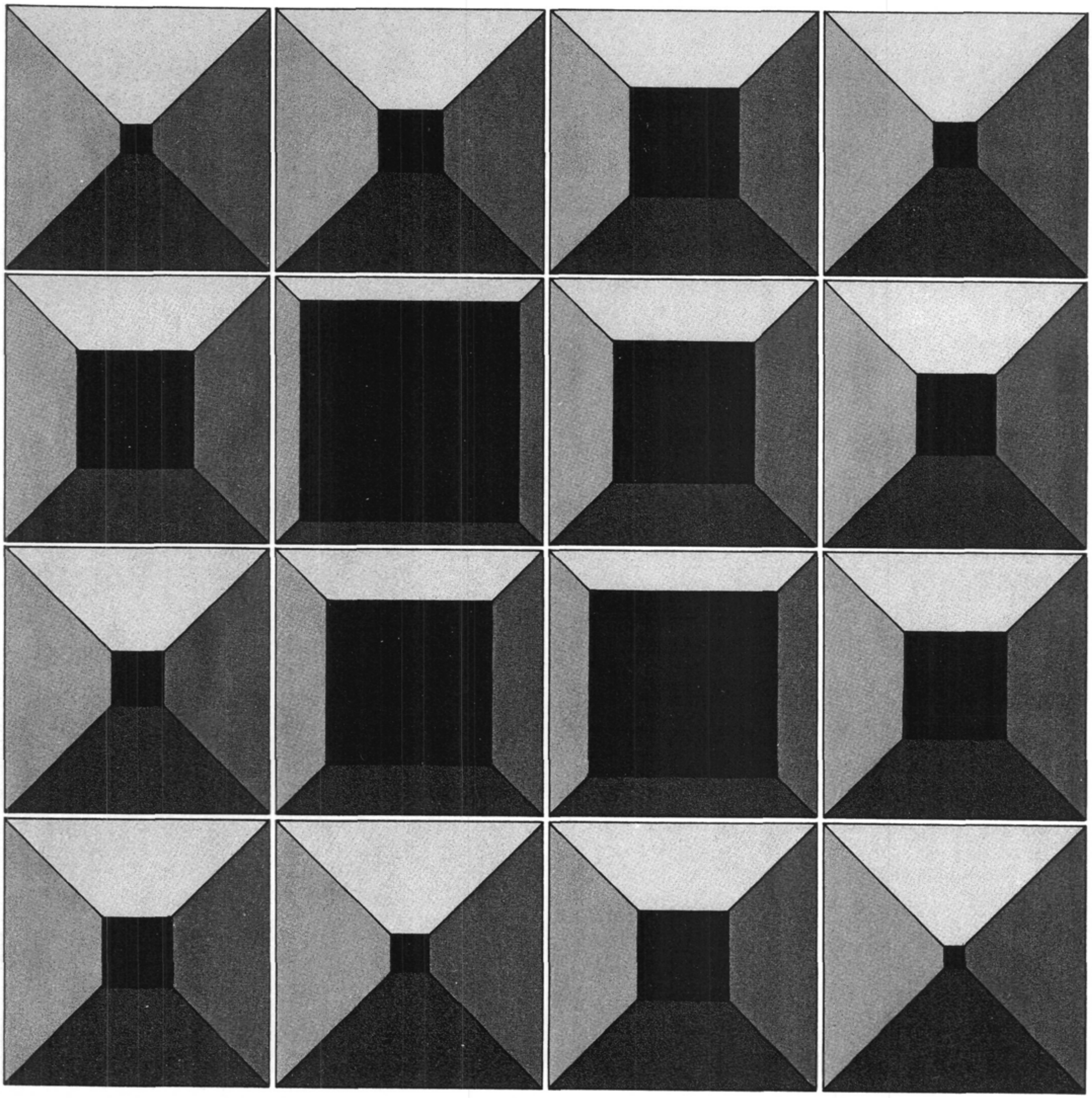
A CBO STUDY

The Clean Air Act, the Electric Utilities, and the Coal Market

April 1982

Congress of the United States
Congressional Budget Office



THE CLEAN AIR ACT,

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NOTES

Except where noted, all dollar figures are expressed in 1980 dollars. All dates are expressed in calendar years.

The projection period analysed begins in 1980 and ends in the year 2000. The most recent year for which most actual data are available is 1979.

PREFACE

In 1981, the Congress began to consider amending the Clean Air Act; that process is still underway. Among the critical areas being examined are the federal standards that regulate air pollutant emissions from new electric power plants using coal. Whether the regulations now in force can control pollutant emissions effectively without imposing undue cost burdens on the utilities and without affecting the distribution of U. S. coal production are critical questions in the Congressional debate.

The Congressional Budget Office has prepared this analysis of these interrelated issues, focusing both on the current standards and four alternative policies that would contribute to abating pollutant emissions from new coal-fired power plants. The study was undertaken at the request of Senator Robert T. Stafford, Chairman of the Senate Committee on Environment and Public Works. In keeping with the CBO's mandate to provide objective analysis, this paper offers no recommendations.

John Thomasian of CBO's Natural Resources and Commerce Division prepared the study, under the supervision of David L. Bodde and Everett M. Ehrlich. The author wishes to express special thanks to Hoff Stauffer of ICF, Incorporated for his assistance in preparing the coal-market analysis, to Johanna Zacharias for assistance in drafting the paper, and to Angela Z. McCollough for typing the manuscript and preparing it for publication. Valuable contributions also were made by Emily W. Fox and Paul Ginsburg of CBO, Richard L. Gordon of Pennsylvania State University, and J. Steven Herod of the U. S. Department of Energy.

Alice M. Rivlin
Director

April 1982

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SUMMARY

As the Congress considers revising portions of the Clean Air Act, it confronts the sometimes difficult balance between two federal objectives:

- o Achievement and maintenance of environmental quality, and
- o Assurance of a reliable and low-cost supply of electricity derived from coal, the nation's most abundant domestic energy source.

At present, coal combustion in utilities furnishes roughly half of the nation's electricity--at the same time emitting nearly two-thirds of all the sulfur dioxide, a gaseous pollutant, released into the United States' atmosphere.

UNDERLYING ISSUES

The Clean Air Act's new source performance standards (NSPS), by regulating pollutant emissions from new power plants, will ultimately bring about a generation of coal-fired facilities that will be markedly cleaner than those supplying most electricity today. By the turn of the next century, the amount of pollution utilities release relative to the volume of fuel consumed will be reduced well below current levels, though the actual quantity of each pollutant, except particulate matter, will continue to grow through the year 2000. Sometime after that date, a measurable reduction in total utility emissions of pollutants should begin to materialize. But because of the very nature of the NSPS, which set standards for new or modified facilities only, much of the emissions control benefit of the regulations lie far ahead.

The Role of the Electric Utilities

The nearer term will largely be a period of investment in cleaner power plants; these will not outnumber their more polluting predecessors for another two or even three decades. The electric utility industry will carry a large share of that air pollution control investment. In complying with the NSPS, utilities burning coal will dedicate some 20 percent of all their capital investment to air pollution control in the next two decades. More than half of this investment will involve meeting the current standards regulating emissions of sulfur dioxide.

