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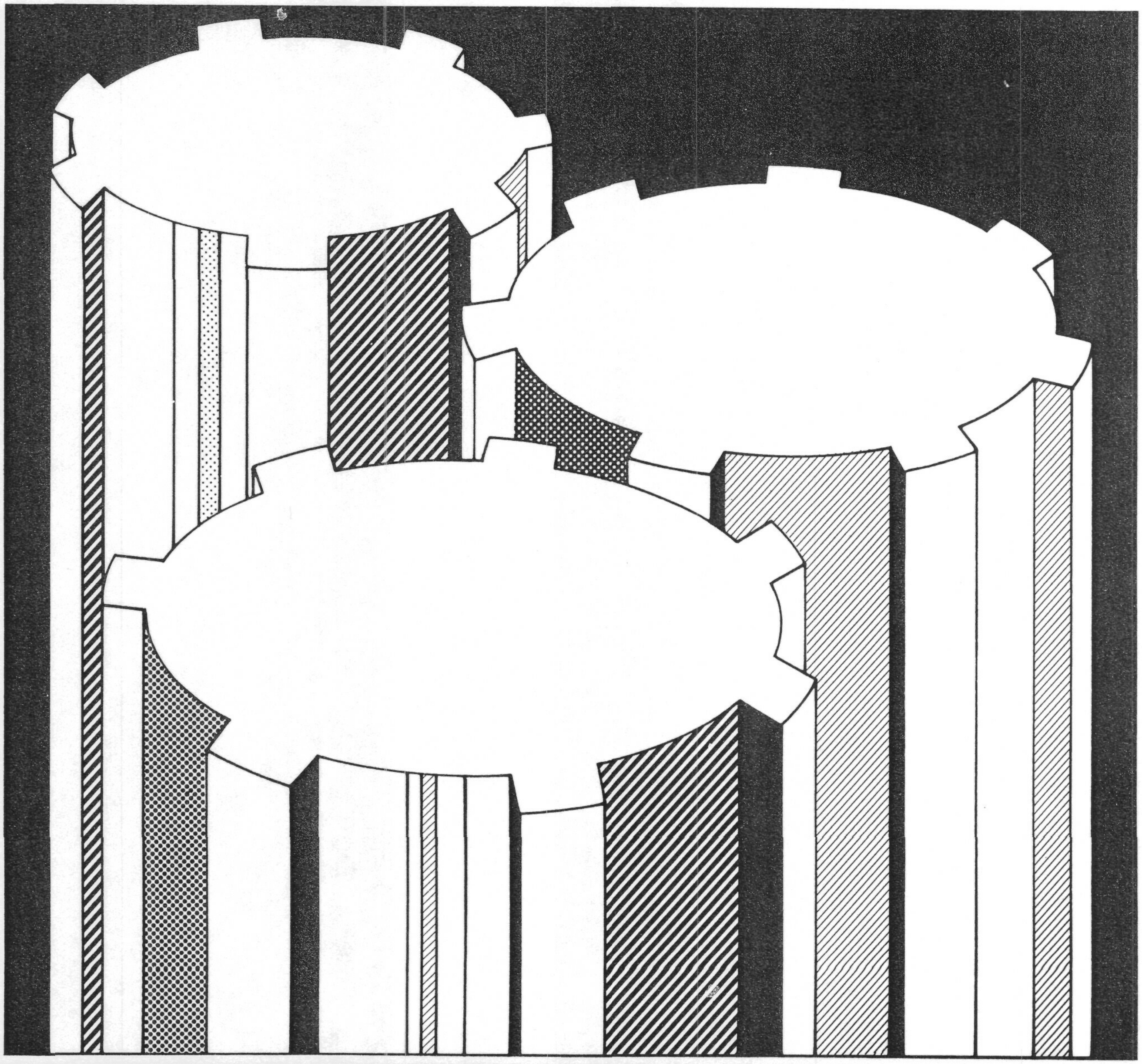
Curbing Acid Rain: Cost, Budget, and Coal-Market Effects



CBO STUDY

CONGRESSIONAL BUDGET OFFICE
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Director

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ERRATA

On page 160, Options IV-1 through IV-3 were mistakenly captioned Options VI. The page should have appeared as below.

Option III-2C: A 10 million ton rollback of SO_2 emissions that requires the 50 highest emitting plants to install scrubbers, and that includes a 90 percent capital subsidy for all retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option IV-1: Imposes a tax on SO_2 emissions of $600 per ton, to achieve a total SO_2 rollback of 9.2 million tons.

Option IV-2: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.5 million tons.

Option IV-3: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy and a 50 percent O&M subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.6 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained in each ton (to the extent that sulfur content exceeds 10 pounds per ton). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained per million Btus (to the extent that sulfur content exceeds 0.4 pounds per million Btus). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option VI-1: A polluter pays rollback of SO_2 emissions based on utilities' achieving a statewide average emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.1 million tons.

Option VI-2: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.9 million tons.

Option VI-3: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 0.7 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 12.3 million tons.

CURBING ACID RAIN:

COST, BUDGET, AND COAL-MARKET EFFECTS

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NOTE

All costs are in 1985 dollars unless otherwise noted.

PREFACE

Throughout the 1980s, acid rain has grown into a prominent environmental concern. Although questions remain on the chemistry and mechanisms of damage from acid rain, both the 98th and 99th Congress have considered proposals to stem this form of pollution. These proposals call for significant reductions in the amount of sulfur dioxide discharged by electric utilities, usually by placing additional controls on older power plants that are principally located in the Midwest and Appalachia and burn coal with a high sulfur content. Such approaches raise complex regional issues of who would pay the sizable abatement costs and which states might suffer substantial losses in coal production and mining jobs. At the request of the Senate Committee on Environment and Public Works, this study examines the key elements of legislative proposals introduced over the last several years, including two recent bills now under consideration in the Congress. In keeping with the Congressional Budget Office's (CBO) mandate to provide objective analysis, this report makes no recommendations.

This paper was written by Marc Chupka and John Thomasian of CBO's Natural Resources and Commerce Division, under the supervision of Everett M. Ehrlich and John Thomasian. The authors wish to express special thanks to William Orchard-Hays and Melinda Hobbs of the Department of Energy for their time and expert knowledge. Lois Trojan, Caryna Baker-Fox, Dolly Riegert, and Tom Young provided valuable research assistance. The authors are also grateful to the many individuals who provided valuable comments on earlier drafts, including Robert Friedman, Rob Brenner, and Paul Portney. Patricia H. Johnston edited the manuscript, and Patricia Joy prepared the report for publication.

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Director

June 1986

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SUMMARY

Over the past several years, the Congress has considered various methods to control "acid rain." Acid rain is a type of air pollution in which acidic compounds in the atmosphere (usually sulfates and nitrates) fall to the earth's surface through the action of rain and gravity. The particles that comprise acid rain can damage structures, ecosystems, and--through respiratory exposure--possibly human health.

The causes of acid rain are generally understood; man-made emissions of sulfur dioxide and nitrogen oxides, often discharged far from the areas they ultimately affect, are the primary culprits. Yet, the extent of the problem and its control remain subjects of debate. A number of Congressional proposals would lower sulfur dioxide (SO_2) emissions from the nation's power plants by between 45 percent and 70 percent from levels reported in 1980, perhaps the year of highest SO_2 discharges in this decade. Sulfur dioxide emissions from electric utilities have been targeted because they represent the pollutant and source most amenable to significant reduction through available techniques. But the high cost of such emission reductions (at least $3.2 billion annually for about a 60 percent national reduction from 1980 levels) and their potentially adverse effect on mining employment in the high-sulfur coal regions of the Midwest and Appalachia have spurred a search for alternative abatement programs.

This paper examines the different types of programs that the Congress has considered to diminish SO_2 emissions. Some control options would place no restrictions on the type of coal used or abatement method chosen; some would restrict switching from high-sulfur to low-sulfur coal; and others would tax either electricity production, sulfur dioxide emissions, or the sulfur content of coal to finance partially the utilities' costs of installing flue gas desulfurization equipment ("scrubbers") as an alternative to burning low-sulfur coal. While this analysis calculates the costs and coal-market effects of various SO_2 reduction alternatives, it does not estimate the benefits of the emission reductions. Such estimates lie beyond the scope of this study.

THE NATURE OF THE PROBLEM

Man-made emissions of SO_2 totaled about 27 million tons nationwide in 1985, of which about 15.8 million tons came from electric utilities. Under current policy, SO_2 emissions from electric utilities are expected to grow to approximately 18.5 million tons per year by 1995. Although new power plants will produce some of this growth, older plants--built before the first federal emission regulations were issued in 1971--will still account for over 90 percent of total utility SO_2 discharges in 1995. The chief federal emission law affecting electric power plants--called the New Source Performance Standard (NSPS)--limits the discharge of SO_2 and other pollutants from new utility boilers. (This regulation was revised and standards tightened in 1978.) Although power plants built before the first NSPS still must meet other requirements of the federal Clean Air Act, their emission limits are generally set by the states and are usually more lenient than the federal NSPS.

The SO_2 emitted from these older sources (as well as from newer, but cleaner plants) is an important primary pollutant in the formation of acid rain. As the SO_2 is carried away from its source--it can travel well over 300 miles--it can be transformed in the atmosphere to sulfate, perhaps the most commonly studied constituent of acid rain. Sulfate compounds and other acid rain pollutants can return to earth in rain, snow, fog, dew, or as dry particles and gases. Upon entering bodies of water, these compounds can threaten aquatic life by raising the acidity of a lake or stream beyond acceptable levels for some fish species. Acid rain has also been linked to crop and tree damage, although airborne pollution may be only one of several explanations for these effects. Finally, some researchers--amid much disagreement--believe that acid rain poses a health risk, primarily among people with preexisting cardiac or respiratory problems.

Proposals to lower the amount of SO_2 discharged from electric utilities typically have called for a reduction of between 8 million tons and 10 million tons annually as measured from 1980 levels. (The year 1980 is a commonly used baseline, since it tends to capture the emissions of the older plants which are most often chosen for control.) Most programs would assign reductions to the individual states through an "excess emissions" formula that targets those states with the most power plants emitting SO_2 in excess of a specified amount.[1] Under the traditional regulatory approach, each state would be required to meet its overall reduction level by placing new emission limits on the power plants it now regulates; states would be

1. Typically, the benchmark used is 1.2 pounds of SO_2 emitted per million British thermal units (Btu) of fuel used, which is the same standard as set by the first utility NSPS of 1971. The excess emissions are defined as the total amount of SO_2 emitted annually by each plant in excess of 1.2 pounds per million Btu. National allocation schemes are subsequently derived by dividing each state's share of excess emissions by the national total of excess emissions and then multiplying this fraction by the appropriate reduction target (for example, either 8 million tons or 10 million tons).

allowed to set the new limits for each power plant. Usually, the states and utilities would be given about 10 years to comply. For this analysis, 1995 is used as the illustrative deadline.

A major issue in all proposals is the relative cost burden that would fall on specific areas of the country. Because of their reliance on older, coal-burning power plants, the states of Missouri, Illinois, Indiana, Ohio, and Pennsylvania account for over 40 percent of annual utility SO_2 emissions. These same states would, therefore, bear the greatest responsibility for lowering SO_2 emissions under most plans.

Coal-Market Issues

Reducing SO_2 emissions nationwide would have varying effects on coal production in different regions of the country, chiefly because the sulfur content of coal differs among the three major coal-producing areas. The Appalachian states contain both high- and low-sulfur coal, which is predominantly mined through expensive underground methods. The Midwest, primarily in the Illinois coal basin, produces mostly high-sulfur coal, which is close to the surface and usually can be mined through less expensive "strip mining" methods. The western states of Wyoming, Montana, and Colorado, contain an abundance of low-sulfur coal which is often closer to the surface than in the Midwest, making it the cheapest coal to mine.

When an existing plant is required to lower SO_2 emissions, it can either switch to a lower-sulfur coal, which costs more, or install scrubbers and continue to use less expensive high-sulfur coal. If given the choice when faced with tighter SO_2 limits, most existing plants would switch coals, since the real annual cost of using a low-sulfur coal is often less than that of building and operating a scrubber for most levels of SO_2 reductions. Because 80 percent of all coal mined is used by utilities, a large-scale switch to low-sulfur coal could lower mining output in the states producing high-sulfur coal--chiefly Illinois, Indiana, Ohio, and Pennsylvania.

STRATEGIES TO REDUCE SO_2 EMISSIONS

This paper presents several types of programs to reduce SO_2 emissions, based in part on current and past legislative proposals (see box). The basic characteristics and effects of the options developed from these program types are contained in Summary Table 1, with the roman numeral in each option indicating the chapter in which it is discussed. The simplest program

TYPES OF PROGRAMS EXAMINED

The Polluter Pays Approach with No Fuel-Switching Restrictions.. This policy is the most traditional method for reducing SO_2 emissions. One example is to set emission reduction goals for each state (using the excess emission formula) and then require each state to set individual power plant emission limits in order to reach the statewide goal. This report examines two such cases in Chapter II: Option II-1A would require an 8 million ton SO_2 reduction from 1980 emission levels, and Option II-2A would require a 10 million ton SO_2 reduction. In contrast, the polluter pays approach could simply establish emission limits for individual power plants, and allow the states to permit either statewide averaging or compliance on a plant-by-plant basis. This method is exemplified by three SO_2 emission reduction options (between 9 million and 12 million tons) in Chapter VI. Options VI-1, VI-2, and VI-3 reflect various provisions of two recent Congressional proposals. In all cases, power plants could meet the assigned reductions by installing scrubbers or by switching to low-sulfur coal.

The Polluter Pays Approach with Fuel-Switching Restrictions. In addition to mandatory statewide emission reductions, these options would also restrict the amount of low-sulfur coal that could be substituted for high-sulfur coal. In this analysis, coal-market restrictions were simulated by requiring that 80 percent of coal purchases made in 1985 (as measured by sulfur content and coal rank) continue through 1995. This prescriptive approach for preserving current coal-market patterns is examined in Options II-1B and II-2B.

Electricity Taxes with Scrubber Subsidies. This type of option would provide financial incentives for installing scrubbers by partially subsidizing either their capital costs or their capital and operating costs. To pay for the subsidies, funds would be collected through a tax on electricity produced from fossil fuels. These alternatives are examined in Options III-1A, III-1B, III-2A, III-2B, and III-2C. In this last option, many high emitting power plants would be required to install scrubbers to meet the reduction goals.

Emissions Taxes with Scrubber Subsidies. These options would not establish specific emission reduction targets, but would provide financial incentives to lower SO_2 emissions by taxing the emissions themselves and, in some cases, by providing subsidies for scrubber installation. These scenarios are described in Options IV-1, IV-2, and IV-3.

Sulfur-in-Fuel Taxes with Scrubber Subsidies. This approach also would not mandate specific emission reduction targets, but instead would encourage SO_2 rollbacks by charging a tax on the sulfur content of coal burned by utilities while providing a rebate for each pound of sulfur removed through scrubbing. Options V-1 and V-2 explore these proposals.

would require each state to reduce SO_2 levels by a specified quantity (as determined by an allocation formula), and would offer no financial relief for doing so (except through existing tax provisions for capital equipment). This approach essentially embodies the "polluter pays" rule, since the polluter would have to assume all the abatement costs. Assuming that the states developed appropriate abatement plans, these options would cost the least, but would also yield the highest drop in expected high-sulfur coal production. A variant of the basic polluter pays approach would mandate the same emission reductions, but would also restrict the amount of low-sulfur coal that could be substituted for high-sulfur coal (the polluter pays with fuel-switching restrictions option). While this approach would raise overall costs by essentially forcing some utilities to install scrubbers, it would also limit projected losses in high-sulfur coal demand.

Other approaches would use economic incentives to discourage coal switching and encourage more scrubber use. One scheme would provide direct grants to those who installed scrubbers, using funds from a tax imposed on fossil-fuel electricity production. Two other alternatives also would subsidize scrubber installation, funding these subsidies by either a tax on SO_2 emissions or a tax on the sulfur content of the coal used. In the latter two policies, the taxes and subsidies themselves would provide financial incentives as the only means to achieve emission reductions.

Comparison of Costs

Two themes emerge from a comparison of the effects of the various options: first, the cost of abating one ton of SO_2 emissions rises as emission reduction targets are increased from 8 million to 12 million tons per year, with costs rising most steeply after 10 million tons; and second, costs rise as efforts are made to protect high-sulfur coal markets through the use of fuel-choice restrictions or subsidy policies designed to encourage scrubber use (see Summary Table 1). Using the polluter pays options as examples, the results show costs would be $270 per ton of SO_2 abated at the 8 million ton rollback level (Option II-1A), rising to $360 per ton at the 10 million ton rollback level (Option II-2A), and reaching $779 per ton at the 12 million ton rollback level (Option VI-3). In fact, the marginal cost of achieving an additional 2 million ton reduction by moving from an 8 million ton to a 10 million ton rollback would be about $720 per ton of SO_2 removed. Further increasing this rollback to 12.1 million tons would cost about $2,775 for each additional ton abated. Costs would rise much more steeply at the stricter levels of SO_2 control because switching to low-sulfur coal--a relatively cost-effective option at moderate reduction levels--would be supplanted by scrubber use as control targets became more ambitious. In effect, scrubber use would become mandated at high levels of emission control.

SUMMARY TABLE 1. CHARACTERISTICS AND EFFECTS OF OPTIONS

Option Characteristics	Polluter Pays Option II-1A	Option II-1B	Option II-2A	Option II-2B
SO_2 Emissions Reduction from 1980 Levels (In millions of tons)	8.0	8.0	10.0	10.0
Scrubber Subsidy Formula or Mandated Coal-Market Restrictions	None	No subsidies; 80% of 1995 coal purchases must be same type as purchased in 1985	None	No subsidies; 80% of 1995 coal purchases must be same type as purchased in 1985
Revenue Mechanism	None	None	None	None
Total Programs Costs (In billions of discounted 1985 dollars) a/	20.4	23.1	34.5	50.8
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	306	360	528
1995 Coal Production Changes in Four Key High-Sulfur States (In millions of tons per year) c/	-48.3	-39.0	-74.6	-44.0
1995 Changes in Coal Mining Employment Levels in Four Key High-Sulfur Coal States c/	-14,100	-11,600	-21,900	-12,800

(Continued)

SUMMARY TABLE 1. (Continued)

Option Characteristics	Electricity Generation Tax and Subsidy: Option III-1A	Option III-1B	Option III-2A	Option III-2B	Option III-2C
SO_2 Emissions Reduction from 1980 Levels (In millions of tons)	8.0	8.0	10.0	10.0	10; 7 from top 50 emitters, remainders from utilities according to excess emissions formula
Scrubber Subsidy Formula or Mandated Coal Market Restrictions	90% of annual capital cost subsidy	Subsidies for 90% of annual capital cost and 50% of annual O&M costs through 2015	Subsidy for 90% of annual capital cost	Subsidies for 90% of annual capital cost and 50% of annual O&M costs through 2015	Subsidy for 90% of annual capital cost
Revenue Mechanism	0.5 mills/ kwh tax on fossil-fuel electricity production	1.0 mills/ kwh tax on fossil-fuel electricity production	0.5 mills/ kwh tax on fossil-fuel electricity production	1.0 mills/ kwh tax on fossil-fuel electricity production	0.75 mills/ kwh tax on fossil-fuel electricity production
Total Program Costs (In billions of discounted 1985 dollars) a/	22.3	30.0	35.5	41.5	49.0
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	291	389	369	431	509
1995 Coal Production Changes in Four Key High-Sulfur States (In millions of tons per year) c/	-36.3	-13.6	-53.5	-37.7	-28.6
1995 Changes in Coal Mining Employment Levels in Four Key High-Sulfur Coal States c/	-10,800	-4,500	-12,600	-11,200	-8,900

(Continued)

SUMMARY TABLE 1. (Continued)

Option Characteristics	Emissions Tax and Subsidy: Option IV-1	Option IV-2	Option IV-3	Sulfur Tax and Subsidy: Option V-1	Option V-2
SO_2 Emissions Reduction from 1980 Levels (In millions of tons)	9.2	9.5	9.6	8.9	8.9
Scrubber Subsidy Formula or Mandated Coal Market Restrictions	None	Subsidy for 90% of annual capital cost	Subsidies for 90% of annual capital cost and 50% of annual O&M costs through 2015	Subsidy for 90% of annual capital cost plus $0.50 rebate per pound of sulfur scrubbed	Subsidies for 90% of annual capital cost plus $0.50 rebate per pound of sulfur scrubbed
Revenue Mechanism	Tax of $600 per ton SO_2 emitted on pre-NSPS sources	Tax of $600 per ton SO_2 emitted on pre-NSPS sources	Tax of $600 per ton SO_2 emitted on pre-NSPS sources	$0.50 per pound of sulfur contained in excess of 10 pounds per ton	$10 per pound of sulfur contained in excess of 0.4 pounds per million Btus
Total Program Costs (In billions of discounted 1985 dollars) a/	37.5	39.2	45.9	32.1	37.4
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	327	330	384	289	339
1995 Coal Production Changes in Four Key High-Sulfur States (In millions of tons per year) c/	-61.0	-43.6	-27.2	-49.7	-44.0
1995 Changes in Coal Mining Employment Levels in Four Key High-Sulfur Coal States c/	-17,900	-12,828	-8,500	-14,600	-12,900

(Continued)

SUMMARY TABLE 1. (Continued)

Option Characteristics	Options Based on Two Recent Congressional Proposals: Option VI-1 [d]	Option VI-2 [e]	Option VI-3 [f]
SO_2 Emissions Reduction from 1980 Levels (In millions of tons)	9.1	9.9	12.1
Scrubber Subsidy Formula or Mandated Coal-Market Restrictions	Amount needed to keep electricity price hikes below 10%; fuel-switching and scrubber costs eligible	Amount needed to keep electricity price hikes below 10%; fuel-switching and scrubber costs eligible	None
Revenue Mechanism	0.5 mill per kwh fee on fossil fuel electricity produced; optional	0.5 mill per kwh fee on fossil fuel electricity produced; optional	None
Total Program Costs (In billions of discounted 1985 dollars) [a]	25.9	34.9	93.6
Cost-Effectiveness (In discounted 1985 dollars per per ton of SO_2 reduced) [b]	299	368	779
1995 Coal Production Changes in Four Key High-Sulfur States (In millions of tons per year) [c]	-57.7	-62.0	-45.8
1995 Changes in Coal Mining Employment Levels in Four Key High-Sulfur Coal States [c]	-17,000	-18,100	-13,400

SOURCE: Congressional Budget Office.

NOTE: For options that involve taxes, excess revenues generated by the option are not considered part of program costs.

a. Reflects present value of sum of annual utility costs incurred over the 1986-2015 period, using a real discount rate of 3.7 percent.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reduction measured over the 1986-2015 period.

c. Based on changes between option and current policy (base case) in 1995 for Illinois, Indiana, Ohio, and Pennsylvania.

d. Based on H.R. 4567 provision requiring achievement of a statewide emission average of 1.2 pounds SO_2 per million Btus for all affected plants.

e. Based on "default" provision of H.R. 4567, requiring all affected plants within a state to meet a 1.2 pounds SO_2 per million Btus limit.

f. Based on S. 2203, which requires affected plants to meet a 0.7 pound SO_2 per million Btus limit.

Costs would also rise, even at low levels of emission rollbacks, if measures were taken to reduce future losses in high-sulfur coal demand. For example, coal-switching restrictions would raise the cost per ton abated (cost-effectiveness) from $270 (Option II-1A) to $306 for the 8 million ton rollback case (Option II-1B). Fuel choice restrictions would cost much more in the 10 million ton rollback case, raising costs from $360 (Option II-2A) to $528 per ton of SO_2 abated (Option II-2B), making this approach the most expensive in the 10 million ton reduction range. Simply mandating scrubber use would be nearly as expensive, however. Option III-2C would require scrubbers on 50 of the highest emitting power plants as part of a 10 million ton reduction, and would cost $509 per ton of SO_2 abated.

Scrubber subsidies, designed to promote scrubber installation and thus discourage fuel switching, also would increase costs. Capital and operation and maintenance (O&M) subsidies provided through an electricity tax would raise the per ton abatement cost of an 8 million ton reduction to $389 (Option III-1B), and that of a 10 million ton reduction to $431 (Option III-2B). The cost-effectiveness values of scrubber subsidy programs would improve, however, when considered in conjunction with SO_2 taxes on emissions or the sulfur content of coal, since these mechanisms would encourage greater emission reductions in addition to influencing the choice of abatement method. For about the same cost per ton reduced, Option IV-3 (employing an SO_2 tax with scrubber subsidies) could reduce SO_2 emissions by 1.6 million tons more than Option III-1B, which also uses subsidies but does not tax emissions. The same trend is also seen with the sulfur-in-fuel tax options that would provide scrubber subsidies.

Summary Table 1 also reports total discounted program costs as measured over the 1986-2015 period. Because this value is an estimate of the cost of a policy over a fixed time period, policies that achieve abatement earlier than others would tend to have higher program costs even if the ultimate abatement levels were comparable. Thus, total program costs would be higher for all the options that tax SO_2 emissions or the sulfur content of coal. This effect would occur because such taxes would be imposed immediately, thus encouraging utilities to reduce SO_2 sooner than would other rollback options, which would cost utilities nothing if they delayed abatement until the required compliance deadline (1995). In this respect, the cost-effectiveness figures--which represent a discounted sum of costs incurred divided by the emission reductions obtained over the period--show less variation caused by the timing of abatement.

Coal-Market Effects

The high-sulfur coal industry is especially prominent in the states of Illinois, Indiana, Ohio, and Pennsylvania. Under current policy, total coal production in these four states is expected to remain virtually constant for the next decade. Enacting SO_2 regulations to control acid rain, however, could lower both coal production and mining employment in these states by 1995.

With no restrictions on the fuel market, an 8 million ton SO_2 reduction (Option II-1A) could lower projected 1995 coal production in the selected states by 48 million tons or 24 percent; similarly, a 10 million ton reduction (Option II-2A) could lead to a 75 million ton decrease, or a 38 percent drop (see Summary Table 1). To alter this trend, it would be necessary to restrict fuel switching outright, require scrubbing, or change the economics of scrubber use to make it more attractive than fuel switching.

With restricted fuel switching, mining production losses in the four key states would range from 39 million tons with an 8 million ton rollback (Option II-1B) to 44 million tons with a 10 million ton rollback (Option II-2B). The respective cost-effectiveness values, however, would jump from $270 to $306 per ton of SO_2 abated under the 8 million ton case, and from $360 to $528 under the 10 million ton case. Alternatively, subsidies from an electricity tax could be used to finance scrubbing, thus making it less expensive to the utilities compared with fuel switching. For a 10 million ton reduction, subsidies on scrubber capital and O&M costs could lower mining losses (in the four selected states) to only 38 million tons (Option III-2B). Mandating that scrubbers be used on the highest emitting power plants (Option III-2C) could further reduce mining losses to just 29 million tons, but with a large increase--to $509 per ton--in the cost of reducing SO_2.

Alternatively, emission or sulfur taxes could be used in combination with scrubber subsidies to maintain high-sulfur coal production, while keeping the cost per ton of SO_2 reduced to a level below those of options that restrict fuel choice or mandate scrubbers. For example, a 9.6 million ton SO_2 reduction could be achieved through a tax of $600 per ton on SO_2 emissions, combined with a subsidy on scrubber capital and O&M costs (Option IV-3). Enacting this option would lower 1995 mining production in the selected states by only 27 million tons, at a cost of $384 per ton of SO_2 abated.

Finally, as the level of control is tightened to a 12 million ton reduction, coal production in these four states could actually fare better than under an unrestricted 10 million ton rollback, because the stringent level of control demanded would essentially force a high degree of scrubber installation even in the absence of subsidies. Thus, under Option VI-3, 1995 coal production would only be 46 million tons less than in the base case. Requiring such stringent emission limits, however, would be exceedingly costly at $779 per ton of SO_2 reduced.

Mining employment in the high-sulfur coal industry also would be affected by these production shifts. For the states of Ohio, Illinois, Indiana, and Pennsylvania, direct mining jobs are expected to remain near the current level of 56,000 under current policy. As expected, the larger the expected production drop in this four-state area, the larger the expected drop in 1995 mining jobs. Thus, Option II-2A, which could lower coal production by 75 million tons from 1995 base case levels, also could eliminate about 21,900 job slots. But if expected job attrition is considered, only 15,300 miners employed in 1985 in these four states would actually lose their jobs by 1995 as a result of the effects of Option II-2A.

These results lead to a straightforward conclusion about SO_2 control programs of 8 million tons or more: policies that mitigate expected losses in high-sulfur coal production and mining jobs increase the cost of reducing SO_2 emissions. These results are illustrated graphically in Summary Figures 1 and 2 which show, respectively, the cost to abate one ton of SO_2 and 1995 mining employment in the four prominent high-sulfur coal states under each option. As job levels rise, so do costs. Some of the options that tax emissions or sulfur content, however, could potentially save the most jobs at the least cost.

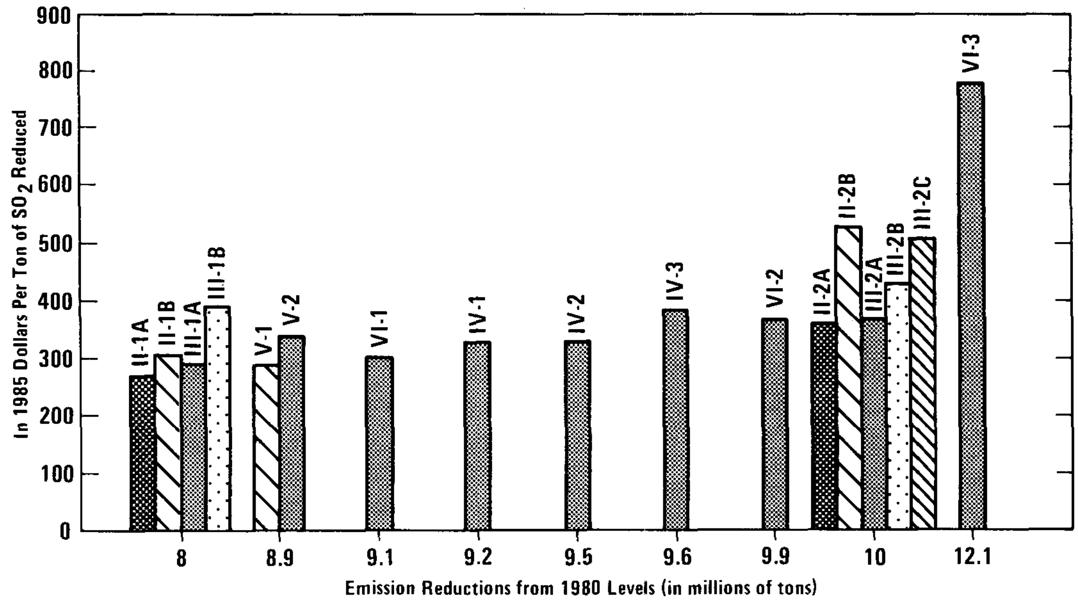
Finally, on a nationwide basis, the coal production and employment losses of the different options tend to be negligible. The potential drop in production and employment in the Midwest and Pennsylvania would be offset by increased production and employment in western states, southern West Virginia, and eastern Kentucky--all sites of abundant quantities of low-sulfur coal.

Effect on Electricity Rates

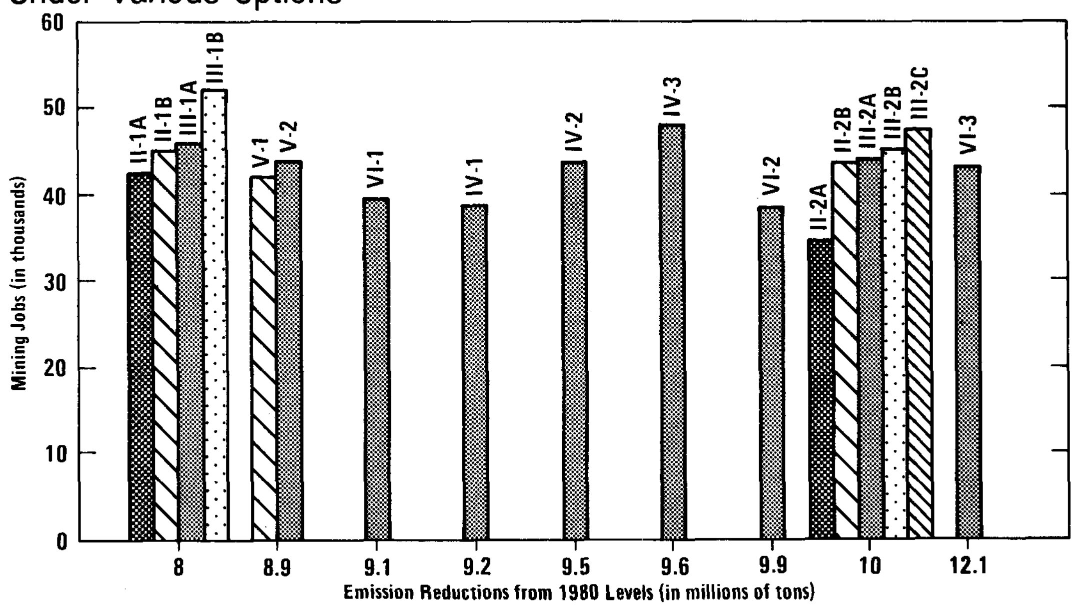
Under any option examined, average electricity rates throughout the country would not rise more than 6 percent over those predicted under current policy, using 1995 as the year of comparison (typically the year when such prices could be highest under any control program). Rate increases in some states could be much higher, however, depending on the option. The highest rate increases are concentrated primarily in the midwestern and Appalachian states because a significant share of emission reductions would occur in those regions. These states have enjoyed some of the lowest rates charged nationwide, though, and the higher prices these areas might experience under an acid rain control plan would still be below the national average price predicted under most options.

Other states, such as West Virginia, might experience wide fluctuations in rates, depending on how much of their electricity is imported or exported.

Summary Figure 1.
Cost-Effectiveness of Various Options



Summary Figure 2.
Mining Jobs in Ohio, Illinois, Indiana, and Pennsylvania in 1995, Under Various Options



(Theoretically, if one state can export excess power to another state at the receiving state's higher cost, consumer costs in the exporting state could fall.) Because of the myriad of electricity rate regulations affecting such interstate transfers, however, such results are open to question.

The Potential Budgetary Effect of Various Tax Schemes

Each of the tax options could potentially raise large amounts of revenue in excess of the cost of the subsidies (if any) that would be granted under the particular program. The smallest surpluses would be generated by the electricity tax and subsidy alternatives. Of these, the largest cash excess would be created by Option III-1A, which would raise about $1.2 billion each year from an electricity tax of 0.5 mills per killowatt-hour over a ten-year period, while paying out subsidies of roughly $239 million each year over roughly a 20-year period. Because revenues would be deposited in a trust fund, interest earnings could produce a closing balance of $15.7 billion in 2015, the year it would expire.

The largest revenue-raising alternative would be Option IV-1--the $600 per ton emissions tax with no subsidy program. This option would collect $4.9 billion annually by 1995, even after some emission reductions occurred. This value would slowly decline as older, taxed power plants were retired, probably by 2015.

The use of excess cash balances created by such programs is open to debate.[2/] In several bills submitted in the 98th Congress, the consensus approach was to refund excess taxes to those who paid them (for example, electricity ratepayers who were subject to an electricity fee). Large excess cash balances, however, might allow some or all of the funds to be used for deficit-reduction activities. Such activities might include using the funds to pay for other environmental programs, thus offsetting funding from general revenues, or simply retaining the funds to offset total federal outlays.

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2. Unless specific exclusions were included, the various tax and subsidy options using trust funds would become subject to the Balanced Budget and Emergency Deficit Control Act of 1985 (P.L. 99-177) if they were enacted into law. Under the Balanced Budget Act, outlays (subsidies) from the trust funds would be subject to sequestration action through fiscal year 1991, although revenues accruing to the fund probably would not be affected. If trust fund outlays were sequestered, or cut, the trust fund balances would continue to grow and would be available for future obligations. Because future sequestration needs cannot now be determined, estimates in this report assume outlays would provide full subsidies, as long as trust fund balances were positive.

CONCLUSIONS

Summary Figures 1 and 2 summarize the dilemma created by schemes to lower SO_2 emissions nationwide--namely, the expense of reducing emissions tends to increase as efforts are made to preserve jobs in the high-sulfur coal industry. Simply restricting fuel choice by requiring that current purchase patterns be maintained appears to be the most expensive approach, both in terms of cost-effectiveness and total costs. Demand for high-sulfur coal could be preserved and cost-effectiveness improved by using economic incentives that tax emissions or sulfur content to help fund scrubber installation. But total costs for these programs could be high because the continuing expense of reducing emissions is incurred earlier than in other programs. In contrast, the least expensive approach--and the least protective for high-sulfur coal demand--would simply mandate emission reduction targets for each state to meet by 1995, placing no restrictions on fuel switching and providing no economic incentives to use scrubbing in place of lower-sulfur coal.

CHAPTER I

INTRODUCTION

Along with hazardous waste disposal, "acid rain" has entered the public spotlight as a key environmental concern of the 1980s. Airborne acidic compounds, which are formed chiefly from man-made air pollution, can harm aquatic ecosystems, crops, materials, forests, and even human health after long exposure. Moreover, contributing sources can produce both local and remote damage, since the acidic substances can travel hundreds of miles in the atmosphere.

The pollutant most often singled out as the principal "precursor" of acid rain is sulfur dioxide (SO_2). It is called a precursor chemical because it can be transformed in the atmosphere to sulfate, the compound that is believed to contribute directly to the total acidity entering ecosystems. U.S. electric utilities produce large quantities of sulfur dioxide (over 17 million tons in 1980, or 65 percent of the man-made total). Coal-fired power plants, most of which are located in the Midwest and parts of the mid-Atlantic region, are almost exclusively responsible for this pollution from utilities. 1/ Those plants burning high-sulfur coal contribute an especially large proportion of the total SO_2 produced by utilities.

Even though other air pollutants have been implicated in the formation of acid rain--most notably nitrogen oxides (also produced from fuel combustion) and photochemical smog (itself a product of hydrocarbon and nitrogen oxide pollution from automobiles and industry)--legislative proposals to mitigate the effects of acid rain have focussed on controlling SO_2 emissions. The sources most often targeted for control are older, coal-fired electricity plants that account for over 90 percent of national utility SO_2 emissions. However, the cost of controlling emissions from these plants is high, the results of curbing them unknown, and the potential effects on domestic coal markets and electricity costs sufficiently large to warrant Congressional scrutiny. These issues form the subject matter of this paper.

1. See Environmental Protection Agency, *National Air Pollutant Emission Estimates, 1940-1980* (January 1982).

THE NATURE OF THE PROBLEM

Acid rain threatens the viability of many thousands of lakes and streams in the eastern United States and Canada, and may have contributed to the destruction of forests and the consequent decline of timber production in these regions. Moreover, airborne fine particles, of which acid rain is a component, have been linked to increased human mortality in areas with elevated pollution levels. Yet, the relationship between SO_2 emissions in a particular location (for example, the Midwest) and the downwind damage of acid rain (in the eastern United States and Canada, for instance) remains elusive to many researchers. While some urge immediate further controls for plants that emit SO_2, others stress that the problem and its corrections need additional research before further actions are undertaken (see box).

THE REAGAN-MULRONEY AGREEMENT

Currently, no regulatory programs exist specifically for controlling acid rain in the United States, although substantial research efforts --with both private and public funding--are devoted to understanding the problem and the means to control it. While some members and committees of the Congress have introduced legislation designed to control pollutants that form acid rain (no legislation has reached the floor of either House in the 99th Congress), the Administration has not taken part in initiating any regulatory action. In 1985, however, President Reagan and Prime Minister Mulroney of Canada commissioned a special study of the acid rain problem. Among the conclusions of the report, delivered on January 8, 1986, was the finding that acid rain was a serious environmental problem that warranted an increased research effort devoted to devising methods to control the sources of pollution.

In a joint statement with Mr. Mulroney on March 19, 1986, President Reagan endorsed the findings of the report and made a commitment to pursue actively the implementation of its recommendations, including: initiation of a $5.5 billion, multi-year program for the commercial demonstration of cost-effective and innovative pollution control technologies for major sources of acid-forming pollutants; continued emphasis on research to help answer critical scientific questions related to transboundary acid rain; and enhanced cooperation between the United States and Canada, such as regular bilateral consultations and information exchanges. While the President did not suggest any regulatory action, he plans to seek funding as needed to meet the recommendations of the report. (For further information, see Environmental Protection Agency, Office of Program Development, "Official Response to the Joint Envoys Report," March 19, 1986.)

This study does not examine the scientific issues concerning the origin, effects, and fate of acid rain pollution. Research in these areas has been described thoroughly in other publications. 2/ Instead, this paper focuses on the difficult policy choices surrounding the further control of SO_2 emissions from the nation's power plants.

