliable service, provided AEP receives its share of reserve allowances from EPA."

Subsequent to the Ohio commission's order, AEP has undertaken preliminary site construction at the Gavin plant to provide for the installation of scrubbers; has applied for permits to construct barge unloading facilities for the transportation of lime used in the scrubbing process; and has sought authorization to issue partially tax-exempt bonds to finance the capital costs of retrofitting Gavin with scrubbers.

B. Allegheny Power System, Inc.

Allegheny Power System (APS) is a utility holding company serving customers in portions of Ohio, Pennsylvania, Maryland, Virginia and West Virginia. In 1990, APS initiated a comprehensive system-wide compliance plan covering all plants in its system for both Phase I and Phase II of Title IV. Its analysis, in the form of a five-volume study, was distributed early in 1991 to the

105. Id. at 28.
106. Id. at 38.
107. Id. at 38.
five state regulatory commissions in its service territory.\textsuperscript{110}

The APS analysis evaluated 31.8 million combinations of scrubbing, fuel-switching, early retirement and other control options at its system plants.\textsuperscript{111} After an initial screening analysis for cost-effectiveness, ten scrubbing and fuel-switching options were selected for more detailed computer modeling.\textsuperscript{112} The APS study also evaluated, but did not explicitly take into account in its recommended compliance strategy, the values of the extension and bonus allowances it could receive through scrubbing and the socioeconomic impacts of fuel-switching in its service territory. Most of the coal currently consumed by APS is produced by mines located within its service territory.

The APS compliance study indicated that scrubbing the three units of the 1,920-megawatt Harrison Station located in Harrison County, West Virginia, was the most reasonable and cost-effective Phase I compliance option.\textsuperscript{113} Scrubbing this plant would generate sufficient emission reductions to cover APS's entire Phase I tonnage reduction requirement, leaving aside the potential extension and bonus allowances APS might receive from EPA.

In early 1991, APS executed contracts for the construction of scrubbers at Harrison and initiated regulatory proceedings seeking pre-construction approval of the prudence of its compliance strategy, and adjustments to its electric rates to provide current recovery of a portion of its CAAA compliance costs during construction. APS estimated its overall Phase I CAAA compliance capital costs at $806 million.\textsuperscript{114}

Extensive public records were developed in the course of APS’s compliance plan reviews in Pennsylvania and West Virginia, the states containing most of APS’s service territory. APS’s plan initially was attacked by natural gas industry intervenors on the grounds that co-firing natural gas at Harrison Station would be more cost-effective than scrubbing. The natural gas intervenors subsequently withdrew from these cases following a negotiated settlement with APS providing for modest additional gas use at some of APS’s other plants.\textsuperscript{115}

\textsuperscript{110} Id.
\textsuperscript{113} Id. at 11-1.
\textsuperscript{114} See ALLEGHENY POWER SYSTEM STRATEGY, supra note 109.
\textsuperscript{115} Memorandum of Agreement on Behalf of the Public Service Commis-
Another objection to APS's plan arose through challenges by consumer advocates to the three-unit scrubbing strategy. The consumer advocates in Pennsylvania\(^{116}\) and West Virginia\(^{117}\) argued that APS should scrub only two of the units at Harrison Station in Phase I, relying on additional energy conservation and other measures to ensure compliance with Phase I. An additional issue in both states concerned the proposed form of financial recovery of project costs.

Although APS had not relied on the availability of extension or bonus allowances in its economic evaluation of the costs of scrubbing and fuel-switching, the potential benefit of these allowances became a major issue in each of the state proceedings.

In an order dated December 12, 1991, the Public Service Commission of West Virginia determined that:

> [T]he three scrubber option is the most cost-effective alternative given the uncertainty of the Companies' ability to economically cover any future excess emissions that would result from the [Consumer Advocate Division's] proposed two scrubber option. This finding is further supported by the potential for excess allowances attached to the three scrubber option and the economic benefits that such excess allowances can produce for the Companies' customers to offset the compliance costs paid by these customers.\(^{118}\)

The West Virginia Public Service Commission's (PSC) decision incorporated a stipulated settlement agreement of the major issues in the case reached among the Consumer Advocate Division, the PSC staff, and a group of industrial intervenors.\(^{119}\) The PSC was presented with an issue of first impression in the determination of the appropriate treatment of allowance sales revenues, which the company argued should be deferred for later

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\(^{117}\) Brief of the Consumer Advocate Division of the Public Service Commission of West Virginia (1991) (No. 91-231-E-CN).

\(^{118}\) Commission Order, Public Service Commission of West Virginia at 12-13 (1991) (No. 91-231-E-CN) [hereinafter Commission Order].