The Coal Market's Role

The U.S. coal industry will also play a part, though a more passive one, in pursuing the two federal goals of clean air and energy self-sufficiency. The industry will benefit significantly from the utilities' expanded use of coal. Coal consumption in power plants, the nation's largest coal user, has already risen by 65 percent from 1970 to 1979; over the coming two decades, it will more than double. Not all coal producers will share equally in this boom, however. Western producers stand to achieve a greater gain than their counterparts in the Midwest and East. The Congress has already linked concerns of the coal market to provisions of the Clean Air Act. In the 1982 debate on the act, similar issues will almost certainly recur: What effects will the current or alternative NSPS--particularly sulfur dioxide standards--have on U.S. coal development?

COAL, SULFUR DIOXIDE EMISSIONS, AND NEW SOURCE PERFORMANCE STANDARDS

An intrinsic chemical property of coal--specifically, its sulfur content--directly affects the amount of sulfur dioxide that results from coal combustion. When burnt in a 500-megawatt power plant without emissions control, a high-sulfur coal could generate roughly 91,980 tons of sulfur dioxide a year. Conversely, combustion of a low-sulfur coal in the same power plant could yield roughly 7,665 tons of sulfur dioxide a year. Though coal is produced in all three subdivisions of the country--the East, the Midwest, and the West--sulfur content varies markedly. Eastern deposits contain both low- and high-sulfur coal; midwestern coal ranges from moderate to high in sulfur content; western coal is generally low in sulfur.

The NSPS of 1971

The act's original provisions regulating new source pollutant emissions--eliciting the utility NSPS of 1971, which applied to all new fossil-fuel-fired generators--did not take these differences into account. The 1971 NSPS mandated that the utilities meet a mass sulfur dioxide emissions limit of 1.2 pounds per million British thermal units (BTUs) of coal burnt, as well as placing limits on nitrogen oxides and particulate matter. Utilities could comply by whatever means was most economical, and most elected to burn low-sulfur coal. One result was a slowing of sulfur dioxide emissions growth; a significant reduction in particulate pollution occurred; but there was little success in curbing nitrogen oxide emissions.

Another result, perceived by high-sulfur coal producers and in turn, by the Congress, was that imposition of the NSPS would change the distribution of U.S. coal production--specifically, that the 1971 NSPS could encourage the production and use of abundant low-sulfur western coal over its high-sulfur counterpart in the Midwest. This perception, together with the desire to promote the use of control technology, led to the revisions in the utility NSPS that became effective in 1978.

The NSPS of 1978

Revisions implemented in 1978 were conceived, in part, to counter the relocation of U.S. coal production. The 1978 standards, which remain in effect and govern all power plants now being planned, were purposefully designed to make high-sulfur coal as economically attractive to utilities as low-sulfur coal. To accomplish this, the revisions stipulated not only that the old mass emissions limit (a "ceiling") must be met, but also that a fixed percentage of all sulfur dioxide be removed from all power plants burning coal. In recognition of the sulfur-content variations in coal, the revised NSPS permitted a sliding scale for emissions removal, to range between 70 and 90 percent, depending essentially on the sulfur content of coal used.

The effect of the provisions under the 1978 NSPS, which are quite rigid compared to the older standards, is to make the use of flue gas desulfurization technology--called "scrubbers"--mandatory. To date, scrubbers are the primary control technique that is commercially available to help utilities meet the NSPS in conventional boilers. No matter what coal is to be used, all new plants subject to the 1978 standards must be equipped with scrubbers or some other suitable control method. The costs of desulfurization will be the single most important element in the utilities' future costs for air pollution control.

THE COSTS OF EMISSIONS CONTROL

The utilities have already invested sizable sums of money to curb pollutant emissions, and they are likely to continue to do so. In each year since 1973, the industry devoted from 5 to 7 percent of all capital expenditures to emissions control hardware. Over the coming two decades (the base period for the Congressional Budget Office's projections), investment in air pollution control equipment is projected to involve 20 percent, or $33.4 billion (in 1980 dollars) of the roughly $167 billion needed to construct new coal-fired generating capacity (not including transmission and distribution).

The utilities' annual air pollution control costs, including operation of scrubbers, fixed capital charges, and premiums on low-sulfur fuel, are expected to rise from $5.35 billion in 1980 to $14.1 billion in the year 2000. By that year, these costs translate to a nationwide average of 3.43 mills per kilowatt-hour, representing roughly 6 percent of the average electricity charge to residential consumers in 1980. Pollution control at new units--by definition, subject to the 1978 NSPS--is expected to cost approximately 6 mills per kilowatt-hour for western power plants, which can use locally mined low-sulfur coal and lower-cost scrubbing methods, and 10 mills per kilowatt-hour for eastern facilities, which typically will use local high-sulfur coal and expensive scrubbing methods, or will ship low-sulfur coal from other regions to lower scrubbing costs.

Effects on The Utilities' Financial Condition

Because of the high capital costs of air pollution control, it is reasonable to question whether the Clean Air Act is placing an unmanageable burden on the electric utilities. Would the industry's finances be stronger if there were no need to invest in pollution control measures? The findings of the CBO analysis indicate that, though controlling emissions is indeed costly, it has not played a major role in impairing the utilities' financial position, and is not likely to do so in the future. A comparison of the bond ratings of two sample groups of firms with appreciable investments in pollution control against the industry as a whole suggests that utilities with commitments to pollution control tend to fare no better and no worse than all electric utilities in general. Special tax provisions and other mitigating factors directed at easing the investment costs of pollution control may account in part for why the costs of emissions control are not especially detrimental. Overall, most utilities, regardless of investment in emissions control, have experienced some financial decline (indicated by downgraded bond ratings), but this pattern may be more properly ascribed to other causes.

State-Mandated Accounting Methods. Accounting methods required by the states' regulatory public utility commissions often tend to make capital investments in new facilities burdensome. In most states, an electric utility cannot incorporate the costs of a new power plant in its rate bases until the facility becomes operational; hence, the utility cannot receive a return on its investment for roughly eight to 12 years, the usual construction period for power plants. On the other hand, rising fuel costs often may be recovered immediately from consumers, with the result that continued operation of older power plants burning oil or gas, though commonly more expensive, is the preferred alternative to investing in scrubber-equipped new facilities entailing high capital expenses.

EFFECTS ON U.S. COAL MARKETS

The westward shift in coal production seen over the past decade cannot be directly linked to the Clean Air Act, although such a shift is certainly clear. In 1960, the producing states in the East accounted for 95 percent of total production. By 1970, the East's share had declined to 85 percent and, by 1979, to roughly 75 percent. By the year 2000, the West is projected to hold a full 66 percent share of the nation's total coal production. Regarding western coal shipments east, sulfur dioxide limitations of the NSPS have influenced this only partly, and despite the intent of the revised NSPS to counter this trend, western producers are projected to capture a still greater share of the total midwestern and eastern coal markets in the future. In 1979, western producers shipped some 22 million tons of coal east to utilities; by the year 2000, some 127 million tons of western coal, or 7 percent of the total 1.9 billion tons produced in that year, are expected to be shipped east.