UTILITY REGULATION AND DOMESTIC COAL MARKETS

To understand the public policy issues impinging on proposals to control acid rain, it is helpful to understand the relationship between SO_2 control and coal use. Because coal with a high sulfur content releases a large volume of SO_2 when burned, its producers fear that additional reductions in allowable SO_2 emissions could lower the demand for high-sulfur coal and increase the use of low-sulfur coal. The major midwestern coal-producing states of Indiana, Illinois, and Ohio, plus Pennsylvania, would be most affected by such a substitution. These states produce an abundant quantity of high-sulfur coal and employ thousands of miners. Displacing high-sulfur coal with low-sulfur coal, however, would benefit the western states and West Virginia. These regions contain large quantities of low-sulfur coal and would be able to produce and sell more of it, as well as enjoy higher employment under a plan to control acid rain.

Under the provisions of the original Clean Air Act of 1970, coal-fired power plants had to meet individual sulfur dioxide emission limits, measured as pounds of SO_2 per million British Thermal Units (Btus) of fuel used. For plants built before 1971, states were allowed to determine the allowed emission limit; for plants built later, the federal government had established a uniform standard that applied nationwide. In establishing these standards, the federal government and most states allowed utilities to choose either to burn low-sulfur coal to keep SO_2 emissions down, or to use high-sulfur coal and remove SO_2 in the exhaust gas with scrubbers. 3/ When allowed a choice, utilities generally complied by using low-sulfur coal.

2. Many publications are available on the scientific issues underlying the acid rain problem. These include two recent documents, one published by the Congressional Office of Technology Assessment, *Acid Rain and Transported Air Pollutants: Implications for Public Policy*, June, 1984; and the other published by the National Academy of Sciences, *Acid Deposition: Atmospheric Processes in Eastern North America* (1983). The reader is urged to consult these and other studies for more details.

3. A scrubber is a large and expensive piece of equipment that removes sulfur dioxide from combustion gasses before they are emitted from the stack. Most are designed to remove about 90 percent of the potential sulfur dioxide emissions produced during combustion, and can cost as much as $120 million when placed on a medium-size (500 megawatt) new power plant. A scrubber placed on an older power plant usually costs more, however, if it is not part of the original design. This expense would confront many of the power plants that would be targeted under an acid rain control program.

Since the sulfur content of domestic coal resources varies geographically, significant changes in nationwide SO_2 emission regulations could influence the regional distribution of coal production. The East mines both low- and high-sulfur coal and can supply either to utilities. Eastern low-sulfur coal is very high quality and could be burned without scrubbers and still meet strict SO_2 emission standards, but this region's high-sulfur coal would need scrubbers when burned under the same conditions. The Midwest mines essentially only high-sulfur coal, and power plants under strict SO_2 emission limits typically would have to use scrubbers to burn midwestern coal. The West, on the other hand, can produce and ship as much low-sulfur coal as needed.

Partly to counter a potential reliance on low-sulfur coal as a control strategy, the 1977 Amendments to the Clean Air Act changed the nature of SO_2 emission standards for new plants by essentially requiring scrubbing for all new plants regardless of the type of coal used. (The term "new power plant," as used here, refers to facilities built after the emission regulations that arose from the amendments passed by the Environmental Protection Agency in 1978.) Before that law was enacted, utilities had often turned toward low-sulfur coal to meet SO_2 standards. The 1977 amendments (and subsequent 1978 emission standards established specifically for power plants) eliminated the advantage of using low-sulfur coal to meet SO_2 emission limits in new plants. Only the newest plants are subject to the stricter requirements, however, and older plants remain covered by typically less strict federal or state regulations. In the Midwest, these state standards often are written to allow high-sulfur coal to be burned in older power plants that are remotely located and that use tall stacks to disperse the pollution. Because of the more lenient standards for old plants--and the elimination of low-sulfur coal use as a sole SO_2 compliance strategy in new plants--midwestern coal production is expected to remain strong for many years under current clean air rules.

THE POTENTIAL EFFECTS OF ACID RAIN LEGISLATION

Acid rain proposals directed at reducing utility SO_2 emissions raise two principal concerns: possible regional shifts in the coal market and the cost of further controlling SO_2. Most proposals have considered reducing U.S. sulfur dioxide emissions by between 8 million tons and 10 million tons per year (measured from 1980 levels). Power plant SO_2 emissions in the continental United States are now about 16 million tons per year, and are expected to rise to 18.5 million tons annually by 1995. The Congressional Budget Office projects that a one-time only reduction in sulfur dioxide emissions of 8 million tons, directed at power plants built before 1980 (and paid for entirely by the affected utilities), would add between $1.9 billion and $2.1 billion each year to the cost of current regulations; a 10 million ton reduction program would add between $3.3 billion and $4.7 billion each year.[4] These costs depend greatly on whether the new legislation would permit switching from high- to low-sulfur coal to meet emission standards--which would alter existing coal-market patterns--or whether scrubbers would be required--which would help mitigate the advantage of using low-sulfur coal to meet standards. Unrestricted coal markets that permit fuel switching generally lower costs, while the required use of scrubbers generally raises costs.

Many diverse interests would be affected by a new SO_2 control program directed at electric utilities. From the utilities' perspective, most would prefer the freedom to choose a compliance method--either low-sulfur coal or scrubbers, whichever would cost less. Because utility costs ultimately are passed through to consumers, electricity customers also would prefer the cheapest method of compliance. From the perspective of coal producers, preferences are influenced by geography. Western and eastern producers of low-sulfur coal hope that fuel switching would be allowed under an acid rain control program. In contrast, midwestern and some eastern high-sulfur coal producers favor the required use of scrubbers. Finally, geography also differentiates between, for example, states thought to benefit from a control program and those believed to bear its costs; the Midwest and some mid-Atlantic states would face the greatest cleanup costs, while the Northeast might enjoy the greatest potential benefits from a reduction in acid rain.

In an attempt to satisfy this diverse set of concerns, the Congress has been exploring proposals that alter the basic "polluter pays" principle. This principle requires that sources responsible for pollution--in this case, the coal-fired electric utilities--pay for the cost of cleanup. Adhering to this rule could require two areas of the country--namely, the Midwest and mid-Atlantic--to pay a large share of the cleanup costs of an acid rain control program. Thus, schemes have been proposed that would distribute more evenly the costs of cleanup throughout the nation, as well as lower the potential nationwide redistribution of coal production that might result from new SO_2 regulations. This paper analyzes these options, concentrating on how much various control programs would cost, who would bear these costs, how the programs would affect coal markets and mining jobs, how much

4. Power plants operating by 1980 in almost all cases were started before the 1978 regulations, and were thus not subject to the newer standard that requires all new plants to install scrubbers regardless of the type of coal burned.

emissions would be lowered, and how the programs could be financed and administered. Four approaches are examined:

- The traditional **polluter pays approach** that requires utilities and their consumers to pay for sulfur dioxide controls without placing restrictions on the use of control method; and a similar control program, but one that would deny utilities the choice to change to a low-sulfur coal as a control strategy;

- A control program that places no formal restrictions on choice of control technology, and that **partially finances scrubber installation with an electricity tax**;

- An option that **taxes sulfur dioxide emissions** to motivate utilities to adopt control measures, and that provides partial subsidies to the utilities for installing scrubbers; and

- An alternative that **taxes the sulfur content of fuel** and that provides subsidies for scrubber installation to motivate emissions reduction.

Through the use of subsidies, some of the approaches would alter the basic polluter pays principle by transferring costs from those who pollute the most to those who pollute the least. All would do so in an attempt to strike a balance among competing goals: achieving emission reductions, alleviating the costs to consumers and utilities in any one region, and minimizing disruptions to coal market patterns and employment in the high-sulfur coal industry.

CHAPTER II

CURRENT POLICY AND THE POTENTIAL COSTS OF FURTHER REDUCTIONS IN SO_2 EMISSIONS

From 1985 through 1995, the electric utility industry is expected to spend about $190 billion on new capital equipment; of this amount as much as 20 percent will pay for devices to control air pollution. The use of coal also is expected to grow over this period--from 883 million tons shipped in 1985 to 1,129 million tons shipped in 1995. This growth will be spurred mostly by new coal-fired power plants built to meet increasing demand for electricity. Concurrent with growing demand for electricity, annual sulfur dioxide emissions from utilities will rise from 15.8 million tons in 1985 to almost 18.5 million tons in 1995.

What would be the cost of imposing new regulations designed to increase control of sulfur dioxide emissions? To answer this question, this study examines federal options that would lower SO_2 emissions from electric utility plants by 8 million tons or 10 million tons annually (measured from the commonly used baseline level of 1980). As a starting point, this chapter reports the cost of such regulations, assuming that abatement expenses are borne directly by the affected utilities, without benefit of any cost-sharing program or taxation-subsidy scheme. Later chapters present various cost-allocation and taxation-subsidy programs to control acid rain, describing how they might affect utilities, electricity consumers, and coal markets.

The results of the Congressional Budget Office's (CBO) analysis suggest that a SO_2 control program to abate acid rain would be expensive and would affect U.S. coal-market patterns. An SO_2 reduction of 8 million tons (from 1980 levels) could add between $1.9 billion to $2.1 billion to annual electricity production costs by 1995; similarly, a rollback of 10 million tons could raise 1995 electricity costs by $3.2 billion to $4.7 billion. In addition, such regulations could alter future patterns of coal production in specific regions. Predicted demand for midwestern high-sulfur coal would fall, while predicted demand for low-sulfur coal from eastern (Appalachian) and western mining regions would grow. To retard the substitution of low-sulfur coal for high-sulfur coal under a SO_2 rollback, fuel switching could be restricted directly (by regulation) or indirectly (by requiring that SO_2 emission scrubbers be used by all power plants regardless of the kind of coal burned). Limiting fuel choice, however, would force overall costs to the higher end of the ranges cited.

REQUIREMENTS OF THE CLEAN AIR ACT CURRENTLY AFFECTING ELECTRIC UTILITIES

To help meet and maintain national ambient (atmospheric) air quality standards established under the Clean Air Act (last amended substantially in 1977), several key regulations have been developed to control emissions from sources of air pollution. 1/ Electric utility plants represent a large category of such sources. Power plants built before 1971 (predating the promulgation of the first federal emission limits for utilities) must meet emission standards set by the states through "state implementation plans" (SIPs). These standards vary by state and by regions within a state, depending on local air quality. Their primary purpose is to ensure that plant emissions do not prevent achievement or maintenance of ambient air quality standards established by the Environmental Protection Agency (EPA).

For plants built after 1971, the federal government has established uniform emission standards--called new source performance standards (NSPS)--that limit the amount of air pollution from new or modified facilities. 2/ Two NSPS have been developed for utility plants--one in 1971 and one in 1979 (see Table 1). The important difference between the two standards is that the 1971 NSPS allowed low-sulfur coal to be used as a pollution control strategy, while the 1978 one does not. The 1978 standard essentially requires the use of scrubbers--no matter what type of coal is burned--by mandating a percentage reduction of all SO_2 emissions.

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1. This chapter is not intended to provide a thorough description of current air pollution control policy. For a complete description of the Clean Air Act and the effect of its regulations, see National Commission on Air Quality, *To Breath Clean Air*, Final Report to Congress (March 1981).

2. For new plants, the NSPS typically represent the norm for emissions control. The states and federal government generally do not require stricter standards except in certain situations, which usually can be avoided through careful siting of the facility to minimize its pollution effect. Nevertheless, certain situations may call for controls stricter than the federal NSPS. For example, in areas where the ambient air quality standards are already exceeded, states may set stricter emission limits for a new facility (subject to federal approval) if such limits are needed to attain standards. Alternately, in areas where air quality is very good, new plants may be given stricter standards if pollution from the plant at NSPS levels would degrade the air quality beyond permissable amounts. (The regulations outlining this strategy are called Prevention of Significant Deterioration, and are described in *To Breathe Clean Air*.) Finally, simply at their own discretion, states may enact standards stricter than the federal NSPS, a practice that has occurred only infrequently and mostly in the West.

TABLE 1. NEW SOURCE PERFORMANCE STANDARDS FOR COAL-FIRED ELECTRIC UTILITIES

Pollutant	1971 Maximum Allowable Emissions	1978 Maximum Allowable Emissions
Sulfur Dioxide	No more than 1.2 pounds per million Btus of any coal consumed	No more than 1.2 pounds per million Btus of fuel consumed, plus 90 percent emissions reduction, or no more than 0.6 pounds per million Btus of fuel consumed plus 70 percent emissions reduction
Nitrogen Oxide	No more than 0.7 pounds per million Btus of all anthracite, bituminous, and subbituminous coals consumed; 0.6 pounds for lignite a/	No more than 0.6 pounds per million Btus of all anthracite, bituminous, subbituminous, and lignite coals consumed
Particulate Emissions	No more than 0.1 pounds per million Btus of fuel consumed	No more than 0.03 pounds per million Btus of fuel consumed

SOURCE: Congressional Budget Office, from Environmental Protection Agency.

NOTE: For emissions limits for oil- or gas-fired utility plants, see 36 Federal Register 15703 (December 23, 1971) and 44 Federal Register 33580 (June 11, 1979).

a. Anthracite, bituminous, subbituminous, and lignite are types (or ranks) of coal, differentiated by inherent differences in chemical composition.

Emission Patterns Under Current Policy

In 1985, utility power plants emitted roughly 15.8 million tons of SO_2, representing between 60 percent and 70 percent of the annual SO_2 man-made emissions in the U.S. 3/ By 1995, in the absence of any new regulations, this figure should grow to about 18.5 million tons per year as new plants are built

3. The percent of national sulfur dioxide emissions contributed by utilities is based on projected and historical figures presented in Office of Technology Assessment, *Acid Rain and Transported Air Pollutants: Implications for Public Policy* (June 1984), p. 60.

to meet growing demand for electricity.[4] Most of the SO_2 discharged in 1985 came from utility plants built before the first NSPS was enacted in 1971--a trend that will continue through 1995. In fact, over 97 percent of the 15.8 million tons of SO_2 released in 1985 was from older plants covered solely by state emission standards, and not from newer plants covered by the NSPS. By 1995, these pre-NSPS plants will still contribute 90 percent of all utility sulfur dioxide emissions. The remainder of emissions will be from plants built under either the first power plant NSPS of 1971 or under the more recent one of 1978. Thus, older, pre-NSPS sources will be the target of any new strategy to reduce utility SO_2 emissions, since NSPS-covered plants already are well-controlled and offer little room for further reductions.

Expected Growth in Coal Use Under Current Policy

From 1985 through 1995, the amount of coal mined in the United States is expected to grow by almost 30 percent--from 883 million tons in 1985 to 1,129 million tons in 1995. Almost all of the projected growth can be attributed to electric utilities since they use, on average, over 80 percent of all coal mined. Over two-thirds of this increase will occur in the eastern states of West Virginia, Kentucky, and Pennsylvania. Another one-quarter of the production rise will occur in Texas alone. In contrast, the midwestern states of Ohio, Indiana, Illinois, and Missouri could face over a 10 percent decline in coal production over the period, while the major western coal-producing states--Montana and Wyoming--are expected to maintain about current production levels.

Similarly, the level of coal mining employment could rise over 30 percent by 1995, based on coal mining productivity figures currently available. Most of the job growth also will take place in the eastern states; midwestern job levels are expected to decline slightly, while those in most western states are anticipated to rise somewhat.

Regional Coal Characteristics and Coal Prices

In general, U.S. coal production can be divided into three regions: the East, where the productive Appalachian region spans West Virginia, Kentucky, and

4. Utilities also emit substantial quantities of nitrogen oxides and particulate matter. In 1985, roughly 6.6 million tons of nitrogen oxides and 1.3 million tons of particulate matter per year were emitted by power plants. These emissions are expected to grow to 8.7 million tons per year for nitrogen oxides and 1.6 million tons per year for particulate matter by 1995. Nevertheless, sulfur dioxide emissions remain the subject of this study.

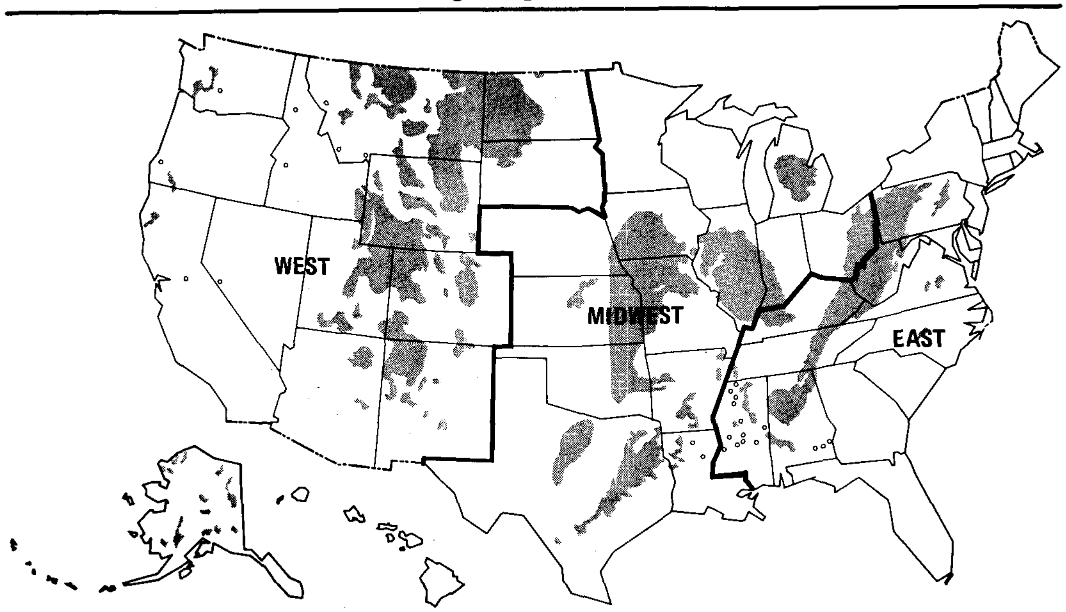
Pennsylvania; the Midwest, which contains the abundant Illinois coal basin and Texas lignite fields and extends to the western borders of Minnesota, Nebraska, Kansas, Oklahoma, and Texas; and the West, which contains several major coal basins throughout Montana, Wyoming, Colorado, New Mexico, and Utah. (Figure 1 depicts each of the major coal-producing regions in the continental United States.) Coals mined in each of these regions generally possess different characteristics, including the method by which they are obtained (either deep mined, or "stripped" by surface mining techniques), energy content, and the amount of sulfur contained by weight. Each of these characteristics can affect the delivered price of the coal, as can the distance it must be transported.

The **mining method** used is the most important determinant of coal prices. Surface mining is generally more productive (and less expensive) than deep mining (see Table 2). Surface mining can only be used, however, where the coal is close to the surface and accessible to equipment, and where the land can be economically reclaimed after mining.

In the East, the choice of mining method is roughly split between surface (40 percent) and deep mining (60 percent). The cost for coal mined underground in the East can range from $30 to $46 per ton (as measured by

Figure 1.

U.S. Coal Fields and Producing Regions



SOURCE: Adapted by the Congressional Budget Office from the President's Commission on Coal, "Coal Data Book" (February 1980).

TABLE 2. COAL COSTS AND AVERAGE SULFUR CONTENT OF COAL, BY REGION [a]

	Cost in 1985 Dollars (In dollars per ton)			
	Under-ground	Surface	Average	Average Sulfur Content (In percents) [b]
		East		
Alabama	45.55	43.82	44.66	1.5-1.7
Georgia	N.A.	w	w	w
Kentucky, East	30.99	28.98	29.78	0.9-1.2
Kentucky, West	29.86	26.55	27.91	2.3-3.5
Maryland	w	w	29.18	1.5-1.6
Pennsylvania	39.43	30.52	34.85	1.9-2.1
Tennessee	31.12	27.76	30.18	1.2
Virginia	32.49	32.26	32.45	1.0-1.1
West Virginia	36.28	32.56	35.58	1.1-2.0
		Midwest		
Illinois	32.68	28.73	31.12	2.7-3.1
Indiana	w	w	26.00	2.3-2.9
Iowa	w	w	26.36	w
Kansas	N.A.	28.01	28.01	3.5-4.4
Missouri	N.A.	25.57	25.57	3.6-5.0
Ohio	43.95	29.21	34.53	3.5
Oklahoma	N.A.	33.45	33.45	1.9-3.6
Texas	N.A.	11.60	11.60	1.2-1.7
		West		
Arizona	N.A.	w	w	w
Colorado	28.48	21.54	24.02	0.5-0.6
Montana	N.A.	14.13	14.13	0.6
New Mexico	w	w	20.20	0.5-0.8
North Dakota	N.A.	9.87	9.87	0.9-1.0
Utah	30.40	N.A.	30.40	0.5
Washington	N.A.	w	w	w
Wyoming	w	w	12.38	0.5

SOURCE: Department of Energy, Energy Information Agency, *Coal Production 1984* (November 1985).

NOTES: N.A. indicates no reported production over 100,000 tons; w indicates data withheld to avoid disclosure of individual company data.

a. Coal costs are measured by mine-mouth prices.

b. As measured by shipments to electric utilities and "other industrial" users, in percent of sulfur by weight.

mine-mouth price); for coal mined by stripping, from \$27 to \$44. In the Midwest, most coal is mined by surface methods, although some underground mining takes place. Midwest strip-mining costs run from \$12 to \$34 per ton, while deep-mining costs run from \$33 to \$44 per ton. Finally, most western coals are close to the surface and are, therefore, extracted by strip-mining methods. These western surface mines are typically more productive than either eastern or midwestern surface mines, and have extraction costs ranging from \$10 to \$22 per ton. 5/ Even accounting for the fact that many western coals contain 25 percent less energy than most midwestern and eastern coals, the difference in mining costs is still significant. (Assuming a 25 percent difference in energy content, an amount of western coal equal to a ton of eastern coal would only cost between \$12.50 and \$27.50 to mine, still less than all other types, except Texas lignite.)

After mining costs, the most important factor affecting the delivered price of coal is the **distance it must be transported**. Most coal moves by rail during some if not all of its trip to utility plants. Rail haulage rates generally range from 20 mills to 40 mills per ton for each mile carried (called a "ton-mile"), with western rates generally lower than those in the East. 6/ At a cost of 25 mills per ton-mile, a haul of 300 miles can increase the mine-mouth price of coal by \$7.50 per ton. For 1,000 mile hauls, \$25 can be added to the price of each ton of coal. Though unusual in the East, where coal hauls average 300 miles, hauls of 1,000 miles or more are not uncommon for coal originating in the West. Thus, by the time a western coal reaches a midwestern destination, its original purchase cost might have doubled. Moreover, because of the typically low energy content of western coals, more must be shipped than if eastern or midwestern coals--which have higher energy contents--were used.

A third factor affecting delivered price--and one more difficult to quantify--is **sulfur content** (see Table 2). About 95 percent of the sulfur contained in fossil fuels is converted to sulfur oxides during combustion in most power plant boilers. If not controlled, these oxides are released to the atmosphere along with the other combustion gases. A simple limit on sulfur dioxide emissions would allow utilities to choose the method of control: either installation of a scrubber or a switch to low-sulfur coal. The

5. See Department of Energy, Energy Information Administration, *Coal Production 1984* (November 1985). All costs have been adjusted to 1985 dollars.

6. For example, western coal can be shipped to the mid-Atlantic region at a rate of about 17.2 mills per ton-mile as compared with mid-Atlantic intraregional shipment rates that may cost 38 mills per ton-mile. (Mill rates have been adjusted to reflect 1985 dollars.) See Department of Transportation, *1984 Carload Waybill Statistics* (1986).

difference between these two choices can be thought of as a low-sulfur fuel premium. Using a scrubber adds about 8.8 mills per kilowatt-hour (kwh) of electricity generated, which is equivalent to adding roughly $21 per ton to the price of coal being burned. 7/ Therefore, a plant manager could purchase a low-sulfur "compliance" coal that costs up to $21 per ton more than a "scrubbed" high-sulfur coal and still spend less than if he chose to install a scrubber. (This example assumes the energy content of both coals is similar.) Thus, sulfur dioxide emission limits can influence the choice of coal. High-sulfur coal can become less valued, resulting in shifts in geographic coal-market patterns.

EFFECTS OF REQUIRING ROLLBACKS IN SULFUR DIOXIDE EMISSIONS

Proposals to control acid rain would change emission, cost, and coal-market patterns from those expected under current policy. This section examines two options--one would require that utilities reduce their SO_2 emissions by 8 million tons from 1980 levels; the other would require a 10 million ton SO_2 reduction from 1980 levels (only plants operating as of 1980 would be affected). 8/ Both options assume the enabling law would go into effect in 1986 and that the utilities would be given until 1995 to comply with the regulations.

The rollback levels chosen encompass the most common range of reductions contained in legislative proposals to date. The formula used to assign the emission reductions to each state is called the "excess emission" formula, also a common item in acid rain control bills. 9/ In essence, the excess emissions formula first calculates for each state the total amount of

7. Figures based on a 500 megawatt (Mw) plant using a scrubber costing about $240 per kilowatt of capacity at an interest rate of 10.8 percent (nominal) and on operation and maintenance cost of 4 mills per kilowatt-hour. Assumed scrubber life is 30 years (for a new plant). Capacity factor for plant is assumed to be 65 percent. Values represent first-year costs in 1985 dollars. See also Department of Energy, Energy Information Administration, *Cost and Quantity of Fuels for Electric Utilities, 1984* (July 1985), Table 37, for a range of scrubber capital and variable costs.

8. 1980 is commonly used as a baseline because it represents a year of measured emissions that do not include power plants operating under the 1978 NSPS. Even though more recent data may be available, 1980 remains the baseline of choice.

9. For a list of recent proposals and general comparisons, see Larry Parker, "Acid Rain: Issues in the 99th Congress," Congressional Research Service, October 22, 1985. Two recent proposals, S. 2203 and H.R. 4567, are discussed in Chapter VI of this report.

SO_2 discharged in 1980 by each plant that was over 1.2 pounds of SO_2 per million British Thermal Units (Btus). National allocation ratios for each state are then derived by dividing each state's share of excess emissions by the national total of excess emissions. Each state's reduction amount would be determined by multiplying its ratio by either 8 million tons or 10 million tons, depending on the applicable national reduction goal. Other methods could of course be used--such as simply assigning an emission limit for all plants--but the excess emissions formula remains the most popular.

In the options of this chapter, each state would be allowed to develop an emission reduction plan to meet its respective goal, much like current strategies for meeting existing air quality standards. Because reductions would be set at the state, and not the plant, level, states would be free to develop the most cost-effective plan to control utilities within their territory, a condition reflected in this analysis. Such plans could include "emissions trading," through which plants having lower marginal control costs could sell SO_2 reductions to plants with high marginal control costs within the same state, as long as statewide reduction targets were met. (The appendix describes 1980 emission levels and the required reductions for each state according to the allocation formula for 8 million and 10 million tons.) [10]

Methodology

To analyze the SO_2 rollback options, the Congressional Budget Office used a computer-based simulation model that portrays utility emissions, utility costs, and coal-market supply and demand patterns under different policy assumptions. The model, called the National Coal Model, is maintained by the Department of Energy.

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10. Two items are important to note about these emission reduction options. The first is that each requires only a reduction from 1980 emissions, meaning that after lowering emissions from 1980 levels by 8 million tons or 10 million tons annually, emissions growth from sources built after 1980 would be allowed to occur. This is to be distinguished from an emissions "cap," designed to hold total statewide emissions to some predetermined level. An emissions cap would require much greater initial reductions so that new source emissions could be accomodated. The second point is that this study uses 1985 and 1995 as base years from which to make comparisons, while still using 1980 as the basis for determining how much reduction should occur. For both of these reasons, the 8 million ton and 10 million ton emission reduction cases, using 1980 as a base year, show only about a 7 million ton and 9 million ton rollback, respectively, when 1995 levels under each option are compared with 1995 levels expected under current policy. This discrepancy is caused by the emissions growth that would occur between 1980 and 1995.

The model estimates the cheapest way to produce electricity nationwide, taking into account the cost of purchasing coal from different regions, the expense of transporting it, the cost of using different types of power plants as well as building new ones, and the effect of different emission regulations. Coal is distinguished by its origination in 31 supply regions (more than the actual number of states that produce coal) for shipment to 44 demand regions (representing roughly each state in the continental United States). Coal is further differentiated by sulfur content, coal rank, and energy content, which are later used to determine the type of power plant in which it can be burned. Demand regions are defined, in part, by their prevailing emission regulations and expected growth in electricity demand.

After a particular policy scenario has been established--including constraints on SO_2 emissions in each demand region--the model estimates an optimal solution based on the lowest annual real power cost that can be obtained in each region under the specified policy. Solutions are provided for three target years: 1985, 1990, and 1995. For this study, most policy changes were considered to be implemented fully by the 1995 solution year, with most comparisons among different options also based on that year. As part of this analysis, many assumptions used in the model were altered and portions of the computer code were revised. The appendix contains more details on these revisions and the methodology in general. In addition, caution should be exercised when interpreting model results (see box).

Emission Projections Under Each Rollback Option

Four different SO_2 rollback schemes are examined in this chapter: [11]

- **Option II-1A** would require an 8 million ton reduction of SO_2 from 1980 utility emission levels, allowing utilities to choose either fuel switching or scrubbers (whichever is cheaper) as a compliance strategy;

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11. Because of the many options discussed in this paper, CBO has devised a standard option format. The roman numeral identifies the chapter in which the options are presented--for example, option II appears in this chapter. In this chapter, the arabic number 1 identifies an 8 million ton reduction of SO_2, while the arabic number 2 identifies a 10 million ton reduction. The capital letters A and B identify the specific type of option--fuel switching or scrubbers, taxes and subsidies, and so forth. For easy identification, a glossary defining all the emission rollback options that appear in this and subsequent chapters is presented at the end of this report.

- **Option II-1B** would also require an 8 million ton rollback, but would restrict how much utilities could switch fuels by requiring that 80 percent of the same type of coal purchased in 1985 be purchased in 1995;

- **Option II-2A** is like Option II-1A above, but differs by requiring a 10 million ton rollback; and

- **Option II-2B** is like Option II-1B above, but again differs by requiring a 10 million ton rollback.

INTERPRETING MODEL RESULTS

To estimate the costs and coal-market effects of alternative acid rain control policies, CBO used the National Coal Model (NCM), which is housed and maintained by the Energy Information Administration (EIA). The NCM is a linear programming model, which has been used by EIA and other analysts to study the effects of fuel and transportation costs, government energy policies, and environmental regulations on national coal production and use in the electric utility industry.

Linear programming can provide the least costly (or "least-cost" in economic terminology) solutions to various problems concerning resource allocation. This particular linear program estimates the lowest annual electricity cost that can be attained in different U.S. regions, subject to constraints on how much sulfur dioxide can be emitted in each region, on where certain types of coal can be obtained and at what cost, and on the cost and effectiveness of scrubbers in reducing emissions. The model's results provide the least-cost solution for each policy. Real-life situations, however, rarely afford a least-cost solution because of small and varied inefficiencies present in all systems and behavior that does not replicate the ideal market. Moreover, in developing SO_2 reduction strategies, states may fail to specify least-cost emission reductions for utilities within their borders, a possibility that is not recognized in the model. Thus, when interpreting model results, it is important to remember that the costs shown for individual policy options probably reflect a lower bound of costs for that policy, with actual costs likely being higher. Conservative assumptions are used throughout the analysis to help counter this bias, though. More useful in many cases than absolute costs are the **differences** shown among optional policies. Thus, focusing on a $4 billion difference between two policies may be a more accurate reflection of costs than reporting that one policy costs $6 billion and the other $2 billion.

Options II-1A and II-2A would allow a choice in meeting reduction standards, much as the first utility NSPS of 1971 did. In contrast, Options II-1B and II-2B would mitigate production and employment losses in regional coal markets--particularly in the Midwest--by their tendency to "lock in" many current coal contracts. By denying such fuel flexibility, however, the second set of options would require more scrubbers, thus producing higher overall costs.

Both the 8 million ton and 10 million ton rollback programs would lower emissions substantially by 1995, although the differences between the 1995 predicted levels under current policy and either rollback option would reflect something less than the 8 million ton or 10 million ton goal specified, because of growth in new source emissions after 1980, the baseline year for measuring reductions. Under either scheme, the midwestern states of Ohio, Indiana, Illinois, and Missouri and the eastern states of West Virginia and Pennsylvania would face the largest emission reductions (see Table 3). Each of these states contains a large amount of coal-fired capacity that emits SO_2 in quantities greater than 1.2 pounds per million Btus of fuel input, the standard that serves as the basis of the excess emissions formula. In fact, many power plants in the Midwest (built before the first utility NSPS was issued) discharge SO_2 in excess of 6 pounds per million Btus under current state regulations.

To lower emissions significantly from these power plants, the utilities would have to use lower-sulfur coal or install scrubbers. If the midwestern plants wanted to switch to a lower-sulfur coal, they would have to import fuel from the East (Appalachia) or the West (Wyoming, Montana, or Colorado). In contrast, power plants in both West Virginia and Pennsylvania are closer to indigenous low-sulfur coal mines, and could use this locally available but more expensive fuel. In both cases, costs probably would rise.

Compared with power plants in the Midwest, Pennsylvania, and West Virginia, most of those in the northeastern states would face relatively low emission reduction requirements. Strict measures to control sulfur dioxide already exist in many parts of the Northeast, leaving little room for further improvement. Although the actual quantity of sulfur dioxide released in the region is lower than in many less populated areas to the south, emission sources concentrated near many urban centers have caused high atmospheric levels. This has prompted strict SO_2 control measures on nearby combustion sources, including large numbers of coal- and oil-fired utilities. Thus, emissions from most plants in the Northeast already are lower than the standard of 1.2 pounds of SO_2 per million Btus used in the excess emissions formula.

Overall Cost of Emission Rollback Programs

Several measures of cost are used throughout this report (see box). One important measure estimates a total stream of costs expended by the electric utility industry over a specified period to meet a SO_2 rollback. This stream of costs--summed and discounted over the 1986 through 2015 period --provides an estimate of total program costs in 1985 dollars. Thus, an 8 million ton SO_2 rollback would have a discounted program cost of $20.4 billion, assuming fuel switching was unconstrained (Option II-1A), and about $23.1 billion (in discounted 1985 dollars) assuming limits were placed

COST MEASURES USED IN THIS REPORT

This report uses several measures of cost to compare different policies. These measures attempt to account for variations in abatement levels, cost-sharing provisions, and the assumed timing of costs and emission reductions over the period considered. In this chapter, three concepts are used:

Annual Utility Cost is the cost that governs utility choices in the National Coal Model and that determines rates in the electricity price model used in this analysis (see appendix). It consists of the annual real capital and variable costs associated with the production and transmission of electricity in a given year, usually 1995 for the base case and alternatives. These include the cost of purchasing and transporting coals to various regions, as well as those of operating power plants under specific emission limits.

Discounted Program Cost is a measure of overall utility costs incurred from 1986 through 2015 to meet an SO_2 emission reduction policy. (The 1986-2015 time frame simply represents the period over which most rollback costs likely will be incurred.) A stream of annual real utility costs first are estimated for each year during the 1986-2015 period, based on results from the NCM; this series is discounted by 3.7 percent and then summed to give discounted program costs as a net present value (producing discounted 1985 dollars). (Discounting converts future dollar figures to their value in an earlier year, reflecting the notion that a dollar held in the future is worth less than one held today).

Cost-Effectiveness is a measure that represents average abatement costs over the 1986-2015 period. This measure takes into account the amount of emission rollback, but assigns no dollar value to the benefits that might accrue from them. The numerator of this fraction is simply discounted program costs as calculated above. The denominator consists of a summed series of discounted (at 3.7 percent) annual emission reductions relative to the base case (roughly representing the value of benefits obtained). For a given emission reduction over the period, one policy can be more cost-effective than another--that is, expend fewer dollars per ton of SO_2 reduced--if its costs are lower or if they occur later. Likewise, for a given stream of costs, a policy can be more cost-effective than another if its emission reduction is greater or if it occurs earlier.

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TABLE 3. PROJECTED 1995 EMISSIONS FOR 8 AND 10 MILLION TON SO_2 REDUCTION PROGRAMS, BY STATE [a] (In thousands of tons of SO_2)

State	Base Case 1985	Base Case 1995	8 Million Ton Reduction Option II-1A	8 Million Ton Reduction Option II-1B	10 Million Ton Reduction Option II-2A	10 Million Ton Reduction Option II-2B
Alabama, Mississippi	586	704	489	489	414	415
Arizona	114	122	117	117	106	115
Arkansas, Oklahoma, Louisiana	200	336	304	292	302	293
California	3	25	25	25	25	25
Carolinas, North and South	728	1,063	606	615	577	577
Colorado	71	92	94	94	94	90
Dakotas, North and South	60	105	105	105	105	105
Florida	489	772	605	568	566	546
Georgia	731	635	407	403	352	341
Idaho	0	0	0	0	0	0
Illinois	1,071	1,142	566	566	408	408
Indiana	1,210	1,433	799	800	553	554
Iowa	259	326	192	193	167	167
Kansas, Nebraska	154	174	167	173	163	165
Kentucky	707	796	512	527	466	449
Maine, Vermont, New Hampshire	109	64	56	59	44	45
Maryland, Delaware	282	371	215	215	189	189
Massachusetts, Connecticut, Rhode Island	294	305	241	241	219	219
Michigan	525	598	423	414	374	374
Minnesota	176	230	159	159	146	146

(Continued)

TABLE 3. (Continued)

State	Base Case 1985	Base Case 1995	8 Million Ton Reduction Option II-1A	8 Million Ton Reduction Option II-1B	10 Million Ton Reduction Option II-2A	10 Million Ton Reduction Option II-2B
Missouri	1,133	1,257	482	483	293	295
Montana	71	71	68	73	68	69
Nevada	75	90	80	80	80	80
New Mexico	43	62	62	62	62	62
New York (Downstate), New Jersey	269	270	247	247	245	242
New York (Upstate)	325	343	193	193	141	143
Ohio	1,901	2,017	963	963	629	629
Pennsylvania	1,345	1,439	839	839	578	599
Tennessee	676	761	421	421	281	281
Texas	369	586	569	571	567	569
Utah	45	87	61	63	61	63
Virginia, District of Columbia	97	213	180	176	175	173
Washington, Oregon	37	111	108	102	104	98
West Virginia	968	1,042	511	512	421	417
Wisconsin	574	746	272	272	199	200
Wyoming	58	69	70	69	70	69
Total	15,756	18,455	11,208 b/	11,179 b/	9,241 b/	9,209 b/

SOURCE: Congressional Budget Office.

a. To permit greater computational efficiency, the National Coal Model groups some states or portions of states into common regions.

b. Neither the 8 million ton nor the 10 million ton rollback options would meet the goal specified if measured against 1995 base case emissions because of growth in new source emissions after 1980, the baseline year for measuring reductions.

on the amount of fuel switching allowed (Option II-1B). Similarly, the discounted program cost of a 10 million ton SO_2 rollback would range from $34.5 billion (Option II-2A) to $50.8 billion (Option II-2B), depending on whether fuel switching was allowed or restricted (all in discounted 1985 dollars). Table 4 shows total program costs and cost-effectiveness estimates of each rollback option compared with current policy.

The cost-effectiveness figures shown in Table 4 provide a different measure from program costs, one closely related to average abatement cost. These represent the discounted program costs under each option divided by the amount of SO_2 reduced from current policy levels over the 1986-2015 period. They show that, under either program, emission reductions would be cheaper if the coal market is unrestricted. When fuel switching is allowed, the average annual cost to abate one ton of SO_2 would be $270 under an 8 million ton program (Option II-1A). When an attempt is made to restrict fuel switching, this number jumps to $306 per ton of SO_2 abated (Option II-1B). Likewise, a 10 million ton SO_2 reduction would cost $360 per ton of

TABLE 4. COMPARISON OF TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF TWO ROLLBACK PROGRAMS

	8 Million Ton SO_2 Reduction		10 Million Ton SO_2 Reduction	
	Option II-1A	Option II-1B	Option II-2A	Option II-2B
Total Program Cost (In billions of discounted 1985 dollars) a/	20.4	23.1	34.5	50.8
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	306	360	528

SOURCE: Congressional Budget Office.

a. Reflects present value of sum of annual utility costs incurred from 1986 through 2015, discounted to 1985 dollars. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reductions measured over the 1986-2015 period.

SO_2 abated when coal markets are not restricted (Option II-2A), compared with $528 a ton when fuel choices are limited to maintain current patterns. In each case, costs would increase because more scrubbers would have to be used to meet emission standards.[12] Moreover, the marginal cost of emission reductions would rise as abatement targets increased from 8 million tons to 10 million tons.

Annual Cost to Utilities. The annual cost to utilities for an 8 million ton SO_2 rollback program would range between $1.9 billion (Option II-1A) and $2.1 billion (Option II-1B), based on the 1995 cost difference between current policy and each option (see Table 5). Similarly, a 10 million ton program would cost utilities between $3.2 billion (Option II-2A) and $4.7 billion (Option II-2B) per year in 1995 (see Table 6). The difference between the higher and lower costs of each option depends on whether current coal-market patterns are preserved (more scrubbers would be needed if current coal contracts are kept) or whether fuel switching would be allowed as a compliance strategy. If fuel switching is restricted, roughly $8.8 billion in capital would be needed above current policy between 1986 and 1995 to meet the 8 million ton reduction, and about $25.2 billion more would be needed to meet the 10 million ton reduction. If fuel switching is allowed (which would lower scrubbing requirements) the additional capital requirements between 1986 and 1995 would be greatly reduced: $4.4 billion versus $8.8 billion would be needed under the 8 million ton case and $11.2 billion versus $15.2 billion under the 10 million ton case. These large savings in expected capital outlays would more than offset the higher costs of using lower-sulfur fuel.