\(^{119}\) Id. at Exhibit A.
consideration when the number of allowances that might be available were known with certainty. The stipulated settlement indicated that any such revenues should be passed back to ratepayers:

The analysis presented in this case by APS indicates that it is likely that installing scrubbers on all three units at Harrison power station will result in APS generating more sulfur dioxide reductions than required for APS total system during Phase I under the CAAA. Under the provisions of the CAAA these excess allowances may be bought and sold. As an integral part of the agreement to waive all objections to the project and to the agreement to pay for a portion of the project during construction, the parties agree that [Monongahela Power Company and Potomac Edison’s] share of revenues produced by the sale of excess sulfur dioxide allowances should be passed back to ratepayers.\(^{120}\)

The West Virginia PSC found that the stipulated agreement on allowance sales proceeds was reasonable, and directed that the companies “should be required to defer revenues from allowance sales so that any such revenues will be available for disposition as directed by the Commission.”\(^{121}\) The commission also concluded that the construction of scrubbers at the three units was reasonable, and that the applicants should receive a certificate of public convenience and necessity for the proposed construction.\(^{122}\) The commission further approved a form of cost recovery as proposed by the stipulated agreement.\(^{123}\)

APS’s proceeding in Pennsylvania was initiated by West Penn Power Company on April 3, 1991, and the case was heard before an administrative law judge in October 1991. The recommended decision of the administrative law judge was handed down on December 6, 1991.\(^{124}\) In its filings, West Penn Power, a part-owner of the Harrison Station power plant, had sought a declaratory order from the commission that its plan to scrub three units at Harrison Station was reasonable, prudent, and in the public

\(^{120}\) Id. at 3.

\(^{121}\) Commission Order, \textit{supra} note 118, at 15.

\(^{122}\) Id. at 19-20.

\(^{123}\) Id. at 20.

\(^{124}\) Recommended Decision Before the Pennsylvania Public Utilities Commission (1991) (Nos. P-910511, P-910512 & P-910512C001) [hereinafter Recommended Decision].
interest. West Penn Power also sought approval of a rate surcharge for current recovery of a portion of its CAAA compliance costs.

The Pennsylvania Office of Consumer Advocate, the Office of Trial Staff, and industrial intervenors mounted a variety of legal and technical arguments against West Penn Power's petitions. It was asserted that the commission lacked the authority to issue a declaratory order on the prudence of West Penn’s compliance plan; that rate relief was not permissible because the installation of scrubbers would generate revenues through the sale of emission allowances, contravening a Pennsylvania requirement that pollution control facilities be “non-revenue-producing” for purposes of obtaining rate relief prior to their in-service dates; and that West Penn Power had not established through its five-volume compliance study that scrubbing three units at Harrison represented the least-cost compliance option.

The administrative law judge found support for the commission's authority to enter a declaratory order; recommended against a rate surcharge for current recovery of a portion of the company’s CAAA compliance costs; and determined that the proposed compliance plan met the applicable standards for prudence.

130. Recommended Decision, supra note 124, at 42-48 (relying in part on 66 PA. C. S. 381(f), providing that the commission may issue declaratory order to terminate a controversy or remove uncertainty).
131. Id. at 93. The administrative law judge accepted the arguments of various intervenors that 66 Pa. C.S. 1307(a), providing for a sliding scale of rates and adjustments, can only be used as an expense recovery mechanism and cannot be used as a device to recover revenue requirements or a return on rate base. The usual purpose of automatic adjustment clauses in Pennsylvania is limited to recovery of operating expenses such as state taxes, fuel costs, and the like, and not expenditures that increase a company’s rate base or provide a return on rate base. Id. at 80-82.
132. Id. at 57-60, 98 (citing, inter alia, Pennsylvania Public Util. Comm’n v.
The potential value of the extension and bonus allowances that West Penn could receive as a result of its scrubbing strategy was noted by the administrative law judge, but did not provide support for his recommended finding of prudence:

Scrubbing of the three units at Harrison makes APS eligible to apply for up to 572,000 bonus and extension allowances. . . . If the allowances are valued at $500 to $1000 each, the benefit from the extension and bonus allowances would amount to a net present value in 1995 dollars of $325 million to $650 million. If West Penn is entitled to forty-two percent of these allowances (which is roughly its ownership share in Harrison), that would result in potential revenue of between $136 million and $273 million. . . . Thus, if West Penn constructs the three scrubbers and receives all of the bonus and extension allowances for which it may apply, and if the market price for emission allowances is anything close to that which is projected at the present time, sale of the allowances would offset, at worst, almost fifty percent of the cost of construction of the scrubbers. Should the market price of the allowances be close to the high end of present estimates, sale of the allowances could offset the cost of the scrubbers entirely.