The current NSPS appear to have little influence to bolster midwestern and eastern coal production against such growth in the West. Western coal production is rising for several intrinsic reasons. First, lower-cost mining methods predominate there. Second, with this initial cost advantage, western coal can be shipped long distances, and even in the face of high and rising rail shipment costs, it can often compete favorably with indigenous midwestern coal. Third, the West is slated for a sizable expansion of its coal-fired electrical capacity, which will raise local demand for western coal. Thus, the prospects for the current NSPS to reverse the coal market's westward shift in production appear slight.

ALTERNATIVE APPROACHES TO THE CURRENT NEW SOURCE PERFORMANCE STANDARDS FOR ELECTRIC UTILITIES

All four of the policy choices the CBO has examined would affect the act's current NSPS as they pertain to sulfur dioxide emissions. Three of the alternatives would follow the general approach of existing standards, in that they would apply only to new coal-fired power plants. The fourth would depart from established approaches in allowing old as well as new sources to participate in the control of emissions under the standards. After a brief description of the options (also displayed in the Summary Table), the following analysis focuses on three potential effects:

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SUMMARY TABLE. ALTERNATIVE SULFUR DIOXIDE EMISSIONS STANDARDS (Projected to year 2000; emissions limits in pounds per million BTUs of fuel consumed)

Options and Descriptions	Effects on Emissions
Current NSPS Sets a ceiling of 1.2 pounds and a floor of 0.6 pounds; 90 percent scrubbing required for emissions above floor, and 70 percent for those below floor a/	Total emissions growth limited to annual 21 million tons; new plant emissions total 1.6 million tons a year
Option I Sets a ceiling of 1.2 pounds	Total emissions growth limited to annual 22.8 million tons; new plant emissions total 4 million tons a year
Option II Sets a ceiling of 1.2 pounds and a floor of 0.8 pounds; 70 percent scrubbing required for emissions above floor a/	Total emissions growth limited to annual 22.1 million tons; new plant emissions total 2.8 million tons a year
Option III Sets a ceiling of 1.2 pounds and a floor of 0.6 pounds; 90 percent scrubbing required for emissions above floor a/	Total emissions growth limited to annual 21.9 million tons; new plant emissions total 2 million tons a year
Option IV Requires same total emissions control as under current NSPS; allows emissions trading between old and new sources to meet overall limit	Total emissions growth limited to annual 21 million tons; new plant emissions total 2.5 million tons a year

a/ Applies to new electricity sources only.

(continued)

SUMMARY TABLE. (Continued)

Cost Effectiveness Relative to 1971 NSPS	Capital and Operating Cost Effects	Coal Market Changes
$2,411 per ton of sulfur dioxide removed	Total capital outlays of $33.4 billion; annual operating costs $14.1 billion in year 2000	High midwestern and lower western production; 127 million tons western coal shipped east
Basis of Comparison	Total capital outlays of $14 billion; annual operating costs $9.8 billion in year 2000	High western and low midwestern coal production; 151 million tons western coal shipped east
$1,929 per ton of sulfur dioxide removed	Total capital outlays of $14.6 billion; annual operating costs $11.1 billion in year 2000	High western and low midwestern coal production; 164 million tons western coal shipped east
$3,400 per ton of sulfur dioxide removed	Total capital outlays of $17.1 billion; annual operating costs $12.8 billion in year 2000	High western and midwestern coal production; 145 million tons western coal shipped east
$550 per ton of sulfur dioxide removed	Total capital outlays of $14.7 billion; annual operating costs $10.8 billion in year 2000	High western and moderate midwestern coal production; 149 million tons western coal shipped east

SOURCE: Congressional Budget Office

- o Emissions,
- o The electric utilities' costs to meet the standards and the options' cost effectiveness, and
- o Effects on U.S. coal markets.

In the analysis, no attempt is made to weigh costs against benefits. Though the costs of such governmental regulations as pollution control are reasonably amenable to being quantified and compared, the benefits are not. No generally acceptable measures exist for gauging health improvements, preservation of natural and structural assets, or other societal gains that may result from federal emissions limits. Thus, the CBO has not assessed measurable costs of abatement against important but intangible benefits.

Option I. Revert to the NSPS of 1971

Reenactment of the original NSPS would effectively rescind the present requirement that all new power plants be equipped with scrubbers. The only standard would be a mass emissions limit of 1.2 pounds of sulfur dioxide per million BTUs of fuel consumed; no fixed percentage of that pollutant would have to be removed. Thus, combustion of low-sulfur coal would offer an acceptable means of compliance.

Option II. Achieve 70 Percent Control of Sulfur Dioxide Emissions and Set a 0.8 Pound Floor

Following the general structure of the current NSPS, this option would require scrubbing for some plants but not all, depending on the coal used. Sulfur dioxide emissions, between a maximum permissible ceiling of 1.2 pounds and a floor of 0.8 pounds per million BTUs of fuel, would have to also be reduced by 70 percent. For emissions below the floor, no specific percentage reduction levels would be mandated. Thus, low-sulfur coal could be burnt with little or no scrubbing; high-sulfur coal would have to be scrubbed to remove at least 70 percent of sulfur dioxide emissions.

Option III. Achieve 90 Percent Control of Sulfur Dioxide Emissions and Set a 0.6 Pound Floor

A variant of Option II and the current standards, this alternative would stipulate the same sulfur dioxide emissions ceiling (1.2 pounds per million

BTUs) but would establish an emissions floor of 0.6 pounds. The percentage removal for emissions between the ceiling and floor would be 90 percent, while no control requirements would be specified for emissions below the floor. This option would thus retain the current scrubbing requirement for high-sulfur coal, reduce the amount necessary for low-sulfur coals, and eliminate it entirely for very low-sulfur coals.

Option IV. Constrain Total Emissions Growth by Balancing Sulfur Dioxide Emissions from Old and New Sources

This option, a fundamental departure from other approaches, would allow old as well as new sources to be involved in meeting emissions standards. While still directed at new sources, the standards would permit a new facility to trade emissions with other existing power plants to achieve the same quantity of emissions control as required under the present NSPS. Within a given area--in this example, a state--a planned plant would be allowed to find a trading partner among existing sources. If the old source could meet standards sufficiently below its applicable regulations, its new source trading partner could exceed the limit by an equal amount, so long as the old source continued to operate. This approach is termed new source "bubbling", since it allows control to be balanced between all emissions within a given atmospheric area, so long as the total quantity leaving the bubble remains constant. Acceptable methods of compliance would involve both scrubbing and low-sulfur fuels at both old and new power plants.

Effects of the Alternatives on Future Emissions

In contrast to the current NSPS, which would hold the growth of sulfur dioxide emissions from electric utilities to a total of 20 percent over the coming two decades, Option I would allow emissions to rise by 30 percent. This translates into 21 million tons under current law and 22.8 million tons under Option I. These figures represent the upper and lower bounds of emissions control achievable under all the options. Inasmuch as old sources are projected to account for some 80 percent of all sulfur dioxide emissions through the year 2000, there is little room for improvement to be achieved over the projection period by regulations governing new sources only. Similarly, Option IV, while reducing the costs of emissions control and spreading the burden between new and old sources, cannot be expected to bring about any radical change in overall emissions levels, since the control levels are based on current NSPS. New power plants constructed subject to Option I would emit roughly twice the amount of sulfur dioxide as those constructed under the current standards. These differences in total emissions would become measurable only when the older generation of dirtier facilities retire, sometime around the year 2010.