Two general patterns emerge from the effect of a SO_2 emissions rollback on annual utility costs, although each has several exceptions. First, utilities in Pennsylvania, West Virginia, Ohio, Indiana, Illinois, and Missouri would bear about half of the total cleanup costs, regardless of whether coal switching occurs or whether the required SO_2 reduction is 8 million tons or 10 million tons. Thus, utilities in these states would face annual costs in

12. Recent oil price reductions have two implications for this analysis. First, should oil prices continue to fall or remain stable in real terms until 1995, the overall cost of each option could fall, partly from reduced costs in existing oil-fired plants and partly from plants shifting from more expensive gas to less expensive oil (for those plants capable of using either fuel). A possible countervailing trend, however, is the potential for increased electricity demand as prices fall. Second, if oil prices remain lower than expected, rail rates--especially for long-haul shipments--might not be as costly as once thought. Thus, greater than expected western coal penetration into eastern markets might occur under an acid rain control plan, making coal-market restrictions even more costly. In both cases, while falling oil prices might lower the absolute costs of each option described in this study, the relative rankings between them would remain unchanged. See the appendix for more details.

TABLE 5. ANNUAL UTILITY COSTS AS OF 1995 OF 8 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of 1985 dollars)

State	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Alabama, Mississippi	4,224	4,307	4,291	83	67
Arizona	1,944	1,930	1,954	-15	10
Arkansas, Oklahoma, Louisiana	9,591	9,698	9,716	107	125
California	10,565	10,722	10,747	157	182
Carolinas, North and South	4,759	4,886	4,845	127	86
Colorado	1,093	1,097	1,114	4	21
Dakotas, North and South	567	565	569	-1	3
Florida	6,127	6,202	6,204	75	77
Georgia	2,555	2,618	2,601	63	45
Idaho	221	221	221	0	0
Illinois	4,189	4,312	4,278	124	89
Indiana	3,095	3,202	3,200	107	105
Iowa	1,230	1,288	1,304	58	74
Kansas, Nebraska	1,854	1,860	1,863	7	9
Kentucky	3,103	3,170	3,142	68	40
Maine, Vermont, New Hampshire	1,123	1,119	1,121	-4	-2
Maryland, Delaware	1,885	1,853	1,698	-32	-186
Massachusetts, Connecticut, Rhode Island	3,513	3,633	3,629	120	116

(Continued)

TABLE 5. (Continued)

State	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Michigan	2,817	2,874	2,865	57	48
Minnesota	1,186	1,184	1,223	-2	37
Missouri	2,024	2,137	2,150	113	126
Montana	676	675	681	-1	5
Nevada	1,096	1,122	1,120	25	24
New Mexico	1,158	1,138	1,163	-21	5
New York (Downstate), New Jersey	4,878	4,902	4,894	25	16
New York (Upstate)	2,395	2,443	2,437	48	41
Ohio	4,239	4,397	4,378	158	138
Pennsylvania	5,512	5,711	5,925	199	413
Tennessee	2,078	2,118	2,133	40	55
Texas	15,852	15,834	15,840	-18	-12
Utah	1,345	1,367	1,357	22	12
Virginia, District of Columbia	1,884	1,923	1,925	39	41
Washington, Oregon	4,219	4,147	4,155	-72	-64
West Virginia	1,784	1,936	2,028	153	244
Wisconsin	1,572	1,671	1,707	98	135
Wyoming	1,026	1,034	1,032	8	6
Total	117,380	119,298	119,510	1,919	2,130

SOURCE: Congressional Budget Office.

TABLE 6. ANNUAL UTILITY COSTS AS OF 1995 OF 10 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of 1985 dollars)

State	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Difference from 1995 Base Case: Option II-2B
Alabama, Mississippi	4,224	4,364	4,557	140	333
Arizona	1,944	1,943	1,951	-2	6
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,778	132	187
California	10,565	10,822	10,849	257	284
Carolinas, North and South	4,759	4,895	4,829	136	70
Colorado	1,093	1,100	1,134	7	41
Dakotas, North and South	567	565	570	-1	3
Florida	6,127	6,198	6,184	71	57
Georgia	2,555	2,622	2,602	67	46
Idaho	221	221	221	0	0
Illinois	4,189	4,432	4,404	244	216
Indiana	3,095	3,233	3,477	139	382
Iowa	1,230	1,327	1,216	97	-15
Kansas, Nebraska	1,854	1,862	1,958	8	104
Kentucky	3,103	3,499	3,500	396	398
Maine, Vermont, New Hampshire	1,123	1,123	1,125	0	2
Maryland, Delaware	1,885	1,654	1,707	-231	-178
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,669	165	156

(Continued)

TABLE 6. (Continued)

State	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Difference from 1995 Base Case: Option II-2B
Michigan	2,817	2,944	2,911	127	94
Minnesota	1,186	1,228	1,217	42	31
Missouri	2,024	2,206	2,270	182	246
Montana	676	675	682	-1	6
Nevada	1,096	1,122	1,121	25	25
New Mexico	1,158	1,144	1,163	-14	5
New York (Downstate), New Jersey	4,878	5,200	4,892	322	14
New York (Upstate)	2,395	2,236	2,523	-160	128
Ohio	4,239	4,271	4,898	32	659
Pennsylvania	5,512	6,056	6,075	544	563
Tennessee	2,078	2,028	2,023	-51	-55
Texas	15,852	15,844	15,853	-7	2
Utah	1,345	1,368	1,359	23	13
Virginia, District of Columbia	1,884	1,926	1,921	42	37
Washington, Oregon	4,219	4,068	4,076	-151	-143
West Virginia	1,784	2,278	2,377	494	594
Wisconsin	1,572	1,734	1,981	162	408
Wyoming	1,026	1,039	1,033	12	7
Total	117,380	120,630	122,105	3,250	4,725

SOURCE: Congressional Budget Office.

1995 of about $854 million (out of the national total of $1.9 billion) to meet an 8 million ton SO_2 control program that allowed fuel switching (Option II-1A); if coal switching was not allowed (Option II-1B), these states would face annual costs of about $1.1 billion compared with the national total of $2.1 billion. Similarly, under a 10 million ton reduction program, 1995 annual costs for utilities in these six states would range between $1.6 billion (Option II-2A) and $2.7 billion (Option II-2B) out of the respective national totals of $3.2 billion and $4.7 billion, with an unencumbered coal-market policy providing the lower costs in each range. The disproportionately large costs would arise because these states would need to achieve the greatest proportion of emission reductions, regardless of whether they import costly, low-sulfur coal or install scrubbers.

These results illustrate the second trend: costs would be greatly increased if coal switching was restricted and scrubber use increased accordingly. In the 8 million ton rollback program, the option that would restrict fuel switching produces 10 percent higher costs than the option that would not (see Table 5); in the 10 million ton program, the no fuel switching case has over 50 percent higher costs (see Table 6). This implies that preserving current coal supply and demand patterns when reducing SO_2 emissions can cost more than allowing freedom of fuel choice. Individual exceptions to this condition exist, however. For example, under an 8 million ton case, it appears almost equally expensive for plants in Indiana to import and burn low-sulfur coal as it would be to burn high-sulfur coal with a scrubber (see Table 5). When a ten million ton reduction is required, however, the cost per ton of SO_2 removal (cost-effectiveness) is higher when more scrubbing is used instead of fuel switching (see Table 6).

Finally, some areas could experience lower costs in 1995 under a sulfur dioxide rollback plan than under current policy. For example, in all cases, costs in Maryland and Delaware and Washington and Oregon would fall slightly (compared with the 1995 base case) if a SO_2 emission reduction plan was instituted. One explanation is the expected decline in high-sulfur coal prices caused by the SO_2 rollback requirements (under any scenario, high-sulfur coal prices will fall while low-sulfur coal prices will rise). In such situations, plants already burning high-sulfur coal (whether or not they were using a scrubber) could experience a price reduction. Another reason is that, under a rollback program, some utilities would choose to build less new capacity or generate less power from existing plants, importing electricity from other regions instead to control emissions in their own areas. Such a choice would show lower generation costs in the region importing power since it would generate less electricity than under current policy. Consumers, however, would not necessarily benefit from this choice because the imported electricity would probably be more expensive.

Effect on Electricity Prices. Nationally, the 8 million ton and 10 million ton reduction programs would raise average electricity prices between 1 percent and 5 percent, respectively, from projected 1995 levels under current policy (see Tables 7 and 8). But larger regional price changes could occur under these same emission reductions schemes. For example, electricity prices in West Virginia could rise as much as 31 percent over expected 1995 levels under the 8 million ton rollback case, and could more than triple under the 10 million ton rollback option. (A large percentage of these high increases represents the passthrough to consumers of significant amounts of capital costs in 1995, which would be incurred to meet the control program deadlines; as this debt is retired in the rate base, prices would fall in later years.) 13/

In contrast, electricity prices under either rollback plan could fall in some areas that would export power--such as North and South Dakota, Nevada, and New Mexico--since the power sold outside the state could subsidize power sold within the state. The electricity price model used in this study employs such an assumption in assigning costs. Actual power transactions across state borders, however, are subject to a myriad of pricing rules and such an assumption may not always hold.

Shifts in Coal Supply and Demand Patterns

Domestic coal production is expected to rise from its current level of around 883 million tons per year to about 1.13 billion tons annually by 1995. Requirements to control sulfur dioxide emissions from utilities should not affect these national projections but, depending on the nature of the regulation, they could affect regional output. A key anticipated trend is that, under all SO_2 reduction scenarios, coal production in the Midwest and Pennsylvania would fall, as demand shifts from high-sulfur coal to low-sulfur coal. This trend--which will occur to some extent even under current laws--could be mitigated but not reversed by limiting coal switching.

Assuming no change in current policy, the states of Ohio, Illinois, Indiana, and Pennsylvania could experience slightly lower coal production in 1995 compared with 1985--from 197 million tons to 192 million tons (see

13. The schedule of costs that are passed to consumers in electricity prices (shown in Tables 7 and 8) is somewhat different than the annual levelized costs for utilities (shown in Tables 5 and 6), which represent the annual average of annuitized capital and operating costs over the life of the program. Most electricity rate decisions allow capital costs to be recovered during the early years of a plant's economic life. Rates during this period are, therefore, higher than the average rates experienced over the life of the plant. Thus, the electricity prices shown in Tables 7 and 8 reflect actual first-year prices of the program, and are not based on average annual costs over the utility's lifetime.

TABLE 7. ELECTRICITY PRICE CHANGES AS OF 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case 1995	Option II-1A	Option II-1B	Percent Difference from 1995 Base Case: Option II-1A	Percent Difference from 1995 Base Case: Option II-1B
Alabama, Mississippi	46.6	46.9	47.1	0.8	1.1
Arizona	55.9	55.5	55.9	-0.6	0.1
Arkansas, Oklahoma, Louisiana	77.5	78.5	78.3	1.3	1.0
California	78.3	78.3	78.5	0.0	0.3
Carolinas, North and South	50.3	51.2	50.9	2.0	1.2
Colorado	57.4	57.6	60.6	0.3	5.6
Dakotas, North and South	32.1	31.4	31.6	-2.4	-1.6
Florida	75.2	76.0	75.7	1.2	0.7
Georgia	54.2	56.1	55.9	3.6	3.2
Idaho	43.0	43.3	43.2	0.6	0.5
Illinois	59.3	60.8	60.5	2.4	2.0
Indiana	53.9	55.0	55.0	2.1	2.0
Iowa	59.3	61.1	62.0	2.9	4.5
Kansas, Nebraska	57.9	58.1	58.2	0.3	0.6
Kentucky	55.0	55.9	55.5	1.7	0.9
Maine, Vermont, New Hampshire	80.9	80.4	80.6	-0.6	-0.4
Maryland, Delaware	66.4	67.6	68.3	1.9	2.9
Massachusetts, Connecticut, Rhode Island	80.6	83.0	83.1	3.0	3.2

(Continued)

TABLE 7. (Continued)

State	Base Case 1995	Option II-1A	Option II-1B	Percent Difference from 1995 Base Case: Option II-1A	Percent Difference from 1995 Base Case: Option II-1B
Michigan	57.7	58.4	58.2	1.2	1.0
Minnesota	54.2	54.4	55.1	0.5	1.8
Missouri	59.6	62.3	62.7	4.5	5.1
Montana	41.1	41.0	41.5	-0.4	1.0
Nevada	48.8	47.1	47.1	-3.6	-3.6
New Mexico	68.2	66.9	64.0	-1.9	-6.1
New York (Downstate), New Jersey	99.3	100.0	99.8	0.7	0.5
New York (Upstate)	53.1	53.7	53.6	1.0	0.8
Ohio	57.8	59.8	59.3	3.4	2.5
Pennsylvania	58.2	59.3	59.6	2.0	2.4
Tennessee	46.9	47.3	47.1	1.0	0.5
Texas	79.4	79.4	79.2	0.0	-0.3
Utah	39.0	44.7	44.6	14.6	14.4
Virginia, District of Columbia	58.7	60.0	59.9	2.2	1.9
Washington, Oregon	35.4	35.3	35.3	-0.3	-0.1
West Virginia	27.2	26.8	35.7	-1.6	31.2
Wisconsin	52.7	55.1	57.0	4.6	8.2
Wyoming	43.0	43.3	43.2	0.6	0.5
National Average	62.0	62.8	62.9	1.3	1.5

SOURCE: Congressional Budget Office.

TABLE 8. ELECTRICITY PRICE CHANGES AS OF 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case 1995	Option II-2A	Option II-2B	Percent Difference from 1995 Base Case: Option II-2A	Percent Difference from 1995 Base Case: Option II-2B
Alabama, Mississippi	46.6	45.6	43.2	-2.1	-7.3
Arizona	55.9	55.9	55.8	0.0	-0.1
Arkansas, Oklahoma, Louisiana	77.5	78.8	78.9	1.6	1.7
California	78.3	78.3	78.6	0.0	0.4
Carolinas, North and South	50.3	51.2	50.6	1.8	0.8
Colorado	57.4	57.7	61.3	0.6	6.8
Dakotas, North and South	32.1	30.4	30.5	-5.3	-5.2
Florida	75.2	75.9	75.3	1.0	0.2
Georgia	54.2	56.2	55.8	3.7	3.0
Idaho	43.0	43.5	43.3	1.0	0.6
Illinois	59.3	62.4	63.2	5.1	6.5
Indiana	53.9	55.5	59.8	3.0	10.9
Iowa	59.3	62.3	61.9	5.0	4.3
Kansas, Nebraska	57.9	58.4	58.7	0.9	1.4
Kentucky	55.0	55.0	52.3	0.0	-4.9
Maine, Vermont, New Hampshire	80.9	80.3	80.4	-0.7	-0.6
Maryland, Delaware	66.4	69.2	70.2	4.2	5.8
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.5	5.1	4.9

(Continued)

TABLE 8. (Continued)

State	Base Case 1995	Option II-2A	Option II-2B	Percent Difference from 1995 Base Case: Option II-2A	Percent Difference from 1995 Base Case: Option II-2B
Michigan	57.7	58.2	57.9	0.9	0.4
Minnesota	54.2	55.1	57.4	1.8	6.0
Missouri	59.6	63.8	65.5	7.0	9.9
Montana	41.1	41.0	41.7	-0.3	1.3
Nevada	48.8	47.0	47.0	-3.7	-3.7
New Mexico	68.2	67.2	64.1	-1.5	-6.1
New York (Downstate), New Jersey	99.3	100.3	100.1	1.0	0.9
New York (Upstate)	53.1	55.3	55.3	4.1	4.1
Ohio	57.8	62.2	80.3	7.6	38.8
Pennsylvania	58.2	60.0	60.4	3.1	3.8
Tennessee	46.9	50.7	53.7	8.1	14.6
Texas	79.4	79.4	79.3	0.0	-0.2
Utah	39.0	44.7	44.7	14.6	14.6
Virginia, District of Columbia	58.7	60.7	65.8	3.4	12.0
Washington, Oregon	35.4	35.4	35.5	0.2	0.3
West Virginia	27.2	46.7	92.0	71.5	238.2
Wisconsin	52.7	57.9	65.2	9.9	23.8
Wyoming	43.0	43.5	43.3	1.0	0.6
National Average	62.0	63.5	65.4	2.5	5.4

SOURCE: Congressional Budget Office.

Tables 9 and 10). Total production from these same states in 1995 could drop even further under SO_2 reduction plans--by as much as 25 percent under an 8 million ton rollback (Option II-1A) and by as much as 39 percent under a 10 million ton reduction (Option II-2A), assuming no restrictions are placed on choice of fuels. If fuel switching is severely limited, future pro-

TABLE 9. COAL PRODUCTION CHANGES AS OF 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of tons)

State	Base Case 1985	Base Case 1995	Option II-1A	Option II-1B	Difference from 1995 Base Case: Option II-1A	Difference from 1995 Base Case: Option II-1B
Alabama	26.6	23.8	25.5	21.4	1.7	-2.4
Arizona	10.3	14.2	13.8	14.2	-0.4	0.0
Colorado	17.0	19.1	20.3	24.5	1.3	5.5
Illinois	62.1	56.4	46.2	48.9	-10.2	-7.4
Indiana	36.6	29.2	24.3	25.3	-4.9	-3.9
Iowa	0.6	1.5	0.5	0.5	-1.0	-1.0
Kansas	1.0	2.5	0.4	1.2	-2.0	-1.3
Kentucky	158.3	208.9	211.6	193.3	2.7	-15.7
Maryland	3.3	2.5	1.6	2.3	-0.9	-0.2
Missouri	5.6	8.1	5.4	5.5	-2.7	-2.6
Montana	32.9	34.0	26.0	41.1	-8.0	7.1
New Mexico	19.5	31.9	31.8	32.2	0.0	0.3
North Dakota	25.9	22.7	22.7	22.4	0.0	-0.3
Ohio	33.3	24.3	4.0	9.8	-20.2	-14.4
Oklahoma	4.5	7.7	7.0	7.0	-0.6	-0.6
Pennsylvania	65.0	82.3	69.4	69.2	-12.9	-13.1
Tennessee	7.1	5.3	6.9	4.8	1.6	-0.6
Texas	45.2	109.4	108.8	98.4	-0.6	-10.9
Utah	13.0	31.6	31.8	31.1	0.2	-0.4
Virginia	44.0	50.6	57.2	58.6	6.6	8.0
Washington	4.2	0.5	0.5	0.5	0.0	0.0
West Virginia	132.1	232.2	261.7	259.2	29.4	27.0
Wyoming	135.2	130.5	151.7	160.3	21.2	29.8
U.S. Total	883.2	1,128.9	1,129.1	1,131.8	0.2	2.9

SOURCE: Congressional Budget Office.

duction would still fall, but by less; expected 1995 levels would be 20 percent lower under the 8 million ton case (Option II-1B) and 23 percent lower under the 10 million ton case (Option II-2B). In contrast, states with large reserves of low-sulfur coal--such as West Virginia, Wyoming, and Colorado--would increase their expected 1995 production over the base case under all SO_2 rollback alternatives.

TABLE 10. COAL PRODUCTION CHANGES AS OF 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK, BY STATE (In millions of tons)

State	Base Case 1985	Base Case 1995	Option II-2A	Option II-2B	Difference from 1995 Base Case: Option II-2A	Difference from 1995 Base Case: Option II-2B
Alabama	26.6	23.8	22.1	20.1	-1.7	-3.7
Arizona	10.3	14.2	13.9	14.2	-0.3	0.0
Colorado	17.0	19.1	23.5	31.9	4.5	12.8
Illinois	62.1	56.4	37.6	47.0	-18.8	-9.4
Indiana	36.6	29.2	19.7	23.5	-9.5	-5.7
Iowa	0.6	1.5	0.5	0.5	-1.0	-1.0
Kansas	1.0	2.5	0.4	1.5	-2.0	-1.0
Kentucky	158.3	208.9	195.9	187.8	-13.0	-21.1
Maryland	3.3	2.5	1.5	2.3	-1.0	-0.2
Missouri	5.6	8.1	5.3	5.4	-2.8	-2.7
Montana	32.9	34.0	26.0	40.5	-8.1	6.5
New Mexico	19.5	31.9	31.9	32.5	0.0	0.7
North Dakota	25.9	22.7	22.7	22.2	0.0	-0.5
Ohio	33.3	24.3	4.0	8.9	-20.2	-15.3
Oklahoma	4.5	7.7	7.0	7.0	-0.6	-0.7
Pennsylvania	65.0	82.3	56.3	68.8	-26.0	-13.5
Tennessee	7.1	5.3	4.9	4.8	-0.4	-0.6
Texas	45.2	109.4	108.8	98.5	-0.6	-10.8
Utah	13.0	31.6	32.8	31.1	1.2	-0.5
Virginia	44.0	50.6	56.0	55.2	5.3	4.6
Washington	4.2	0.5	0.5	0.5	0.0	0.0
West Virginia	132.1	232.2	274.6	228.2	42.4	-4.0
Wyoming	135.2	130.5	191.2	205.2	60.7	74.7
U.S. Total	883.2	1,128.9	1,137.1	1,137.6	8.1	8.6

SOURCE: Congressional Budget Office.

Under either rollback scheme--but especially when fuel choice is not restricted--demand would increase for low-sulfur coal at the expense of high-sulfur coal. (In this study, low-sulfur coal is defined as producing fewer than 1.2 pounds of SO_2 per million Btus, and high-sulfur coal as more than 5.0 pounds of SO_2 per million Btus.) Under current regulations, low-sulfur coal production in 1995 is estimated to be 368 million tons, while high-sulfur coal production is estimated at 198 million tons. Under an 8 million ton reduction scenario without any fuel restrictions (Option II-1A), low-sulfur coal production could reach 485 million tons by 1995, and high-sulfur coal production could fall to 146 million tons. Under a similar 10 million ton program (Option II-2A), low-sulfur coal production could jump to 557 million tons in 1995, while high sulfur coal production could plummet to 118 million tons. The "winners" from such an effect would be the low-sulfur coal producing areas of the East (mostly West Virginia) and the western coal producing states in general. The "losers," of course, would be the midwestern states and Pennsylvania, which produce an abundance of high-sulfur coal.

Effect on Coal Market Employment

From the actual and estimated coal production figures described above, CBO estimated the effects of a SO_2 rollback scheme on coal mining jobs, using labor productivity (average tons of coal produced per miner per year) available for each region of the country. 14/ Two types of job measures are important: changes estimated from current actual job holders, and changes estimated from expected 1995 job slots under current law.

Changes from 1985 Employment. The CBO estimates that from 1985 through 1995, direct coal mining employment should grow nationally from about 208,000 to just over 275,000. Enactment of a SO_2 rollback policy (see Tables 11 and 12) might lower these national estimates somewhat, as demand inevitably increased for low-sulfur western coal, which is mined principally by highly productive surface methods that require less labor. Of more concern, however, are the regional shifts that might occur in the coal mining job market.

14. These projections of employment are based on productivity measures contained in Department of Energy, Energy Information Agency, *Coal Production 1983*. These values include all employees engaged in production, preparation, processing, development, maintenance, repair, and shop or yard work at mining operations. They exclude office workers, but include mining operations management and all technical and engineering personnel. Productivity was assumed to remain constant over the period of analysis.

TABLE 11. COAL MINING EMPLOYMENT CHANGES AS OF 1995 UNDER 8 MILLION TON SO_2 ROLLBACK, BY COAL-PRODUCING STATE

	Number of Jobs				Difference from 1985			Difference from 1995 Base Case	
State	Base Case 1985	Base Case 1995	Option II-1A	Option II-1B	Base Case 1995	Option II-1A	Option II-1B	Option II-1A	Option II-1B
Alabama	9,077	8,124	8,714	7,318	-953	-363	-1,759	590	-805
Arizona	855	1,177	1,141	1,177	322	286	322	-36	0
Colorado	2,927	3,288	3,510	4,235	360	583	1,307	223	947
Illinois	16,228	14,733	12,068	12,787	-1,495	-4,160	-3,441	-2,665	-1,946
Indiana	6,694	5,342	4,446	4,623	-1,352	-2,248	-2,071	-896	-719
Iowa	136	344	110	110	208	-27	-26	-234	-234
Kansas	306	753	129	353	447	-177	47	-624	-399
Kentucky	47,753	63,014	63,818	58,291	15,261	16,065	10,538	804	-4,723
Maryland	923	695	447	649	-228	-476	-274	-248	-46
Missouri	1,348	1,948	1,297	1,323	600	-51	-26	-651	-625
Montana	1,209	1,251	956	1,513	42	-253	303	-295	261
New Mexico	1,741	2,846	2,844	2,876	1,104	1,103	1,134	-2	30
North Dakota	1,570	1,375	1,374	1,359	-195	-196	-211	-1	-15
Ohio	9,797	7,136	1,183	2,895	-2,662	-8,614	-6,902	-5,953	-4,241
Oklahoma	1,377	2,344	2,146	2,158	967	770	781	-197	-186
Pennsylvania	23,134	29,299	24,701	24,624	6,165	1,567	1,490	-4,598	-4,675
Tennessee	2,685	2,010	2,616	1,796	-675	-69	-889	606	-214
Texas	2,851	6,890	6,855	6,201	4,039	4,004	3,350	-35	-689
Utah	3,283	7,978	8,040	7,867	4,695	4,757	4,583	62	-111
Virginia	16,803	19,339	21,852	22,387	2,536	5,049	5,584	2,513	3,048
Washington	426	48	48	48	-378	-378	-378	0	0
West Virginia	50,893	89,473	100,811	99,864	38,580	49,918	48,971	11,337	10,391
Wyoming	5,975	5,768	6,706	7,086	-207	731	1,111	938	1,318
U.S. Total	207,992	275,172	275,812	271,539	67,181	67,820	63,547	640	-3,634

SOURCE: Congressional Budget Office.

TABLE 12. COAL MINING EMPLOYMENT CHANGES AS OF 1995 UNDER 10 MILLION TON SO_2 ROLLBACK, BY COAL-PRODUCING STATE

	Number of Jobs				Difference from 1985			Difference from 1995 Base Case	
State	Base Case 1985	Base Case 1995	Option II-2A	Option II-2B	Base Case 1995	Option II-2A	Option II-2B	Option II-2A	Option II-2B
Alabama	9,077	8,124	7,543	6,862	-953	-1,534	-2,215	-581	-1,262
Arizona	855	1,177	1,155	1,177	322	300	322	-22	0
Colorado	2,927	3,288	4,062	5,498	360	1,135	2,571	775	2,210
Illinois	16,228	14,733	9,823	12,273	-1,495	-6,405	-3,955	-4,910	-2,460
Indiana	6,694	5,342	3,611	4,294	-1,352	-3,083	-2,401	-1,732	-1,049
Iowa	136	344	110	110	208	-27	-26	-234	-234
Kansas	306	753	129	462	447	-177	156	-624	-291
Kentucky	47,753	63,014	59,098	56,649	15,261	11,345	8,897	-3,916	-6,365
Maryland	923	695	417	649	-228	-505	-274	-278	-46
Missouri	1,348	1,948	1,276	1,297	600	-72	-51	-672	-651
Montana	1,209	1,251	955	1,490	42	-254	281	-296	238
New Mexico	1,741	2,846	2,846	2,906	1,104	1,104	1,164	0	60
North Dakota	1,570	1,375	1,374	1,345	-195	-196	-225	-1	-29
Ohio	9,797	7,136	1,183	2,633	-2,662	-8,614	-7,164	-5,953	-4,503
Oklahoma	1,377	2,344	2,146	2,131	967	770	754	-197	-213
Pennsylvania	23,134	29,299	20,042	24,482	6,165	-3,092	1,349	-9,257	-4,816
Tennessee	2,685	2,010	1,859	1,796	-675	-826	-889	-151	-214
Texas	2,851	6,890	6,854	6,208	4,039	4,004	3,357	-36	-683
Utah	3,283	7,978	8,282	7,862	4,695	4,998	4,579	304	-116
Virginia	16,803	19,339	21,375	21,076	2,536	4,572	4,273	2,036	1,738
Washington	426	48	48	48	-378	-378	-378	0	0
West Virginia	50,893	89,473	105,792	87,936	38,580	54,899	37,043	16,319	-1,537
Wyoming	5,975	5,768	8,451	9,072	-207	2,476	3,097	2,683	3,304
U.S. Total	207,992	275,172	268,431	258,255	67,181	60,439	50,263	-6,741	-16,917

SOURCE: Congressional Budget Office.

In terms of potential job losses, the high-sulfur coal states of Illinois, Indiana, Ohio, and Pennsylvania would be particularly sensitive to the effects of a SO_2 rollback. Under current law, these states might employ about the same number of miners in 1995 as in 1985. Under an 8 million ton SO_2 rollback, however, anywhere from 11,000 to 13,500 current job slots in these four states could be lost (Options II-1B and II-1A, respectively). Similarly, a 10 million ton SO_2 rollback could eliminate from 12,200 to 21,200 current job slots (Options II-2B and II-2A, respectively). Of course, the number of miners actually employed in 1985 who would lose their jobs by 1995 because of an acid rain policy would be lower because of natural attrition; perhaps 10.5 percent of miners currently employed might simply retire by 1995.[15] Thus, of the miners employed in the four-state region in 1985, as many as 5,900 could be expected to retire by 1995, reducing losses among current job holders accordingly. For example, under a 10 million ton rollback, between 6,300 and 15,300 currently employed miners could lose their jobs by 1995 (Options II-2B and II-2A, respectively).

In contrast to high-sulfur coal states, some states producing low-sulfur coal could prosper from enactment of a SO_2 rollback plan. In the West, Wyoming and Colorado have the greatest potential for higher overall coal production--and hence, employment--under a SO_2 reduction plan, although restrictions on fuel switching could temper this trend (see Tables 11 and 12). Moreover, while production could rise significantly in these states (see Tables 9 and 10), the effect on mining employment also would be dampened by the high productivity of the process. This does not hold, however, for the East's great low-sulfur coal resource--West Virginia. West Virginia's coal mining employment levels could roughly double by 1995 under either an 8 million ton or 10 million ton SO_2 rollback that allowed unlimited fuel switching (Options II-1A and II-2A, respectively). Such employment increases from current levels would be aided not only by increased production but also by the labor-intensive nature of Appalachian coal mining.

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15. Estimates of job attrition in the coal mining industry are quite difficult to calculate, a situation that is reflected by the sparsity of such estimates in the literature. One notable exception is a monograph by Joseph P. Brennan, President of the Bituminous Coal Operator's Association, "Coal Industry Labor Issues," *Proceedings: Fuel Supply Seminars* (Electric Power Research Institute, March 1983). The 10.5 percent retirement factor over the 1985-1995 period is based on this publication's reported age profile for United Mine Workers in 1980. Assuming the same profile applies to all miners (including nonunion miners) in 1985, 10.5 percent of the worker population would reach retirement age (65) in 1995. Such estimates, while illustrative, do not even consider early retirement, disability, or natural job turnover and should thus be assumed to represent a lower bound.

Changes from Expected 1995 Levels. Although employment changes from 1985 through 1995 provide insight into how many people in today's workforce might lose (or gain) employment because of future policies, they reveal little about how one policy might change the anticipated employment levels (job slots) compared with the effects of a different policy. Because comparing the future job slots of different policies avoids the difficulties of estimating job attrition or the potential errors of comparing actual levels (those measured today) with predicted ones, the remainder of this report concentrates on 1995 job levels. Such comparisons can overestimate job losses and underestimate the potential gains of today's workforce, however, because they do not consider attrition.

For the predominantly high-sulfur coal-producing states of Illinois, Indiana, Ohio and Pennsylvania, job slots are expected to rise to 56,500 in 1995 (or 660 above the 1985 level). Under a rollback scheme that does not prevent fuel switching, job losses from forecasted levels could be significant. An 8 million ton SO_2 reduction could lower expected 1995 employment in these states by 14,100 (Option II-1A), while a 10 million ton reduction could lower them by 21,900 (Option II-2A). Restricting the amount of allowed fuel switching would provide little additional job protection under a 8 million ton SO_2 reduction (jobs would still fall by 11,600 in 1995 under Option II-1B), but would retard losses under a 10 million ton rollback program (jobs slots would fall by 12,800 in 1995 under Option II-2B).

From a national perspective, more jobs might be lost if an attempt were made to preserve current coal market supply and demand patterns (the no fuel switching case) than if fuel switching were allowed (see Tables 11 and 12). If current coal patterns were preserved, the job losses that did occur in eastern and midwestern states would be only partially offset by increased western coal consumption. Yet, from the Midwest's perspective, more jobs would be saved if fuel switching were restricted than if it were not, because midwestern high-sulfur coal mines would still meet a large portion of coal demand in that area.

CHAPTER III

ALLOCATING EMISSION REDUCTION COSTS THROUGH TAXES COLLECTED ON ELECTRICITY PRODUCTION

During the 98th Congress, several proposals to reduce sulfur dioxide emissions were introduced that would provide substantial subsidies for the installation of scrubbers on the affected electricity power plants. The subsidies would be funded by a temporary tax on electricity production, and the proceeds distributed through a federal trust fund. 1/ The purpose of these proposals is twofold: (1) to lower the cost of scrubbers and, thus, to encourage their use by the utilities most affected by more stringent emission regulations--such as those in the Midwest and parts of the mid-Atlantic region; and (2) to preserve high-sulfur coal mining jobs, while spreading program costs more evenly throughout the country. This chapter explores several tax and subsidy alternatives to rollback sulfur dioxide emissions by 8 million tons and 10 million tons, and compares them with the basic polluter pays options described in Chapter II.

In contrast with the simple polluter pays approach which establishes emission reductions but does not stipulate or encourage any particular control method, a generation tax and scrubber subsidy option would cost more to lower emissions by the same amount. Recalling the results of Chapter II, the total program cost of an 8 million ton SO_2 reduction (based on 1980 emissions) would be roughly $20 billion (in discounted 1985 dollars), assuming no restrictions on the choice of control method or coal used (Option II-1A). Under the same assumptions, the total program cost of a 10 million ton reduction would be about $35 billion (Option II-2A). (Options II-1A and II-2A are used for comparative purposes throughout this chapter. For easy reference, the options are described in the glossary at the end of this report.) In comparison, an 8 million ton SO_2 reduction program that both provides a 90 percent capital and 50 percent operation and maintenance (O&M) subsidy for scrubber use and collects funds through a self-financing temporary 1 mill per kilowatt-hour (mill/kwh) tax on fossil-fuel electricity generation

1. For the purposes of this study, the terms "fee" and "tax" simply refer to the revenue collection mechanism; they do not reflect the way these terms are used in the federal budget for accounting purposes. In the federal budget, taxes are classed as revenue, while fees are defined as offsetting receipts. For further information, see Government Accounting Office, *A Glossary of Terms Used in the Federal Budget Process* (March 1984).

would cost about $30 billion (in discounted 1985 dollars). A comparable 10 million ton program would cost about $42 billion. In both cases, the higher costs arise chiefly from the purchase and use of more scrubbers as a result of the subsidy program. (This study does not consider the potential efficiency losses that could occur from the imposition of generation taxes.)

While the generation tax and subsidy programs would be more costly than the polluter pays approach, they would also be more effective in limiting the loss of mining jobs in the key high-sulfur coal states because they encourage the use of scrubbers rather than switching to low-sulfur coal. For example, coal mining employment in Illinois, Indiana, Ohio, and Pennsylvania is estimated to be 56,500 in 1995 under current law. In contrast, an 8 million ton SO_2 emission rollback with no restrictions on fuel switching could lower 1995 employment to 42,400 in these states, and a comparable 10 million ton reduction program could reduce it to 34,700. A rollback program with generation taxes and scrubber capital and operating subsidies could lessen job losses in high-sulfur coal mining. Employment in the four states would fall from 56,500 in 1995 to only 52,000 under an 8 million ton program, and to 45,300 under a 10 million ton program.

Finally, the most expensive option was found to be a program that required the top 50 SO_2 "emitters" to install scrubbers achieving an initial SO_2 reduction of about 7 million tons. States would then have to meet a total reduction of 10 million tons of SO_2 from 1980 levels by instituting additional control measures. Coupled with a 0.75 mill/kwh fee on electricity production, this option would cost roughly $49 billion (in discounted 1985 dollars), compared with $35 billion (in discounted 1985 dollars) under the polluter pays approach of Option II-2A. This option could be the most effective, however, in preventing the loss of future high-sulfur coal jobs, holding employment levels in Illinois, Indiana, Ohio, and Pennsylvania to 47,600 in 1995, higher than under any of the other subsidy schemes with a 10 million ton SO_2 reduction and significantly above the 34,700 expected under Option II-2A.

RATIONALE BEHIND SUBSIDIZING CONTROL COSTS THROUGH AN ELECTRICITY TAX

Chapter II described the effect of sulfur dioxide rollback programs that did not involve any fees or subsidies, but only required each state to meet certain emission reduction targets. Two key findings arose from the analysis in that chapter. First, significant costs for pollution control would be concentrated in the Midwest, Pennsylvania, and West Virginia. Second, high-sulfur coal production could significantly fall from anticipated levels, principally affecting jobs in the Midwest and Pennsylvania, as utilities switched to low-sulfur coal to meet emission targets. (Employment might increase in West Virginia, however, because of the greater demand for its low-sulfur coal.) The possibility of these shifts has prompted a search for ways to redistribute costs and coal-market effects, to lessen the burden on the Midwest and parts of the East (especially Pennsylvania).

A system of fees and subsidies to abate acid rain was popular in legislation proposed during the 98th Congress. 2/ Several common elements characterized these proposals. Most would require a total SO_2 reduction of ten million tons from 1980 levels. As a cornerstone of these plans, the 50 power plants with the highest SO_2 emissions (based on 1980 levels) would be required to install scrubbers, which would reduce this pollutant by roughly 7 million tons. These plans called for the states to achieve an additional 3 million ton reduction using the excess emissions formula, described on page 14 in Chapter II.

Affected plants that installed scrubbers (either by choice or by law), would receive a subsidy up to 90 percent of the scrubber's capital costs. Some proposals would also fund a portion of annual scrubber operation and maintenance costs. To raise funds for the subsidies, the typical approach would tax electricity produced by plants fired by fossil fuels. Usually, nuclear power and sometimes hydroelectric power were excluded. 3/ The tax would begin immediately upon passage of the legislation at a level ranging from 1 to 3 mills/kwh (sometimes indexed for inflation) and would con-

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2. Several bills that would allocate the cost of acid rain controls through a generation tax and emissions control subsidy program were introduced in the 98th Congress. These include H.R. 5794 (Rep. Eckart), H.R. 5970 (Rep. Vento), H.R. 4906 (Rep. Rinaldo), H.R. 4404 (D'Amours), and H.R. 3400 (Rep. Sikorski), which was identical to H.R. 5314 (Rep. Waxman). All bills called for a 10 million ton reduction in SO_2 emissions from 1980 levels within 10 years of enactment, affecting the contiguous 48 states. The bulk of emission reductions was to be accomplished through scrubber retrofits on the top 50 SO_2 emitters whose emission rates were also above 3.0 pounds SO_2 per million Btus. The electricity fee rates ranged from 1 to 1.5 mill/kwh and were indexed for inflation in all cases except H.R. 3400 and H. R. 5314. Nuclear-generated electricity was exempted from the tax in all proposals, and hydro power also was exempted in H.R. 4906 and H.R. 4404. H.R. 5970 provided up to a 50 percent capital credit for retrofitted scrubbers, but H.R. 3400 and H.R. 5314 provided a 90 percent credit. H.R. 5794 includes an O&M subsidy of 50 percent the first year and 45 percent the second.

3. The rationale behind these exclusions, though not always stated, was that hydro power already inherently produced little pollution and that nuclear generation already was taxed (at 1 mill/kwh) to finance the federal radioactive waste disposal program. See Congressional Budget Office, *Nuclear Waste Disposal: Achieving Adequate Financing* (August 1984).

tinue for 10 years to 1995, by which time emission reduction goals were to be achieved. Capital payments could begin as early as 1990 and would continue until all scrubbers were constructed. Finally, most proposed legislation placed revenues in an interest-bearing government trust fund. Some bills would have the Treasury keep any excess funds at the end of the program, while others would return them to the consumers according to each state's contribution.

The advantages of such proposals are that they would be effective in raising large sums of money through modest and relatively equal increases in regional electricity prices. The subsidy schemes also would promote greater scrubber use and, thus, could help preserve future demand for high-sulfur coal. Opponents, however, believe that such schemes would tax utilities in western states unfairly since they are not responsible for the acid rain problem in the East, the area that such programs are designed to aid. Moreover, while those power plants that possibly contribute most to the problem (the high emitting plants of the Midwest) would be taxed at the same rate as other power plants, they would receive the most aid. All these concerns have foundation and lie at the heart of selecting the most appropriate cost allocation scheme. 4/

ELECTRICITY TAX AND SUBSIDY OPTIONS

This section examines five different emission reduction options using taxes and subsidies and covering two levels of sulfur dioxide reduction: 8 million tons and 10 million tons, both measured from 1980 levels. Table 13 summarizes the options. Each would be accompanied by an electricity fee to cover all subsidy requirements of the program. Collection would begin in 1986 and end in 1995, with revenues deposited in an interest-bearing trust fund. Subsidies would be designed to pay for most of the annual cost of capital over the useful life of the installed scrubbers, which is estimated as 20 years for retrofits. Payments from the fund would begin in 1991--the year construction is assumed to begin--and would end in 2015--the last year of the useful life of those scrubbers whose installation is assumed to be completed in 1995.