. . . Unless the Commission waits to see if APS can win the EPA call-in derby, the Commission will not know if West Penn will receive the extra allowances. . . . While the federal government appears to have chosen to distribute bonus and extension allowances on the basis of what amounts to a game of chance, it would be absurd to declare a compliance strategy "prudent" which relied upon the outcome of such a game. West Penn argues that its scrubber compliance strategy is justified without reliance upon the extension and bonus allowances.133

As in West Virginia, a regulatory policy issue raised in Pennsylvania concerned the disposition of the potential revenues Pennsylvania Power Co., 64 Pa. P.U.C. 308, 317 (1987): "Prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. In determining whether a judgment was prudently made, only those facts available at the time judgment was exercised can be considered. Hindsight review is impermissible." (emphasis in original)).

133. Id. at 53-56 (citations omitted).
gained by the sale of bonus and emission allowances. West Penn Power took the position in its filings that "to the extent that ratepayers share in [the cost of the scrubbers], they would share in any allowance benefits to offset those costs when those allowances are received." However, the administrative law judge had noted at trial the possibility that "the Company might come back and ask that the Commission allocate some of the excess value to the stockholders," and West Penn Power agreed that such a request was possible.

The recommended decision of the administrative law judge reasoned that a prudence determination "would reduce the risk to West Penn's investors, while shifting it, to a degree, to the ratepayers . . . ." The judge concluded that any excess benefit from bonus or extension allowances should flow to the ratepayers, because "to rule otherwise would make pollution control equipment both less risky and more profitable than generation and distribution equipment."

VI. CONCLUSION

Initial state CAAA compliance proceedings underscore the Byrd-Bond Amendment's potential for encouraging the use of emission control technology during Phase I, and for achieving a degree of deferred cost-sharing among states and utility systems through the sale of emission allowances. The 3.5 million ton pool of extension and bonus allowances is emerging as an important, if uncertain, regulatory benefit both for utilities and for ratepayers. Clearly, electric utilities faced with Phase I compliance decisions cannot afford to overlook the potential economic value of the extension and bonus allowances to which they may be entitled under section 404 of CAAA. This economic value may be real-

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134. Id. at 46 (citing West Penn St. 1 at 5).
135. Recommended Decision, supra note 124, at 48.
136. Id. at 50.
137. Id. The recommended decision reasoned that:

If West Penn receives the declaration which it seeks, the risk associated with investment in the scrubbers will be substantially reduced (albeit not eliminated), while at the same time West Penn will be positioned to benefit financially should the allowance market develop in such fashion that West Penn's excess allowances have considerable monetary value. While the ratepayers will have paid for the scrubbers, West Penn proposes to wait until a future date to determine whether the ratepayers will receive any financial benefits which may accompany the allowances over and above the cost of the scrubbers themselves.

Id. at 48-49.
ized by the direct sale of allowances, or by banking allowances for subsequent use and thereby delaying Phase II control actions.

The development of a private, _pro rata_ allocation of the 3.5 million ton allowance pool following EPA's initial distribution of these allowances in mid-1992 would encourage the widest dissemination of allowance benefits. By spreading the allowance pool broadly, and taking advantage of the extremely high emission reduction potential of current and emerging control technologies, Phase I emission reductions could be concentrated at several dozen plants rather than spread among all 111 plants targeted for Phase I reductions.

The regional fairness of the Title IV acid rain control program will not be known until early in the next century. The emission allowance trading program for SO2 emissions, at this point the subject of proposed regulations in the _Federal Register_, already is being touted as a model for the control of carbon dioxide and other greenhouse gases associated with global climate change.138 Utilizing market incentives for pollution control, as an abstract economic concept, has broad appeal. However, previous efforts by EPA to incorporate economic incentives within environmental protection programs have had mixed success.139 Title IV of the CAAA is a major gamble by Congress and the Bush Administration that economic incentives will prove more efficient in reducing pollution than traditional source-specific control programs.

The efficiency of Title IV emission allowance trading, and the degree of interregional cost-sharing that it provides, will be measured in both financial and social terms as the program is implemented over the next decade. Direct utility compliance costs will be relatively easy to determine. If the Byrd-Bond Amendment achieves a substantial measure of employment protection for coal miners and the communities that depend on the coal industry, as its sponsors intended, the indirect social costs of Title IV should be reduced. But if the allowance market disenfranchises scores of coalfield communities, resulting social costs must be counted against any direct utility cost savings achieved through the trading


program. This accounting could provide an acid test for the subsequent use of free-market principles in federal environmental regulation.