Cost Effect on Utilities

Although the CBO analysis suggests that capital costs for air pollution control may not be detrimental to the utilities' financial condition, the high capital expense of scrubbing does appear to raise overall costs for the utilities and the consumers. The current NSPS would require the greatest capital outlay ($33.4 billion) and would result in the highest annual cost ($14.1 billion by the year 2000). In contrast, Option I (the previous NSPS), which would allow widespread use of low-sulfur coal, would require only $14 billion in capital and $9.8 billion in annual costs by the year 2000. The other options, by promoting different mixes of scrubbing and low-sulfur coal combustion, fall somewhere in between, although the capital requirements of each of these options appear not to be nearly so high as the current standards.

Cost Effectiveness. A true measure of the cost differences between each option can only be made when differences in emissions are also taken into account. A rough gauge of cost effectiveness may be derived by measuring the costs of reducing sulfur dioxide emissions below the highest levels projected--in this case, the 22.8 million tons per year projected under Option I. The current NSPS would cost $2,411 for each ton of sulfur dioxide removed below that level. Option II would cost $1,929, and Option III--the most costly in these terms--$3,400 per ton removed. Option IV, in contrast, offers the prospect of lowering sulfur dioxide levels at a cost of only $550 per ton removed for as long as existing old sources remain in operation; the reason for this potential economy is the ability to achieve low-cost emissions reductions at existing facilities by relying on lower-sulfur fuels. For example, converting a 500-megawatt plant from high- to low-sulfur coal would cost $431 for each ton of sulfur dioxide removed from previous emissions levels; such reductions might be used in a trade. Costs for a new plant, in contrast, might total some $1,230 per ton to achieve similar levels of reduction below the 1.2 pounds sulfur dioxide emissions limit of Option I.

Coal Market Effects

From the standpoint of the U.S. coal market, any emissions standards that would place heavy emphasis on the use of scrubbers should discourage the purchase of nonlocal coal to meet emissions standards. Conversely, de-emphasizing control technology in favor of mass emissions limits should increase the demand for and value of low-sulfur coal. These effects are partly borne out in projections of the coal market under each alternative. Thus, implementing Options I or IV would tend to perpetuate the trend observed during the 1970s, during which low-sulfur coal production grew and western coal sales expanded eastward. Option II, because of its low scrubbing requirement and high emissions floor, also would promote the use of low-sulfur coal. Only continuing the current NSPS or adopting Option III, both of which would entail sizable amounts of scrubbing, would tend to counter that trend, fostering greater use of high-sulfur coal from the East and the Midwest.

Neither the current NSPS or any of the alternatives examined appears to have great potential to stem the growth of western coal production or the penetration of western low-sulfur coal into markets to the east. Even the current NSPS, with their universal requirement of scrubbing, can only slow the rate of shipments of western coal to utilities in the Midwest and the East. Options I and IV would offer no provisions that would counter this trend, and Options II and III, with some scrubbing requirements but less than the current NSPS, would have almost as little effect. As has been observed since the early 1970s, inherent factors in western and coal production are expected to continue to overwhelm any influence on coal markets arising from pollutant emissions standards. Circumstances that could significantly alter this projected pattern include higher-than-anticipated rail shipment rates and significantly lower costs for control technology.

CONCLUDING REMARKS

Which of the federal government's goals receives higher Congressional priority would determine which of the options analyzed offers the better prospects. The Clean Air Act's current NSPS are best suited to holding down emissions and safeguarding midwestern coal production, but at sizable costs to the utility industry. The utilities would be better served by Options II or III, but at some sacrifice in pollution abatement. Under Options I or IV, the act's pollution control goals would be advanced to different degrees at minimal costs, but the coal producers of the Midwest would pay a price in markets lost to western suppliers. In short, the analysis suggests that the several objectives of constraining sulfur dioxide emissions, easing the electric utilities' financial burden, and protecting midwestern coal producers cannot all be pursued with equal emphasis.

THE CLEAN AIR ACT,

THE ELECTRIC UTILITIES, AND THE COAL MARKET

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CHAPTER I. INTRODUCTION

Federal policies that would protect the nation's air quality and others that would ensure a reliable, low-cost supply of electricity can sometimes interact in difficult ways. This study examines the question of whether clean air and energy policies as they affect the electric utilities are in fact on a collision course. The mechanisms by which the air quality goal is sought are embodied in the Clean Air Act, administered by the Environmental Protection Agency (EPA) and last amended in 1977. 1/ The establishment of a secure and inexpensive power supply rests on encouraging greater use of the United States' most abundant energy source: coal.

Since 1970, coal combustion has supplied roughly half of all yearly electrical production and promises to furnish an even greater share in the coming decades. Though plentiful and not vulnerable to foreign supply interruptions--and inexpensive in comparison with oil and gas--coal is also a major source of air pollution. The burning of coal by utility plants, which account for more than four-fifths of the nation's total coal consumption, accounts for approximately 60 percent of all sulfur dioxide emissions in the United States, 25 percent of all nitrogen oxide emissions, and 15 percent of all particulate emissions. 2/ The control of these pollutants--especially sulfur dioxide--is expensive, complicating the interaction between clean air policy and the desire to promote coal use in electricity production.

COAL AND POLLUTANT EMISSIONS

Chemical characteristics unique to coal have had a direct bearing on the shaping of federal emissions control regulations and their effects both

1. First enacted in 1968 as Public Law 88-206, the Clean Air Act has undergone several major legislative revisions since that date. The structure of the act that prevails today, underlying the analysis in this paper, was adopted under the Clean Air Act Amendments of 1977 (Public Law 95-95).

2. These data, supplied by the EPA, reflect estimated pollutant levels for 1979, the most recent year for which data are available.

on utility companies and on the coal industry itself. When coal is burnt, it generates noxious gases (sulfur dioxide and nitrogen oxides) and particulate matter (unburnt material and ash). In particular, the generation of sulfur dioxide has the greatest bearing on how emissions regulations can affect the utility and coal industries. The amount of sulfur dioxide produced during coal combustion is a direct function of the sulfur content of the raw fuel. Coal's sulfur content varies from source to source, ranging between less than 1 to greater than 4 percent by weight. Mines in the West generally produce coal low in sulfur content; medium- and high-sulfur coals predominate in the Midwest; eastern mines produce coals with a full range of sulfur contents. The higher coal's sulfur content, the higher its emissions of sulfur dioxide. The evolution of emissions regulations for utility plants under the Clean Air Act, and the debate surrounding such regulations, reflect these particular properties of coal.