Two types of subsidies are examined. The first would pay for 90 percent of the annual capital cost of scrubber installation (including interest

4. For additional discussion of the rationale behind and administrative issues surrounding such allocation schemes, see Rob Brenner and Milton Russell, "Allocating the Costs of Acid Rain Controls," in *Changing Patterns in Regulation, Markets, and Technology: The Effect on Public Utility Pricing*, Public Utility Papers (Michigan State University Press, 1984).

charges) for plants choosing to retrofit scrubbers under each SO_2 reduction program (Options III-1A and III-2A for 8 million ton and 10 million ton rollbacks, respectively). Payments from the trust fund would continue over the expected useful life of the scrubber. The second type of subsidy not only would cover 90 percent of capital retrofit cost but also would pay for 50 percent of annual O&M costs over the same 20-year period (Options III-1B and III-2B for 8 million ton and 10 million ton rollbacks, respectively). The rationale for the additional subsidy for O&M is to encourage greater scrubber use than might be expected if only capital costs were subsidized.

TABLE 13. EMISSION REDUCTION OPTIONS USING TAXES AND SUBSIDIES

Policy Option	Emission Reduction from 1980 Levels	Tax System	Subsidy System for Retrofit Scrubbers
Option III-1A	8 million tons, excess emissions formula	0.5 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital
Option III-1B	8 million tons, excess emissions formula	1 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, 50 percent annual cost of O&M
Option III-2A	10 million tons, excess emissions formula	0.5 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital
Option III-2B	10 million tons, excess emissions formula	1 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, 50 percent annual cost of O&M
Option III-2C	10 million ton--7 million ton from top 50 emitters; remainder from utilities in states according to excess emissions formula	0.75 mill per kwh on fossil-fuel utilities	90 percent annual cost of capital, including retrofitting the top 50 emitting plants as well as others needed to meet reduction targets.

SOURCE: Congressional Budget Office.

The first four emission reduction schemes examined in this chapter base state-by-state emission control targets on the excess emissions formula. An exception--the proposal to retrofit scrubbers on the top 50 SO_2 emitting power plants--is examined in Option III-2C. This option is similar to the bills submitted by Representatives Waxman and Sikorski during the 98th Congress, although the version contained here has several variations. In particular, the CBO version differs by requiring all emission reductions to occur by 1995 (instead of some in 1992 as required by H.R. 5314), and by setting a fee of 0.75 mill/kwh in constant dollars, compared with the 1 mill/kwh fee in nominal dollars contained in the original proposal.

Effect on Utility Emissions

Option III-1A would achieve a 7.3 million ton emission reduction from 1995 projected levels (after accounting for emissions growth from the baseline year of 1980); similarly, Options III-2A, III-2B, and III-2C would lower expected 1995 emissions by 9.3 million tons. These results are very similar to the 8 and 10 million ton SO_2 reductions achieved under the polluter pays options of Chapter II (see Table 3).

Most of the required emission reductions would occur in the Midwest, Pennsylvania, and West Virginia--as they would under the options in Chapter II. The emission reduction pattern resulting from installing scrubbers on the top 50 emitters throughout the United States (Option III-2C) also is similar to those based on the excess emissions formula (Options III-2A and III-2B). This suggests that the excess emissions formula--which sets state-wide emission limits--is largely influenced by high-emitting power plants. Unlike the "top 50" approach, however, which sets limits for individual plants, the excess emissions formula allows greater flexibility in compliance.

Total Program Costs of Each Option

Total program costs for the tax and subsidy options would be higher and the cost-effectiveness inferior compared with the simple polluter pays approach. Option II-1A would cost about $20 billion with SO_2 reductions obtained at a price of $270 per ton. In comparison, the cheapest generation tax and subsidy scheme that could achieve a comparable reduction (Option III-1A) would cost about $22 billion, or $291 per ton of SO_2 abated from 1995 levels under currrent policy (see Table 14). Similarly, Option II-2A would cost roughly $35 billion, or $360 per ton of SO_2 abated. The cheapest tax and subsidy scheme with a comparable 10 million ton rollback

TABLE 14. COMPARISON OF TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF VARIOUS OPTIONS UNDER TWO ROLLBACK PROGRAMS

	8 Million Ton SO_2 Reduction		
	Polluter Pays, No Fuel Restrictions (Option II-1A)	90 Percent Capital Subsidy (Option III-1A)	90 Percent Capital, 50 Percent O&M Subsidies (Option III-1B)
Total Program Cost (In billions of discounted 1985 dollars) a/	20.4	22.3	30.0
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	291	389

	10 Million Ton SO_2 Reduction			
	Polluter Pays, No Fuel Restrictions (Option II-2A)	90 Percent Capital Subsidy (Option III-2A)	90 Percent Capital 50 Percent O&M Subsidies (Option III-2B)	Top 50 Plant SO_2 Reduction (Option III-2C)
Total Program Cost (In billions of discounted 1985 dollars) a/	34.5	35.5	41.5	49.0
Cost-effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	360	369	431	509

SOURCE: Congressional Budget Office.

a. Reflects net present value of sum of annual utility expenditures--including the subsidized portions but not including taxes--incurred between 1986 and 2015, discounted to 1985 dollars. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reductions measured over the 1986-2015 period.

(Option III-2A) would be more expensive, costing \$36 billion overall and \$369 for each ton of SO_2 reduced. (All costs are in discounted 1985 dollars.)

Because the options presented in this chapter involve taxes and subsidies, the definitions of cost measures change somewhat from those given in Chapter II. For example, in a program with tax and subsidies, discounted program costs represent all the expenses incurred by the utilities (including taxes and subsidies), plus the costs of running the trust fund, minus the balance remaining at the end of the fund's life (see box). In addition, this study assumes that no additional costs would be incurred by the transfer of funds from the private sector into a government trust fund, as long as any surplusses were eventually returned to the contributors. 5/

Annual Net Cost to Utilities. Compared with current policy, the additional 1995 net annual costs of an 8 million ton emission reduction program (including generation fees but subtracting subsidies) would range between \$3.0 billion (Option III-1A) and \$3.6 billion (Option III-1B). Compared with the polluter pays approach of Chapter II (Option II-A), however, Option III-1A would cost \$1.1 billion more per year in 1995 and Option III-1B, \$1.7 billion more. These higher costs would arise from the electricity tax and the subsidy system, which encourages scrubbing--a more expensive method of emission abatement than fuel switching (see Table 15).

For a 10 million ton reduction program--again compared with current policy in 1995--the utilities' net annual costs, including fees and subsidies would range from \$4.3 billion (Option III-2A) to as high as \$5.4 billion (Option III-2C). In contrast with Option II-2A, the net costs in 1995 of the fee and subsidy programs would range from \$873 million to \$2.1 billion higher (see Table 16).

The different subsidy schemes influence utilities' choice of control strategy between installing scrubbers or switching to low-sulfur coal. Under the 8 million ton reduction option, the total amount spent on scrubbers rises dramatically--nearly tripling from \$3.8 billion to over \$11.1 billion--when the subsidy is increased from 90 percent on capital investment (Option III-1A) to both 90 percent on capital and 50 percent for O&M (Option III-1B). When the subsidy under the 10 million ton option is similarly increased, total scrubber investment rises by more than 60 percent, from \$7.1 billion under Option III-2A to \$11.9 billion under Option III-2B. Yet,

5. The real discount rate used in calculating the earnings of the trust fund and determining the net present value of the program costs were the same--3.7 percent. The rate represents the average cost the government pays to finance credit.

THE EFFECT OF TAXES AND SUBSIDIES ON COSTS

The introduction of taxes and subsidies into the abatement programs examined in this chapter requires modifying program cost accounting concepts. When utilities pay taxes and receive subsidies to control pollution, the market value of the resources consumed in the abatement effort may differ from the amount the utilities actually pay. The amount of resources purchased to control pollution, including the value of the subsidies, approximates the overall economic cost of the emission reduction efforts (assuming key variables--such as output, demand, interest rates, and cost to other industries--remain unaffected). On the other hand, the net amount actually spent by utilities--total resource costs plus taxes, minus subsidies--represents the costs utilities will face when choosing control alternatives. Relevant definitions used in this chapter are explained below.

Annual net utility cost is the cost that governs utility choices in the National Coal Model and determines electricity rates for consumers (see the appendix). It is defined as the total resources expended by the utility sector to meet the specified pollution reduction targets, plus taxes paid to finance trust funds, minus subsidies given to install scrubbers. Annual net utility cost is the same as the annual utility cost described in Chapter II only neither subsidies nor taxes are included in the options, such as the polluter pays alternatives.

Discounted program cost is similar to the term used in Chapter II, except that the annual costs discounted in this chapter represent all resources, including subsidies, expended in excess of current law to achieve the desired emission reductions over the 1986-2015 period. For example, for all options in this chapter, 100 percent of the annual capital costs for scrubbers is included when calculating discounted program cost, even though 90 percent of the capital costs may be subsidized by an electricity fee. While such subsidies may lower a utility's net cost (see above), they do not lower the overall cost of the progam (the subsidized portion of the program still represents money spent by society). Taxes and fees are excluded in this measure since they are assumed to be pure transfers--that is, money transferred to and held by the government and not resources consumed.

Cost-effectiveness is similar to the definition used in Chapter II: discounted program cost is simply divided by the discounted stream of annual emissions reductions measured over the same period. It is important only to note that in this chapter cost-effectiveness represents the total discounted dollars (including subsidies) needed to reduce SO_2 from base case levels over the 1986-2015 period.

TABLE 15. ANNUAL UTILITY COSTS AS OF 1995 OF 8 MILLION TON SO_2 ROLLBACK WITH TAX AND SUBSIDY OPTIONS COMPARED WITH POLLUTER PAYS OPTION, BY STATE (In millions of discounted 1985 dollars)

State	Base Case 1995	Polluter Pays Option II-1A	Option III-1A	Option III-1B	Differences from Polluter Pays (Option II-1A) Option III-1A	Option III-1B
Alabama, Mississippi	4,224	4,307	4,324	4,340	17	33
Arizona	1,944	1,930	1,944	1,961	15	32
Arkansas, Oklahoma, Louisiana	9,591	9,698	9,804	9,895	106	198
California	10,565	10,722	10,812	10,913	90	191
Carolinas, North and South	4,759	4,886	4,910	4,940	24	54
Colorado	1,093	1,097	1,112	1,130	15	33
Dakotas, North and South	567	565	572	578	7	13
Florida	6,127	6,202	6,256	6,308	53	105
Georgia	2,555	2,618	2,641	2,647	23	29
Idaho	221	221	234	246	12	25
Illinois	4,189	4,312	4,313	4,225	1	-87
Indiana	3,095	3,202	3,223	3,258	22	56
Iowa	1,230	1,288	1,320	1,299	32	11
Kansas, Nebraska	1,854	1,860	1,883	1,906	23	45
Kentucky	3,103	3,170	3,199	3,231	29	61
Maine, Vermont, New Hampshire	1,123	1,119	1,124	1,128	4	9
Maryland, Delaware	1,885	1,853	1,872	1,866	19	13
Massachusetts, Connecticut, Rhode Island	3,513	3,633	3,657	3,672	24	39

(Continued)

TABLE 15. (Continued)

State	Base Case 1995	Polluter Pays Option II-1A	Option III-1A	Option III-1B	Differences from Polluter Pays (Option II-1A) Option III-1A	Option III-1B
Michigan	2,817	2,874	2,899	2,915	25	40
Minnesota	1,186	1,184	1,210	1,227	26	43
Missouri	2,024	2,137	2,184	2,132	47	-5
Montana	676	675	686	694	10	19
Nevada	1,096	1,122	1,132	1,144	11	22
New Mexico	1,158	1,138	1,146	1,154	8	16
New York (Downstate), New Jersey	4,878	4,902	4,946	4,961	43	58
New York (Upstate)	2,395	2,443	2,462	2,486	19	43
Ohio	4,239	4,397	4,463	4,521	66	124
Pennsylvania	5,512	5,711	5,766	5,741	55	30
Tennessee	2,078	2,118	2,160	2,220	41	102
Texas	15,852	15,834	15,995	16,129	161	295
Utah	1,345	1,367	1,378	1,381	10	14
Virginia, District of Columbia	1,884	1,923	1,947	1,981	24	58
Washington, Oregon	4,219	4,147	4,176	4,186	29	39
West Virginia	1,784	1,936	1,933	1,874	-4	-63
Wisconsin	1,572	1,671	1,683	1,697	12	26
Wyoming	1,026	1,034	1,040	1,044	6	10
Total Net Utility Costs	117,380	119,298	120,403	121,029	1,104	1,731

SOURCE: Congressional Budget Office.

TABLE 16. ANNUAL UTILITY COSTS AS OF 1995 OF 10 MILLION TON SO_2 ROLLBACK WITH TAX AND SUBSIDY OPTIONS COMPARED WITH POLLUTER PAYS OPTION, BY STATE (In millions of discounted 1985 dollars)

						Differences from Polluter Pays (Option II-2A)		
	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Option III-2A	Option III-2B	Option III-2C
Alabama, Mississippi	4,224	4,364	4,363	4,341	4,382	-1	-23	18
Arizona	1,944	1,943	1,945	1,961	1,952	2	19	10
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,814	9,910	9,872	91	187	149
California	10,565	10,822	10,913	11,013	10,959	91	191	136
Carolinas, North and South	4,759	4,895	4,926	4,963	4,925	30	67	29
Colorado	1,093	1,100	1,113	1,132	1,124	13	31	24
Dakotas, North and South	567	565	572	578	575	7	13	10
Florida	6,127	6,198	6,251	6,307	6,455	53	109	257
Georgia	2,555	2,622	2,640	2,651	2,704	17	28	82
Idaho	221	221	234	246	240	12	25	19
Illinois	4,189	4,432	4,441	4,448	4,436	8	16	3
Indiana	3,095	3,233	3,165	3,257	3,299	-69	23	66
Iowa	1,230	1,327	1,343	1,370	1,332	16	43	5
Kansas, Nebraska	1,854	1,862	1,895	1,900	1,899	33	38	37
Kentucky	3,103	3,499	3,567	3,579	3,471	68	80	-29
Maine, Vermont, New Hampshire	1,123	1,123	1,130	1,130	1,128	7	7	5
Maryland, Delaware	1,885	1,654	1,727	1,708	1,689	73	54	35
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,706	3,713	3,714	27	35	35

(Continued)

TABLE 16. (Continued)

	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Differences from Polluter Pays (Option II-2A) Option III-2A	Option III-2B	Option III-2C
Michigan	2,817	2,944	2,980	2,989	2,996	36	45	53
Minnesota	1,186	1,228	1,253	1,272	1,293	26	45	65
Missouri	2,024	2,206	2,223	2,196	2,274	17	-11	68
Montana	676	675	684	694	690	9	19	15
Nevada	1,096	1,122	1,132	1,144	1,138	10	22	16
New Mexico	1,158	1,144	1,146	1,154	1,150	2	10	6
New York (Downstate), New Jersey	4,878	5,200	5,221	5,228	5,238	21	28	38
New York (Upstate)	2,395	2,236	2,273	2,289	2,282	38	54	46
Ohio	4,239	4,271	4,348	4,344	4,490	76	73	218
Pennsylvania	5,512	6,056	5,995	5,891	6,105	-61	-165	49
Tennessee	2,078	2,028	2,014	2,060	2,352	-14	32	324
Texas	15,852	15,844	16,002	16,135	16,074	158	291	229
Utah	1,345	1,368	1,377	1,381	1,384	10	14	16
Virginia, District of Columbia	1,884	1,926	1,950	1,983	1,973	24	57	47
Washington, Oregon	4,219	4,068	4,093	4,109	4,106	25	41	38
West Virginia	1,784	2,278	2,265	2,257	2,226	-13	-21	-52
Wisconsin	1,572	1,734	1,757	1,770	1,777	23	36	42
Wyoming	1,026	1,039	1,045	1,053	1,045	6	15	6
Total Net Costs	117,380	120,630	121,503	122,156	122,746	873	1,526	2,116

SOURCE: Congressional Budget Office.

while the addition of an O&M subsidy appears to encourage further scrubber investment, the maximum amount invested under both emission reduction programs is almost identical--about $11 billion to $12 billion. This is the reason that the fee level remains the same for similar subsidy programs under different emission control targets. This also suggests that for these options the practical limit of scrubber use is quickly reached with the highest subsidy case under the 8 million ton SO_2 rollback, and that any further abatement beyond this level will almost exclusively be obtained through coal-switching. To achieve the same additional reductions through use of scrubbers would simply cost more.

The Importance of the Tax and Subsidies on Net Utility Costs. The subsidies provided through distribution of the electricity tax would help lower the utilities' net costs below their actual expenditures needed to satisfy the program. For the 8 million ton reduction case, the subsidies would range from $239 million (Option III-1A) to $1.1 billion (Option III-1B) per year; Option III-1B would cost more because it funds both capital and O&M expenses. For the 10 million ton program, the annual subsidies would range from $368 million (Option III-2A) to about $1.1 billion (Option III-2B). Requiring controls for the 50 highest emitting powerplants (Option III-2C) would use roughly $922 million in annual capital subsidies (see Table 17). [6]

Net utility costs would fall considerably after 1995 when the electricity fee would expire. The annual net costs for the 8 million ton program would fall to between $900 million and $1.6 billion, and those for the 10 million ton program, to between $2.0 billion and $3.4 billion. Once the fee expires but subsidies continue, net annual costs would be lower than even the polluter pays approach, which had net annual costs ranging from $1.9 billion to $2.1 billion for an 8 million ton SO_2 rollback and from $3.2 billion to $4.7 billion for a 10 million ton SO_2 rollback.

Trust Fund Revenues and Outlays. Before the electricity taxes expired in 1995, they would raise substantial revenue, with their largest annual proceeds occurring in 1995. In that year, the 0.5 mill tax (used in Options III-1A and III-2A) should raise approximately $1.2 billion; the 0.75 mill tax (Option III-2C) should raise about $1.8 billion; and the 1.0 mill tax should raise about $2.4 billion (see Table 18).

6. Unless specific exclusions were included, the various tax and subsidy options using trust funds would become subject to the Balanced Budget and Emergency Deficit Control Act of 1985 (P.L. 99-177). Under the Balanced Budget Act, outlays (subsidies) from the trust funds would be subject to sequester action through fiscal year 1991, although revenue to the fund probably would not be affected. If trust fund outlays are sequestered, or cut, the trust fund balances would continue to grow and would be available for future obligations. Because future sequester needs cannot now be determined, estimates in this report assume full subsidies.

TABLE 17. ANNUAL SUBSIDIES PROVIDED TO UTILITIES AS OF 1995 UNDER TWO ROLLBACK PROGRAMS AND THREE SUBSIDY OPTIONS, BY STATE (In millions of 1985 dollars)

State	8 Million Ton Rollback Option III-1A	8 Million Ton Rollback Option III-1B	10 Million Ton Rollback Option III-2A	10 Million Ton Rollback Option III-2B	10 Million Ton Rollback Option III-2C
Alabama, Mississippi	0	22	7	104	41
Colorado	0	2	0	2	0
Florida	0	0	0	0	45
Georgia	0	5	0	13	37
Illinois	127	259	50	64	103
Indiana	4	24	5	38	131
Kansas, Nebraska	0	0	0	32	0
Kentucky	1	1	1	73	58
Maine, Vermont, New Hampshire	0	0	3	5	0
Maryland, Delaware	0	51	4	102	0
Massachusetts, Connecticut, Rhode Island	0	22	10	22	0
Michigan	1	23	1	5	32
Missouri	0	144	55	115	132
New York (Downstate), New Jersey	1	2	1	31	1
New York (Upstate)	0	0	0	18	0
Ohio	2	23	5	18	56
Pennsylvania	86	242	187	281	132
Tennessee	14	69	14	21	60
Texas	1	53	5	53	2
Utah	0	10	0	10	0
Washington, Oregon	0	1	0	1	0
West Virginia	0	151	20	45	90
Wisconsin	1	0	0	22	0
Total	239	1,102	368	1,077	922

SOURCE: Congressional Budget Office.

Note: States not shown receive no subsidies.

TABLE 18. REVENUES FROM ELECTRICITY TAX IN 1995
(In millions of 1985 dollars)

State	Option III-1A 0.5 mill per kwh	Option III-1B 1.0 mill per kwh	Option III-2A 0.5 mill per kwh	Option III-2B 1.0 mill per kwh	Option III-2C 0.75 mill per kwh
Alabama	34.2	68.4	34.2	68.3	51.3
Arizona	14.9	29.7	14.8	29.7	22.3
Arkansas, Oklahoma, Lousiana	86.2	172.4	86.2	172.4	130.0
California	90.5	181.0	91.0	182.0	136.5
Carolinas, North and South	48.0	96.0	48.0	96.0	72.0
Colorada	18.9	37.8	18.9	37.8	28.4
Dakotas, North and South	6.5	12.9	6.5	12.9	9.7
Florida	61.0	121.3	60.7	121.3	91.0
Georgia	27.4	54.9	27.4	54.9	41.1
Idaho	12.4	24.8	12.4	24.8	18.6
Illinois	36.2	73.4	36.5	73.0	54.7
Indiana	43.5	88.4	43.6	87.1	65.5
Iowa	18.0	35.9	18.0	36.0	27.0
Kansas, Nebraska	20.4	40.7	20.4	40.7	30.5
Kentucky	42.2	84.3	42.2	84.4	63.0
Maine, Vermont, New Hampshire	2.7	5.4	2.7	5.4	4.0
Maryland, Delaware	25.1	50.2	24.5	49.0	36.4
Massachusetts, Connecticut, Rhode Island	25.9	51.7	25.8	51.6	38.7
Michigan	31.1	60.8	31.1	62.1	46.6

(Continued)

TABLE 18. (Continued)

State	Option III-1A 0.5 mill per kwh	Option III-1B 1.0 mill per kwh	Option III-2A 0.5 mill per kwh	Option III-2B 1.0 mill per kwh	Option III-2C 0.75 mill per kwh
Minnesota	16.3	32.6	16.4	32.8	24.7
Missouri	28.1	55.9	28.1	56.3	42.2
Montana	8.1	16.2	8.1	16.2	12.2
Nevada	11.0	22.1	11.0	22.1	16.5
New Mexico	8.2	16.3	8.2	16.3	12.2
New York (Downstate), New Jersey	32.3	64.6	33.4	66.8	51.2
New York (Upstate)	18.0	36.0	16.9	33.8	24.2
Ohio	83.5	167.0	83.4	166.8	118.3
Pennsylvania	56.1	112.3	56.9	113.8	85.7
Tennessee	35.9	71.9	36.0	72.0	53.9
Texas	146.9	293.8	146.9	293.8	220.4
Utah	10.7	21.5	10.7	21.5	16.1
Virginia, District of Columbia	30.0	60.0	30.0	60.0	45.0
Washington, Oregon	20.8	41.5	20.3	40.5	30.4
West Virginia	17.2	34.4	17.0	34.0	32.2
Wisconsin	21.8	43.6	21.7	43.4	32.5
Wyoming	6.6	13.2	6.6	13.2	9.9
Total	1,197	2,393	1,196	2,393	1,795

SOURCE: Congressional Budget Office.

NOTE: Fee revenues may differ under similar tax rates because of slight changes in electricity generation patterns under different options.

Each tax and subsidy system also could leave a significant trust fund balance at the end of the program, if static assumptions about electricity demand and interest rates hold. 7/ The 0.5 mill fee would provide a closing balance of $15.7 billion in 2015 for Option III-1A and a balance of $11.2 billion for Option III-2A. The 0.75 mill tax should leave about $4.4 billion in the trust fund when Option III-2C ends. The 1.0 mill tax program should close with a balance of $12.5 billion under Option III-1B and $13.3 billion under Option III-2B.

The balances remaining in the trust funds would actually be smaller if viewed in terms of today's dollars. When discounted by an annual real rate of 3.7 percent to reflect the time-value of money (a dollar today is worth more than a dollar tomorrow), none of the balances under any option would exceed $5.5 billion (in 1985 discounted dollars). When the funds expire, essentially two options exist for disposal of the balance: retain the balance and add it to general revenues, or return it to consumers according to some prorated formula that considers relative contributions to the fund. In the case of small amounts, it might be most practical for the Treasury to retain the balance or earmark it for certain uses, such as acid rain research or enforcement of the program itself. Outlays might also be targeted for mitigating the effects of acid rain--such as treating lakes with lime to reduce acidity--or to help develop newer control technology that would reduce SO_2 emissions for less cost than scrubbers or that would control other pollutants such as nitrogen oxides. Finally, if the remaining balance was sufficiently large, refunds to consumers in states most burdened by the tax might be practical. Many of the bills proposed during the 98th Congress included a refund clause.

Effect on Electricity Prices. Under an 8 million ton reduction program, nationwide electricity prices could rise between 1.3 percent (Option III-1A) and 1.8 percent (Option III-1B) over projected 1995 levels under current law. Naturally, a 10 million ton program would increase prices somewhat more: Option III-2A prices would be 2.3 percent higher than expected; Option III-2B would be 2.9 percent higher, and Option III-2C would raise

7. It is important to note that key macroeconomic variables affecting trust fund balances are held constant in this analysis. Thus, factors such as electricity generation (as prompted by demand) and interest rates all remain unchanged. In fact, these factors can change over time because of a variety of economic conditions, some possibly arising from the tax and subsidy programs themselves.

nationwide prices an average of 3.7 percent. 8/ In each of the estimated price increases, the electricity tax plays only a small role, since the highest rate assessed would be 1 mill per kwh. Even after accounting for transmission losses, a 1 mill per kwh tax would raise delivered prices by no more than 1.1 mill per kwh. 9/

Electricity prices in most regions would be somewhat higher under the tax and subsidy schemes compared with the polluter pays approach. But in some of the states most affected by the emission reduction requirements--Illinois, Indiana, Ohio, Missouri, and Pennsylvania--prices would be somewhat lower as a result of the subsidy options, which were designed to transfer funds from other regions to those undergoing most of the cleanup (see Tables 19 and 20). The one exception is Option III-2C, which tends to increase control costs even in the states subject to greatest reductions (except Illinois). After 1995, electricity prices should fall below even those of the polluter pays option in most regions as the tax would have expired but subsidies would continue, reducing the utilities' net costs.

Effect on Coal Markets

The five cases examined in this chapter would have little national effect on the total expected increase in coal use between 1985 and 1995. In fact, coal production would rise very slightly under each tax and subsidy option, mostly from the use of more low-sulfur western coal. Because western coal has a

8. In many cases, electricity price increases in 1995 might surpass the basic increases predicted in annual utility costs for that year. This stems from differences between what the 1995 annual utility costs represent and what is embodied in the electricity price estimates. The annual utility costs reported by the model represent (in 1985 dollars) the average yearly expenses a utility might face for invesments made through 1995. It thus averages costs over a 20- to 30-year period--including any real price inflation that might occur over the useful life of the investments made in 1995. In contrast, the electricity price estimates for 1995 represent only the costs the consumer might face for that year. Therefore, it only reflects the real costs experienced for that year, including how capital is scheduled for inclusion in the rate base; in most cases, the capital components of price are quite high in the early years and lower in later years.

9. Since the generation tax is a tax on the generation of electricity--not its consumption--the final cost of the tax to the electricity consumer can be higher than that to the generator because of losses along the transmission system, usually amounting to no more than 10 percent. Since fossil fuel-fired electricity rarely accounts for 100 percent of all power in a given region, however, the extra cost of transmission losses alone would be kept to less than 10 percent in most cases.

TABLE 19. ELECTRICITY PRICE CHANGES BY 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK PROGRAM AND SEVERAL OPTIONS, BY STATE (in mills per kwh)

State	Base Case 1995	Polluter Pays Option II-1A	Option III-1A	Option III-1B	Percent Differences from Polluter Pays (Option II-1A) Option III-1A	Option III-1B
Alabama, Mississippi	46.6	46.9	47.2	47.8	0.6	1.7
Arizona	55.9	55.5	55.9	56.3	0.7	1.3
Arkansas, Oklahoma, Louisiana	77.5	78.5	79.2	79.8	0.8	1.5
California	78.3	78.3	78.7	79.0	0.5	1.0
Carolinas, North and South	50.3	51.2	51.4	51.6	0.3	0.7
Colorado	57.4	57.6	57.8	58.4	0.4	1.4
Dakotas, North and South	32.1	31.4	31.9	32.3	1.7	3.1
Florida	75.2	76.0	76.5	76.7	0.6	0.9
Georgia	54.2	56.1	56.3	56.8	0.4	1.2
Idaho	43.0	43.3	43.8	44.3	1.3	2.4
Illinois	59.3	60.8	59.9	59.7	-1.4	-1.7
Indiana	53.9	55.0	54.3	55.0	-1.4	-0.1
Iowa	59.3	61.1	61.8	61.7	1.3	1.0
Kansas, Nebraska	57.9	58.1	58.6	59.1	0.9	1.8
Kentucky	55.0	55.9	56.2	56.7	0.4	1.3
Maine, Vermont, New Hampshire	80.9	80.4	80.6	80.9	0.3	0.6
Maryland, Delaware	66.4	67.6	67.9	67.7	0.4	0.1
Massachusetts, Connecticut, Rhode Island	80.6	83.0	83.4	83.5	0.5	0.6

(Continued)

TABLE 19. (Continued)

State	Base Case 1995	Polluter Pays Option II-1A	Option III-1A	Option III-1B	Percent Differences from Polluter Pays (Option II-1A): Option III-1A	Percent Differences from Polluter Pays (Option II-1A): Option III-1B
Michigan	57.7	58.4	57.7	57.9	-1.1	-0.7
Minnesota	54.2	54.4	55.1	55.6	1.3	2.1
Missouri	59.6	62.3	63.1	61.8	1.3	-0.8
Montana	41.1	41.0	41.6	42.0	1.5	2.7
Nevada	48.8	47.1	47.8	48.5	1.6	3.1
New Mexico	68.2	66.9	63.4	63.9	-5.2	-4.5
New York (Downstate), New Jersey	99.3	100.0	100.2	100.6	0.3	0.6
New York (Upstate)	53.1	53.7	54.0	54.4	0.6	1.3
Ohio	57.8	59.8	59.9	60.1	0.2	0.5
Pennsylvania	58.2	59.3	58.6	58.5	-1.2	-1.4
Tennessee	46.9	47.3	46.5	46.2	-1.9	-2.4
Texas	79.4	79.4	79.1	79.7	-0.4	0.3
Utah	39.0	44.7	45.2	46.0	1.3	2.9
Virginia, District of Columbia	58.7	60.0	60.3	60.7	0.5	1.2
Washington, Oregon	35.4	35.3	35.5	35.6	0.5	0.9
West Virginia	27.2	26.8	27.1	28.4	1.0	5.8
Wisconsin	52.7	55.1	55.2	55.5	0.1	0.7
Wyoming	43.0	43.3	43.8	44.3	1.3	2.4
U.S. Average	62.0	62.8	62.8	63.1	0.1	0.5

SOURCE: Congressional Budget Office.

TABLE 20. ELECTRICITY PRICE CHANGES BY 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK PROGRAM AND SEVERAL OPTIONS, BY STATE (In 1985 mills per kwh)

State	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Percent Differences from Polluter Pays (Option II-2A) Option III-2A	Option III-2B	Option III-2C
Alabama, Mississippi	46.6	45.6	45.8	44.9	46.9	0.3	-1.5	2.8
Arizona	55.9	55.9	55.9	56.3	56.1	0.1	0.7	0.4
Arkansas, Oklahoma, Louisiana	77.5	78.8	79.3	79.9	79.7	0.7	1.5	1.1
California	78.3	78.3	78.7	79.1	78.9	0.5	1.0	0.7
Carolinas, North and South	50.3	51.2	51.4	51.7	51.5	0.6	1.1	0.6
Colorado	57.4	57.7	57.8	58.4	58.2	0.2	1.2	0.8
Dakotas, North and South	32.1	30.4	31.0	31.6	32.1	1.9	4.0	5.5
Florida	75.2	75.9	76.3	76.8	77.4	0.6	1.2	1.9
Georgia	54.2	56.2	56.4	54.6	57.9	0.4	-2.8	3.0
Idaho	43.0	43.5	44.0	44.6	44.2	1.3	2.7	1.7
Illinois	59.3	62.4	61.1	61.4	61.8	-2.0	-1.5	-0.9
Indiana	53.9	55.5	55.0	54.9	58.3	-1.0	-1.2	5.0
Iowa	59.3	62.3	62.8	63.4	62.5	0.8	1.7	0.2
Kansas, Nebraska	57.9	58.4	58.9	59.5	59.0	0.8	1.9	1.0
Kentucky	55.0	55.0	55.5	54.9	57.2	0.9	0.0	4.0
Maine, Vermont, New Hampshire	80.9	80.3	80.1	80.4	80.3	-0.2	0.1	0.0
Maryland, Delaware	66.4	69.2	69.4	68.4	69.7	0.2	-1.1	0.7
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.6	85.0	85.2	-0.1	0.4	0.6

(Continued)

TABLE 20. (Continued)

State	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Percent Differences from Polluter Pays (Option II-2A) Option III-2A	Option III-2B	Option III-2C
Michigan	57.7	58.2	57.9	58.1	58.3	-0.4	-0.1	0.1
Minnesota	54.2	55.1	55.8	56.1	55.5	1.3	1.7	0.7
Missouri	59.6	63.8	62.5	62.6	67.3	-2.0	-1.8	5.6
Montana	41.1	41.0	41.5	42.0	41.8	1.3	2.6	2.1
Nevada	48,8	47,0	47.9	48.5	48.2	1.8	3.2	2.5
New Mexico	68.2	67.2	63.4	63.9	67.8	-5.7	-4.9	0.9
New York (Downstate), New Jersey	99.3	100.3	100.5	100.2	100.6	0.1	-0.1	0.3
New York (Upstate)	53.1	55.3	56.0	56.3	56.0	1.3	1.7	1.3
Ohio	57.8	62.2	62.2	63.6	63.7	0.1	2.2	2.4
Pennsylvania	58.2	60.0	57.2	58.0	61.3	-4.6	-3.3	2.3
Tennessee	46.9	50.7	49.5	50.8	49.0	-2.4	0.1	-3.3
Texas	79.4	79.4	79.1	79.7	79.4	-0.4	0.3	0.0
Utah	39.0	44.7	45.2	46.0	45.6	1.2	2.9	2.0
Virginia, District of Columbia	58.7	60.7	60.7	61.3	61.1	0.0	0.9	0.6
Washington, Oregon	35.4	35.4	35.6	35.7	35.7	0.4	0.9	0.6
West Virginia	27.2	46.7	45.4	49.5	56.6	-2.7	6.0	21.3
Wisconsin	52.7	57.9	58.2	58.5	59.6	0.6	1.1	3.0
Wyoming	43.0	43.5	44.0	44.6	44.2	1.3	2.7	1.7
U.S. Average	62.0	63.5	63.4	63.8	64.3	-0.2	0.4	1.2

SOURCE: Congressional Budget Office.

lower energy content than midwestern and eastern coal, more must be burned to produce the same power output.

Tables 21 and 22 compare the coal-market effects of the tax and subsidy options with that of the polluter pays option with no restrictions on fuel switching, (Option II-2A). As expected, the subsidy schemes--which encourage greater scrubber use--offer some limited protection to the chief high-sulfur coal-producing states (Illinois, Indiana, Ohio, and Pennsylvania). The most significant differences occur under the scenarios that require a 10 million ton SO_2 emission rollback. For example, in Pennsylvania, coal production is expected to reach 82.3 million tons annually by 1995 under current policy. Under Option II-2A, production could fall to 56.3 million tons. A subsidy system for scrubbers would temper this loss. Option III-2A would bring the 1995 production level in Pennsylvania to 67.8 million tons (11.5 million tons more than Option II-2A), and Option III-2B would bring production up to 69.7 million tons (13.4 million tons more than Option II-2A). Moreover, by simply requiring more scrubbing--as in Option III-2C--the higher coal production figure of 69.7 million tons per year could be maintained without adding an O&M subsidy.

Effect on Direct Coal Mining Jobs. As Chapter II pointed out, mandated emission rollbacks using the polluter pays approach of Option II-2A could lead to losses in expected 1995 job slots in the high-sulfur coal states (see Tables 23 and 24). Sulfur dioxide rollback programs coupled with subsidies for scrubber use could retard this trend, however. For example, without a change in current policy, Pennsylvania might expect mining employment to reach 29,300 jobs in 1995, rising from 23,100 in 1985.[10] But under a 10 million ton reduction program with no subsidies or restrictions on fuel choice, 1995 employment levels could fall to 20,000 (see Table 24). In contrast, Option III-2A could keep 1995 employment levels from falling below 24,100, and Option III-2B could hold employment to 24,800 in 1995. Option III-2C could also hold employment to 24,800 in 1995, but would cost more overall.

Although regional shifts would occur, national coal employment would change little under each option. However, predicted changes in national employment shown in Tables 23 and 24 do not always vary proportionally to the coal production figures shown in Tables 21 and 22. While employment generally tends to rise or fall with production, western low-sulfur coal requires much less labor to mine than the high-sulfur coal in the Midwest and East. Thus, as more low-sulfur coal was used in place of high-sulfur coal, national employment could fall even if national tonnage rose or stayed the same.

10. See Tables 11 and 12 in Chapter II for estimates of 1985 coal mining employment.

TABLE 21. COAL PRODUCTION CHANGES AS OF 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK PROGRAM AND VARIOUS OPTIONS, BY STATE (In millions of tons per year)

State	Base Case 1995	Polluter Pays Option II-2A	Option III-1A	Option III-1B	Differences from Polluter Pays (Option II-2A) Option III-1A	Option III-1B
Alabama	23.8	25.5	25.7	23.8	0.2	-1.7
Arizona	14.2	13.8	13.8	13.8	0.0	0.0
Arkansas	0.0	0.0	0.0	0.0	0.0	0.0
Colorado	19.1	20.3	20.4	19.9	0.0	-0.4
Illinois	56.4	46.2	48.4	56.9	2.3	10.8
Indiana	29.2	24.3	25.8	28.2	1.5	3.8
Iowa	1.5	0.5	0.7	1.5	0.2	1.0
Kansas	2.5	0.4	1.4	2.5	1.0	2.0
Kentucky	208.9	211.6	197.3	188.6	-14.3	-23.0
Maryland	2.5	1.6	2.1	2.3	0.5	0.7
Missouri	8.1	5.4	7.1	8.1	1.7	2.7
Montana	34.0	26.0	30.0	32.6	4.0	6.6
New Mexico	31.9	31.8	31.8	31.8	0.0	0.0
North Dakota	22.7	22.7	22.7	22.7	0.0	0.0
Ohio	24.3	4.0	12.0	19.9	8.0	15.8
Oklahoma	7.7	7.0	7.1	7.7	0.1	0.7
Pennsylvania	82.3	69.4	69.7	73.6	0.2	4.2
South Dakota	0.0	0.0	0.0	0.0	0.0	0.0
Tennessee	5.3	6.9	6.8	6.8	-0.2	-0.2
Texas	109.4	108.8	110.6	110.2	1.8	1.4
Utah	31.6	31.8	31.8	31.8	0.0	-0.1
Virginia	50.6	57.2	57.2	57.2	0.0	0.0
Washington	0.5	0.5	0.5	0.5	0.0	0.0
West Virginia	232.2	261.7	258.4	253.8	-3.2	-7.9
Wyoming	130.5	151.7	150.8	138.0	-0.9	-13.7
Total	1,128.9	1,129.1	1,132.0	1,131.8	2.9	2.7

SOURCE: Congressional Budget Office.

TABLE 22. COAL PRODUCTION CHANGES AS OF 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK PROGRAM AND VARIOUS OPTIONS, BY STATE (In millions of tons per year)

State	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Differences from Polluter Pays (Option II-2A)		
						Option III-2A	Option III-2B	Option III-2C
Alabama	23.8	22.1	21.2	23.0	23.0	-0.9	0.9	0.9
Arizona	14.2	13.9	13.8	13.8	13.8	-0.2	-0.2	-0.2
Arkansas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colorada	19.1	23.5	23.5	22.3	22.0	0.0	-1.3	-1.5
Illinois	56.4	37.6	43.7	47.4	51.0	6.1	9.8	13.4
Indiana	29.2	19.7	23.2	25.8	28.2	3.5	6.0	8.4
Iowa	1.5	0.5	0.5	0.5	1.5	0.0	0.0	1.0
Kansas	2.5	0.4	0.4	1.4	1.4	0.0	1.0	1.0
Kentucky	208.9	195.9	195.4	193.6	192.0	-0.5	-2.4	-4.0
Maryland	2.5	1.5	1.5	2.1	2.3	0.0	0.6	0.8
Missouri	8.1	5.3	5.4	5.8	7.1	0.1	0.5	1.8
Montana	34.0	26.0	30.1	31.9	30.5	4.1	6.0	4.5
New Mexico	31.9	31.9	31.8	31.8	31.8	0.0	0.0	0.0
North Dakota	22.7	22.7	22.7	22.7	22.7	0.0	0.0	0.0
Ohio	24.3	4.0	4.0	11.6	14.7	0.0	7.5	10.6
Oklahoma	7.7	7.0	7.0	7.1	7.7	0.0	0.1	0.7
Pennsylvania	82.3	56.3	67.8	69.7	69.7	11.5	13.3	13.3
South Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Tennessee	5.3	4.9	6.3	4.8	6.8	1.3	-0.2	1.8
Texas	109.4	108.8	108.9	108.2	110.6	0.1	-0.6	1.8
Utah	31.6	32.8	31.8	31.8	31.8	-1.0	-1.0	-1.0
Virginia	50.6	56.0	56.0	55.7	56.0	0.0	-0.3	0.1
Washington	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
West Virginia	232.2	274.6	258.5	250.0	250.0	-16.1	-24.6	-24.6
Wyoming	130.5	191.2	183.2	175.7	159.7	-7.9	-15.4	-31.5
Total	1,128.9	1,137.1	1,137.0	1,137.0	1,134.5	0.0	0.0	-2.6

SOURCE: Congressional Budget Office.