REGULATORY MECHANISMS

In its present form, the act is designed to protect air quality through several chief mechanisms. 3/ The primary objective of the act is to ensure that all areas of the country achieve air quality equal to or better than national ambient air quality standards (NAAQS), which are established by the EPA. These standards reflect the maximum acceptable pollutant concentrations that offer a safe environment for the public's health and welfare. Two important programs are designed around the NAAQS. A "nonattainment program" requires states to develop plans providing for attainment of all NAAQS in areas not currently meeting them; the prevention of significant deterioration (PSD) program directs the EPA and the states to limit the increase of pollution in areas with air better than the NAAQS. Finally, as an aid in limiting pollution growth and maintaining the NAAQS, the act directs the EPA to establish uniform nationwide emissions limits for most major new facilities. These standards, termed new source performance standards (NSPS), apply to specific categories of new and modified air pollution sources nationwide, and they reflect the minimum acceptable levels of control for these facilities. The effects of these NSPS on the utility and coal industries are a major focus of this study.

Since the act's passage, the EPA has twice established NSPS for the electric utility industry. These regulations affect all new and modified

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3. For further information on the Clean Air Act, see National Commission on Air Quality, To Breathe Clean Air, Final Report (March 1981).

facilities built after the effective date of the particular standard and limit the emissions of most gaseous and solid pollutants. In general, these standards have met with little controversy; however, the emissions control requirements for sulfur dioxide have remained a subject of intense debate.

The first set of NSPS was established in 1971 and was designed to allow the utilities to meet sulfur dioxide emissions standards using either low-sulfur coal alone or high-sulfur coal with special equipment developed to reduce sulfur dioxide emissions. The equipment used to reduce such emissions is flue gas desulfurization technology, commonly referred to as "scrubbers." Though available at the time of the first NSPS, scrubbers were expensive, and since they were not mandatory, utility managers generally avoided installing them in new units. Instead, low-sulfur coal was typically employed as an emissions control strategy. As a result, controversy arose over the 1971 regulations with respect to their possible effects on the nation's coal market, focusing on whether they would encourage the production of low-sulfur coal (primarily a western product) at the expense of medium- and high-sulfur coal produced in the Midwest and East.

In amending the Clean Air Act in 1977, the Congress changed the criteria on which the EPA bases emissions standards for facilities using fossil fuels. Two factors underlay the change: concern over the apparent regional inequities in the coal market fostered by the old regulations, and intent to encourage use of pollution control technology. The new emissions regulations the EPA adopted--the NSPS of 1978, which are still in effect--require that all newly built power plants curb sulfur dioxide emissions from any coal they burn. In effect, these NSPS dictate that scrubbers be installed in all new utility units, since no other commercially available technology can meet the EPA standards. As a result, since scrubbers became virtually mandatory, utility managers now have little motivation to use low-sulfur coal except where it is most readily available--that is, where it is locally produced. Implemention of these regulations, it was believed, would minimize new emissions everywhere and would correct regional inequities in coal production.

ISSUES BEFORE THE CONGRESS

Two controversies now surround the NSPS for sulfur dioxide emissions:

- Whether the high capital costs of scrubbers overburden the utility industry in proportion to the control they achieve; and

- Whether the costs of scrubbers jeopardize the economic advantage of coal relative to costlier fuels, namely oil and gas.

With these issues in mind, the Congress has already begun to consider further revisions to the Clean Air Act. For a third time, legislators will likely reassess the provisions by which the act requires the utilities to control emissions.

To assist in clarifying the issues under Congressional debate, this study explores four critical questions:

- What is the likely future effect of the current NSPS on sulfur dioxide and other pollutant emissions?

- What are likely to be the costs of reducing pollutant emissions at coal-fired power plants, and what financial burden do these costs put on electric utilities?

- How might emissions standards influence the patterns of coal production and use in the United States?

- What other forms might emissions control standards take, and what might their effects be on the utility and coal industries?

As before, questions of economic efficiency will probably arise again in the course of the debate. Will the societal benefits of pollution abatement warrant their considerable economic costs? Only so long as the benefits outweigh the costs can those costs be justified. In considering this question, the Congress will want to identify emissions regulations that will achieve an economically correct level of abatement. Because the damage that environmental deterioration may cause--to public health, agriculture, structures, and other national assets--is difficult to quantify, the benefits to be gained from clean air policy are equally difficult to gauge. Though critically important in Congressional decisionmaking, these issues are beyond the scope of this paper.

PLAN OF THE PAPER

Chapter II of this paper describes the costs of the Clean Air Act to the electric utility industry. Chapter III reviews the present financial condition of utilities and examines the costs to them of pollution control. Chapter IV analyses the effects of the Clean Air Act on the prospects for conversion and replacement of oil- and gas-fired generating capacity with coal. The focus of Chapter V is on the Clean Air Act's implications for the U.S. coal market. The closing portion of the paper, Chapter VI, outlines four alternative emissions standards for the utilities, exploring the potential of those choices on sulfur dioxide emissions, on utilities' capital and operating costs, and on the U.S. coal market.

CHAPTER II. STANDARDS AFFECTING THE ELECTRIC UTILITY INDUSTRY--THEIR EFFECTS ON EMISSIONS AND COSTS

The current air pollution control regulations required by the Clean Air Act will bring about a generation of power-producing facilities that will be significantly cleaner than their predecessors, but at considerable expense to the electric utility industry. Meeting the act's emissions control requirements will require significant capital investment for the industry during the coming two decades. According to the Congressional Budget Office's analysis, the total electric capacity of U.S. utilities between 1980 and the year 2000 will increase by some 44 percent, from 588 gigawatts to 844 gigawatts. 1/ The cumulative capital requirements for new nuclear and coal plants alone (not including transmission and distribution facilities) are projected to be $320 billion over this period; of that sum, roughly $176 billion will be attributable to an anticipated 168 gigawatts of new coal-fired capacity. Efforts to meet the federal new source performance standards (NSPS) for utility plants and, to a lesser extent, local air pollution control regulations, will account for roughly one-fifth ($33.4 billion) of that $176 billion. This chapter presents an analysis of how the NSPS and other key provisions of the Clean Air Act influence both the quantity of pollutant emissions nationwide and the costs of generating electricity.

CLEAN AIR ACT REQUIREMENTS AFFECTING ELECTRIC UTILITIES

To help meet and maintain national ambient air quality standards (that is, the act's NAAQS) several key provisions of the act serve to regulate pollutant emissions from electric utility plants. For plants built before the first federal emissions regulations for utilities in 1971, the states are required to develop plans, including emissions limits for individual plants, to achieve and maintain the NAAQS. These plans are called state implementation plans. The act also requires the EPA to limit the amount of air pollution that a new or modified facility may emit. These regulations are the NSPS, and they are established (and reviewed every four years) by the

1. A gigawatt is a unit of power equal to one billion watts. A commercial generator of 500 megawatts (0.5 gigawatts) operating at a 70 percent capacity factor can produce approximately 3.1 billion kilowatt-hours of electricity a year, the amount consumed by roughly 371,000 households.

EPA for many categories of pollution sources, including utilities. Finally, to ensure that areas already meeting NAAQS preserve their good air quality, the EPA, together with the states, operate the prevention of significant deterioration (PSD) program. This program establishes an elaborate review and permit procedure for new facilities and allows states and the EPA to adopt control measures even tighter than the NSPS. (The PSD provisions are discussed in greater detail below; their effects on utility emissions limits and administrative costs are discussed in Appendix A.)

The main focus of this study is on the NSPS (particularly the sulfur dioxide limits) for electric utilities; to a lesser extent, the study also considers the PSD provisions. The majority of future electric generating capacity will be built in areas already meeting the NAAQS, and the majority of future costs for air pollution control will be attributable to the NSPS, although a small portion of these expenses will result from the tighter state and local standards, implemented in most cases under the PSD provisions of the act.

The New Source Performance Standards of 1971 and 1978

Because of the great variation in sulfur content of coal across the country, coal-fired power plants could emit sulfur dioxide in widely differing amounts if such emissions were not controlled. For example, an uncontrolled 500-megawatt power plant could emit sulfur dioxide at rates ranging from less than 0.5 to more than 6 pounds of that gas per one million British thermal units (BTUs) of fuel consumed. In the course of a year, this range would translate into less than 7,665 and more than 91,980 tons of sulfur dioxide. The NSPS introduced in 1971 under the Clean Air Act focused directly on this problem, setting a uniform nationwide limit of 1.2 pounds of sulfur dioxide emissions per million BTUs for all new or modified power plants burning coal. 2/ Similar limits were established under the NSPS for nitrogen oxides and particulate emissions. The 1971 NSPS were set with considerations of economic effects, energy costs, and environmental and public health concerns taken into account.

In 1978, these standards were revised, with much stricter sulfur dioxide and other emissions limits set for the electric utilities. The revisions in

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2. Regulations under both the NSPS apply also to gas- and oil-fired plants. The limit set for new oil-burning plants was 0.8 pounds of sulfur dioxide emissions per million BTUs of fuel consumed.

1978 reflected a fundamental change in the act's NSPS provisions, changes that were designed, in part, to encourage the use of control technology and to foster the use of local coal regardless of its sulfur content. Table 1 contrasts the provisions of the two sets of new source performance standards.

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

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

SOURCE: U.S. Environmental Protection Agency.

NOTE: Table does not show emissions limits applying to either oil-or gas-fired utility plants. See 36 Federal Register 15703 (December 23, 1971) and 44 Federal Register 33580 (June 11, 1979).

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The 1978 revisions did not supersede the older NSPS. Plants licensed to operate under the 1971 NSPS remained (and still are) subject to them. Rather, the new standards added stringent requirements for those new plants to which they would apply. Besides limiting emissions to 1.2 pounds of sulfur dioxide per million BTUs generated from coal, new or modified plants burning coal (or any fossil fuel) must now also remove a finite percentage of that pollutant from emissions. 3/ The level of mandatory pollutant removal is not uniform, however, requiring that between 70 and 90 percent of all sulfur dioxide emissions be eliminated. The determinant of what percentage sulfur dioxide removal a plant must achieve, based on its final emissions rate, is whether the plant will burn high- or low-sulfur coal.

Methods of Compliance and Effects. A typical method for a utility plant's meeting the 1971 NSPS was to use fuel with inherently low emissions characteristics--that is, low-sulfur coal or oil. Under the new NSPS, however, sulfur dioxide emissions must be reduced from any variety of coal being burnt. At present, the only commercially available device that can achieve the required reductions in conventional power plants is a scrubber; thus, in effect, the 1978 NSPS mandates the use of scrubbers in all new coal-fired power plants. Though no new or modified coal-fired utility generators planning to use scrubbers under the 1978 regulations are yet in full commercial operation, the effect of scrubbing will be to cut emissions by more than a half from levels allowed under the old NSPS. 4/

The 70-90 percent sliding scale for sulfur dioxide emissions removal effectively gives utilities an economic choice between using "wet" and "dry" scrubbers, depending on the sulfur content of the coal they plan to burn. 5/

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3. The regulation chiefly affects new coal plants, since the Power Plant and Industrial Fuel Use Act of 1978 prohibits the burning of oil or gas in major new power plants.

4. In view of the time lag that intervenes between a firm's decision to build a new plant and the time that plant is actually generating power, the effects of the 1978 NSPS cannot be expected to materialize before well into the 1990s.

5. Wet scrubbers remove sulfur dioxide by passing exhaust gases through an aqueous chemical spray that absorbs the sulfur dioxide, leaving the exhaust gas with a lower sulfur dioxide concentration. (Particulates are

Wet scrubbers, which can remove 90 percent or more of the sulfur dioxide a power plant emits, are by far the costlier choice; installation of a wet scrubber can add as much as 20 percent of the initial capital costs of a new plant. They do, however, permit combustion of medium- and even high-sulfur-content coal. Dry scrubbers, capable of 70 percent sulfur dioxide removal and considerably cheaper--accounting for perhaps 10 percent of initial capital outlays for a new plant--are suitable only for low-sulfur coal combustion under the present regulations. Commercial experience with dry scrubber systems on utility plants is lacking, because the technology is relatively new; however, it is a fairly well proven technology, and many utility systems have dry scrubbers on order for their new plants.

Prevention of Significant Deterioration

For areas now attaining the NAAQS, the Clean Air Act mandates that, if possible, air quality be prevented from deteriorating to the level of the NAAQS because of new air pollution. The act's provisions applying to such regions are encompassed in the PSD program, and as the term implies, they cover regions where the air quality is relatively good at the time a utility firm or other industry contemplates locating a new plant there. The PSD provisions are designed to preserve air quality while at the same time avoiding hindrance of industrial growth. The amount of pollution-caused degradation allowed in an area (possibly up to but not exceeding the NAAQS) is denoted by specified increments or classes, shown in Table 2. The Clean Air Act Amendments of 1977 classified certain areas, such as national parks, as mandatory Class I. Other public use areas, such as national recreation areas, were originally classified as Class II and may not be changed to Class III. All other areas were originally classified as Class II and may be redesignated by the state with the governor's approval.

Under the PSD program, a utility considering construction of a new power plant undergoes a rigid preliminary review process, of which two components are especially influential both to costs and to air quality. First, the planners of a new facility must demonstrate to the state and regional

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5. (Continued)
removed prior to scrubbing.) The product of the scrubber is a precipitate of high water content, which typically is filtered and chemically stabilized before disposal. A dry scrubber involves much less water and combines both particulate and sulfur dioxide removal in the final step, leaving a dry product for disposal.

TABLE 2. NATIONAL AMBIENT AIR QUALITY STANDARDS AND ALLOWABLE INCREMENTS UNDER PREVENTION OF SIGNIFICANT DETERIORATON PROVISIONS
(In micrograms per cubic meter)

		Increments Under PSD		
Pollutants	NAAQS	Class I a/	Class II b/	Class III c/
Sulfur Dioxide				
Annual average	80	2	20	40
24-hour average d/	365	5	91	182
Three-hour average d/	1,300	25	512	700
Total Suspended Particulate Matter				
Annual average	75	5	19	37
24-hour average d/	150	10	37	75

SOURCE: U.S. Environmental Protection Agency.

a/ Designed to protect pristine areas such as National Parks.

b/ Areas meeting NAAQS but not originally designated Class I in 1977.

c/ Certain Class II areas may be redesignated to Class III to allow greater development; none have been redesignated to date.

d/ Not to be exceeded more than once a year.

environmental protection authorities that emissions from the plant contemplated, combined with emissions already present from other sources in the same locale, will not exceed certain maximum limits established by PSD increments (see Table 2). Background pollution levels, plus the specified PSD increment, are combined to establish the upper bound of allowed pollution in the area, provided such totals would not jeopardize the NAAQS. Emissions from any new facility in the area must not cause a violation of this maximum allowable limit.