TABLE 23. COAL MINING EMPLOYMENT CHANGES BY 1995 UNDER AN 8 MILLION TON SO_2 ROLLBACK PROGRAM AND VARIOUS OPTIONS, BY STATE (In number of job slots)

State	Base Case 1995	Polluter Pays Option II-1A	Option III-1A	Option III-1B	Differences from Polluter Pays (Option II-1A) Option III-1A	Option III-1B
Alabama	8,124	8,714	8,773	8,117	59	-597
Arizona	1,177	1,141	1,141	1,141	0	0
Colorado	3,288	3,510	3,511	3,437	1	-73
Illinois	14,733	12,068	12,658	14,880	591	2,812
Indiana	5,342	4,446	4,713	5,149	267	703
Iowa	344	110	164	346	54	237
Kansas	753	129	441	753	311	624
Kentucky	63,014	63,818	59,508	56,881	-4,310	-6,937
Maryland	695	447	597	650	150	203
Missouri	1,948	1,297	1,705	1,941	408	644
Montana	1,251	956	1,104	1,198	148	242
New Mexico	2,846	2,844	2,844	2,844	0	0
North Dakota	1,375	1,374	1,374	1,374	0	0
Ohio	7,136	1,183	3,525	5,840	2,342	4,657
Oklahoma	2,344	2,146	2,187	2,347	41	200
Pennsylvania	29,299	24,701	24,789	26,180	88	1,479
Tennessee	2,010	2,616	2,550	2,550	-66	-66
Texas	6,890	6,855	6,966	6,944	111	89
Utah	7,978	8,040	8,034	8,019	-6	-21
Virginia	19,339	21,852	21,851	21,836	-1	-16
Washington	48	48	48	48	0	0
West Virginia	89,473	100,811	99,563	97,775	-1,248	-3,035
Wyoming	5,768	6,706	6,667	6,102	-38	-604
Total	275,172	275,812	274,714	276,352	-1,098	540

SOURCE: Congressional Budget Office.

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TABLE 24. COAL MINING EMPLOYMENT CHANGES BY 1995 UNDER A 10 MILLION TON SO_2 ROLLBACK PROGRAM AND VARIOUS OPTIONS, BY STATE (In number of job slots)

State	Base Case 1995	Polluter Pays Option II-2A	Option III-2A	Option III-2B	Option III-2C	Differences from Polluter Pays (Option II-2A) Option III-2A	Option III-2B	Option III-2C
Alabama	8,124	7,543	7,223	7,844	7,844	-320	302	302
Arizona	1,177	1,155	1,141	1,141	1,141	-13	-13	-13
Colorado	3,288	4,062	4,062	3,842	3,797	0	-220	-265
Illinois	14,733	9,823	11,409	12,392	13,325	1,586	2,569	3,502
Indiana	5,342	3,611	4,245	4,713	5,149	634	1,103	1,538
Iowa	344	110	110	110	339	0	0	230
Kansas	753	129	129	441	441	0	311	311
Kentucky	63,014	59,098	58,944	58,383	57,901	-154	-715	-1,197
Maryland	695	417	425	597	650	8	179	233
Missouri	1,948	1,276	1,296	1,402	1,705	20	126	429
Montana	1,251	955	1,107	1,175	1,122	152	220	167
New Mexico	2,846	2,846	2,844	2,844	2,844	-2	-2	-2
North Dakota	1,375	1,374	1,374	1,374	1,374	0	0	0
Ohio	7,136	1,183	1,183	3,401	4,316	0	2,218	3,133
Oklahoma	2,344	2,146	2,146	2,187	2,347	0	41	200
Pennsylvania	29,299	20,042	24,119	24,789	24,789	4,078	4,747	4,747
Tennessee	2,010	1,859	2,361	1,796	2,550	502	-63	691
Texas	6,890	6,854	6,859	6,817	6,966	4	-37	112
Utah	7,978	8,282	8,034	8,021	8,039	-248	-260	-243
Virginia	19,339	21,375	21,374	21,278	21,401	-1	-96	26
Washington	48	48	48	48	48	0	0	0
West Virginia	89,473	105,792	99,590	96,300	96,300	-6,202	-9,493	-9,493
Wyoming	5,768	8,451	8,100	7,769	7,060	-351	-682	-1,390
Total	275,172	268,431	268,125	268,665	271,448	-306	234	3,017

SOURCE: Congressional Budget Office.

CHAPTER IV

REDUCING SULFUR DIOXIDE LEVELS WITH EMISSION TAX AND SUBSIDY PROGRAMS

Chapters II and III explored means to reduce sulfur dioxide emissions using the traditional system of requiring and enforcing emission limits on specific sources, often called the "command and control" approach. This chapter examines another method: reducing sulfur dioxide emissions from electric utilities by charging a tax (or fee) on each ton of SO_2 emitted. In addition to giving utilities a financial incentive to limit emissions, the tax would generate revenues that could be used to influence the choice of abatement method by providing subsidies for utilities that install scrubbers. Although subsidies would raise total program costs, they would also encourage additional emission reductions, lower the costs borne by utilities and consumers, and maintain the use of high-sulfur coal.

The CBO examined two basic emission tax schemes: a tax program without a subsidy for scrubbing, and a tax program in which subsidies--drawn from the tax revenues--would be given to utilities that install scrubbers (see Table 25). A simple tax option without subsidies would lower utility emissions primarily through fuel switching. For example, a $600 per ton SO_2 tax levied on older, state-regulated utility sources (Option IV-1) would lower projected total annual emissions in 1995 from 18.5 million tons under current policy to 10.0 million tons, and would provide $4.9 billion in annual revenues as of 1995.1/ The SO_2 tax would be relatively cost-effective at $327 per ton of SO_2 removed compared with the 10 million ton polluter pays reduction with no fuel restrictions (Option II-2A), which would cost $360 per ton. The simple tax would, however, allow slightly more emissions.2/ The total program cost of Option IV-1 over the 1986-2015 period would also be somewhat higher than Option II-2A--$37.5 billion compared with $34.5 billion, respectively (in discounted 1985 dollars). The cost-effectiveness measure, however, captures the benefits from emission reductions that would occur earlier than 1995--the compliance deadline governing previous op-

1. As is true for the options examined in Chapters II and III, it is assumed that the alternatives in this chapter would not apply to newer utililties that must conform to the New Source Performance Standards.

2. For easy reference, all options in this report are defined in the glossary at the end of the paper.

tions--which are ignored in the total program cost calculation. These benefits derive from the assumption that utilities would respond more quickly to an immediate annual financial penalty than to a relatively distant compliance date, thus incurring abatement costs earlier. Finally, Option IV-1 would provide about 4,000 more mining jobs in 1995 in Illinois, Indiana, Ohio, and Pennsylvania than expected under Option II-2A.

CBO also examined two subsidy schemes to accompany the $600 per ton SO_2 tax: Option IV-2 would grant a 90 percent subsidy for the cost of purchasing and installing a scrubber, and Option IV-3 would combine a 50 percent subsidy for operation and maintenance with the 90 percent capital subsidy for scrubbers. Options IV-2 and IV-3 would lower 1995 SO_2 emissions to about 9.6 million tons, while providing $4.7 billion in annual tax receipts in 1995. These subsidies would raise toal discounted program costs to $39.2 billion with Option IV-2 and $45.9 billion with Option IV-3. Unlike the programs that combine scrubber subsidies with specific emission targets, however, these scrubber subsidies also would encourage additional emission reductions above those resulting from the tax. These additional reductions would make Option IV-2 at $317 per ton removed, almost as cost-effective as Option IV-1. The additional subsidy granted under Option IV-3 would result in higher costs with nearly the same emission levels as Option IV-2, thus raising the cost per ton abated to $384.

TABLE 25. EMISSION TAX OPTIONS

Policy Option	Resulting Emission Reduction from 1980 Levels	Tax System	Scrubber Subsidies
Option IV-1	9.2 million tons	$600/ton ($.30/lb.) tax on SO_2 emitted from pre-NSPS coal- and oil-fired sources	None
Option IV-2	9.5 million tons	Same as above	90 percent annual cost of capital
Option IV-3	9.6 million tons	Same as above	90 percent annual cost of capital, 50 percent annual cost of O&M

SOURCE: Congressional Budget Office.

In addition to reducing emission levels, these subsidies also would lower the net costs to the utilities and ease the electricity rate increases expected under the SO_2 tax. This would be especially evident in the Midwestern and Appalachian states which would incur the largest share of the abatement costs, and would still pay a large portion of the taxes collected even after reductions occur. Scrubber subsidies also would promote high-sulfur coal production and employment in Illinois, Indiana, Ohio, and Pennsylvania. Compared with Option II-2A, 1995 mining employment in those states would be greater by 9,000 jobs under Option IV-2 and by over 13,300 jobs with Option IV-3.

RATIONALE FOR AN EMISSIONS TAX

Effluent taxes possess many economic advantages over the traditional command and control style of environmental regulation. Advocates of this approach usually invoke the microeconomic theory of external cost to frame their arguments. [3]

External cost is defined as the difference between the private cost of producing a commodity--the market value of the resources devoted to its production--and the social cost of producing that good--which includes the cost of any environmental damage. If producers minimize only private cost in making decisions, then their actions can impose an additional (external) cost on society for which they pay nothing. In this context, the market price no longer reflects the true resource cost of producing that good, and the competitive market no longer leads the economy to the desirable point of maximum efficiency. A tax levied on emissions, if properly specified, can allow the competitive market to "regulate" pollution in a theoretically simple fashion. When producers are forced to pay the full social cost associated with their output, then the incentive to minimize production costs will include the incentive to reduce pollution. Producers will employ the most economically efficient methods of pollution abatement (for example, investing in additional control equipment, changing the input mix, or reducing output) until the costs incurred by abating another unit of pollution outweighs the tax that they must pay to emit that unit. If the tax truly captures the external cost of production, then the resulting levels of output and effluent would be socially optimal.

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3. See, for example, Frederick R. Anderson and others, *Environmental Improvement Through Economic Incentives* (Baltimore: The Johns Hopkins University Press, 1977).

The strict theoretical case for effluent fees requires that the regulators correctly estimate the monetary value of pollution damage from each source, and set taxes for individual plants accordingly. In the case of acid rain, however, the precise cause and extent of pollution damage remains uncertain. Therefore, only a nationwide uniform tax rate is considered here, and its level is largely determined by the amount of emission reductions it can achieve.

Regulators should also have extensive information about producers in order to set the tax to achieve a certain level of emissions. Although some uncertainty remains about the effect of tax rates on emission levels, an emissions tax can simplify the administrative task of attaining approximate emission targets because the regulators no longer have to identify those sources with the lowest-cost abatement opportunities. An emission tax allows individual emitters to decide the cheapest abatement strategy for themselves. The emissions that remain come from the plants that face the highest additional control costs; their tax payments constitute a true "polluter pays" fee for the remaining emissions.

Emissions Taxes as Financial Incentive Versus Simple Revenue Sources

A true emission tax, designed to reduce pollution output, should be distinguished from a simple revenue-raising tax that uses emissions as a tax base. Examples of the latter can be found in the Federal Republic of Germany's water discharge fees--used to finance local treatment plants--and in Japan's SO_2 emission taxes in selected urban areas--used to compensate victims of illnesses related to air pollution. [4] In the United States, a proposal introduced into the 98th Congress (S. 2001) by Senator Durenberger would have levied a temporary tax on sulfur dioxide and nitrogen oxide emissions from all major stationary sources. This tax was meant to provide revenues of $40 billion dollars over 10 years for scrubber subsidies. S. 2001 stipulated that only two-thirds of the revenues would originate from SO_2 taxes. Since utilities emit roughly two-thirds of the SO_2 emitted nationwide, they would have provided $18 billion of the total revenues. Taxes on other stationary sources of SO_2 and nitrogen oxide, as well as mobile sources of nitrogen oxide, would provide the remainder ($22 billion). The SO_2 reductions required in S. 2001 would not be motivated by the tax,

4. See Congressional Budget Office, *Environmental Regulation and Economic Efficiency* (March 1985) for a discussion of these policies, which have typically applied low rates to broad tax bases. While such policies may provide some incentives to control pollution, the primary goal is the collection of revenue.

but instead would be dictated by the excess emission formula (applied to the 31 eastern and midwestern states), in the same way that the options examined in Chapters II and III allocated state reduction targets.

Taxing SO_2 emissions from electric utilities could provide about $18 billion after 10 years with a tax of about $100 dollars per ton on all power plants, assuming that utility emissions hold steady in the interim. Such a small tax, however, probably would not affect utility decisions regarding emissions control. This proposal is similar to Option III-2B described in the last chapter, simply replacing a generation tax with an emission tax to subsidize scrubber installation and use. The fundamental difference lies in the geographic distribution of the tax burden: S. 2001 would have concentrated the tax burden in the states where emission rates are currently high, whereas the generation fee policies would spread much of the tax burden over other states. Thus, S. 2001 was neither a punitive emission tax nor a policy designed to spread costs geographically, but rather an extension of the polluter pays idea with an emphasis on scrubbing. Moreover, the ratio of administrative expenses to revenues raised would likely be high, even allowing for the relative ease of assessing SO_2 taxes on electric generating plants. Therefore, the remainder of this chapter is devoted to examining tax policies which rely on an emission tax rate high enough to encourage abatement without additional regulatory intervention.

Administrative Issues

The relatively uniform characteristics of electric generating plants would allow regulators to monitor compliance and determine tax liabilities. The relationship between the efficiency of a plant, the sulfur and heat content of the fuel burned, the generation of power, and the resulting emissions are straightforward and can be calculated with information that the utilities already must file with various regulatory agencies. In the absence of continuous emission monitoring, the administrators of a tax system could rely on standard formulas to calculate taxable emissions. While some uncertainties will always exist, such as the reliability of scrubbers, these would be present under any system of regulation designed to reduce utility emissions. Because much standardization exists in the industry, a broad-based formulaic approach to assessing annual taxes could be devised. The burden of proof that an estimating procedure does not faithfully represent a particular plant could rest with the utility.

Because there are relatively few generation plants, the administrative costs of assessing and collecting a sulfur dioxide tax from electric utilities would be small relative to revenues collected. As of December 1984, there were 1,300 coal-fired electric utility boilers in commercial operation. 5/ In 1985 these boilers emitted a total of 15.2 million tons of SO_2--for an average of 11.7 thousand tons per unit. With a tax of $600 per ton of SO_2, average annual revenues per source would equal $7.0 million before any reductions occurred. 6/

Cost Passthrough Issues. To encourage emission reductions in the absence of prescriptive regulations, emission tax rates would have to be high enough so that a substantial number of firms could lower total costs if they reduced pollution. To ensure maximum emission reductions from an emission tax, the tax would have to be permanent, because utilities might simply pass the costs of a temporary tax through to consumers and wait until the tax expires. Without the threat of continued tax payments, the rewards of developing a long-run abatement program might disappear, since future abatement actions would not lower emission tax payments.

For an emission tax to work, incentives would have to be present for firms to minimize production costs. In the unregulated market, competition provides this incentive. In the regulated market of the electric utility industry, however, the state public utility commissions, charged with setting electricity rates, would have to ensure that costs are minimized. The commissions would need to review utility decisions to determine that emission reductions programs were cheaper than the cost of the tax. Otherwise, the utilities might choose to pay the tax and pass most of the payments on to consumers in the form of rate increases. Of course, even if utilities implemented a cost-effective abatement plan to avoid the punitive emission tax, the taxable emissions that remain would still raise generation costs. State commissions should allow utilities to raise electricity prices to reflect this legitimate additional operating expense.

EMISSION TAX APPROACHES

The CBO used a modified version of the National Coal Model (introduced in Chapter II and described in the appendix) to predict the effects of a national emission tax. The emission tax is simply a charge levied on a utility plant for each unit of SO_2 it emits while generating electricity. Utilities

5. See Department of Energy, Energy Information Administration, *Inventory of Power Plants in the United States 1984* (July 1985).

6. This calculation is only approximate, since some of these boilers were built under federal regulations and, thus, would be exempt from a tax levied only on older, state-controlled sources.

trying to minimize the total cost of supplying electricity may chose among plant types and among fuels of various heat and sulfur contents. A value of $600 per ton (in 1985 dollars) of SO_2 emitted from power plants subject to state regulations was chosen to obtain an emissions reduction roughly comparable to the 10 million ton polluter pays option (Option II-2A).

Sulfur Dioxide Emissions Under an Emission Tax

A key determinant in setting the level of an emission tax is the relationship between the tax rate and ultimate emission level. The CBO estimates that a permanent $600 per ton SO_2 tax would reduce the projected annual emissions from electric utilities in 1995 from 18.5 (current policy) to 10.0 million tons (Option IV-1). When this tax is combined with a 90 percent capital subsidy for retrofit scrubbers (Option IV-2) or a 90 percent capital and 50 percent O&M subsidy (Option IV-3), emissions are further reduced to an annual level of 9.6 million tons in 1995. Table 26 shows the utility SO_2 emissions under the three tax and subsidy programs.

The emission tax and subsidy policies yield a 1995 level of total emissions slightly higher than Option II-2A. The distribution of the emissions, as expressed by the percentage of the total reduction originating from each state under the tax policies, is nearly identical to the distribution mandated by the standard excess emission formula. For example, six states account for 59 percent of the emission reduction under Option II-2A: Illinois, Indiana, Missouri, Ohio, Pennsylvania, and West Virginia. Under the tax policies, this share remains virtually constant at about 60 percent.

The excess emission formula is designed to penalize most heavily the states with high emission rates in the belief that the least expensive reduction opportunities can be found there. The finding that a uniform nationwide emission tax would elicit a distribution of reductions that is quite similar suggests that the excess emission formula has substantial merit as a method of identifying the appropriate regions. Of course, the tax retains its advantage over the allocation formula in intrastate reductions, since regulators would not have to identify the actual plants within regions with the least costly reduction opportunities. 7/

7. Unfortunately, the model employed by CBO cannot fully capture the potential for intraregional efficiency gains implied by using an emission tax compared with prescriptive emission targets, since the intraregional costs are minimized in either case. See the appendix for a more detailed description of the model.

TABLE 26. EMISSIONS UNDER THREE EMISSION TAX OPTIONS COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In thousands of tons of SO_2 emitted in 1995)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Alabama, Mississippi	704	414	479	466	435	65	52	21
Arizona	122	106	106	106	122	0	0	17
Arkansas, Oklahoma, Louisiana	336	302	311	310	310	9	8	8
California	25	25	25	25	25	0	0	0
Carolinas, North and South	1,063	577	532	522	512	-45	-54	-65
Colorado	92	94	87	87	88	-7	-7	-6
Dakotas, North and South	105	105	105	104	96	-1	-1	-9
Florida	772	566	561	547	541	-4	-19	-24
Georgia	635	352	327	327	324	-25	-25	-28
Idaho	0	0	0	0	0	0	0	0
Illinois	1,142	408	488	490	492	80	82	84
Indiana	1,433	533	601	593	593	49	41	40
Iowa	326	167	155	145	148	-12	-22	-18
Kansas, Nebraska	174	163	149	149	149	-14	-14	-14
Kentucky	796	466	480	436	432	15	-29	-34
Maine, Vermont, New Hampshire	64	44	39	35	35	-5	-9	-9
Maryland, Delaware	371	189	223	223	223	34	34	34
Massachusetts, Connecticut, Rhode Island	305	219	306	306	306	87	87	87

(Continued)

TABLE 26. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Michigan	598	374	368	355	355	-6	-20	-20
Minnesota	230	146	136	123	121	-10	-23	-24
Missouri	1,257	293	255	268	295	-38	-25	1
Montana	71	68	68	68	68	0	0	0
Nevada	90	80	74	75	75	-6	-5	-5
New Mexico	62	62	62	62	62	0	0	0
New York (Downstate), New Jersey	270	245	250	254	254	5	9	10
New York (Upstate)	343	141	209	213	213	68	72	72
Ohio	2,017	629	728	689	692	99	60	62
Pennsylvania	1,439	578	769	584	582	191	6	4
Tennessee	761	281	337	332	332	56	51	51
Texas	586	567	586	586	545	19	19	-22
Utah	87	61	71	70	70	10	8	8
Virginia, District of Columbia	213	175	189	189	190	14	14	15
Washington, Oregon	111	104	112	103	97	8	-1	-8
West Virginia	1,042	421	435	435	446	14	14	25
Wisconsin	746	199	285	285	283	86	86	84
Wyoming	69	70	70	69	68	0	0	-2
U.S. Total	18,455	9,241	9,977	9,631	9,576	737	391	336

SOURCE: Congressional Budget Office.

These three tax cases show that increasing subsidies for scrubbers--in the presence of an emission tax--might eventually become ineffective at inducing further reductions, although that point might only be reached with fairly high subsidy levels. The value of subsidies for lowering costs to utilities and encouraging the use of high-sulfur coal remain, of course, even when no further emission reductions occur.

Emissions in the Midwest and the East. The four largest emitting states in the Midwest--Illinois, Indiana, Ohio, and Missouri--would reduce emissions dramatically under each tax option. These four states currently account for one-third of nationwide utility emissions. In each case, this region would reduce expected emissions in 1995 by 65 percent--from over 5.8 million tons to about 2.1 million tons, although individual state levels vary among policies. Scrubber use in these four states would increase substantially if subsidies were granted, but overall emissions would remain fairly constant because of increased reliance on high-sulfur coal compared with the tax-only Option IV-1.

The Appalachian states of Kentucky, Pennsylvania, and West Virginia would also reduce SO_2 emissions drastically under each of the tax schemes. Under Option IV-1, emissions in this region would be reduced from 3.3 million tons to 1.7 million tons per year as of 1995. Adding a 90 percent capital subsidy (Option IV-2) to the tax program would reduce emissions further to 1.5 million tons annually. Most of this additional reduction would come from the state of Pennsylvania, which would increase scrubber use from 24 percent of existing coal-fired capacity in 1985 to 85 percent by 1995. The addition of a 50 percent O&M subsidy (Option IV-3) would induce no additional reductions in this region, even though scrubber use would rise slightly in West Virginia.

A closer look at the distribution of emissions in these regions yields a seemingly counterintuitive result--emissions in some states could actually rise as subsidies for scrubbers became available or were increased. Missouri provides an example of this phenomenon. Under the simple emission tax, buying expensive low-sulfur coal from Wyoming would be cheaper than using scrubbers for many Missouri utilities. When a 90 percent capital subsidy is included, or when O&M is subsidized as well, however, some plants would switch to midwestern coal with roughly five times the sulfur content, while installing enough scrubbing capacity to remove only three quarters of the additional SO_2. Emissions (and taxes), thus, would be higher, but the additional cost of the taxes would be more than offset by the combination of using subsidized scrubbers and very inexpensive nearby coal. While most regions would respond to additional scrubber subsidies by reducing emissions, the effect described here is prevalent enough nearly to offset those reductions. This explains why 1995 utility emissions under Option IV-3 are only slightly lower than under Option IV-2, even as scrubber use increases substantially.

Emissions in the West. In the absence of any policy changes, sulfur dioxide emissions from utilities in the West (states west of the Mississippi, except Minnesota, Iowa, and Missouri) will rise from 1.3 million tons in 1985 to 1.9 million tons by 1995. This increase would be only slightly checked under the three tax policies, each of which would result in western emission levels of about 1.8 million tons by 1995. The taxes and subsidies would have little effect for two reasons. First, many existing plants in the West are already subject to very stringent state emission standards, and historically have burned very low-sulfur western coal, gas, or oil. The remaining emissions come from new sources that are subject to the current federal New Source Performance Standards (NSPS) and would be exempted from the emission tax. Therefore, very few economical opportunities exist for marginal reductions, even in the presence of a $600 per ton penalty for emitting SO_2.

The Cost of Emission Tax and Subsidy Options

Comparing the costs incurred under the financial incentive policies (Chapters IV and V) with those incurred under the targeted rollback schemes (Chapters II and III) requires care, since the assumed timing of costs and emission reductions differ markedly. Specifically, CBO assumes that utilities will respond more quickly--both in reducing emissions and in incurring costs--in their efforts to reduce emission tax payments, compared with simply meeting the 1995 compliance deadline assumed in previously discussed options. Therefore, the cost-effectiveness figure--which takes into account both the timing of emission reductions and costs--becomes a more valid comparative measure, since society presumably attaches a greater value to earlier emission reductions.

Using the net present value measure, the total program cost of Option IV-1 over the period from 1986 through 2015 would be $37.5 billion (in discounted 1985 dollars).[8] Corresponding figures for Option IV-2 and Option IV-3 are $39.2 billion and $45.9 billion, respectively. Table 27 displays these results along with the program cost of $34.5 billion for Option II-2A.

In contrast, the cost-effectiveness figures, by accounting for the discounted stream of emission reductions, suggest that the tax policies would be more efficient than traditional rollback schemes, even when combined with partial subsidies for scrubbers. Table 27 shows that Option IV-1 would

8. Present value is defined in the box on page 19.

cost \$327 per ton annually of SO_2 abated, while Option II-2A would cost \$360 per ton. The additional reductions occuring from the scrubbing subsidy granted in Option IV-2 would nearly offset the additional costs incurred, and only increase the cost-effectiveness figure to \$330 per ton abated, while Option IV-3 would cost \$384 per ton abated.

Cost to Utilities. The annual net utility cost in 1995 under a \$600 per ton tax on SO_2 would be \$7.7 billion higher than the cost under current policy (the base case). The subsidies for scrubbers in Option IV-2 and Option IV-3 would lower this additional cost to \$7.2 billion and \$6.4 billion, respectively. These costs are significantly higher than those in other proposals because they include the \$4.9 billion collected in annual tax payments with Option IV-1 and the \$4.7 billion collected under Option IV-2 and Option IV-3. Table 28 compares the 1995 costs under the three tax policies with the costs of the base case and Option II-2A.

TABLE 27. COMPARISON OF TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF THREE EMISSION TAX OPTIONS WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS

	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3
Total Program Cost (In billions of discounted 1985 dollars) a/	34.5	37.5	39.2	45.9
Cost-Effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	360	327	330	384

SOURCE: Congressional Budget Office.

a. Reflects net present value of sum of program costs incurred from 1986 through 2015, discounted to 1985 dollars. These costs consist of real annual utility expenditures in excess of current policy, which is equivalent to net utility cost, plus subsidies, minus taxes paid. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reduction from current policy measured over the 1986-2015 period.

The distribution of net utility costs under the tax policies would vary across regions in a manner similar to the distribution of emission reductions, with the midwest and Appalachian states bearing a large proportion of these costs under each option. These regions would not only incur heavy abatement costs, but also pay a substantial portion of the 1995 emission taxes even after reductions occur. The six states that contribute 60 percent of the emission reductions (Illinois, Indiana, Missouri, Ohio, Pennsylvania, and West Virginia) would incur between 30 percent and 33 percent of the net utility costs under the tax policies; these states also contribute about 36 percent of total tax revenues collected in 1995. Although many of the costs are concentrated in this region, utilities there would also receive most of the subsidies--88 percent of the total subsidies granted under Option IV-2, and 63 percent of the total granted under Option IV-3.

The amount spent on retrofit scrubbers would vary substantially among the three cases. Under Option IV-1, utilities would spend only $34 million in additional annual capital costs for retrofitting existing plants with scrubbers. Thus, the emissions would be reduced primarily by switching to lower-sulfur coals. In Option IV-2, the utilities would increase these annual capital payments to $513 million, of which $462 million, or 90 percent, would be covered by government subsidies. Option IV-3 also would add O&M subsidies of $464 million per year. The addition of a 50 percent O&M subsidy for retrofits would bring annualized capital expenditures for retrofits up to $977 million, of which the subsidies would pay for $879 million per year. Thus, the additional O&M subsidy would encourage the utilities to spend greater amounts on installing scrubbing capacity since the overall costs of operation would be lowered.

Scrubber subsidies would lower net utility costs in most regions, with a few exceptions. In some areas, total generation costs would rise simply because the areas produced more electricity than they needed and transmitted the surplus to meet demand in another location. In other areas, generation would remain constant, but the increased nationwide scrubber use could raise the price of high-sulfur coal to plants (mostly built under the NSPS) that already employ scrubbing. This price rise would not overcome the cost advantage of high-sulfur coal, but simply would make it more expensive.

Electricity Rates Under an Emission Tax Policy

To the extent permitted by state public utility commissions, electric utilities would pass additional tax and abatement costs through to the final consumers through electricity rate increases. This link would depend on pooling (interregional transmission) and the treatment of capital and variable costs in determining revenue requirements for each utility region. In

TABLE 28. ANNUAL UTILITY COSTS AS OF 1995 OF THREE EMISSION TAX OPTIONS COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of 1985 dollars)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Alabama, Mississippi	4,224	4,364	4,621	4,588	4,527	257	224	163
Arizona	1,944	1,943	1,990	1,990	1,985	47	47	43
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,768	9,782	9,783	45	59	60
California	10,565	10,822	10,568	10,568	10,573	-254	-254	-249
Carolinas, North and South	4,759	4,895	5,245	5,202	5,190	350	307	294
Colorado	1,093	1,100	1,131	1,132	1,130	31	32	30
Dakotas, North and South	567	565	586	586	581	20	20	16
Florida	6,127	6,198	6,494	6,470	6,471	296	272	273
Georgia	2,555	2,622	2,836	2,809	2,797	213	187	174
Idaho	221	221	221	221	221	0	0	0
Illinois	4,189	4,432	4,659	4,574	4,465	227	142	33
Indiana	3,095	3,233	3,602	3,555	3,510	369	322	277
Iowa	1,230	1,327	1,410	1,421	1,414	83	94	87
Kansas, Nebraska	1,854	1,862	1,943	1,950	1,942	81	88	81
Kentucky	3,103	3,499	3,402	3,375	3,394	-97	-124	-105
Maine, Vermont, New Hampshire	1,123	1,123	1,150	1,149	1,146	27	26	23
Maryland, Delaware	1,885	1,654	2,052	2,037	1,976	398	383	322
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,717	3,707	3,695	38	29	16

(Continued)

TABLE 28. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Michigan	2,817	2,944	3,111	3,099	3,084	167	155	140
Minnesota	1,186	1,228	1,269	1,269	1,273	42	42	45
Missouri	2,024	2,206	2,355	2,363	2,314	149	157	108
Montana	676	675	685	685	687	10	10	12
Nevada	1,096	1,122	1,135	1,135	1,135	14	14	14
New Mexico	1,158	1,144	1,165	1,165	1,158	21	21	14
New York (Downstate), New Jersey	4,878	5,200	5,044	5,037	5,023	-156	-163	-177
New York (Upstate)	2,395	2,236	2,525	2,527	2,518	289	292	283
Ohio	4,239	4,271	4,847	4,790	4,695	576	518	423
Pennsylvania	5,512	6,056	6,131	6,056	5,930	75	0	-126
Tennessee	2,078	2,028	2,348	2,350	2,330	321	322	303
Texas	15,852	15,844	16,073	16,073	16,047	228	228	202
Utah	1,345	1,368	1,380	1,380	1,380	12	12	12
Virginia, District of Columbia	1,884	1,926	2,019	2,007	2,010	93	81	84
Washington, Oregon	4,219	4,068	4,258	4,258	4,252	190	190	184
West Virginia	1,784	2,278	2,397	2,344	2,309	118	66	30
Wisconsin	1,572	1,734	1,841	1,825	1,805	107	91	70
Wyoming	1,026	1,039	1,074	1,073	1,070	36	35	32
U.S. Total	117,380	120,630	125,051	124,554	123,821	4,421	3,924	3,191

SOURCE: Congressional Budget Office.

this study, emission taxes are assumed to be passed directly to the consumer as operating expenses. An important assumption to recall when interpreting these results is the fact that electricity demand remains fixed in the analysis: consumers do not respond to higher rates with cutbacks in electricity use.

Table 29 compares the average electricity rates in the states under the three tax policies with Option II-2A and the base case. The pattern of rate increases from the tax policies and scrubber subsidies resembles the distribution of costs described in the previous section, in that the largest rate increases would appear in the midwestern and Appalachian states, while western utilities would raise rates only slightly. The tax-only policy, Option IV-1, would raise average electricity rates by 2.9 mills per kilowatt hour (4.7 percent) in 1995 compared with the base case. This is nearly twice the average rate increase under Option II-2A, primarily because of the continuing tax on remaining emissions. This burden, while substantial, would fall mostly on states already predicted to enjoy lower than average 1995 base case rates. In the case of the 11.4 mill per kwh rate hike in West Virginia (a 42 percent increase from the base case), the rates would still remain among the lowest in the nation, and even fall below their predicted levels under Option II-2A. Thus, the tax policy tends to lessen--but not necessarily eliminate--the unit cost advantage enjoyed by states which have historically burned cheap local coal to generate electricity.

Predicted 1995 electricity rates for Option IV-2 and IV-3 show that subsidies for scrubbers would effectively limit rate increases in several regions. The average electricity price with a 90 percent capital subsidy would rise by 2.3 mills per kwh under Option IV-2, and only 1.8 mills per kwh with the additional 50 percent O&M subsidy of Option IV-3. Under the latter policy, several states would experience smaller rate increases than under Option II-2A, notably Illinois, Missouri, Ohio, Pennsylvania, Tennessee, and West Virginia. The subsidy for scrubbers, although not effective at this level for reducing overall emissions, does represent an effective way to ease the burden to electricity consumers in regions most adversely affected by the emission tax.

Revenues and Outlays with Emission Taxes and Subsidies

If the $600 per ton fee had been assessed on 1985 emissions--assuming that utilities could not significantly alter their fuel mix, transmission decisions, or scrubber use in the short run--tax revenues would have been nearly $9.1 billion in the first year. The stream of revenues in succeeding years would then depend on the speed with which utilities could lower their emissions to reduce tax payments. The initial reductions under all policies would probably occur as utilities increase generation from units with lower emission rates and begin to purchase coal with less sulfur content. By 1995 annual revenues from the simple emission tax would be $4.9 billion, which represents a level of taxable emissions attained almost completely by fuel switching.

The planning and construction time of additional scrubbing units would not allow utilities to use retrofits until the early 1990s. Additional erosion of the tax base because of emission reductions attained through subsidized scrubbing would occur by 1995, which would result in annual tax revenues from Option IV-2 and Option IV-3 of $4.7 billion as of 1995. Table 30 shows the state breakdown of emission tax receipts and trust fund outlays.

Taxing only pre-NSPS sources would provide utilities with a strong incentive to retire these units sooner than they would under current policy, particularly if they choose not to install scrubbers. While an analysis of this effect lies beyond the scope of this study, this could lower revenues soon after the turn of the century. Eventually, all taxed sources would be replaced with newer plants that are subject to the federal NSPS, which are not taxed.

Annual Outlays. Annual outlays for scrubber subsidies under Option IV-2 would be $462 million by 1995. Pennsylvania and Illinois would receive 75 percent of this total ($347 million). This implies that Option IV-2 would run annual surpluses of $4.3 billion by 1995. With an additional 50 percent O&M subsidy, utilities would receive total subsidies of $1.3 billion per year by 1995, leaving Option IV-3 with annual surpluses of $3.3 billion. Under Option IV-3, Illinois and Pennsylvania utilities would receive an additional $168 million per year over Option IV-2. Together with utilities in Missouri and Ohio, they would receive $725 million annually, or over half of all subsidies given nationwide.

Other Uses for Tax Revenues. Since annual revenues from the emission tax would always exceed any scrubbing subsides granted, substantial amounts of revenues would accumulate under each tax policy. A trust fund based on Option IV-3 beginning in 1986, for example, could accumulate almost $80 billion by 1995, and reach $250 billion by 2015. Options IV-1 and IV-2 would collect even more. The potential for such large balances suggests that, if an emission tax scheme was enacted, collected funds would not be allowed to lie in a trust fund simply to collect interest, but might be diverted to other uses. Such uses might include adding to general revenues

TABLE 29. ELECTRICITY PRICES IN 1995 UNDER THREE EMISSION TAX OPTIONS COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Alabama, Mississippi	46.6	45.6	50.1	49.7	48.4	9.8	9.1	6.2
Arizona	55.9	55.9	57.3	57.3	57.2	2.6	2.6	2.3
Arkansas, Oklahoma, Louisiana	77.5	78.8	78.8	78.9	78.9	0.1	0.2	0.2
California	78.3	78.3	78.3	78.3	78.3	0.0	0.0	-0.1
Carolinas, North and South	50.3	51.2	54.2	53.8	53.7	5.9	5.2	5.0
Colorado	57.4	57.7	58.8	58.6	58.5	1.9	1.5	1.4
Dakotas, North and South	32.1	30.4	31.6	31.6	30.1	3.9	3.9	-1.0
Florida	75.2	75.9	78.7	78.4	78.4	3.7	3.3	3.3
Georgia	54.2	56.2	58.7	58.3	56.0	4.6	3.9	-0.2
Idaho	43.0	43.5	44.7	44.7	44.5	2.8	2.8	2.4
Illinois	59.3	62.4	64.1	62.1	61.7	2.7	-0.4	-1.0
Indiana	53.9	55.5	60.3	58.8	58.9	8.5	6.0	6.0
Iowa	59.3	62.3	65.3	65.4	65.1	4.8	5.0	4.5
Kansas, Nebraska	57.9	58.4	60.5	60.6	60.4	3.5	3.6	3.5
Kentucky	55.0	55.0	59.2	58.6	58.9	7.6	6.6	7.1
Maine, Vermont, New Hampshire	80.9	80.3	81.3	80.7	80.7	1.3	0.4	0.6
Maryland, Delaware	66.4	69.2	70.3	69.9	67.0	1.5	1.0	-3.1
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.4	83.5	83.6	-0.3	-1.4	-1.3

(Continued)

TABLE 29. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Michigan	57.7	58.2	60.7	60.2	60.1	4.3	3.5	3.3
Minnesota	54.2	55.1	57.8	57.8	57.9	4.9	4.9	5.0
Missouri	59.6	63.8	67.1	66.2	63.6	5.3	3.9	-0.3
Montana	41.1	41.0	41.7	41.7	41.8	1.8	1.8	2.1
Nevada	48.8	47.0	49.9	50.0	50.0	6.0	6.2	6.3
New Mexico	68.2	67.2	69.0	64.8	64.4	2.6	-3.5	-4.1
New York (Downstate), New Jersey	99.3	100.3	101.9	100.9	100.9	1.6	0.6	0.6
New York (Upstate)	53.1	55.3	55.2	55.3	54.8	-0.2	-0.1	-0.9
Ohio	57.8	62.2	62.9	62.6	60.8	1.1	0.6	-2.3
Pennsylvania	58.2	60.0	63.7	58.4	58.8	6.1	-2.7	-2.0
Tennessee	46.9	50.7	49.5	48.2	46.8	-2.4	-4.8	-7.7
Texas	79.4	79.4	80.5	80.5	79.2	1.3	1.3	-0.3
Utah	39.0	44.7	41.2	41.2	41.2	-7.7	-7.7	-7.7
Virginia, District of Columbia	58.7	60.7	61.8	61.5	61.7	1.8	1.4	1.5
Washington, Oregon	35.4	35.4	35.2	35.2	35.3	-0.7	-0.7	-0.5
West Virginia	27.2	46.7	38.6	38.6	40.3	-17.3	-17.3	-13.6
Wisconsin	52.7	57.9	59.2	58.7	58.0	2.3	1.4	0.3
Wyoming	43.0	43.5	44.7	44.7	44.5	2.8	2.8	2.4
U.S. Average	62.0	63.5	64.9	64.3	63.8	2.2	1.2	0.4

SOURCE: Congressional Budget Office.