A second critical feature in the PSD review process entails the use of the "best available control technology" (BACT) in a new generating facility. Determinations of what the best available control technology actually is, in light of specific costs, environmental effects, energy costs, and other considerations, are made on a case-by-case basis by the reviewing agencies, including both federal and state environmental officials.

In theory, best available control technology should be strict enough to allow further growth in the area and preserve PSD air pollution limits, while never exceeding the applicable NSPS--and often surpassing it in stringency. In practice, however, the reviewing agencies commonly establish BACT at levels commensurate with the applicable NSPS, unless siting choices and the characteristics of the area would cause emissions at NSPS levels to violate the applicable PSD increment. In the case of power plants locating in PSD areas, BACT limits have been set tighter than NSPS only in certain instances; this has occurred more often under the NSPS of 1971 than under the NSPS of 1978. Since adoption of the 1978 NSPS, most BACT designations for new power plants require no more than NSPS-mandated levels, except in some western states. For the purpose of this analysis, the NSPS are considered the dominant influence on future utility emissions, except for assumptions regarding some western states' emissions limits (see Appendix A and assumptions outlined in Appendix B).

EFFECTS ON POLLUTANT EMISSIONS

The NSPS promulgated in 1971 have had mixed effects on national utility emissions of the three pollutants discussed in this study. As of 1979, the most marked improvement--attributed in part to the federal NSPS and in part to stricter state regulations--was in particulate emissions. These declined by a full 62 percent from 1970 levels, despite major increases in the utilities' use of coal (which rose by 50 percent). 6/ Effects on gaseous emissions, however, were inconsistent. The clearer improvement was in emissions of sulfur dioxide, which increased only slightly, primarily because of utilities' efforts to use more low-emissions fuels--mostly oil and low-sulfur coal. Success in controlling nitrogen oxide emissions was minimal, however; these increased by 50 percent. This apparent failure is ascribed largely to the lack of available control methods for this pollutant.

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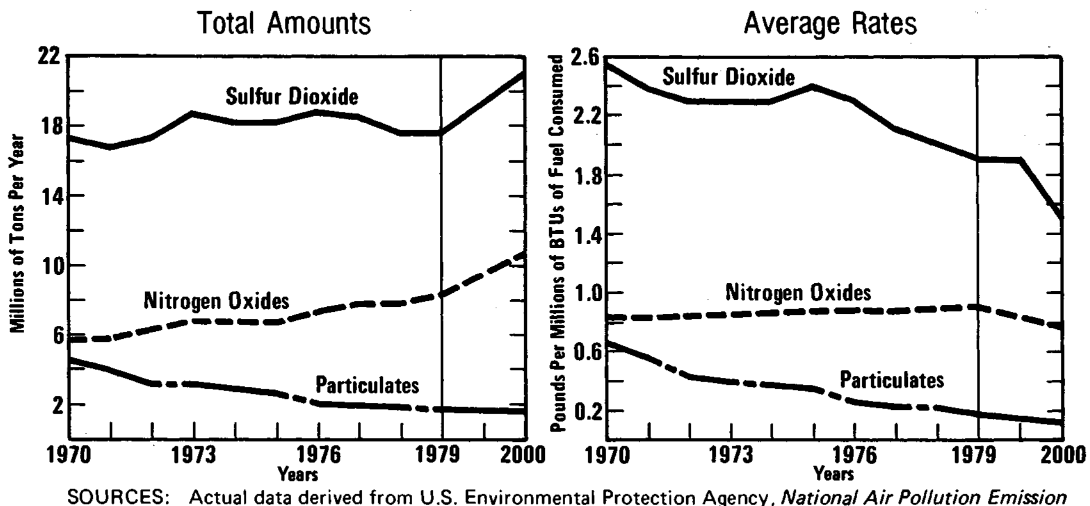
6. See Environmental Protection Agency, National Air Pollution Emission Estimates 1970-1979 (March 1981).

In spite of the sharp tightening of the NSPS enacted in 1978, projections of the national utility emissions trends over the coming two decades show no dramatic reversals in overall emissions, although the average emissions rates of the industry should fall as cleaner facilities are added to existing total capacity (see Figure 1). Particulate emissions from utility combustion are likely to continue declining by as much as 6 percent (from the 1.7 million tons of 1979 to 1.6 million tons by the year 2000). Emissions of sulfur dioxide are likely to rise somewhat more steeply than in the 1970s, increasing by 17 percent (from 18 million to 21 million tons). The problem of nitrogen oxide emissions is expected to worsen, with emissions increasing by 29 percent (from 8.3 million tons to 10.7 tons). The cause underlying the continued high emissions levels will be the utilities' continuing use of older-generation (pre-NSPS) power generators. By far the bulk of anticipated emissions of each pollutant--as much as 80 percent--will be attributable to these older sources, at least through the year 2000 and perhaps until 2010.

After the turn of the next century, however, the prospects should brighten as antiquated generators are phased out and newer ones capable of emitting far less pollution take their place. Sometime around the year 2010, a trend in significantly lower emissions can reasonably be expected. The remainder of this chapter examines the costs of attaining that improvement through the coming two decades.

Figure 1.

Actual and Projected Pollutant Emissions from Electric Utility Plants—Total Amounts and Average Rates



SOURCES: Actual data derived from U.S. Environmental Protection Agency, *National Air Pollution Emission Estimates* (March 1981), and U.S. Department of Energy, *The 1980 Annual Report to Congress* (April 1981). Projections based on CBO/ICF analysis (see Appendix B).

NOTES: Shows only those pollutant emissions regulated under Clean Air Act new source performance standards. Projection period starts at 1979, the last year of actual data.

NATIONWIDE POLLUTION CONTROL COSTS TO UTILITIES AND TO ELECTRICITY CONSUMERS

To meet federal and state air pollution control requirements established over the last decade, the utility industry has already made sizable capital investments. Between 1973 and 1980, the utilities' expenditures for pollution control rose at an average annual rate of 10.7 percent, while total capital expenditures rose at the slower rate of 8.9 percent. 7/ During this period, investments in pollution control equipment ranged between 5 and 7 percent of the industry's total yearly expenditures. In 1980, the industry's total capital commitments reached $29.2 billion, of which $1.8 billion (6 percent) went for pollution control.