TABLE 30. 1995 REVENUES AND SUBSIDIES UNDER THREE EMISSION TAX OPTIONS (In millions of 1985 dollars)

State	1986 Tax Revenues [a]	Revenues Option IV-1	Revenues Option IV-2	Revenues Option IV-3	Subsidies Option IV-2	Subsidies Option IV-3
Alabama, Mississippi	352	240	232	214	0	108
Arizona	60	48	48	58	0	0
Arkansas, Oklahoma, Louisiana	78	62	62	62	0	0
California	2	6	6	6	0	0
Carolinas, North and South	433	268	262	257	0	0
Colorado	39	35	35	35	0	2
Dakotas, North and South	3	20	20	15	0	10
Florida	246	241	240	240	0	0
Georgia	439	163	163	164	0	13
Idaho	0	0	0	0	0	0
Illinois	643	283	284	285	160	234
Indiana	698	261	256	255	3	62
Iowa	153	68	61	63	0	0
Kansas, Nebraska	76	66	66	65	0	0
Kentucky	400	197	170	175	1	1
Maine, Vermont, New Hampshire	65	23	21	21	3	5
Maryland, Delaware	169	116	116	116	0	91
Massachusetts, Connecticut, Rhode Island	177	184	184	184	14	21

(Continued)

TABLE 30. (Continued)

State	1986 Tax Revenues [a]	Revenues Option IV-1	Revenues Option IV-2	Revenues Option IV-3	Subsidies Option IV-2	Subsidies Option IV-3
Michigan	313	205	197	197	1	4
Minnesota	105	71	63	62	0	0
Missouri	668	132	140	156	20	112
Montana	12	10	10	10	0	0
Nevada	31	23	24	24	0	0
New Mexico	22	21	21	21	0	0
New York (Downstate), New Jersey	161	150	152	152	23	35
New York (Upstate)	189	102	105	105	0	18
Ohio	1,141	437	414	415	9	98
Pennsylvania	807	455	344	343	187	281
Tennessee	406	202	199	199	14	86
Texas	186	195	195	171	0	71
Utah	19	20	19	19	0	0
Virginia, District of Columbia	58	98	98	99	0	0
Washington, Oregon	22	37	37	37	0	3
West Virginia	581	255	255	261	27	56
Wisconsin	345	142	142	141	0	33
Wyoming	31	37	37	36	0	0
U.S. Total	9,129	4,873	4,679	4,665	462	1,343

SOURCE: Congressional Budget Office.

a. Calculated by using 1985 emissions and \$600 per ton SO_2 tax.

to reduce deficits, reducing other taxes, or eventually returning the money to the states based on their contributions.

To the extent that the economy benefits from emission reductions, emission taxes can represent an economically efficient method of collecting general revenues--a crucial concern in this era of high budget deficits. 9/ Economists typically voice concern about the potential distortions caused by current methods of taxing economic activity; taxes levied on income earned from labor or investment may reduce the incentive to work or save. Individuals or corporations respond to taxation by avoiding or reducing economic activity that is taxed. Under an emission tax policy, these same incentives would promote a valuable response--the reduction of pollution. Collected tax revenues could be used to offset other, less beneficial taxes, while tax revenues lost through successful abatement efforts would represent a benefit to society if the tax rate approximates to some degree the level of damage caused by additional emissions.

Alternatively, a rebate scheme could be devised, through which states would receive revenues based on their net contributions. These revenues could be used to reduce other state taxes, or they could be redistributed to those electricity consumers who had suffered the highest rate increases. This would reduce the burden on the midwestern and Appalachian states, but still encourage emission reductions. The states could also target some of these revenues for relief programs for unemployed miners. Finally, to ease the initial burden to utilities and consumers, the Congress might consider phasing in the tax or delaying its commencement for several years. In the early years of an emission tax (that is, 1986-1990 in this analysis), utilities would only gradually reduce emissions. The speed of emission reductions might not be greatly affected by taxing emissions at less than the full rate initially. The threat of a future emission tax at a punitive (reduction-forcing) level must remain credible, however, for utilities to develop abatement plans in the interim.

COAL MARKETS AND MINING EMPLOYMENT

Emission tax policies would affect the distribution of coal production and employment. Regions that produce primarily high-sulfur coal would face lower coal production and employment under an emission tax policy to con-

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9. For a discussion and estimates of the benefits of substituting effluent tax revenues for some corporate and personal income tax revenues, see David Terkla, "The Efficiency Value of Effluent Tax Revenues," *Journal of Environmental Economics and Management*, vol. 11, no. 2 (June 1984).

trol acid rain than they would if current policy was continued. Subsidies for scrubbers could only partially mitigate this effect. Tables 31 and 32 compare 1995 coal production and employment under the three tax policies with base case projections and Option II-2A.

Coal-Market Shifts Without Subsidies. The imposition of a simple emission tax without subsidies (Option IV-1) would shift coal production from the midwestern high-sulfur coal mines to eastern low-sulfur coal sources (large-

TABLE 31. 1995 COAL SHIPMENTS UNDER THREE EMISSION TAX OPTIONS COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of tons)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Alabama	23.8	22.1	26.9	23.5	23.8	4.8	1.4	1.7
Arizona	14.2	13.9	13.9	13.9	13.8	0.0	0.0	-0.2
Colorado	19.1	23.5	21.9	21.6	20.8	-1.7	-2.0	-2.7
Illinois	56.4	37.6	39.5	47.4	51.0	2.0	9.8	13.4
Indiana	29.2	19.7	23.8	24.5	28.2	4.1	4.8	8.4
Iowa	1.5	0.5	0.5	0.5	1.3	0.0	0.0	0.8
Kansas	2.5	0.4	0.4	1.4	1.4	0.0	1.0	1.0
Kentucky	208.9	195.9	202.5	198.6	197.7	6.5	2.6	1.8
Maryland	2.5	1.5	1.5	1.8	2.2	0.0	0.3	0.7
Missouri	8.1	5.3	5.3	6.5	7.1	0.0	1.2	1.8
Montana	34.0	26.0	26.8	31.1	32.4	0.9	5.1	6.4
New Mexico	31.9	31.9	31.9	31.9	31.7	0.0	0.0	-0.1
North Dakota	22.7	22.7	22.7	22.7	22.7	0.0	0.0	0.0
Ohio	24.3	4.0	4.0	7.9	16.1	0.0	3.9	12.1
Oklahoma	7.7	7.0	7.2	7.2	7.7	0.1	0.1	0.7
Pennsylvania	82.3	56.3	63.9	68.8	69.7	7.6	12.5	13.3
Tennessee	5.3	4.9	6.9	4.9	6.8	2.0	0.0	1.8
Texas	109.4	108.8	108.6	108.6	110.1	-0.2	-0.2	1.3
Utah	31.6	32.8	31.1	31.1	31.2	-1.7	-1.7	-1.6
Virginia	50.6	56.0	59.4	55.4	56.9	3.5	-0.5	0.9
Washington	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
West Virginia	232.2	274.6	276.1	269.9	254.9	1.5	-4.7	-19.6
Wyoming	130.5	191.2	156.5	154.2	147.3	-34.7	-36.9	-43.9
U.S. Total	1,128.9	1,137.1	1,131.7	1,133.7	1,135.2	-5.4	-3.4	-1.9

SOURCE: Congressional Budget Office.

TABLE 32. DIRECT COAL MINING EMPLOYMENT IN 1995 UNDER THREE EMISSION TAX OPTIONS COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In miner-years)

State	Base Case	10 Million Ton Rollback Option II-2A	Option IV-1	Option IV-2	Option IV-3	Difference from 10 Million Ton Rollback (Option II-2A) Option IV-1	Option IV-2	Option IV-3
Alabama	8,124	7,543	9,182	8,018	8,128	1,640	476	585
Arizona	1,177	1,155	1,155	1,155	1,141	0	0	-13
Colorado	3,288	4,062	3,773	3,725	3,590	-289	-337	-472
Illinois	14,733	9,823	10,333	12,392	13,325	510	2,569	3,502
Indiana	5,342	3,611	4,355	4,487	5,149	744	876	1,538
Iowa	344	110	110	110	305	0	0	195
Kansas	753	129	129	441	441	0	311	311
Kentucky	63,014	59,098	61,061	59,894	59,641	1,964	796	543
Maryland	695	417	417	504	616	0	86	199
Missouri	1,948	1,276	1,277	1,554	1,705	1	277	429
Montana	1,251	955	987	1,142	1,192	32	187	237
New Mexico	2,846	2,846	2,846	2,846	2,835	0	0	-11
North Dakota	1,375	1,374	1,374	1,374	1,375	0	0	1
Ohio	7,136	1,183	1,183	2,321	4,740	0	1,138	3,557
Oklahoma	2,344	2,146	2,190	2,190	2,347	44	44	200
Pennsylvania	29,299	20,042	22,749	24,482	24,789	2,707	4,411	4,747
Tennessee	2,010	1,859	2,614	1,859	2,550	755	-1	691
Texas	6,890	6,854	6,841	6,841	6,939	-13	-13	84
Utah	7,978	8,282	7,852	7,852	7,882	-430	-430	-399
Virginia	19,399	21,375	22,695	21,168	21,714	1,321	-207	-339
Washington	48	48	48	48	48	0	0	0
West Virginia	89,473	105,792	106,371	103,982	98,222	579	-1,810	-7,570
Wyoming	5,768	8,451	6,917	6,818	6,511	-1,534	-1,633	-1,940
U.S. Total	275,172	268,431	276,461	275,202	275,183	8,030	6,771	6,752

SOURCE: Congressional Budget Office.

ly in West Virginia) and, to a less extent, to western low-sulfur coal mines (mostly in Wyoming). Predicted 1995 coal production in Illinois, Indiana, Ohio, and Pennsylvania could decline by 61 million tons compared with expectations under current policy. Such a production shift would reduce projected mining employment in this region by nearly 18,000 jobs in 1995, or nearly 17,300 jobs less than current levels. 10/ This shift would still be

10. See Table 12 in Chapter II for 1985 employment figures.

about 14 million tons (representing 4,000 jobs) less than the regional decline expected under Option II-2A, although its magnitude could still warrant concern. Since the emission tax would generate nearly $4.9 billion annually by 1995, however, any funding devoted explicitly to employment assistance would still comprise only a small fraction of the annual surplus.

Coal Markets with Scrubber Subsidies. Subsidies for scrubbers would retard, but not eliminate, the shift away from high-sulfur coal mined in Illinois, Indiana, Ohio, and Pennsylvania. Compared with predicted employment for Options II-2A, II-2B, and II-2C, the subsidies combined with an emission tax would provide greater production and employment in these four states.[11] Compared with Option IV-1, Option IV-2 would increase 1995 production in the region by over 17 million tons, and help preserve almost 5,100 mining jobs. The addition of the 50 percent O&M subsidy would basically double these benefits, as 1995 production would be nearly 34 million tons higher than under Option IV-1. This additional production would require nearly 9,400 miners more than Option IV-1.

Even with scrubber subsidies, some states would lose mining employment compared with 1985 levels. Under the most heavily subsidized policy, Option IV-3, the four states that lose the most compared with 1985 employment--Alabama, Illinois, Indiana, and Ohio--would lose only 10,500 jobs. After taking into account likely productivity gains and normal attrition, an assistance program aimed at currently employed miners could be relatively inexpensive, especially when compared with annual surpluses from the emission tax.

11. Options IV-2 and IV-3, however, would yield slightly higher 1995 emissions (9.6 million tons) than the 10 million ton rollback options (9.2 million tons).

CHAPTER V

LOWERING SULFUR DIOXIDE LEVELS WITH TAX ON SULFUR CONTENT IN COAL AND SUBSIDIES FOR SCRUBBING

The direct emission tax discussed in Chapter IV represents one example of using economic incentives to control pollution. This chapter examines a related approach in which regulators would impose a sales tax on coal based on its sulfur content, and grant subsidies for utilities that remove sulfur dioxide from the flue gas with scrubbers. Two policies are considered, differing only in the basis for the tax. In the first option, the tax rate would be determined by the sulfur content **per ton**, while in the second case, the tax per ton would be calculated using the sulfur content **per British thermal unit**, a measure of energy content. Because of the variations in both energy and sulfur contents of U.S. coals, tax rates that elicit similar emission reductions could lead to different program costs, electricity rates, coal-market patterns, and net tax revenues.

The first policy would place a $0.50 tax on each pound of sulfur contained in a ton of coal (for sulfur content in excess of 10 pounds per ton), and would provide both a 90 percent capital subsidy for retrofit scrubbers and a $0.50 subsidy for each pound of sulfur removed from the flue gas. Representative Aspin introduced this proposal in the 98th Congress as H.R. 4483, and it is referred to here as Option V-1. The second policy, Option V-2, would grant identical scrubber subsidies, but would levy a tax per ton equal to $10 for every pound of sulfur per million Btus (for sulfur content in excess of 0.4 pounds per million Btus).

Both policies would lower sulfur dioxide emissions in 1995 to about 10.3 million tons from the projected level of 18.5 million tons under current policy. The program cost of Option V-1 over the 1986 through 2015 period would total $32.1 billion, and would cost $289 for each ton of SO_2 reduced by 1995. The corresponding costs of Option V-2 would be $37.4 billion over the period, or $339 per ton of SO_2 abated. (All dollar amounts are in discounted 1985 dollars.) Both policies appear to be relatively cost-effective, considering their level of emission reductions and their high degree of retrofit scrubber use.

Using the Option V-1 formula, the average tax rate in 1995 would be $7.00 per ton of coal. Assessing the tax on sulfur content per ton favors the low-sulfur, low-heat content of western coals over high-sulfur coals having high-heat content, such as those found in the Midwest and parts of the East. Coal production in Illinois, Indiana, Kentucky, Ohio, and Pennsylvania would be 62 million tons lower in 1995 than projected annual levels, which would also lower predicted mining employment in these states by 18,400 jobs. (Kentucky is included in this group because of its sensitivity to the various sulfur-tax options.)

The sales tax based on sulfur content per Btu (Option V-2) would alter these results. The average tax collected per ton in 1995 would be $7.48; it is higher than the average under Option V-1 chiefly because a higher rate would be levied on western low-sulfur coal and Texas lignite. The 1995 production shortfall in the five states listed above would be limited to 42.8 million tons, and associated employment would be only 12,600 jobs less than projected under base case conditions.

TAXING THE SULFUR CONTENT OF FUEL: THEORY AND IMPLEMENTATION

Several countries have imposed taxes on material inputs used by industries in processes that produce pollution. Examples include sulfur taxes on oil in Norway and on sulfur in all fossil fuels in the Netherlands, and taxes on chemical feedstocks that constitute the basis for the hazardous waste clean-up effort under "Superfund" in the United States. 1/ While these charges are levied primarily to generate revenues, taxing the constituents of pollution can force input substitutions or output reductions that lower the ultimate level of emissions.

Input taxes designed to reduce emissions are a feasible alternative to direct effluent charges in many cases. When emissions are difficult to detect, monitor, or measure and arise from many distinct sources, then emission fees could become prohibitively costly to assess and collect. This is not the case with coal-fired power plants, however. Yet, if a fairly direct link exists between one (or at most a few) materials and the generation of pollution, and if firms can purchase other substitute resources that will produce less pollution when used, then input taxes still may be effective regulatory instruments. Coal-fired power plants certainly meet these latter criteria. Moreover, because the government can collect an input tax at the point of an existing market transaction--the sale of coal--few additional resources would be required for enforcement.

1. See *Pollution Charges in Practice* (Paris: Organization for Economic Cooperation and Development, 1980) for a description of European experiences with sulfur taxes; and Congressional Budget Office, *Hazardous Waste Management: Recent Changes and Policy Alternatives* (May 1985) for an examination of Superfund.

Neither of the proposals studied in this chapter are pure input tax programs, since they include subsidies for scrubber use. Because coal purchases are routinely assayed for chemical content, setting a tax on sulfur content would be relatively easy. The amount of sulfur scrubbed out of the flue gas would have to be measured or estimated fairly accurately, however, in order to provide the subsidy for emission reduction. Administrators could develop standard formulas to estimate the amount of sulfur removal in plants that use scrubbers. Out of 1,300 coal-fired boilers operating as of December 1984, 125 were equipped with scrubbers (92 new, 33 retrofit). [2] For all other plants, regulators would need only the data contained on fuel receipts, until more scrubbers were retrofitted on existing plants under the scrubber installation subsidy.

These proposals that combine a sulfur tax with a subsidy for sulfur removal resemble deposit and refund systems. When utilities purchase coal subject to the sulfur tax, they pay a fee for the potential sulfur dioxide that might be discharged. For example, a high-emitting midwestern plant could pay about $30 million per year in higher coal prices under Option V-1 and roughly $25 million per year with Option V-2. [3] Utilities that simply emit SO_2 into the atmosphere would forgo this deposit, while power plants that scrub out most of the sulfur before emitting it as SO_2 would receive a refund. Such a system would provide a strong incentive to reduce emissions either by fuel switching or by scrubbing. In contrast, a sulfur tax alone would only encourage fuel switching, since scrubbing is most economical when the price of high-sulfur coal remains low relative to low-sulfur coal--precisely the opposite situation expected under a tax on sulfur content.

THE EFFECTS OF SULFUR TAXES AND SUBSIDIES

The two sulfur tax policies considered in this chapter are shown in Table 33. The taxes levied on coal would begin in 1986 (based on 1985 coal usage) and are assumed to be permanent. The subsidy for sulfur removed with existing scrubbers also would begin in 1986. Capital subsidies for scrubber retrofits would not be required until 1991, because of the planning and construction time required for retrofit scrubbers, and all additional retrofits are assumed

2. Figures are from Department of Energy, Energy Information Administration, *Inventory of Power Plants in the United States* and *Cost and Quality of Fuels for Electric Utility Plants* (both July 1985).

3. This analysis is based on operation of a 500 megawatt plant used for baseload generation (65 percent capacity factor at 10,000 Btu per kwh generated) using a bituminous coal (12,000 Btu per lb.) that emits 5 pounds of SO_2 per million Btu.

TABLE 33. SULFUR AND SUBSIDY OPTIONS

Policy Option	Tax Rate and Exemption	Subsidies
Option V-1 (H.R. 4483)	$0.50 per pound of sulfur contained in each ton of coal, to the extent that sulfur content exceeds 10 pounds per ton.	$0.50 subsidy granted for each pound of sulfur scrubbed out of flue gas, plus a 90 percent capital subsidy for retrofitted scrubbers.
Option V-2	$10 per pound of sulfur contained in a million Btus, to the extent that sulfur content exceeds 0.4 pounds per million Btus. When multiplied by the heat content of the coal (in millions of Btus per ton), this figure gives the tax rate per ton.	$0.50 subsidy granted for each pound of sulfur scrubbed out of flue gas, plus a 90 percent capital subsidy for retrofitted scrubbers.

SOURCE: Congressional Budget Office.

to be completed by 1995. These subsidies are computed as 90 percent of annual capital costs, and continue for the entire financial life (20 years) of the scrubber.

Because the sulfur tax would be levied on all coal sales, some of the cost, revenue, and coal-market effects would depend on nonutility coal purchases (by domestic metallurgical, industrial, and commercial users plus exports). 4/ Currently, nonutility demand accounts for about one-quarter of all coal mined in the United States. In this analysis, the demand for coal is assumed to remain stable regardless of price changes. Even though coal used by nonutilities tends to be low in sulfur content, some of the costs of this program would be shifted to other coal purchasers.

Emissions Under Sulfur Tax and Subsidy Policies

The geographic distribution of emission reductions is quite similar in both options, and remains consistent with the distribution predicted under other

4. In H.R. 4483, export coal (which currently accounts for less than 10 percent of total coal mined in the U.S.) was exempted from the tax. In the National Coal Model, however, this was not possible. Even if the tax were applied to exports, it would not raise their prices significantly, because of the low-sulfur content of export coal.

proposals. The vast majority of SO_2 reductions would occur in the midwestern and Appalachian states, while modest emission growth in the West would remain unaffected. Table 34 displays utility SO_2 emissions in 1995 under each policy, and provides comparisons with the basic 8 million ton and 10 million ton polluter pays reductions reported in Chapter II. The 10.3 million tons of SO_2 expected under each of the sulfur tax policies is equivalent to an 8.9 million ton reduction, as measured from 1980 emission levels from old sources.

Emissions in 1995 from most of the midwestern and Appalachian states would be between those expected under the 8 million ton and 10 million ton rollbacks as specified by the excess emissions formula. Compared with that allocation formula, the two tax policies would limit emissions slightly more in Missouri, Indiana, and Pennsylvania (all of which would yield emission levels close to the 10 million ton reduction program), while exerting less influence on emissions from Illinois (where 1995 emissions would be closer to those predicted under the 8 million ton reduction).

State by state comparisons show only small emission differences between the two sulfur tax policies. This similarity, however, hides the important difference that scrubber utilization would be higher under Option V-2 than under Option V-1. Utilities in Missouri, Ohio, and West Virginia would retrofit over twice as much existing capacity with scrubbers under Option V-2, installing $3.4 billion worth of equipment. While much more local high-sulfur coal would be burned, emissions in these three states would be only 0.12 million tons higher under Option V-2 than under Option V-1.

In states west of the Mississippi (not including Minnesota, Iowa, and Missouri), emissions would continue to rise slightly from current levels under each policy. As discussed in earlier chapters, plants in the West already employ strict control measures, and further reductions would not be economical under either tax program.

The Cost of Sulfur Tax and Subsidy Programs

As discussed in Chapter IV, comparing the costs of tax incentive policies with the costs of policies that use a compliance deadline requires care, since the timing of costs incurred, as well as emission reductions obtained, may differ among approaches. In particular, incentive schemes would probably encourage utilities to incur abatement costs earlier and reduce emissions sooner than would a rollback policy based on a 10-year compliance deadline. Under these circumstances, the cost-effectiveness numbers yield more fruitful comparisons than the discounted program cost figures.

TABLE 34. EMISSIONS UNDER TWO SULFUR TAX OPTIONS COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS, BY STATE (In thousands of tons of SO_2 emitted in 1995)

State	Base Case	8 Million Ton Rollback Option II-1A	10 Million Ton Rollback Option II-2A	Option V-1	Option V-2
Alabama, Mississippi	704	489	414	469	468
Arizona	122	117	106	118	122
Arkansas, Oklahoma, Louisiana	336	304	302	322	315
California	25	25	25	25	25
Carolinas, North and South	1,063	606	577	564	563
Colorado	92	94	94	90	97
Dakotas, North and South	105	105	105	103	99
Florida	772	605	566	605	584
Georgia	635	407	352	404	380
Idaho	0	0	0	0	0
Illinois	1,142	566	408	570	518
Indiana	1,433	799	553	617	598
Iowa	326	192	167	159	177
Kansas, Nebraska	174	167	163	153	156
Kentucky	796	512	466	463	496
Maine, Vermont, New Hampshire	64	56	44	36	35
Maryland, Delaware	371	215	189	224	224
Massachusetts, Connecticut, Rhode Island	305	241	219	306	306

(Continued)

TABLE 34. (Continued)

State	Base Case	8 Million Ton Rollback Option II-1A	10 Million Ton Rollback Option II-2A	Option V-1	Option V-2
Michigan	598	423	374	355	367
Minnesota	230	159	146	129	132
Missouri	1,257	482	293	309	329
Montana	71	68	68	68	68
Nevada	90	80	80	74	82
New Mexico	62	62	62	62	62
New York (Downstate), New Jersey	270	247	245	260	260
New York (Upstate)	343	193	141	214	219
Ohio	2,017	963	629	772	837
Pennsylvania	1,439	839	578	602	592
Tennessee	761	421	281	356	367
Texas	586	569	567	586	575
Utah	87	61	61	73	86
Virginia, District of Columbia	213	180	175	220	199
Washington, Oregon	111	108	104	104	99
West Virginia	1,042	511	421	487	504
Wisconsin	746	272	199	288	298
Wyoming	69	70	70	70	66
U.S. Total	18,455	11,208	9,241	10,256	10,305

SOURCE: Congressional Budget Office.

In terms of discounted program costs, Option V-1 would cost \$32.1 billion, while the same figure for Option V-2 would be \$37.4 billion (see Table 35). Compared with the 10 million ton polluter pays program (Option II-2A) at \$34.5 billion, these numbers seem high, given the ultimate emission reductions obtained. When the earlier reductions expected under the tax policies are taken into account by using the measure of cost-effectiveness developed in previous chapters, however, these policies appear much better: Option V-1 would cost \$289 per ton of SO_2 reduced while Option V-2 would cost \$339 per ton abated. This compares favorably with Option II-2A, at \$360 per ton of SO_2 abated, but less so with the 8 million ton polluter pays program (Option II-1A), costing \$270 per ton abated. 5/

Comparing these cost-effectiveness figures with the generation tax and subsidy options presented in Chapter III shows that the sulfur tax and subsidy policies of this chapter represent a relatively efficient way to encourage emission reductions while promoting scrubber use. The most heavily subsidized 8 million ton reduction using a generation tax (Option III-1B) would cost \$389 per ton of SO_2 removed, prompting scrubber use similar to Options V-1 and V-2, while allowing nearly one million tons of additional annual SO_2 emissions. A similarly subsidized 10 million ton reduction with a generation tax (Option III-2B) would cost as much as \$431 per ton of SO_2 abated.

Cost Burden to Other Industries of a Sulfur Tax. Not included in the estimates of program costs is the burden of a sulfur tax on coal-using industries other than utilities. Demand for coal from other sectors--industrial, commercial, metallurgical, and export--is represented in the National Coal Model as predetermined regional energy requirements, and is assumed to remain constant regardless of price increases. Given this assumption, nonutility coal expenditures in 1995 would rise by \$1.82 billion under Option V-1 and by \$1.65 billion under Option V-2. About half of this additional expense would be accounted for by tax revenues collected in 1995 on these purchases--\$910 million under Option V-1, and \$850 million under Option V-2. The remainder of the additional expenditures would arise from higher prices for low-sulfur coal resulting from the increased utility demand.

These expenditures represent an extremely high estimate of costs that would be shifted to the nonutility sector, since nonutility users would substitute cheaper fuels when economical and feasible. 6/ The Congress could, of

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5. See the glossary at the end of this report for definitions of all options.

6. Compared with the base case calculations of nonutility coal purchases in 1995, policies examined earlier in this report would raise expenditures in the nonutility sector by between \$200 million and \$550 million. Because the actual response of nonutility coal users is impossible to estimate with the National Coal Model, and because the additional costs are likely to be smaller than their expenditures suggest, these figures also were not included as program costs in earlier options.

course, choose to exempt nonutility coal purchases, thus reducing the tax burden to other coal users. Some additional costs would remain, however, as the overall demand for low-sulfur coal--and thus its price--would rise in response to the tax policy.

The Effect on Annual Utility Costs. Electric utilities nationwide would pay an additional $2.7 billion annually by 1995 if the Option V-1 tax were levied on coal purchases, and slightly more--$2.9 billion--if the Option V-2 formula were used instead. Despite the similarity in overall net utility costs, however, the two tax programs exhibit important regional differences.

As Table 36 shows, utilities in every state east of the Mississippi would incur less cost under Option V-2 than under Option V-1, while the utilities west of the river (especially Texas) would pay more. In the key states of Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee, and West Virginia, utilities would spend a total of $1.7 billion more in 1995 with Op-

TABLE 35. TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF TWO SULFUR TAX OPTIONS COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS

	Polluter Pays Rollbacks		Sulfur Tax Proposals	
	8 Million Ton Rollback Option II-1A	10 Million Ton Rollback Option II-2A	Option V-1	Option V-2
Total Program Costs (In billions of discounted 1985 dollars) a/	20.1	34.5	32.1	37.4
Cost-effectiveness (In discounted 1985 dollars per ton of SO_2 reduced) b/	270	360	289	339

SOURCE: Congressional Budget Office.

a. Reflects net present value of sum of program costs incurred from 1986 through 2015, discounted to 1985 dollars. These costs consist of real annual utility expenditures in excess of current policy, which is equivalent to net utility cost, plus subsidies, minus taxes paid. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reductions from current policy measured over the 1986-2015 period.

TABLE 36. ANNUAL COST OF ELECTRICITY GENERATION IN 1995 UNDER SULFUR TAX OPTIONS COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS, BY STATE (In millions of 1985 dollars)

State	Base Case	Polluter Pays Options: 8 Million Ton Rollback Option II-1A	Polluter Pays Options: 10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Alabama, Mississippi	4,224	4,307	4,364	4,402	4,370
Arizona	1,944	1,930	1,943	1,921	1,932
Arkansas, Oklahoma, Louisiana	9,591	9,698	9,723	9,615	9,615
California	10,565	10,722	10,822	10,527	10,541
Carolinas, North and South	4,759	4,886	4,895	5,009	4,972
Colorado	1,093	1,097	1,100	1,033	1,085
Dakotas, North and South	567	565	565	580	604
Florida	6,127	6,202	6,198	6,297	6,239
Georgia	2,555	2,618	2,622	2,697	2,670
Idaho	221	221	221	221	221
Illinois	4,189	4,312	4,432	4,356	4,343
Indiana	3,095	3,202	3,233	3,368	3,332
Iowa	1,230	1,288	1,327	1,252	1,282
Kansas, Nebraska	1,854	1,860	1,862	1,884	1,882
Kentucky	3,103	3,170	3,499	3,250	3,213
Maine, Vermont, New Hampshire	1,123	1,119	1,123	1,130	1,128
Maryland, Delaware	1,885	1,853	1,654	1,931	1,915
Massachusetts, Connecticut, Rhode Island	3,513	3,633	3,678	3,532	3,523

(Continued)

TABLE 36. (Continued)

State	Base Case	Polluter Pays Options: 8 Million Ton Rollback Option II-1A	Polluter Pays Options: 10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Michigan	2,817	2,874	2,944	2,966	2,943
Minnesota	1,186	1,184	1,228	1,193	1,214
Missouri	2,024	2,137	2,206	2,220	2,228
Montana	676	675	675	671	674
Nevada	1,096	1,122	1,122	1,115	1,109
New Mexico	1,158	1,138	1,144	1,153	1,110
New York (Downstate), New Jersey	4,878	4,902	5,200	4,893	4,884
New York (Upstate)	2,395	2,443	2,236	2,449	2,434
Ohio	4,239	4,397	4,271	4,628	4,567
Pennsylvania	5,512	5,711	6,056	5,774	5,712
Tennessee	2,078	2,118	2,028	2,262	2,260
Texas	15,852	15,834	15,844	15,563	16,100
Utah	1,345	1,367	1,368	1,342	1,331
Virginia, District of Columbia	1,884	1,923	1,926	1,938	1,924
Washington, Oregon	4,219	4,147	4,068	4,213	4,236
West Virginia	1,784	1,936	2,278	2,035	1,994
Wisconsin	1,572	1,671	1,734	1,728	1,713
Wyoming	1,026	1,034	1,039	967	997
U.S. Total	117,380	119,298	120,630	120,115	120,296

SOURCE: Congressional Budget Office.

tion V-1, but only $1.4 billion more with Option V-2. This difference stems partly from greater use of scrubber subsidies in the latter case (primarily in Ohio and West Virginia), but also from the lower tax rate applied to the high-sulfur, high-energy content coal mined and mostly burned in the midwestern and Appalachian states.

Three states bordering the Mississippi River on the west--Minnesota, Iowa, and Missouri--could experience higher costs under Option V-2 than under Option V-1. The higher tax rate on Wyoming and North Dakota low-sulfur coal explains higher costs under Option V-2 in Iowa and Minnesota. Utilities in Missouri would install more scrubber capacity in order to burn high-sulfur coal from the Midwest (which has high-energy content) under Option V-2 than under Option V-1. While this would raise costs, it would, nevertheless, remain cheaper than burning low-sulfur, low-energy content western coal subjected to Option V-2 tax rates.

In several states west of the Mississippi, utility costs would actually decrease under both tax programs; in most of these cases, Option V-1 would lower costs more than Option V-2. This would occur because the tax rates applied to western coal would be very low (at times zero), while the $0.50 reward for each pound of sulfur removed by scrubbing would still be granted. A special case is Texas, described below.

Utility Costs in Texas and Tax Rates on Lignite Coal. The most dramatic difference in utility costs between Option V-1 and Option V-2 would occur in Texas, because of the predominance of lignite coal mined and burned there. Texas lignite coal is a medium-sulfur coal (emitting an average of 3 pounds of SO_2 per million Btus burned) of exceptionally low-energy content. The 1995 tax per ton under Option V-1 would average $5.17, while those rates would more than double--to an average of $10.74--if Option V-2 rates were levied instead.

Under Option V-1, the annual cost of generating electricity in Texas in 1995 would decrease by about $290 million dollars compared with current policy. Although $572 million in tax revenues would be collected in 1995 on lignite coal burned by Texas utilities, it would be more than offset by the $821 million granted in payments for sulfur removal in plants that employ scrubbers. In contrast, the imposition of the tax embodied in Option V-2 would raise revenues from Texas lignite mined and burned in Texas to $990 million per year in 1995, while increasing subsidy levels only to about $900 million. After taking into account additional bituminous coal shipments from other states, as well as the cost of scrubbers required to burn this coal in new plants, utilities in Texas would spend about $250 million more in 1995 under Option V-2 than predicted under the base case.

Electricity Rates Under a Sulfur Tax and Subsidy Program

Average electricity rates nationwide would be about 1 mill per kilowatt hour higher in 1995 (1.6 percent) under both of the sulfur tax policies examined in this chapter. Thus, the policies would raise 1995 electricity rates slightly higher than the 0.8 mill per kilowatt hour rise expected under Option II-1A, but would remain less than the 1.5 mill per kwh hike predicted with Option II-2A. The regional price changes, however, display substantial variation, as shown in Table 37.

Most of the rate increases in the midwest (east of the Mississippi) and Appalachian states lie in the 3 percent to 6 percent range under both options. In every case, 1995 rates in these regions would rise less under Option V-2 than under Option V-1, which is consistent with the utility cost results described in the previous section. 7/ The difference between prices charged under Option V-1 and those under Option V-2 in the East and Midwest would be about 0.5 mills per kwh in most cases. In contrast, 1995 rates in Missouri would rise by 5.4 mills per kwh (9.1 percent) in the Option V-1 case, and by 7.6 mills per kwh (12.8 percent) with Option V-2. These represent the largest increases expected under either policy.

With either option, a few western states would experience modest electricity rate increases, while others could expect significant decreases. States in which predicted 1995 electricity prices under the tax policies would be lower than base case projections tend to be those which burn primarily low-sulfur coal in NSPS plants with scrubbers. Since these plants would receive subsidies for sulfur removal that would have occurred anyway, rates would be lower, assuming that state commissions would pass the cost savings through to consumers.

Government Revenues and Outlays with Sulfur Taxes and Subsidies

Revenues and Outlays in 1986. Both tax policies would generate enough revenues to cover all subsidy obligations. Table 38 shows the tax rates and

7. One striking exception to the pattern of moderate rate increase would occur in West Virginia, where generation costs would rise between 12 percent and 14 percent under the sulfur tax policies (see Table 36), but where electricity rates are projected to decline by about 30 percent. This spurious result arose from the way the algorithm used accounts for interregional sales, which are priced at the avoided cost of the importing region. Since utilities in West Virginia produce power very cheaply with local coal, and are projected to export over half of their generation in 1995 to adjacent states, the revenues collected from out-of-state sales would rise more than generation costs rise--thus reducing dramatically the price charged to West Virginia consumers. In reality, state commissions would probably set the interregional price somewhere in between the generation cost and the avoided cost, thereby limiting this rate reduction.

TABLE 37. 1995 ELECTRICITY PRICES UNDER SULFUR TAX POLICIES COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case	Polluter Pays Options: 8 Million Ton Rollback Option II-1A	Polluter Pays Options: 10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Alabama, Mississippi	46.6	46.9	45.6	48.2	47.9
Arizona	55.9	55.5	55.9	55.4	55.7
Arkansas, Oklahoma, Louisiana	77.5	78.5	78.8	77.8	77.8
California	78.3	78.3	78.3	78.1	78.2
Carolinas, North and South	50.3	51.2	51.2	52.3	52.0
Colorado	57.4	57.6	57.7	56.7	56.9
Dakotas, North and South	32.1	31.4	30.4	32.3	33.3
Florida	75.2	76.0	75.9	76.9	76.5
Georgia	54.2	56.1	56.2	56.7	54.9
Idaho	43.0	43.3	43.5	40.9	42.0
Illinois	59.3	60.8	62.4	61.8	61.0
Indiana	53.9	55.0	55.5	57.0	56.4
Iowa	59.3	61.1	62.3	60.8	61.5
Kansas, Nebraska	57.9	58.1	58.4	58.0	58.4
Kentucky	55.0	55.9	55.0	57.1	56.6
Maine, Vermont, New Hampshire	80.9	80.4	80.3	80.9	80.8
Maryland, Delaware	66.4	67.6	69.2	68.1	67.6
Massachusetts, Connecticut, Rhode Island	80.6	83.0	84.7	81.0	80.8

(Continued)

TABLE 37. (Continued)

State	Base Case	Polluter Pays Options: 8 Million Ton Rollback Option II-1A	Polluter Pays Options: 10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Michigan	57.7	58.4	58.2	58.9	58.7
Minnesota	54.2	54.4	55.1	54.7	55.6
Missouri	59.6	62.3	63.8	65.0	67.2
Montana	41.1	41.0	41.0	40.7	40.9
Nevada	48.8	47.1	47.0	46.2	45.2
New Mexico	68.2	66.9	67.2	63.6	60.2
New York (Downstate), New Jersey	99.3	100.0	100.3	99.5	99.3
New York (Upstate)	53.1	53.7	55.3	54.3	54.0
Ohio	57.8	59.8	62.2	61.6	60.5
Pennsylvania	58.2	59.3	60.0	60.9	60.3
Tennessee	46.9	47.3	50.7	49.0	48.6
Texas	79.4	79.4	79.4	78.6	80.5
Utah	39.0	44.7	44.7	38.7	38.0
Virginia, District of Columbia	58.7	60.0	60.7	60.3	59.9
Washington, Oregon	35.4	35.3	35.4	35.2	35.3
West Virginia	27.2	26.8	46.7	19.2	18.5
Wisconsin	52.7	55.1	57.9	57.0	56.2
Wyoming	43.0	43.3	43.5	40.9	42.0
U.S. Average	62.0	62.8	63.5	63.0	63.0

SOURCE: Congressional Budget Office.

TABLE 38. TAX REVENUES AND AVERAGE TAX RATES UNDER TWO SULFUR TAX OPTIONS, BY STATE (Revenues in millions of 1985 dollars; rates in 1985 dollars per ton of coal)

State	Option V-1				Option V-2			
	1986 Revenues	1986 Tax Rate	1995 Revenues	1995 Tax Rate	1986 Revenues	1986 Tax Rate	1995 Revenues	1995 Tax Rate
Alabama	252	12.50	232	9.12	210	10.39	221	7.91
Arizona	21	1.51	21	1.51	28	2.00	28	2.00
Colorado	31	1.65	31	1.53	36	1.89	51	2.40
Illinois	1,451	24.12	1,198	25.26	1,373	22.82	1,146	23.65
Indiana	562	21.97	527	21.69	531	20.77	510	20.82
Iowa	3	29.60	13	28.08	3	30.60	14	29.06
Kansas	39	31.95	13	32.10	36	29.31	98	26.13
Kentucky	2,083	12.71	1,361	6.93	1,776	10.84	1,434	6.82
Maryland	17	15.52	20	13.43	14	12.88	29	13.50
Missouri	156	28.65	155	28.72	160	29.35	230	29.35
Montana	89	3.06	140	4.14	135	4.63	162	5.24
New Mexico	46	1.98	60	1.89	79	3.40	102	3.27
North Dakota	69	4.21	16	0.71	164	10.00	96	4.23
Ohio	704	29.77	52	27.46	628	26.57	128	22.82
Oklahoma	59	20.49	89	11.88	49	17.27	98	11.72
Pennsylvania	1,274	17.97	1,204	17.48	1,052	14.82	1,031	14.81
Tennessee	58	12.42	71	10.24	48	10.22	58	8.44
Texas	182	4.16	572	5.17	453	10.37	990	10.74
Utah	56	3.74	110	3.37	52	3.47	173	5.21
Virginia	250	5.78	240	4.44	191	4.41	204	3.66
Washington	27	7.39	4	8.53	41	11.30	0	0.00
West Virginia	1,583	12.19	1,745	6.41	1,256	9.67	1,423	5.44
Wyoming	64	0.56	75	0.47	194	1.70	161	1.13
U.S. Total Revenues and Average Tax Rate	9,076	10.93	7,951	7.00	8,507	10.24	8,386	7.48

SOURCE: Congressional Budget Office.

revenues under each policy.[8] If the tax stipulated in Option V-1 was levied on the amount of coal used in 1985 (assuming that in the short run,

8. These figures are derived from the 1985 solution of the National Coal Model and not actual shipments. This may underestimate tax revenues slightly, as the solution yielded slightly less production in 1985 than actually occurred. In addition, export coal tax revenues are included, although they would likely be exempted.

current contracts would continue), the average nationwide tax rate would be $10.93 per ton, providing $9.1 billion in first-year revenues. Most of this revenue ($7.1 billion, or 78 percent) would come from coal shipped from Illinois, Kentucky, Ohio, Pennsylvania, and West Virginia. The average tax rate in this region would be $22.28 per ton, but could range as high as $29.77 in Ohio. In contrast, coal from Wyoming would be subject to an average tax of only $0.56 per ton; for most Wyoming coal, no taxes would be charged because its sulfur content lies below the threshhold level of 10 pounds per ton.

The initial revenues expected under Option V-2 would be somewhat lower, at $8.5 billion per year. Revenues from coal shipped from the five states mentioned above would total $6.1 billion (72 percent of the total), with tax rates in this region averaging $19.11 (compared with the nationwide average of $10.24 per ton). The average rate applied to Wyoming would be $1.70. Since the Option V-2 formula takes into account heat content, the rates applied to high-sulfur coal from the Midwest would be lower than under Option V-1, and the low-energy content coals mined in the West would be taxed at slightly higher rates. Although initial revenues from both proposals would be high, these policies would also grant subsidies ($0.50 for each pound of sulfur removed) for currently operating scrubbers. The CBO estimates that these obligations would require $2.4 billion in 1986, based on current utility scrubber use. Since both policies would grant identical subsidies, the first year fund surplus would be $6.7 billion for Option V-1 and $6.2 billion for Option V-2.

Revenues and Outlays in 1995. Annual revenues under both proposals would decline over time as utilities responded to higher coal prices by switching to lower-sulfur coal. Although the volume of coal shipments would increase by over 25 percent over the next 10 years, the average sulfur content under both options would decline sufficiently to lower the total revenues collected. In 1995 annual revenues from Option V-1 would become $8.0 billion (an average of $7.00 per ton) and revenues collected under Option V-2 would become $8.4 billion (an average of about $7.50 per ton). [9]

Subsidy levels would increase significantly in 1995 from their 1986 levels. The annual payments made to utilities for sulfur removed by scrubbing would rise to $3.3 billion in 1990 under both policies. This 1990 figure assumes that 1985 scrubber use would continue, and adds the subsidies required for planned utility plants for which operation would begin between

9. These figures assume that nonutiltity coal users would not substitute other fuels. Also, the National Coal Model collects some revenues from exported coal (between $400 million and $500 million for each option in 1995), which probably would be exempted under a legislated policy.

1986 and 1990. These annual payments would increase dramatically by 1995, to \$6.2 billion for Option V-1 and to \$6.8 billion for Option V-2 (see Table 39). The incentives inherent in the sulfur removal subsidy would encourage utilities to operate retrofit scrubbers as soon as completed. Therefore, outlays for sulfur removal are assumed to rise steadily between 1991 and 1995, in contrast with the retrofit O&M subsidies examined in Chapter III (Options III-1B and III-2B) which would begin at the 1995 compliance deadline.

The yearly subsidy for retrofit scrubbers (90 percent of annual capital cost) would begin in 1991 and reach about \$620 million in 1995 under Option V-1, and almost \$800 million with Option V-2. This latter figure represents the third highest amount for retrofit capital subsidies of all policies considered in this study, exceeded only by the "top 50" approach (Option III-2C of Chapter III) and the most subsidized emission tax policy (Option IV-3 of Chapter IV). Thus, the total annual outlays in 1995 with Option V-1 would be \$6.8 billion (for a yearly surplus of \$1.2 billion), while outlays under Option V-2 would total \$7.6 billion (an annual \$0.8 billion surplus).

All revenues, outlays, annual capital costs, and yearly operating costs incurred by the sulfur tax policies are assumed to remain constant between 1995 and 2015 in order to estimate the net present value of program costs as well as the trust fund holdings by the government. 10/ Annual program costs are discounted at 3.7 percent, which is also the real interest rate applied to government holdings, such as the trust fund arising from the sulfur tax revenues. Under these assumptions, the net government trust fund balance under either option could exceed \$50 billion by 1995, and would continue to grow despite increased subsidy obligations.

Policies that rely on financial incentives to reduce emissions tend to generate large trust fund balances. The options for fund management and possible disbursement outlined in Chapter IV apply to the balances accumulated under Options V-1 and V-2 as well. These include transferring all or some of the surplus to general revenues to lower budget deficits, transferring surpluses to the states based on their net contributions for rate relief and targeted miner employment programs. Trust fund balances also could be limited by phasing in the tax or by delaying the commencement date.

10. Capital expenditures are tapered off between 2010 and 2015 for purposes of calculating net present value, but the total subsidy figure remains constant to determine trust fund balances. This partially compensates for the fact that new sources would qualify for the sulfur removal subsidy and would, therefore, receive new subsidies as old sources are retired. (Net present value is defined in the box on page 19.)

Coal-Market Effects of Sulfur Tax and Subsidy Policies

Although both Options V-1 and V-2 would elicit a high degree of retrofit scrubber use, the midwestern and some Appalachian coal fields would still experience production and employment losses compared with 1995 base case projections. Compared with production losses predicted under the polluter pays options, however, the two sulfur tax policies would tend to limit midwestern coal losses. This is particularly evident when the projected coal shipments under Option V-2 are compared with shipments expected with a polluter pays, 10 million ton reduction. Table 40 shows predicted 1995 coal production, and Table 41 presents 1995 mining employment under these policies.

In the Midwest and East. Both tax policies would reduce 1995 coal production in Illinois, Indiana, Ohio, and Pennsylvania from the predicted level of 192.2 million tons under current policy to only 142.5 million tons under Option V-1 and 148.2 million tons under Option V-2. Predicted 1995 mining employment in these states also would decline by 14,600 jobs with Option V-1 and by 12,900 jobs under Option V-2. The differences between policies would be particularly acute in Ohio, where Option V-1 would reduce 1995 production to only 1.9 million tons (6 percent of the current level) while production under Option V-2 would be 5.6 million tons, a difference of nearly 1,100 jobs.

In Kentucky, the difference between the two policies would be even more pronounced. With Option V-1, 1995 coal shipments would be 196.3 million tons (very close to Option II-2A), but would reach a level of 210.1 million tons under Option V-2 (nearly the level expected in Option II-1A). This translates into a difference of 4,200 jobs between the two tax alternatives.

In the West and Texas. The Option V-2 formula would assess a higher rate per ton on most western coal, because of its low energy content. The largest western coal producer, Wyoming, would experience a gain in coal production in 1995 of 27.0 million tons over base case projections under Option V-1, but would gain only 12.2 million tons under Option V-2. This would represent an employment difference between policies of less than 700 jobs, because of the low labor requirements for surface mining in the West.

In contrast with most other policies examined in this study, Option V-2 would affect the production of Texas lignite coal, which has moderate sulfur content but very low energy content. 11/ When the Option V-2 tax rate is

11. The two policies examined in Chapter II that restricted fuel switching (Options II-1B and II-2B) also lowered 1995 lignite coal production in Texas by roughly 11 million tons, compared with a decline of more than 17 million tons under Option V-2. Other programs would have negligable effects on Texas coal shipments.

TABLE 39. ANNUAL SUBSIDIES IN 1995 UNDER TWO SULFUR TAX OPTIONS, BY STATE (In millions of 1985 dollars)

	Option V-1			Option V-2		
State	Sulfur Removal Subsidy	Capital Subsidy	Total	Sulfur Removal Subsidy	Capital Subsidy	Total
Alabama, Mississippi	175	0	175	194	18	211
Arizona	50	0	50	47	0	47
Arkansas, Oklahoma, Louisiana	313	0	313	364	0	364
California	49	0	49	49	0	49
Carolinas, North and South	89	0	89	110	0	110
Colorado	44	0	44	59	0	59
Dakotas, North and South	18	2	20	14	0	14
Florida	230	0	230	224	0	224
Georgia	70	0	70	139	4	143
Idaho	0	0	0	0	0	0
Illinois	631	170	801	595	165	760
Indiana	158	4	161	168	3	171
Iowa	23	0	23	25	0	25
Kansas, Nebraska	173	0	173	168	0	168
Kentucky	484	1	485	490	1	490
Maine, Vermont, New Hampshire	18	3	22	20	3	23
Maryland, Delaware	200	60	260	202	60	262
Massachusetts, Connecticut, Rhode Island	75	14	89	75	14	89

(Continued)

TABLE 39. (Continued)

State	Option V-1 Sulfur Removal Subsidy	Option V-1 Capital Subsidy	Option V-1 Total	Option V-2 Sulfur Removal Subsidy	Option V-2 Capital Subsidy	Option V-2 Total
Michigan	64	1	64	96	1	97
Minnesota	68	0	68	82	0	82
Missouri	194	21	215	385	100	485
Montana	61	0	61	61	0	61
Nevada	9	0	9	19	0	19
New Mexico	101	0	101	101	0	101
New York (Downstate), New Jersey	117	26	143	117	26	143
New York (Upstate)	158	12	170	166	12	178
Ohio	143	9	152	257	71	328
Pennsylvania	687	187	874	692	187	878
Tennessee	187	16	203	166	15	181
Texas	821	0	821	899	0	899
Utah	71	0	71	129	0	129
Virginia, District of Columbia	122	0	122	122	0	122
Washington, Oregon	72	0	72	51	0	51
West Virginia	282	79	360	305	96	402
Wisconsin	95	18	113	87	20	107
Wyoming	107	0	107	80	0	80
U.S. Total	6,158	621	6,779	6,754	796	7,550

SOURCE: Congressional Budget Office.

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applied to this coal, it would average $10.74 per ton in 1995 (compared with an Option V-1 rate of $5.17), which would cause 1995 production to drop from an expected level of 109.4 million tons to 92.2 million tons. Expected employment in 1995 would be lowered by 1,200 mining jobs. Despite this loss of projected 1995 production with Option V-2, Texas lignite production and employment would still more than double from current levels over the next 10 years.

TABLE 40. COAL PRODUCTION AS OF 1995 UNDER TWO SULFUR TAX OPTIONS COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS, BY STATE (In millions of tons)

State	Base Case	8 Million Ton Rollback Option II-1A	10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Alabama	23.8	25.5	22.1	25.5	27.9
Arizona	14.2	13.8	13.9	13.8	14.2
Colorado	19.1	20.3	23.5	20.4	21.3
Illinois	56.4	46.2	37.6	47.4	48.4
Indiana	29.2	24.3	19.7	24.3	24.5
Iowa	1.5	0.5	0.5	0.5	0.5
Kansas	2.5	0.4	0.4	0.4	3.7
Kentucky	208.9	211.6	195.9	196.3	210.1
Maryland	2.5	1.6	1.5	1.5	2.1
Missouri	8.1	5.4	5.3	5.4	7.8
Montana	34.0	26.0	26.0	33.7	30.9
New Mexico	31.9	31.8	31.9	31.9	31.2
North Dakota	22.7	22.7	22.7	22.7	22.7
Ohio	24.3	4.0	4.0	1.9	5.6
Oklahoma	7.7	7.0	7.0	7.5	8.3
Pennsylvania	82.3	69.4	56.3	68.9	69.7
Tennessee	5.3	6.9	4.9	6.9	6.9
Texas	109.4	108.8	108.8	110.6	92.2
Utah	31.6	31.8	32.8	32.5	33.3
Virginia	50.6	57.2	56.0	54.0	55.7
Washington	0.5	0.5	0.5	0.5	0.0
West Virginia	232.2	261.7	274.6	272.3	261.6
Wyoming	130.5	151.7	191.2	157.5	142.7
U.S. Total	1,128.9	1,129.1	1,137.1	1,136.4	1,121.3

SOURCE: Congressional Budget Office.

TABLE 41. COAL MINING EMPLOYMENT IN 1995 UNDER TWO SULFUR TAX POLICIES COMPARED WITH TWO POLLUTER PAYS ROLLBACK PROGRAMS, BY STATE (In number of job slots)

State	Base Case	8 Million Ton Rollback Option II-1A	10 Million Ton Rollback Option II-2A	Sulfur Tax Options: Option V-1	Sulfur Tax Options: Option V-2
Alabama	8,124	8,714	7,543	8,705	9,531
Arizona	1,177	1,141	1,155	1,141	1,177
Colorado	3,288	3,510	4,062	3,516	3,675
Illinois	14,733	12,068	9,823	12,392	12,658
Indiana	5,342	4,446	3,611	4,448	4,479
Iowa	344	110	110	111	111
Kansas	753	129	129	129	1,145
Kentucky	63,014	63,818	59,098	59,204	63,381
Maryland	695	447	417	425	597
Missouri	1,948	1,297	1,276	1,296	1,886
Montana	1,251	956	955	1,241	1,135
New Mexico	2,846	2,844	2,846	2,846	2,784
North Dakota	1,375	1,374	1,374	1,375	1,374
Ohio	7,136	1,183	1,183	556	1,653
Oklahoma	2,344	2,146	2,146	2,304	2,555
Pennsylvania	29,299	24,701	20,042	24,514	24,789
Tennessee	2,010	2,616	1,859	2,614	2,614
Texas	6,890	6,855	6,854	6,967	5,807
Utah	7,978	8,040	8,282	8,218	8,400
Virginia	19,339	21,852	21,375	20,625	21,263
Washington	48	48	48	48	0
West Virginia	89,473	100,811	105,792	104,899	100,773
Wyoming	5,768	6,706	8,451	6,964	6,309
U.S. Total	275,172	275,812	268,431	274,538	278,094

SOURCE: Congressional Budget Office.

CHAPTER VI

TWO RECENT CONGRESSIONAL PROPOSALS

Two proposals concerning acid rain have recently been introduced in the 99th Congress, both differing somewhat from the options described in the previous chapters. The most recent one (House bill H.R. 4567, introduced by Congressman Waxman) would require utilities to reduce SO_2 emissions by 9 million tons to 10 million tons from 1980 levels, depending on how the states respond to the requirements. The earlier and more stringent proposal (Senate bill S. 2203, introduced by Senator Stafford) would call for a SO_2 reduction of about 12 million tons from 1980 utility emissions. These bills also contain additional requirements that would lower SO_2 emissions from industrial facilities and nitrogen oxide emissions from utilities, industrial plants, and motor vehicles. Nevertheless, the sulfur dioxide control components remain the heart of each program, and would produce the greatest emission reductions and cost the most to achieve.

In this chapter, the sulfur dioxide provisions of each bill are examined as Options VI-1, VI-2, and VI-3. Option VI-1 is based on the House bill; it would lower utility SO_2 emissions by 9.1 million tons from 1980 levels, by requiring states to develop plans to limit utilities to a statewide average emission rate of 1.2 pounds of SO_2 per million British thermal units. Option VI-2 also is based on the House bill; it examines the effects of the so-called "default" provision that would be invoked if states did not establish control plans. This provision would require each affected power plant to meet an SO_2 emission limit of 1.2 pounds per million Btus, leading to a 9.9 million ton reduction from 1980 levels. Option VI-3 is based on the Senate bill, which, like the default portion of the House bill, would set a uniform emission rate for each affected power plant. The requirement under Option VI-3 would be far more stringent, however, stipulating that each plant limit SO_2 emissions to 0.7 pounds per million Btus burned, achieving an overall SO_2 reduction of 12.1 million tons from 1980 levels. None of the options provides a tax and subsidy scheme to encourage scrubbing; in this respect, they reflect the polluter pays principle. The House bill does have a potential subsidy mechanism to provide electricity rate relief if rate hikes exceed 10 percent as a result of the program, but this provision would not influence choice of control technology as the subsidy programs in earlier chapters would.

The discounted program cost of each bill differs greatly. Option VI-1 would cost about $26 billion (in discounted 1985 dollars) over the 1986-2015 period, while the default version, Option VI-2, would cost about $35 billion over the same period. Option VI-3, in contrast, would cost nearly $94 billion by 2015. These differences in costs remain substantial even when the level of emission reduction is taken into account using the cost-effectiveness measure. Option IV-1 would cost $299 per ton of SO_2 removed, with the figure rising to $368 per ton removed under Option VI-2. This value would more than double--to $779 per ton--under the provisions of Option VI-3. In comparison, the polluter pays, 10 million ton SO_2 reduction of Chapter II (Option II-2A) would cost $34.5 billion over the 1986-2015 period and roughly $360 per ton of SO_2 reduced. (All figures in discounted 1985 dollars.)

In terms of coal-market effects, the four most sensitive high-sulfur coal states--Illinois, Indiana, Ohio, and Pennsylvania--would face significant losses in expected 1995 mining jobs. Option VI-1 would reduce 1995 job slots in these states by 17,000 from the base case, and Option VI-2, by 18,100. Suprisingly, Option VI-3 would yield less of an employment loss in these states, as 1995 mining employment would be only 13,400 jobs lower than predicted under the base case. This slighter effect would occur because the strict emission limit prescribed under the Senate bill would make scrubbing the most economical, and often the only feasible, method to control emissions, thus discouraging switching to low-sulfur coal. The effects of these options may be compared with the 10 million ton SO_2 polluter pays reduction (Option II-2A), which would result in almost 21,900 lost job slots by 1995 in the four sensitive high-sulfur coal mining states.

METHODOLOGY USED TO EXAMINE THE TWO APPROACHES

The bills on which Options VI-1, VI-2, and VI-3 are based include more regulatory details than do any of the options so far considered in this report. For example, both bills would control pollution sources other than utilities and both would require reductions in nitrogen oxide emissions as well as SO_2 (see Table 42). In addition, neither bill calls for emission reductions to occur precisely by 1995. The House bill would have utilities reduce emissions in two phases, culminating in 1997. The Senate bill would require utilities eventually to retire individual boilers that could not meet the emission limit of 0.7 pounds SO_2 per million Btus; the retirement deadline would be within 10,000 hours of operation (roughly 2 years for most plants) after 1991. Finally, although neither bill contains a tax and subsidy program designed to encourage scrubbing, the House bill would partially subsidize utility costs if residential electricity rates rose by more than 10 percent above the expected rates. Such a subsidy would be funded by a temporary generation tax on fossil-fuel power plants of no more than 0.5 mills per kilowatt-hour (mills/kwh).

Despite the additional provisions included in each bill, the SO_2 reduction portions remain their most expensive element.[1] To estimate the cost of these recent proposals and allow comparison with previous options in this report, several simplifying assumptions were made for the analysis in this chapter. First, all emission reductions were assumed to take place by 1995, which is the compliance date for all options discussed in previous chapters. Second, all emission limits would be based on annual averages, typically the most lenient method allowed. Third, the statewide emission targets of Option VI-1, as well as the plant emission limits of Options VI-2 and VI-3, would apply only to plants built before the first New Source Performance Standard (NSPS) was put into effect. Fourth, Option VI-2, which depicts the default provision of the House bill, assumes that all states would be subject to the plant-by-plant limit, since it is impossible to predict which states would submit acceptable plans to achieve the statewide average limit of 1.2 pounds of SO_2 per million Btus. Finally, the cost and effect of emission control programs directed at sources other than utilities and at pollutants other than sulfur dioxide were not examined. These costs would be small in comparison with the sulfur dioxide control provisions, however. For a more detailed description of the methodology employed in this chapter, consult the appendix to this report.

SULFUR DIOXIDE REDUCTIONS AND COSTS

Compared with anticipated 1995 emission levels (the base case), Option VI-1 would reduce utility SO_2 levels by 8.3 million tons; Option VI-2, by 9.1 million tons; and Option VI-3, by almost 11.6 million tons (see Table 43). Using the familiar baseline of 1980, these options would produce a 9.1, 9.9, and 12.1 million ton SO_2 reduction, respectively, from 1980 levels of utility SO_2 emissions. For the states of Illinois, Indiana, Missouri, Ohio, Pennsylvania, and West Virginia, combined emissions in 1995 would have to be lowered by 60 percent under Option VI-1, 66 percent under Option VI-2, and by 77 percent under Option VI-3. In comparison, the polluter pays, 10 million ton reduction with fuel switching (Option II-2A) would reduce predicted 1995 emissions in this region by 65 percent.

1. See, for example, Office of Technology Assessment, "Response to Questions About H.R. 4567 from Congressman John Dingell," May 9, 1986.

TABLE 42. COMPARISON OF TWO RECENT PROPOSALS WITH OPTIONS EXAMINED

Bill	Sulfur Dioxide Reduction Strategy	Nitrogen Dioxide Reduction Strategy	Tax and Subsidy Provisions
H.R. 4567	Utilities must meet a 10 million ton SO_2 reduction in two phases--by January 1, 1993, they meet a 2.0 pound SO_2 emission limit per million Btus; by January 1, 1997, they must meet a 1.2 pound SO_2 emission limit. a/ Industrial plants must meet a statewide average limit of 1.2 pounds SO_2 per million Btus by January 1, 1997.	Utility and industrial plants must meet a statewide nitrogen oxide emission limit of 0.6 pounds per million Btus by January 1, 1997. Tighter standards are also stipulated for new plants. Motor vehicles are subject to tighter emission standards to further reduce nitrogen oxide emissions.	Utilities whose residential customers experience a 10 percent or more rise in rates from the control program may receive a subsidy to lower price rises below 10 percent. This subsidy would be financed by a temporary fee no greater than 0.5 mills/kwh levied on fossil-fuel power plants. The subsidy would not influence abatement behavior.
S. 2203	After December 31, 1991, each fossil-fuel power plant is limited to 1 to 2 years of continued operation unless they meet an SO_2 limit of 0.7 pounds per million Btus. Meeting this requirement would produce about a 12 million ton reduction from 1980 SO_2 levels. Many older industrial plants would become subject to stricter, new source standards by 1992.	Utility and industrial plants must meet stricter standards by 1995. Levels for these limits are to be set by EPA based on current practices of OECD member countries. Motor vehicles also would be subject to tighter rules.	None.

(Continued)

TABLE 42. (Continued)

Option	Sulfur Dioxide Reduction Strategy	Nitrogen Dioxide Reduction Strategy	Tax and Subsidy Provisions
Option VI-1	Utilities must achieve a 9.1 million ton SO_2 reduction from 1980 levels by January 1, 1995. Reductions based on meeting statewide annual average limit of 1.2 pounds SO_2 per million Btus. No industrial emission reductions required.	None.	No tax and subsidy programs are assumed to influence compliance behavior. A 0.5 mill/kwh tax and subsidy program is discussed separately in text.
Option VI-2	Same as Option VI-1, except that each affected plant within the state must meet the 1.2 pound SO_2 per million Btus limit achieving a 9.4 million ton reduction.	None.	None.
Option VI-3	Utilities must meet a 12 million ton SO_2 reduction from 1980 levels by January 1, 1995. Reductions based on meeting an individual plant rate of 0.7 pounds SO_2 per million Btus. No industrial emission reductions required.	None.	None.

SOURCE: Congressional Budget Office.

a. To lower costs, states may submit plans to achieve the emission limits on a statewide average basis rather than on a per plant basis.

TABLE 43. EMISSIONS UNDER THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In thousands of tons of SO_2 emitted in 1995)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama, Mississippi	704	414	481	407	250	67	-7	-164
Arizona	122	106	113	122	84	8	17	-22
Arkansas, Oklahoma, Louisiana	336	302	290	312	309	-12	10	7
California	25	25	25	25	25	0	0	0
Carolinas, North and South	1,063	577	568	523	313	-9	-54	-263
Colorado	92	94	94	97	87	0	3	-7
Dakotas, North and South	105	105	106	96	87	1	-9	-18
Florida	772	566	672	553	474	106	-12	-92
Georgia	635	352	360	323	196	8	-29	-156
Idaho	0	0	0	0	0	0	0	0
Illinois	1,142	408	518	403	257	110	-5	-151
Indiana	1,433	553	607	557	368	54	4	-185
Iowa	326	167	181	203	141	14	36	-25
Kansas, Nebraska	174	163	174	166	151	11	3	-12
Kentucky	796	466	488	431	340	22	-35	-126
Maine, Vermont, New Hampshire	64	44	49	34	29	5	-10	-15
Maryland, Delaware	371	189	187	223	181	-2	34	-7
Massachusetts, Connecticut, Rhode Island	305	219	221	306	279	2	87	60

(Continued)

TABLE 43. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Michigan	598	374	402	335	205	28	-39	-169
Minnesota	230	146	168	146	117	22	1	-29
Missouri	1,257	293	341	255	230	47	-38	-63
Montana	71	68	71	71	68	3	3	0
Nevada	90	80	79	92	76	-1	12	-4
New Mexico	62	62	62	62	62	0	0	0
New York (Downstate), New Jersey	270	245	253	271	244	9	26	0
New York (Upstate)	343	141	305	170	147	165	30	6
Ohio	2,017	629	704	641	381	75	12	-248
Pennsylvania	1,439	578	715	566	371	136	-12	-207
Tennessee	761	281	303	276	152	22	-5	-129
Texas	586	567	565	555	476	-2	-12	-91
Utah	87	61	60	85	76	-1	23	15
Virginia, District of Columbia	213	175	172	187	151	-4	12	-24
Washington, Oregon	111	104	96	112	92	-8	8	-12
West Virginia	1,042	421	420	444	272	-1	23	-149
Wisconsin	746	199	221	223	152	22	24	-46
Wyoming	69	70	70	69	60	0	0	-9
U.S. Total	18,455	9,241	10,138	9,341	6,903	898	100	-2,337

SOURCE: Congressional Budget Office.

Virtually all the reductions obtained under Options VI-1 and VI-2 would occur as a result of utilities' switching to lower-sulfur coal. This is consistent with the findings of previous chapters; significant use of retrofit scrubbers would not occur at the 8 million ton to 10 million ton reduction level, unless fuel choice was restricted; scrubbers were mandated; or scrubbers were partially subsidized.[2] Significant scrubbing would occur under Option VI-3, however, even in the absence of such incentives. This option's strict emission limit essentially would force utilities to equip a substantial fraction of generating capacity with retrofit scrubbers because such technology represents the most economical and, in some cases, the only feasible method of attaining the required low emission rates.

Program Costs

Over the 1986-2015 period, Option VI-1 would cost roughly \$25.9 billion, achieving a cost-effectiveness price of \$299 per ton of SO_2 reduced (both in discounted 1985 dollars). If the default provision of Option VI-2 were invoked in every state, overall costs would rise to \$34.9 billion, and \$368 per ton of SO_2 reduced. In contrast, Option VI-3 would cost nearly \$94 billion over the same period for a cost-effectiveness value of \$779 per ton of SO_2 reduced (all in discounted 1985 dollars). Table 44 compares the total program costs and cost-effectiveness figures of both options with Option II-2A).

The figures shown in Table 44 highlight the trend found in previous chapters: as emission reductions increase beyond 8 million tons (based on the 1980 emission baseline) costs rapidly increase. For example, the cheapest option--polluter pays 8 million ton reduction (Option II-1A)--would achieve a cost-effectiveness of about \$270 per ton of SO_2 reduced (in discounted 1985 dollars). Moving up to a 9.1 million ton reduction as formulated in Option VI-1, would cost \$299 per ton of SO_2 reduced, only a slight increase over Option II-1A. To achieve a 10 million ton reduction, however, would cost at least \$360 dollars per ton of SO_2 reduced (Option II-2A), indicating a steeper rise in the cost-of-control curve. Option VI-2 would cost slightly more, at \$368 per ton, because of the lack of choice implied by a plant-by-plant emission rate compared with statewide averages that achieve roughly the same total emissions. Finally, a 12.1 million ton reduction, as expressed in Option VI-3, would cost \$779 per ton of SO_2 reduced, well over twice as much as Option VI-1 while achieving only about one-quarter more emission reductions.

2. All options are described in the glossary at the end of this report.

TABLE 44. TOTAL PROGRAM COSTS AND COST-EFFECTIVENESS OF THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS

	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3
Total Program Cost (In billions of discounted 1985 dollars) a/	34.5	25.9	34.9	93.6
Cost-Effectiveness (In 1985 dollars per ton SO_2 reduced) b/	360	299	368	779

SOURCE: Congressional Budget Office.

a. Reflects net present value of sum of program costs incurred from 1986 through 2015, discounted to 1985 dollars. These costs consist of real annual utility expenditures in excess of current policy, which is equivalent to net utility cost, plus subsidies, minus taxes paid. A real discount rate of 3.7 percent was used in the calculations.

b. Represents the discounted program costs, divided by the annual discounted SO_2 reduction from current policy measured over the 1986-2015 period.

The higher costs associated with larger emission reductions can also be described as the cost attributable to abating an incremental ton of SO_2, often called the marginal cost of abatement. For example, the average cost of achieving an additional 2 million ton reduction by moving from 8 million tons to 10 million tons would cost about $720 per ton of SO_2 removed. Similarly, the marginal cost of abating an additional 2.1 million tons by increasing the rollback from 10 million tons to 12.1 million tons is about $2,775 per ton. These figures illustrate that additional reductions would become very expensive at the rollback levels currently being considered. 3/

3. These values are calculated by multiplying the cost-effectiveness figures by their respective reduction from 1980 levels and dividing the resulting differences by the appropriate increment in emission reduction. This is meant only to illustrate the possible magnitude of marginal cost, and would likely understate the true cost of increasing abatement beyond some reference level. Moreover, marginal cost varies considerably by region under allocation schemes that impose reduction targets.

Finally, the costs shown in Table 44 may overestimate the expense of Option VI-3, a policy that relies heavily on accelerated retirement of older, polluting plants as part of its abatement strategy. In this analysis, the total cost of Option VI-3 includes the expense of building new generation facilities to replace those that must be retired in order to comply with the emission reduction targets. But not all of this cost can be correctly assigned to Option VI-3, since many of the plants in question would have to be replaced eventually because of their age. Thus, Option VI-3 would accelerate the pace of replacing older power plants, and only the cost of this accelerated investment should be attributed to the acid rain policy, not the total cost of all the new power plants. To some extent, this problem pertains to all SO_2 control proposals, since plant retirement is always an option available to the utility. The effect is likely more pronounced in Option VI-3, however, which relies on replacement of older, less controlled power plants.

Effect On Utility Costs

Since both the House and Senate proposals embody the polluter pays principle, all direct abatement costs would be reflected in an increase in the annual cost to utilities of generating electricity. A possible exception would occur in the event that the emission control costs under the House bill (Option VI-1) would cause residential electricity rates to increase by 10 percent or more, which would trigger the rate subsidy provision. In most cases, increases of this magnitude probably would not occur.

Table 45 shows the 1995 annual generating cost of the options based on the two bills. Compared with the base case, the total annual utility cost of Option VI-1 would be $2.5 billion more in 1995; under the default provision of Option VI-2, costs would rise by $3.3 billion. In contrast, Option VI-3 would cost $8.8 billion more annually than the base case; this would represent the highest annual costs incurred under any option considered in this report. As expected, most of the expense would be concentrated in the midwestern and Appalachian states, where the costs of Option VI-3 would typically be two to three times higher than Options VI-1 or VI-2.

Comparing these annual costs with Option II-2A (as shown in Table 45), Option VI-1 would cost utilities $761 million less nationwide each year, while Option VI-2 would cost about the same as Option II-2A. The most stringent plan, Option VI-3, would cost nearly $5.6 billion more per year.

Within states, utility costs do not necessarily rise evenly when the level of control is increased. As discussed in earlier chapters, several factors affect regional utility costs. First, the allocation formula, or specified emission limits, can affect regional generating costs unevenly, depending on its severity relative to emission rates that would prevail under current policy. Second, actual generation can change, based on the least costly combination of generation and interregional transmission (importing or exporting electricity) needed to satisfy regional demands. Finally, the amount of installed retrofit scrubbing capacity can effect the relative prices of high-and low-sulfur coal, which, in turn, can influence utility costs in regions not necessarily affected directly by emission reduction policies. Utilities would purchase retrofit scrubber equipment worth nearly $1.9 billion and $3.6 billion under Options VI-1 and VI-2, respectively. These figures are small, however, when compared with the $24.4 billion that would be invested in scrubbers under Option VI-3.

Effect on Electricity Rates

Average electricity rates nationwide in 1995 would rise by 1.5 percent under Option VI-1, 2.0 percent under the default provision of Option VI-2, and 5.7 percent under Option VI-3, compared with the 2.5 percent increase expected under Option II-2A. The national average, however, obscures the regional variation in predicted rate increases, as Table 46 shows.

Option VI-1 would lead to fairly uniform rate increases, with even the most heavily affected midwestern and eastern states typically experiencing rate increases in the 2 percent to 4 percent range, which are slightly below those expected under Option II-2A. One state, Utah, could experience an average rate increase of over 10 percent. Only part of the rate increase would arise from the cost of reducing utilities' emissions, however. The largest part of the increase would result from the higher prices utilities would have to pay for the low-sulfur coal they regularly use. Increased nationwide demand would push up the price of this coal as utilities switched from the more polluting high-sulfur coal. In addition, Utah utilities would receive less revenue from interstate sales.

Under Option VI-2, rate increases by 1995 would tend to be slightly higher--in the 3 percent to 6 percent range--and would be closer to those expected under Option II-2A. Wisconsin (11 percent) and West Virginia (23 percent) would both exceed the subsidy threshold of 10 percent under H.R. 4567, a provision that does not apply under Option VI-2.

The subsidy clause contained in H.R. 4567 has two important aspects. First, the model used by CBO to predict the electricity rate effects of acid rain legislation computes only statewide averages--a simplifying assumption that could overlook the possible variation in rate increases within a state and between residential and industrial customers. Therefore, some utilities

TABLE 45. ANNUAL UTILITY COSTS AS OF 1995 OF THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of 1985 dollars)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama, Mississippi	4,224	4,364	4,305	4,364	4,628	-59	0	264
Arizona	1,944	1,943	1,938	1,926	1,949	-4	-16	6
Arkansas, Oklahoma, Louisiana	9,591	9,723	9,784	9,601	9,793	61	-122	70
California	10,565	10,822	11,038	10,562	10,567	216	-260	-255
Carolinas, North and South	4,759	4,895	4,900	4,986	5,427	5	91	531
Colorado	1,093	1,100	1,097	1,051	1,068	-3	-49	-32
Dakotas, North and South	567	565	565	577	589	0	12	24
Florida	6,127	6,198	6,181	6,234	6,510	-17	36	312
Georgia	2,555	2,622	2,629	2,640	2,883	6	18	260
Idaho	221	221	221	221	221	0	0	0
Illinois	4,189	4,432	4,328	4,321	4,508	-105	-111	76
Indiana	3,095	3,233	3,253	3,265	3,625	19	31	392
Iowa	1,230	1,327	1,295	1,304	1,393	-32	-23	66
Kansas, Nebraska	1,854	1,862	1,860	1,853	1,928	-2	-9	67
Kentucky	3,103	3,499	3,277	3,228	3,812	-222	-272	313
Maine, Vermont, New Hampshire	1,123	1,123	1,120	1,129	1,150	-3	6	27
Maryland, Delaware	1,885	1,654	1,658	1,929	2,170	4	275	516
Massachusetts, Connecticut, Rhode Island	3,513	3,678	3,670	3,534	3,745	-8	-144	67

(Continued)

TABLE 45. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Michigan	2,817	2,944	2,898	3,053	3,215	-45	109	271
Minnesota	1,186	1,228	1,180	1,349	1,391	-48	121	164
Missouri	2,024	2,206	2,179	2,195	2,318	-27	-11	112
Montana	676	675	673	675	674	-2	-1	-2
Nevada	1,096	1,122	1,121	1,104	1,131	-1	-18	9
New Mexico	1,158	1,144	1,144	1,196	1,209	0	52	65
New York (Downstate), New Jersey	4,878	5,200	4,886	5,156	5,216	-314	-43	16
New York (Upstate)	2,395	2,236	2,367	2,282	2,390	131	46	154
Ohio	4,239	4,271	4,498	4,323	4,767	226	52	495
Pennsylvania	5,512	6,056	5,984	5,828	6,198	-72	-228	141
Tennessee	2,078	2,028	2,022	2,450	2,449	-5	422	421
Texas	15,852	15,844	15,843	15,838	15,923	-1	-6	79
Utah	1,345	1,368	1,357	1,355	1,363	-10	-13	-5
Virginia, District of Columbia	1,884	1,926	1,934	1,919	2,221	8	-8	294
Washington, Oregon	4,219	4,068	3,917	4,220	4,216	-151	152	148
West Virginia	1,784	2,278	1,987	2,259	2,638	-292	-20	360
Wisconsin	1,572	1,734	1,724	1,741	1,879	-11	7	144
Wyoming	1,026	1,039	1,035	1,030	1,048	-4	-8	10
U.S. Total	117,380	120,630	119,869	120,699	126,210	-761	69	5,580

SOURCE: Congressional Budget Office.

TABLE 46. ELECTRICITY PRICES IN 1995 UNDER THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In 1985 mills per kilowatt hour)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama, Mississippi	46.6	45.6	45.9	47.8	49.6	0.7	4.9	8.8
Arizona	55.9	55.9	55.7	55.4	54.4	-0.3	-0.8	-2.6
Arkansas, Oklahoma, Louisiana	77.5	78.8	79.2	77.7	78.9	0.5	-1.4	0.2
California	78.3	78.3	78.4	78.2	78.3	0.1	-0.1	0.0
Carolinas, North and South	50.3	51.2	51.3	52.1	55.9	0.3	1.8	9.3 a/
Colorado	57.4	57.7	57.6	57.6	57.9	-0.2	-0.2	0.4
Dakotas, North and South	32.1	30.4	32.0	31.5	31.3	5.2	3.4	2.9
Florida	75.2	75.9	75.8	76.0	78.3	-0.1	0.1	3.2
Georgia	54.2	56.2	56.2	55.3	60.0	0.0	-1.6	6.8 a/
Idaho	43.0	43.5	43.2	43.1	43.4	-0.6	-0.8	-0.1
Illinois	59.3	62.4	61.2	62.6	64.3	-1.9	0.4	3.2
Indiana	53.9	55.5	55.3	56.5	61.3	-0.4	1.8	10.3 a/
Iowa	59.3	62.3	61.4	61.3	64.9	-1.5	-1.7	4.2
Kansas, Nebraska	57.9	58.4	58.1	57.9	59.5	-0.6	-0.9	1.9
Kentucky	55.0	55.0	55.5	56.3	59.1	1.0	2.5	7.6
Maine, Vermont, New Hampshire	80.9	80.3	80.2	80.9	81.9	-0.1	0.8	2.0
Maryland, Delaware	66.4	69.2	69.3	67.4	70.7	0.1	-2.5	2.2
Massachusetts, Connecticut, Rhode Island	80.6	84.7	84.0	81.0	84.8	-0.8	-4.4	0.1

(Continued)

TABLE 46. (Continued)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Percent Difference from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Michigan	57.7	58.2	58.1	60.2	61.9	-0.2	3.5	6.3
Minnesota	54.2	55.1	53.9	58.4	60.1	-2.1	6.0	9.0 a/
Missouri	59.6	63.8	63.2	63.5	66.2	-0.9	-0.4	3.8 a/
Montana	41.1	41.0	40.7	41.0	40.8	-0.6	0.1	-0.3
Nevada	48.8	47.0	47.1	48.4	46.3	0.1	2.9	-1.5
New Mexico	68.2	67.2	67.2	67.0	68.1	-0.1	-0.4	1.3
New York (Downstate), New Jersey	99.3	100.3	99.8	99.5	100.8	-0.5	-0.8	0.4
New York (Upstate)	53.1	55.3	52.5	55.8	57.7	-5.0	0.9	4.2
Ohio	57.8	62.2	60.0	60.5	66.0	-3.5	-2.8	6.1 a/
Pennsylvania	58.2	60.0	59.3	61.0	64.7	-1.1	1.6	7.9 a/
Tennessee	46.9	50.7	49.0	48.5	50.6	-3.4	-4.3	-0.1
Texas	79.4	79.4	79.4	79.6	79.3	0.0	0.1	-0.2
Utah	39.0	44.7	45.4	39.6	40.1	1.6 a/	-11.4	-10.2
Virginia, District of Columbia	58.7	60.7	60.2	59.8	64.5	-0.8	-1.5	6.2
Washington, Oregon	35.4	35.4	35.7	35.1	35.1	0.7	-0.9	-0.9
West Virginia	27.2	46.7	25.5	33.5	68.1	-45.3	-28.2 a/	45.8 a/
Wisconsin	52.7	57.9	56.4	58.4	61.9	-2.5	0.9 a/	7.0 a/
Wyoming	43.0	43.5	43.2	43.1	43.4	-0.6	-0.8	-0.1
U.S. Average	62.0	63.5	62.9	63.3	65.6	-0.9	-0.4	3.2

SOURCE: Congressional Budget Office.

a. Electricity rates in these states would increase by over 10 percent compared with base case predictions. Such increases could trigger utility subsidies under one version of the House bill (Option VI-1), but not under Options VI-2 and VI-3.

could experience residential rate increases that would qualify for the subsidy, without driving the statewide average rate increase over the 10 percent threshold. Second, subsidies would be provided to offset either increased fuel expenses (for switching to low-sulfur coal) or the additional cost of scrubber installation. In this regard, the subsidy would not influence the choice of abatement strategy, as did the scrubber subsidies of previous options. 4/

As expected, Option VI-3 would raise rates substantially in most regions, and would outstrip the predicted rate hikes caused by Option II-2A in all eastern and midwestern state. Utilities in the states of North and South Carolina, Georgia, Indiana, Minnesota, Missouri, Ohio, Pennsylvania, West Virginia, and Wisconsin could raise 1995 rates by over 10 percent on average. Rate increases in West Virginia alone could be nearly 150 percent, although this would result mostly from lower revenues from exported electricity. This large increase, however, would make rates for West Virginia customers only slightly higher than the national average expected under Option VI-3, since their base case levels in 1995 would be the lowest in the nation.

Coal-Market Effects of Each Option

Table 47 shows the 1995 coal production, and Table 48 the mining employment expected under the three options (please note that Tables 47 and 48 compare the three options to the polluter pays, 10 million ton reduction (Option II-2A), while the following discussion examines differences from 1995 base case levels). The coal production and employment figures reflect the relationship between the level of emission control and the subsequent economies of scrubber use. As explained before, electric utilities would almost always use low-sulfur coal in order to meet emission limits under the 9.1 million ton reduction required under Option VI-1. While this approach would keep utility costs fairly low, it would also cause a significant decline in the use of high-sulfur coal by 1995. Total annual coal shipments from Illinois, Indiana, Ohio, and Pennsylvania would decline by 57.7 million tons from predicted 1995 levels under the base case, implying that 17,000 fewer mining jobs would be available in this region. This effect is even more pronounced under the reduction required under Option VI-2. This program could reduce expected 1995 production and employment in these states by 62 million tons and 18,100 jobs, respectively.

4. If subsidies were necessary, the maximum 0.5 mill per kilowatt tax on fossil-fuel fired generation could produce nearly $1.0 billion in 1989, rising to over $1.2 billion annually by 1996, the maximum duration specified in the bill (all figures in undiscounted 1985 dollars).

The prospects for high-sulfur coal production would not worsen, however, as the level of emission reduction was further tightened under Option VI-3, since utilities would find scrubbing both necessary and economical to achieve such low emission rates. While the expense of installing and operating scrubbers would drive utility costs up dramatically, utilities could con-

TABLE 47. 1995 COAL SHIPMENTS UNDER THREE OPTIONS BASED ON TWO RECENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In millions of tons)

						Difference from 10 Million Ton Rollback (Option II-2A)		
State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Option VI-1	Option VI-2	Option VI-3
Alabama	23.8	22.1	26.3	22.4	19.5	4.2	0.3	-2.6
Arizona	14.2	13.9	13.8	13.8	14.2	-0.1	-0.2	0.3
Colorado	19.1	23.5	23.1	21.4	50.0	-0.4	-2.1	26.5
Illinois	56.4	37.6	41.8	39.5	47.4	4.2	2.0	9.8
Indiana	29.2	19.7	23.8	23.8	23.6	4.1	4.1	3.8
Iowa	1.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Kansas	2.5	0.4	0.4	0.4	1.1	0.0	0.0	0.7
Kentucky	208.9	195.9	196.6	202.8	179.1	0.7	6.9	-16.9
Maryland	2.5	1.5	1.5	1.5	1.5	0.0	0.0	0.0
Missouri	8.1	5.3	5.4	5.4	5.6	0.1	0.1	0.3
Montana	34.0	26.0	26.1	29.0	31.9	0.2	3.0	5.9
New Mexico	31.9	31.9	31.9	31.7	39.5	0.0	-0.1	7.6
North Dakota	22.7	22.7	22.7	19.9	17.0	0.0	-2.8	-5.7
Ohio	24.3	4.0	4.0	1.3	6.6	0.0	-2.7	2.5
Oklahoma	7.7	7.0	7.0	7.0	7.0	0.0	0.0	0.0
Pennsylvania	82.3	56.3	64.9	65.6	68.8	8.5	9.2	12.5
Tennessee	5.3	4.9	6.9	4.9	4.8	2.0	0.0	-0.2
Texas	109.4	108.8	108.8	108.8	108.8	0.0	0.0	0.0
Utah	31.6	32.8	32.0	33.2	36.8	-0.8	0.4	4.0
Virginia	50.6	56.0	56.4	58.0	49.9	0.4	2.0	-6.0
Washington	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
West Virginia	232.2	274.6	269.9	279.5	227.6	-4.7	4.9	-47.0
Wyoming	130.5	191.2	169.1	153.7	204.2	-22.1	-37.4	13.0
U.S. Total	1,128.9	1,137.1	1,133.2	1,124.5	1,145.6	-3.9	-12.6	8.5

SOURCE: Congressional Budget Office.

tinue to purchase high-sulfur coal and still attain low emission rates. Consequently, the decrease in base case 1995 coal production under Option VI-3 for the same four-state region would be only 45.8 million tons, or 13,400 jobs. Therefore, 1995 coal production and employment under Option VI-3 could actually exceed the levels expected in this region under the three less stringent programs, Options VI-1, VI-2, and II-2A.

TABLE 48. DIRECT COAL MINING EMPLOYMENT IN 1995 UNDER THREE OPTIONS BASED ON TWO CURRENT LEGISLATIVE PROPOSALS, COMPARED WITH A POLLUTER PAYS ROLLBACK OF 10 MILLION TONS, BY STATE (In miner-years)

State	Base Case	10 Million Ton Rollback Option II-2A	Option VI-1	Option VI-2	Option VI-3	Differences from 10 Million Ton Rollback (Option II-2A) Option VI-1	Option VI-2	Option VI-3
Alabama	8,124	7,543	8,961	7,640	6,639	1,418	97	-903
Arizona	1,177	1,155	1,146	1,141	1,177	-9	-13	22
Colorado	3,288	4,062	3,986	3,694	8,627	-77	-368	4,564
Illinois	14,733	9,823	10,926	10,333	12,392	1,103	510	2,569
Indiana	5,342	3,611	4,355	4,355	4,311	744	744	700
Iowa	344	110	110	111	111	0	1	1
Kansas	753	129	129	129	343	0	-1	214
Kentucky	63,014	59,098	59,303	61,170	54,010	205	2,072	-5,088
Maryland	695	417	417	419	419	0	2	2
Missouri	1,948	1,276	1,296	1,296	1,337	20	20	61
Montana	1,251	955	961	1,065	1,172	6	110	216
New Mexico	2,846	2,846	2,846	2,835	3,525	0	-11	679
North Dakota	1,375	1,374	1,375	1,204	1,031	0	-171	-343
Ohio	7,136	1,183	1,183	382	1,933	0	-800	750
Oklahoma	2,344	2,146	2,148	2,148	2,148	1	1	1
Pennsylvania	29,299	20,042	23,084	23,333	24,482	3,042	3,291	4,441
Tennessee	2,010	1,859	2,614	1,859	1,794	755	-1	-65
Texas	6,890	6,854	6,854	6,854	6,856	0	0	1
Utah	7,978	8,282	8,074	8,377	9,297	-207	96	1,015
Virginia	19,339	21,375	21,527	22,153	19,067	152	778	-2,307
Washington	48	48	48	48	48	0	0	0
West Virginia	89,473	105,792	103,982	107,681	87,673	-1,810	1,888	-18,119
Wyoming	5,768	8,451	7,474	6,796	9,027	-977	-1,655	576
U.S. Total	275,172	268,431	272,797	275,022	275,418	4,366	6,591	-11,013

SOURCE:Congressional Budget Office.

Compared with other programs, Option VI-3 would reduce the demand for all but the lowest-sulfur coals (that is, those that emit less than 0.8 pounds of SO_2 per million Btus). Although scrubber operation is most economical when used with high-sulfur coal, scrubbers would also be needed to allow medium- and many low-sulfur coals to meet emission limits. In West Virginia, this would mean that expected 1995 coal production would decline by 4.7 million tons, erasing the large gains expected there under the other policies examined in this chapter. In Kentucky, expected production would drop by almost 30 million tons. This shortfall would reduce base case 1995 mining employment in these two states by 10,800 job slots, although it would represent a gain of about 47,000 jobs from current levels, since both states are expected to increase coal production substantially, regardless of policies instituted to decrease SO_2 emissions.

CONCLUSIONS

As emission reduction targets become more ambitious, the costs of achieving them would rise sharply. Average abatement costs would rise from $270 per ton under the 8 million ton reduction (Option II-1A) to $368 per ton under the 10 million ton reduction (Option VI-2). They would increase further to $779 per ton under the 12 million ton reduction (Option VI-3). These increments imply that the cost of abating the final ton of SO_2 (the "marginal" cost) would be substantially higher than the average cost at all levels of control.

In contrast to emission rollback levels in the 8 million to 10 million ton range, demand for high-sulfur coal would not inevitably fall when more exacting rollback targets are sought through very strict emission standards. Increasing the level of emission reduction from 8 million tons to 10 million tons would substantially reduce the production of high-sulfur coal and associated mining employment in the Midwest and Pennsylvania. This effect, however, would be partially offset under the 12 million ton reduction, since some utilities would have no other option but to use scrubbers to achieve the strict emission standards. Because scrubbers are most economical when used with high-sulfur coal, demand for this type of coal would maintain the production level expected under the more lenient 8 million ton rollback.

APPENDIX

APPENDIX

THE NATIONAL COAL MODEL AND CBO ANALYSIS AND ASSUMPTIONS

This appendix describes the analytical approach and assumptions employed by the Congressional Budget Office (CBO) in preparing this report. The appendix is organized into two main sections. The first section explains how the National Coal Model was adapted for this study, and the second discusses additional analysis that CBO performed to transform the output from the National Coal Model into the results reported in the text.

THE NATIONAL COAL MODEL

The National Coal Model Version 5 (NCM5) provides the basis for the analysis performed by CBO. The NCM5 is maintained by the Energy Information Administration (EIA), an independent statistical and analytical agency within the Department of Energy. Three EIA publications describe the NCM5. *Model Description and Formulation* (September 1983) contains an overview of the essential structure of the NCM5, as well a listing of some key data inputs. The *User Manual* (June 1984) explains how to operate the basic version of the NCM5 and how to change input data. Finally, the *Software Manual* (September 1984) documents the source code language and programs that generate the basic model.

The National Coal Model: General Description

The NCM5 is a large linear program (LP) designed to simulate the behavior of the domestic coal market under a variety of assumptions, with particular attention devoted to regional coal demands by electric utilities. The NCM5 generates an equilibrium solution that balances the supply of coal (from 31 regions) and the demand for each coal type (in 44 regions) through an extensive transportation network. The solution of the model minimizes the total cost of coal mining and preparation, coal transportation, and electricity generation and transmission required to satisfy given regional levels of electricity demand and nonutility demands for coal. A set of linear inequalities that constrain the solution represents the physical and technical relationships among the individual activities represented in the model. In addition, bounds on certain activities capture the effect of other exogenous factors, such as currently prescribed emission limits.

By using an LP modelling approch, this analysis assumes that production costs are minimized either through competition or (for electric utilities) by the requirements of regulating authorities. If all coal producers and electric utilities individually minimize cost, then the total cost of all their activities will be minimized as well. Because, under other strict assumptions, market forces essentially solve the allocative problem in the same way that a linear program would, an LP can simulate or predict market outcomes as well as provide prescriptive solutions to resource allocation problems. Of course, the real world does not operate at the level of efficiency suggested by an LP solution and an LP cannot capture all real world subtleties. The biases inherent in such modelling persuade analysts to place more faith in the **differences** among solutions (that is, different policy options) than in the absolute numbers predicted by the model. Such comparative emphasis is reflected in the text of this study.

To examine the underlying structure of the NCM5, it is useful to discuss the coal supply and demand sectors separately, and then explain how an equilibrium solution is attained through the transportation network.

Coal Supply. The coal supply component of the NCM5 expresses the relationships between the annual production of various coals and their mine-mouth prices. These supply curves are produced by the Resource Allocation and Mine Costing (RAMC) model, also maintained by the EIA. 1/ In each of the 31 coal supply regions, the RAMC generates supply curves for each type of coal, based on demonstrated reserve data, mining techniques, regional factor prices, local regulatory requirements, taxes, royalties, and financial assumptions. Although coal is disaggregated into five energy-content categories (as measured by the British Thermal Unit or Btu) and six sulfur-content categories, no region contains more than 14 of these 30 possible coal types. The RAMC output consists of a step function that gives the minimum acceptable selling price for the coal type as a function of annual regional production, assuming that the coal mining industry is perfectly competitive. The NCM5 then converts the RAMC step functions into piece-wise linear supply curves.

Coal Demand. The fundamental problem addressed by the NCM5 is satisfying regional coal demands at the lowest cost. Nonutility demands (metallurgical, industrial, residential-commercial, and export) are given exogenously as regional energy requirements, and remain completely inelastic with respect to the prices of coal or other fuels.

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1. For a description of the basic methodology employed, see Department of Energy, Energy Information Administration, *Documentation of the Resource Allocation and Mine Costing (RAMC) Model* (September 1982).

Utility coal demands are derived from the model solution, which minimizes the cost of satisfying fixed regional electricity demands through generation and interregional transmission. Utility coal demand is responsive to the price of coal, the price of other fuels, emission regulations, and the fixed and variable costs of electricity generation and transmission. The primary determinant of overall coal demand, however, remains the assumed regional electricity consumption of base, intermediate, seasonal peak, and daily peak loads.

The NCM5 represents electric utilities in great detail; Table A-1 lists the 34 possible capacity categories. Coal-fired generation is characterized by capital costs (for new plants, retrofit scrubbers, or boiler conversion to subbituminous coal combustion), nonfuel operating and maintenance (O&M) costs, current pollution control equipment, energy efficiencies, allowable coal types, and applicable sulfur dioxide regulations--for example, emission limits set by the New Source Performance Standard (NSPS), Revised New Source Performance Standard (RNSPS), or State Implementation Plans (SIP). Although the NCM5 assigns individual power plants to homogeneous capacity types, fractions of these capacities can be dispatched to satisfy different loads while burning several coal types. Fractions of SIP capacity can be retrofitted as well. This approximates individual plant behavior, while retaining the analytical tractability that results from grouping similar plants together.

Other inputs into the utility component of coal demand include operating costs for hydroelectric, nuclear, oil-fired, and gas-fired generation. Capital costs are given for plant types that utilities are currently allowed to build. Utilities can purchase unlimited quantities of residual or distillate oil and natural gas at fixed regional prices. These fuels are used primarily to satisfy intermediate and peak loads. Lower bounds on new capacity reflect units currently scheduled to commence operation within 10 years, while upper bounds exist to reflect the time required to plan and construct certain plant types.

Transporation and Equilibrium. A transportation network connects the supply and demand components of the NCM5 and provides the mechanism by which the equilibrium solution obtains. Transportation links between specific supply and demand regions consist of a price (dollar per ton) for transport along that link. These tariffs are derived from existing truck, barge, and rail rates through a formula that takes into account the distance, mode, and terrain, as well as the likely effects of competition, congestion, and fuel prices.

The supply, demand, and transportation submodels are linked into an LP matrix. The objective function includes the annual real costs of coal production, coal transportation, coal mixing, electricity generation, electricity transmission, and nonutility consumption of coal. Capital expenditures are converted to annual flows (levelized) by a capital charge rate (capital recovery factor) that depends on the interest rate and asset durability. The sum of the objective function represents the annual real undiscounted cost of satisfying the national demand for electricity and nonutility coal in a given target year. By minimizing this sum--subject to technical, physical, environmental, and material balance constraints--the NCM5 solution provides both a detailed summary of utility decisions and an extensive origin-destination report of coal shipments.

TABLE A-1. NCM5 CAPACITY TYPES

NCM5 Plant Type	NCM5 Plant Definition	Comments
	Coal	
1X	Old coal plant, no scrubber	Unregulated, typically small.
2X	Old coal plant with scrubber	Currently scrubbing.
5X	SIP-1 [a] plant, no scrubber	Up to three emission limits
5R	SIP-1 plant, retrofitted	per region; plants can
6X	SIP-2 plant, no scrubber	choose to meet current
6R	SIP-2 plant, retrofitted	limits by fuel choice or
7X	SIP-3 plant, no scrubber	retrofit scrubber
7R	SIP-3 plant, retrofitted	installation.
8C	SIP-1 convert to subbituminous	Capital cost of conversion
9C	SIP-2 convert to subbituminous	equals $90 per kw, O&M
AC	SIP-3 convert to subbituminous	penalty of 1.77 mills per kwh.
BX	NSPS [b] bituminous, no scrubber	
BR	NSPS bituminous, with scrubber	Plants can choose low-sulfur
CX	NSPS subbituminous, no scrubber	coal or scrubber to meet
CR	NSPS subbituminous, with scrubber	1.2 lb. SO_2 per million
DX	NSPS lignite, no scrubber	Btus SO_2 emission limit.
DR	NSPS lignite, with scrubber	
EN	RNSPS [c] bituminous (scrubber)	
FN	RNSPS subbituminous (scrubber)	Plants must install scrubbers.
GN	RNSPS lignite (scrubber)	

(Continued)

Conceptually, the demand regions seek the least expensive source of energy, given their assumed electricity consumption, specific generation technologies, regulatory constraints, and nonutility coal requirements. The transportation network coefficients convert tons of coal into delivered prices for coal energy (of specific grades and sulfur contents). The delivered price includes transportation and production costs and is expressed in dollars per Btu. All demand regions simultaneously solve the allocation problem--finding the lowest cost distribution of coal--by drawing different types of coal from several supply regions through the transportation network. The mine-mouth prices for coals of various heat and sulfur contents in all supply regions are determined simultaneously as well, and, by con-

TABLE A-1. (Continued)

NCM5 Plant Type	NCM5 Plant Definition	Comments
	Hydroelectric	
HX	Existing hydro (pondage), base	
HN	New hydro (pondage), base	Build limits for new capacity;
IX	Existing hydro (pondage), intermediate	1 kwh of pumped storage re-
IN	New hydro (pondage), intermediate	quires 1.38 kwh of baseload
JX	Existing hydro (pumped storage) peak	generation.
JN	New hydro (pumped storage), peak	
	Nuclear	
KX	Existing nuclear plant	Determined by current and
KN	New nuclear plant	planned capacity.
	Oil and Gas	
3X	Old oil steam plant	
4X	Old gas steam plant	No new oil and gas plants
LX	Existing combustion turbine	currently permitted,
LN	New combustion turbine	except for combustion
MX	Existing combined cycle	turbines.
MN	New combined cycle	

SOURCE: Congressional Budget Office.

a. Plants subject to individual State Implementation Plan (SIP).

b. Plants subject to the first New Source Performance Standard of 1971 (NSPS).

c. Plants subject to the Revised New Source Performance Standard of 1978 (RNSPS).

struction, equal the price needed to induce the total required production of the specific coal from each region. In equilibrium, each type of coal consumed in a demand region carries an identical price (in dollars per million Btus), irrespective of source, while only one regional supply price (in dollars per ton) exists for specific coal types, regardless of destination. 2/ The solution also determines interregional electricity transmission based on the least-cost allocation of generation costs, including the resource cost of transmission and distributional losses.

The NCM5 generates solutions for three target years: 1985, 1990, and 1995. The 1990 and 1995 solutions require assumptions regarding future exogenous inputs, such as electricity demand growth, nonutility coal consumption, and rail rates. They also require information from previous solutions, such as the irreversible production decisions that created available capacity. The NCM5 utilizes such information in subsequent solutions, as well as constraining some activities to keep them close to their previous levels. Future solutions, however, have no effect on previous solutions; the model only considers the current annual costs of activities in selecting the cost-minimizing outcome. Therefore, the NCM5 is not a dymanic model in any sense, but rather three sequentially solved static equilibria.

NCM5 Modifications and Enhancements by CBO

Modifications to the Base case and All Policy Simulations. Some of the input cost data in the NCM5 were changed to reflect more current cost estimates or to conform with CBO financial assumptions. Table A-2 lists these changes, as well as several key assumptions retained from the EIA base case as of January 1985.

Of the data inputs not altered by CBO, one set deserves mention. The EIA base case of January 1985 assumed that the real price of residual fuel oil would rise about 3.5 percent annually over 10 years. 3/ Very recent trends, however, suggest that oil prices, already lower, could remain stable, or even decline, during this period. This could affect three inputs used in the analysis: predicted electricity demand, utility fuel prices, and rail rates.

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2. The existence of lower limits on specific coal shipments will violate the equilibrium condition of a single price for coal of certain types consumed in a particular region. See the discussion of the "RETAIN" feature later in this appendix.

3. For an overview of major assumptions, see Department of Energy, Energy Information Administration, *Annual Energy Outlook 1984* (January 1985). For the NCM5, the EIA adjusts the oil prices to reflect regional variation.

TABLE A-2. CBO ECONOMIC AND FINANCIAL ASSUMPTIONS USED IN THE NATIONAL COAL MODEL

Parameter	Value or Assumption	Comments or Source
Annual Electricity Demand Growth (In percent)		
1985-1995	3.1	EIA Base Case
Annual Nonutility Coal Energy Demand Growth (In percent)		
1985-1990	3.9	EIA Base Case
1990-1995	1.6	
Rail Rates 1985-1995	EIA Base Case	Based on 1984 unit train rates adjusted to reflect future competition, congestion, and lower oil prices.
Real Capital Charge Rate (In percent)	7.7	Based on CBO forecast of utililty financing at 6.5 percent real interest over 30 years.
Capital Charge for Retrofit Scrubbers (In percent)	7.7	Accelerated depreciation rules applied to retrofits offset shorter assumed life of 20 years.
Cost of New Coal-Fired Steam Capacity (In dollars per kilowatt (kw))	1,075	Source: CBO
Scrubber Costs for 90 Percent Control of High-Sulfur Coal, including Sludge Disposal and Spare Modules		Source: Current EPA estimates using the TVA scrubber cost model (except retrofit penalty).
Capital (in dollars per kw)	238	
O&M (in mills per kilowatt hour)	4.28	
Heat Penalty (in percent)	4.81	
Capacity Penalty (in percent)	2.41	
Retrofit Penalty and Boiler Refurbishment (in dollars per kw)	125	Source: CBO
Current Emissions	In compliance	EIA Base Case

SOURCE: Congressional Budget Office.
Note: All dollar figures are in 1985 dollars.

Lower oil prices could increase overall electricity demand by boosting economic growth beyond current projections. The EIA assumes that electricity demand between 1985 and 1995 will increase at an average annual rate of 3.1 percent, based on real gross national product (GNP) increases of 2.7 percent per year. If electricity demand exceeds these predictions, the costs of achieving a specified level of 1995 emissions might rise simply because more generation would be required. By the same reasoning, incentive-based policies could lead to higher emission levels.

On the other hand, power plants that burn oil and natural gas emit far less sulfur dioxide than coal-fired plants. To the extent that utilities could purchase cleaner fuel economically, the cost of an SO_2 abatement policy could decline. Large scale substitution of other fuels for coal, however, might be inhibited by uncertainty about future fuel prices, conversion costs, and regulatory decisions.

Whether overall costs of emission reductions increase or decline because of the two effects described above, it is doubtful that the relative costs of the options considered in this report would change significantly. Lower oil prices, however, could also reduce rail rates, particularly on the longer hauls in which fuel is a substantial component of cost. Lower rail rates could increase western low-sulfur coal shipments to the Midwest, particularly under emission reduction policies. This effect would reduce total utility costs unevenly across policies, as a higher cost differential between fuel switching and scrubbing would increase the relative cost of protecting midwestern high-sulfur coal production. Lower oil prices, therefore, would not alter the basic conclusions presented in the text, but absolute effects might differ.

The CBO adjusted the real capital charge rate (the factor that converts capital expenditures into levelized annual costs) to 7.7 percent. This figure assumes that utilities can finance an asset with a useful life of 30 years by borrowing at a real interest rate of 6.5 percent. No differential was included for retrofit scrubbers, since the current tax laws for accelerated depreciation for pollution control equipment virtually offset the shorter life (20 years) assumed for retrofit scrubbers. The retrofit penalty, however, for installing a scrubber was set at $125 per kilowatt (kw) to account for boiler modifications and additional particulate control that utilities would likely undertake.

Another important CBO modification to the basic model allowed existing state-regulated, coal-fired plants (SIP plants) to reduce emissions below their mandated limits. The SIP generating capacities are essentially defined by their emission limits, and the NCM5 will only allow enough construction of new retrofit scrubbers to meet these predetermined requirements. Since utilities must reduce emissions to levels well below current SIP standards under the options considered here, the ability to use scrubbers to achieve stricter limits must be present. Upper limits on retrofit capacity, however, are also imposed, based on figures provided by the EIA. 4/ These enhancements increased the size of the model to nearly 3,400 rows, over 15,000 columns, and about 115,000 nonzero coefficients.

All policy effects (mandated reductions, subsidies, or taxes) are captured in the 1995 solution, the compliance date stipulated in many bills introduced into the 98th Congress. Additional programs were constructed to convert the 1995 results from the NCM5 into streams of cost, revenues, and subsidy levels during the period from 1986 through 2015. These are described later in the appendix.

Finally, the National Utility Financial Statement (NUFS) was coupled to the NCM5 in order to produce the electricity rate estimates for all options. This model is also housed and maintained at the EIA. Inputs into NUFS include the annualized capital, fuel, and nonfuel O&M costs, as well as regional generation, consumption, imports, and exports of electricity. The NUFS model transforms this information (from all three solution years) into a simple financial statement for each region's utilities, and derives a 10-year profile of electricity rates from the revenue requirements. The CBO also revised some of the financial assumptions embodied in NUFS so that they would conform with CBO assumptions.

Polluter Pays Options in Chapter II. No additional modifications were necessary to simulate the 8 million ton and 10 million ton rollback schemes found in Chapter II, since the NCM5 had been previously modified by the EIA to study these types of policies. The regional emission targets were applied to non-NSPS coal- and oil-fired sources, based on the excess emission formula and using 1980 emissions as a baseline. Table A-3 shows the limits imposed on each state. The 1980 emissions are higher than the 1985 model predictions because of the assumption that all plants are currently in compliance with local SIP standards. Progress toward SIP compliance did in fact occur during this period, and, when this is combined with fairly flat demand growth (averaging only 1.7 percent per year), 1985 estimates seem quite plausible. 5/

4. These figures were based on the "Acid Rain Boiler Population Retrofit Analysis" performed by PEDCo Environmental, Inc., for the Department of Energy in April 1983.

5. The OTA study from which CBO takes emission levels estimates that in 1980 utilities emitted roughly 1.4 million tons more than allowed under the SIP standards. Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Control Proposal: H.R.3400, "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, revised July 12, 1983.

The regional emission targets are incorporated into the NCM5 by imposing a constraint (less than or equal to) on the sum of utility SO_2 emissions within a state. When the NCM5 divides states into more than two or three regions, the constraint applies only to the statewide total. When two or more states comprise an NCM5 region, the individual state targets were summed to construct the constraint. A very limited regional trading scheme was allowed, since states were allowed to exceed their emission targets by 5 percent, as long as the overall national constraint was satisfied.

TABLE A-3. SO_2 REDUCTIONS REQUIRED BY THE EXCESS EMISSIONS FORMULA, BY STATE (In thousands of tons of SO_2)

State	1980 Emissions	8 Million Ton Reduction		10 Million Ton Reduction	
		Amount	Percent	Amount	Percent
Alabama	543	225	41	281	52
Arizona	88	0	0	0	0
Arkansas	27	1	2	1	2
California	78	0	0	0	0
Colorado	78	0	0	0	0
Connecticut	32	0	0	0	0
Delaware	53	13	25	17	32
District of Columbia	5	0	0	0	0
Florida	726	267	37	334	46
Georgia	737	363	49	454	62
Idaho	0	0	0	0	0
Illinois	1,126	603	54	753	67
Indiana	1,540	938	61	1,172	76
Iowa	231	101	43	126	54
Kansas	150	60	40	75	50
Kentucky	1,008	567	56	708	70
Louisiana	25	0	0	0	0
Maine	16	2	13	3	17
Maryland	223	86	39	108	48
Massachusetts	276	83	30	104	38
Michigan	565	187	33	233	41
Minnesota	177	51	29	63	36
Missippi	129	57	45	72	56
Missouri	1,141	716	63	895	78
Montana	23	1	5	2	6
Nebraska	50	6	12	8	15

(Continued)

The "RETAIN" feature was used to simulate a policy of restricted fuel switching. RETAIN is an NCM5 function that specifies a lower limit on specific coal shipments based on the previous solution; setting RETAIN equal to 9 would ensure that at least 90 percent of a coal shipment of a certain sulfur content could be maintained in the subsequent solution (five years later). Thus, a value of 9 would preserve about 80 percent of current coal patterns between 1985 and 1995. In the base case, RETAIN equalled 5, and under all other acid rain policies, RETAIN was set at 1. This latter

TABLE A-3. (Continued)

State	1980 Emissions	8 Million Ton Reduction		10 Million Ton Reduction	
		Amount	Percent	Amount	Percent
Nevada	40	0	0	0	0
New Hampshire	81	40	49	49	61
New Jersey	110	30	27	37	34
New Mexico	85	0	0	0	0
New York	480	178	37	222	46
North Carolina	435	69	16	87	20
North Dakota	83	9	11	12	14
Ohio	2,172	1,272	59	1,590	73
Oklahoma	38	0	0	0	0
Oregon	3	0	0	0	0
Pennsylvania	1,466	677	46	846	58
Rhode Island	5	0	0	0	0
South Carolina	213	75	35	94	44
South Dakota	29	7	25	9	31
Tennessee	934	533	57	666	71
Texas	303	9	3	12	4
Utah	22	0	0	0	0
Vermont	1	0	0	0	0
Virginia	164	21	13	26	16
Washington	69	17	25	22	31
West Virginia	944	457	48	571	61
Wisconsin	486	274	56	343	71
Wyoming	121	6	5	7	6
Total	17,325	8,000	46	10,000	58

SOURCE: Congressional Budget Office, from Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Control Proposal: H.R.3400, "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, revised July 12, 1983.

value reflects the assumption that utilities could break nearly all long-term coal contracts over a 10-year period if the Congress enacted major legislation to reduce SO_2 emissions.

Subsidized Scrubber Options with Generation Taxes in Chapter III. Both the 8 million ton and 10 million ton rollbacks were examined, using the identical emission constraints imposed in Chapter II. Each level of control was accompanied by (1) a 90 percent capital subsidy for retrofit scrubbers, and (2) a 90 percent capital subsidy combined with a 50 percent O&M subsidy for operating the scrubbers. For the capital subsidy, the coefficients in the 1995 objective function that represent the building of a retrofit scrubber were simply reduced by 90 percent. For the O&M subsidy, the 1995 coefficients that represent the operation (generation) of a retrofitted plant were reduced by an amount equal to 50 percent of the variable costs attributed to scrubber operation.

The "Top 50" approach, as embodied in H.R. 3400 (Option III-2C), required more complicated modifications. The list of the top 50 emitters was taken directly from a study done by the Office of Technology Assesment. 6/ In 1995 the appropriate SIP capacity was deducted from the regions affected, most of which was rebuilt at the cost of constructing retrofit scrubbers conforming to the revised NSPS, subsidized at 90 percent. A few plants were simply retired, based on the PEDCo analysis which found them to be impossible or highly uneconomic to retrofit. 7/ This proceedure retained the correct heat rates for the plants and recorded the appropriate capital costs. An additional 90 percent capital subsidy was included for other retrofit scrubbers required to meet the remaining emission targets.

Emission Tax and Subsidy Options in Chapter IV. A tax of $600 per ton of SO_2 emitted ($.30/lb.) was added to the 1995 objective function coefficients that represent the operation of pre-NSPS coal- and oil-fired capacity. The tax was based on calculated emission rates that differ by plant type, fuel, load, and scrubber removal efficiency. Revenues were calculated based on the observed emission levels. In addition, two subsidy levels were granted, as in Chapter III.

Sulfur Content Taxes and Subsidies in Chapter V. In 1995 the coefficients that represent coal supply curves were increased by the appropriate (per

6. See Office of Technology Assessment, *An Analysis of the Sikorsky/Waxman Acid Rain Proposal.*

7. These plants are listed in Office of Technology Assessment, *Additional Analyses of H.R. 3400: "The National Acid Deposition Control Act of 1983,"* Staff Memorandum, September 16, 1983.

ton) tax rates, and equilibrium tax revenues were computed in the coal report program by multiplying the volume of shipments by the specific tax rate applied. A 90 percent capital subsidy was granted for retrofit scrubber installation as well as the $0.50 per pound subsidy granted for each pound of sulfur removed by all scrubbers, including NSPS plants. The latter subsidy was granted by reducing the coefficients of the 1995 objective function that accounted for scrubber operation, based on the calculated removal efficiency and sulfur content of the coal burned.

Recent Proposals in Chapter VI. Since Option VI-1 was based on specific state emission targets, no modifications were required. The emission targets that applied to pre-NSPS sources were obtained from the Office of Technology Assessment, based on an annual average statewide SO_2 emission rate of 1.2 pounds per million Btus. These were incorporated as strict targets, and did not allow individual states the opportunity to exceed their limits by five percent, as permitted in Chapters II and III.

Options VI-2 and VI-3 did not use regional emission targets, but instead were based on all plants meeting specified SO_2 emission rates--1.2 pounds per million Btus for Option VI-2, and 0.7 pounds per million Btus under Option VI-3. First, additional columns were created to represent the operation of retrofit scrubbers at these standards (although for Option VI-3 the scrubbing standard was actually 0.67 pounds per million Btus, since it currently existed in the model). Then, preexisting columns were identified that represented the operation of an unscrubbed plant while burning a coal with sulfur content in excess of the standard, as well as those that portrayed the operation of a scrubbed plant under a more lenient standard than specified in the bills. To stimulate these two policies, the cost of these latter activities were increased to prohibitive levels in the 1995 solution. The solution therefore only allowed the use of plants that complied with the uniform emission rate standard. (Under Option VI-3, coal emitting up to 0.8 pounds of SO_2 per million Btus could be burned without a scrubber, because it is the cleanest category of coal specified in the model.)

ADDITIONAL MODELS

The CBO constructed several smaller models to transform the NCM5 output into the values reported in the tables and text of this paper. The least complex of these simply aggregates the NCM5 results into larger regions, such as states. Another model sums the levelized capital expenditures for the three solution years, and adds the variable cost of the 1995 solution to this in order to approximate the annual costs incurred by utilities in 1995 under different options. The final simple model converts tons of coal mined in each region into labor requirements ("miner years") by applying an appropriate multiplier for each region based on 1983 average productivity.

Two other models warrant a more detailed explanation: the trust fund model and the discounted program cost model.

The Trust Fund Model. The model that computes trust fund balances differs slightly from chapter to chapter, depending on the assumed timing of receipts and outlays. In all cases, however, the model computes real end-of-year balances, based on a real interest rate of 3.7 percent. This represents the CBO forecast of real interest on new debt issued by the Treasury (weighted by maturities). Administrative expenses of $25 million per year are included as outlays each year.

The generation taxes (Chapter III) are not incorporated into the NCM5, but are based instead on predicted fossil fuel generation. Therefore, these taxes neither affect overall electricity consumption nor the dispatching decisions of electric utilities. Such an assumption is warranted by the level and duration of the tax, and the limited opportunities for substitution of hydroelectric and nuclear generation. The tax levels were chosen in order to generate sufficient revenues over 10 years to cover all subsidy obligations predicted by the NCM5.

The annual outlays in Chapter III are based on the response of utilities to the available subsidies. The trust fund outlays for the capital subsidy rise gradually from 1991 until they reach the "steady state" annual level required in 1995. These are then tapered off steadily in the 2011-2015 period. The O&M subsidy begins in 1995 at the annual level suggested by the NCM5 solution, and remains constant through 2015, after which all subsidies expire. The 1995 commencement assumption reflects the lack of incentive for utilities to finish and operate scrubbers until the compliance date.

The tax revenues in Chapter IV and Chapter V are determined by the 1995 solution of the NCM5. In both cases, 1986 revenues are calculated on the 1985 tax base observed in the absence of the tax. This provides a static revenue estimate based on the assumption that utilities can not alter their decisions in a short time in order to reduce tax liabilities. The stream of revenues and outlays between 1986 and 1995, however, requires more assumptions about how quickly the utilities achieve the "steady state" solution predicted by the NCM5.

The direct emission tax policies examined in Chapter IV generate so much more revenue than subsidy obligations that trust fund balances are less of a concern. An account of government holdings is kept, however, for the net present value calculation, and assumes a simple linear decline in emission tax revenues between 1986 and 1995, with both the capital and O&M subsidies rising steadily between 1991 and 1995. The revenue levels remain constant until 2010, after which they decline because of the retirement of two-thirds of the taxed sources by 2015. Similarly, the subsidies gradually decline to zero by the end of 2015.

In the Chapter V policies that tax the sulfur content of coal to provide subsidies for scrubbing, the revenues also decline steadily between 1986 and 1995. On the outlay side, the capital subsidy is phased in between 1991 and 1995. The subsidy for emission reduction, however, takes current scrubbing into account; the 1986 subsidy is based simply on the amount of sulfur removed by scrubbers in 1985. This amount rises slightly as planned scrubbers are constructed for the 1990 solution (without tax incentives taken into account), and steadily increases between 1991 and 1995 to reach the levels predicted by the model. All taxes and outlays remain constant until 2015.

The Discounted Program Cost Model. The inputs into this model include the change in annual utility costs (both capital and variable, as measured against the base case), as well as the level of subsidies, taxes, trust fund balances, and emission reductions. These results are combined with assumptions concerning the timing of expenditures and emission reductions--conforming to the assumptions employed in the trust fund model--to construct a yearly stream of resource costs attributed to the option from 1986 through 2015. These costs, discounted at 3.7 percent annually, are then summed to give the discounted program cost figure reported in the text as a 1985 net present value. To calculate the cost-effectiveness measure, the emission reductions are assumed to coincide with the appropriate expenditures, that is, fuel premiums and scrubber operations. This profile of emission reductions is also discounted at 3.7 percent and summed to provide the denominator of the cost-effectiveness measure, with the discounted program cost as the numerator.

For the options examined in Chapters II and III, no resource costs or emission reductions occur between 1986 and 1990. Utilities begin to build scrubbers in 1991, and complete them in 1995 in order to meet the compliance deadline. These real capital costs are, therefore, phased in during this period, achieving the annual level predicted by the model in 1995. No variable costs (fuel premiums or scrubbing O&M) are incurred, however, until 1995, at which time all emission reductions are assumed to occur. This assumes that utilities can wait until the last possible moment to comply. During the 1995-2015 period, the emission reductions and annual costs are assumed to hold constant, with the exception of the capital costs which are phased out during the last five years.

The incentive-based options discussed in Chapters IV and V require different assumptions regarding the timing of emission reductions and the associated abatement costs. Capital costs are still phased in during the 1991-1995 period, reflecting the planning time necessary to begin scrubber installation. All variable costs, as well as emission reductions, are gradually phased in from 1987 through 1995. This embodies the assumption that utilities will switch fuels and begin to operate scrubbers earlier than assumed in the compliance date policies. While this assumption raises discounted program costs, the benefits of earlier emission reductions are reflected in the cost-effectiveness calculation. The cost and emission assumptions for the 1995 through 2015 period are the same in all chapters, although the options examined in Chapter IV might still produce tax revenues, and the Chapter V options would continue to generate revenues and require subsidies.

Why is the discount rate of 3.7 percent identical to the rate at which the trust fund accumulates interest? Choosing equal rates in this analysis means that the overall discounted program cost of an option will not depend on its period-by-period trust fund balance. This assumes that society attaches no cost to the government's holding excess trust fund balances, as long as the fund earns a rate of return sufficient to compensate contributors before their reimbursement.

Choosing a discount rate becomes especially important--and controversial--when both costs and benefits are examined. Usually the costs attributed to a public project or policy are incurred before benefits (returns) are realized, and the assumed discount rate can determine whether or not a policy represents a net economic gain for society. In this analysis, which does not estimate the dollar values of emission reduction benefits, the discount rate provides a way to compare the overall cost of policies when the timing of actual expenditures differs. The 3.7 percent annual real rate approximates the value of current consumption over the postponement implied by riskless investment--often called in economics "society's rate of pure time preference." This constitutes the lowest rate typically assumed in policy analysis; a low discount rate applied to expenditure streams raises the discounted value of program costs, but also limits somewhat the "penalty" for incurring expenditures sooner.

GLOSSARY

GLOSSARY

This glossary furnishes quick identification of the many options examined in this report. Only key provisions of each option are listed here; the reader should refer to the text for a more detailed description.

The title of each option begins with a roman numeral that indicates the chapter in which it is introduced. For the options examined in Chapters II and III, the arabic numeral designates the level of reduction mandated from 1980 emission levels (1 indicates an 8 million ton reduction; 2 indicates a 10 million ton reduction). For options described in Chapters IV, V, and VI, however, the arabic numeral has no specific meaning beyond identification.

Option II-1A: an 8 million ton rollback of SO_2 emissions that allows fuel switching; polluter pays all costs.

Option II-1B: An 8 million ton rollback of SO_2 emissions that restricts fuel switching; polluter pays all costs.

Option II-2A: A 10 million ton rollback of SO_2 emissions that allows fuel switching; polluter pays all costs.

Option II-2B: A 10 million ton rollback of SO_2 emissions that restricts fuel switching; polluter pays all costs.

Option III-1A: An 8 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-1B: An 8 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy and a 50 percent operation and maintenance (O&M) subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2A: A 10 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2B: A 10 million ton rollback of SO_2 emissions that includes a 90 percent capital subsidy and a 50 percent O&M subsidy for retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option III-2C: A 10 million ton rollback of SO_2 emissions that requires the 50 highest emitting plants to install scrubbers, and that includes a 90 percent capital subsidy for all retrofit scrubbers provided by a temporary tax on electricity generation fired by fossil fuels.

Option VI-1: Imposes a tax on SO_2 emissions of $600 per ton, to achieve a total SO_2 rollback of 9.2 million tons.

Option VI-2: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.5 million tons.

Option VI-3: Imposes a tax on SO_2 emissions of $600 per ton, and includes a 90 percent capital subsidy and a 50 percent O&M subsidy for retrofit scrubbers. Achieves a total SO_2 rollback of 9.6 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained in each ton (to the extent that sulfur content exceeds 10 pounds per ton). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option V-1: Imposes a tax on each ton of coal sold, computed at $0.50 per pound of sulfur contained per million Btus (to the extent that sulfur content exceeds 0.4 pounds per million Btus). Grants a 90 percent capital subsidy on retrofit scrubbers as well as a $0.50 per pound subsidy for any sulfur removed by a scrubber. Achieves a total SO_2 rollback of 8.9 million tons.

Option VI-1: A polluter pays rollback of SO_2 emissions based on utilities' achieving a statewide average emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.1 million tons.

Option VI-2: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 1.2 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 9.9 million tons.

Option VI-3: A polluter pays rollback of SO_2 emissions based on utilities' achieving a plant-by-plant emission rate of 0.7 pounds of SO_2 emitted per million Btus of fuel burned. Achieves a total SO_2 rollback of 12.3 million tons.