The trend of high capital investment for pollution control is expected to continue over the next two decades. The principal cause underlying the persistence of high utility capital investment commited to pollution control is the rigid standards established in 1978. Between 1980 and the year 2000, the utility industry will invest more than $176 billion in new coal-fired power plants alone, with roughly $33.4 billion (19 percent) dedicated to air pollution control. Because of the requirements of meeting the 1978 NSPS, the utilities' air pollution control investment costs will be higher by $19.4 billion that they would be if only the older NSPS were in force.

Aggregate data on the capital costs exacted by controlling air pollutant emissions give only a partial picture; other essential components include the charges for operating pollution control equipment (scrubbers and particulate control devices) in plants burning high-sulfur coal and the incremental costs of using low-sulfur fuels as a means to control emissions in place of less expensive, higher-sulfur fuels. In 1980, these two factors combined entailed an annual expense totaling $5.4 billion, with control equipment accounting for $4.2 billion and low-sulfur fuel premiums accounting for $1.2 billion. By the year 2000, costs of these two components are expected nearly to triple, reaching an annual total of $14.1 billion.

Expressed in terms of average generating charges per kilowatt-hour for all forms of electricity generation, this $5.4 billion in 1980 breaks down

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7. Gary Rutledge and others, "Capital Expenditures by Business for Pollution Abatement," Survey of Current Business, U.S. Department of Commerce (June 1978 and June 1980).

into an average of 2.34 mills per kilowatt-hour. The average charge in 1980 to residential consumers of electricity was 53.6 mills per kilowatt-hour. 8/ Thus, from the ratepayers' standpoint, the cost of air pollution control in 1980 accounted for 4.4 percent of an average residential electricity bill. By the year 2000, however, ratepayers are likely to see an increase of 44 percent, bringing the cost for pollution control to 3.43 mills per kilowatt-hour purchased--just 1.09 mills more than in 1980 or 6 percent of that year's electricity rate. Although this reflects a potentially sharp increase in operating costs for control air pollution, the average nationwide contribution of this expense to total future generating costs should remain quite small. Regional costs will differ markedly, however.

Regional Differences in Air Pollution Control Costs

Aggregate and average national data, though useful for policy analysis, mask regional differences that have very explicit cost consequences for both utility companies and consumers in different areas of the country. (Figures 6 and 7 in Chapter V display the coal-producing and coal-demand regions of the United States.) Three principal factors influence the regional variations in pollution control costs: what fuel is burnt, what state and local emissions standards apply, and the vintage of most of the electricity generators in use.

In an area where a low-emissions fuel predominates--the Gulf states, where indigenous natural gas is the primary energy source, are an example--air pollution control costs are negligible. The New England states, in contrast, typify a different situation; there, though low-emissions fuels (mainly oil) furnish most utility generation, pollution control costs are higher because of the premiums paid to meet rigid local emissions standards with low-sulfur fuels. The costs of air pollution control ranges between 3.7 and 6.2 mills per kilowatt-hour generated in that area.

A utility plant's age also influences regional differences in pollution control costs, particularly with regard to coal-fired plants. In an area where the majority of electricity comes from coal-burning facilities that predate the first NSPS of 1971, pollution costs may be high but only modestly so,

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8. Average residential consumers of electricity use between 500 and 1,000 kilowatt-hours per month in the course of a year; thus, average electricity bills in 1980 ranged from $27 to $54 per month, of which 4.4 percent could be attributed to air pollution control.

precisely because of the relative lenience of the governing standards. The Ohio River Valley, where many existing coal-fired generators are not subject to either NSPS, air pollution control costs average 3.9 mills per kilowatt-hour for these facilities, which is near the low end of the oil-fired power plant costs in New England.

Since the mid-1970s, most new major capacity that has been constructed is coal-fired. Newer plants built under the 1971 NSPS incur control costs ranging from a high of roughly 8.6 mills per kilowatt-hour in the East and North Central areas to less than 3.2 mills per kilowatt-hour in the western Mountain region. In some cases, strict local standards in several areas of the West result in costs at the higher end of this range.

The highest-cost electricity plants in terms of air pollution control will be those coal-fired generators that are being built subject to 1978 NSPS, which implicitly require use of scrubbers. Here again, though, wide variations will occur, with emissions control costs ranging from 5.7 mills to 10.1 mills per kilowatt-hour. Costs in the eastern Central states should fall at the upper end of the range, around 10 mills per kilowatt-hour, because medium- and high-sulfur coals predominate there, necessitating use of expensive wet scrubbers. In the Pacific and Mountain regions, low-sulfur coal is readily available, permitting utilities to meet the rigid federal standards with cheaper dry scrubbers, bringing pollution control costs nearer to the 5.7 mills per kilowatt-hour rate.

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CHAPTER III. POLLUTION CONTROL AND THE ELECTRIC UTILITIES' FINANCIAL CONDITION

The financial condition of the electric utility industry has undergone a steady deterioration over the past two decades. Years of inadequate revenues in the face of escalating real costs for equipment, fuel, and financing have combined to weaken the utilities' economic position. Few of these factors, particularly equipment and interest costs, show signs of improving soon, and although only moderate electrical capacity growth is expected throughout the remainder of this century, the high cost of construction already is expected to strain the financial capacities of the industry at least through this decade. With respect to the Clean Air Act, two interrelated questions arise in this context:

- To what extent are emissions control standards mandated under the act responsible for the utilities' declining financial state? And conversely,

- What implications do the utility industry's poor financial prospects have for the federal government's future pursuit of clean air policy? In other words, will a financially weakened power industry provide an adequate instrument for carrying out the nation's clean air policy?

Emissions control standards, because of their attendant high capital costs to electric utilities, have often been cited as contributors to the financial pressures the utilities are feeling. Available evidence suggests, however, that, though capital investment in air pollution control probably does not enhance a utility's financial performance, it probably cannot be blamed for impairing it either. Instead, the most influential determinants of a utility's financial condition appear to be the regulations imposed on the industry by state public utility commission's (PUCs)--the rate-setting bodies within each state--and management decisions made by a particular firm (a factor that is difficult to gauge). This chapter attempts to assess the relative influence of emissions regulations on the utilities' financial performance, measured here as creditworthiness; in so doing, it explores reasons why PUC rate-making decisions can overwhelm other influences.

FINANCIAL CONDITION OF THE INDUSTRY AND REGULATION BY PUBLIC UTILITY COMMISSIONS

Among several factors, the continued slow erosion of adequate revenues and the increased costs and difficulty of obtaining capital are strong contributors to a general deterioration of the power industry's financial health. Although the situation differs markedly among individual companies, actual rates of return are generally below allowed rates and even farther below the actual costs of equity. In 1980, actual returns on equity were about 11.5 percent, while allowed returns were in the 14 percent range and the cost of capital above 16 percent. Investors have responded to these trends. An average share of common stock for the 100 largest privately owned utilities sold at about 75 percent of book value by the end of 1980. As a result, utility managements are reluctant to enter equity markets to seek new capital, since every share sold dilutes the value of the shares of present stockholders. Debt markets are similarly constrained, since requirements for interest coverage bar many companies from this source of capital. (Utilities' interest coverage, which is the rates of total earnings to total interest charges, as a general rule is prohibited from falling below two). To a large extent, the PUCs' rate-making decisions have exacerbated these problems.

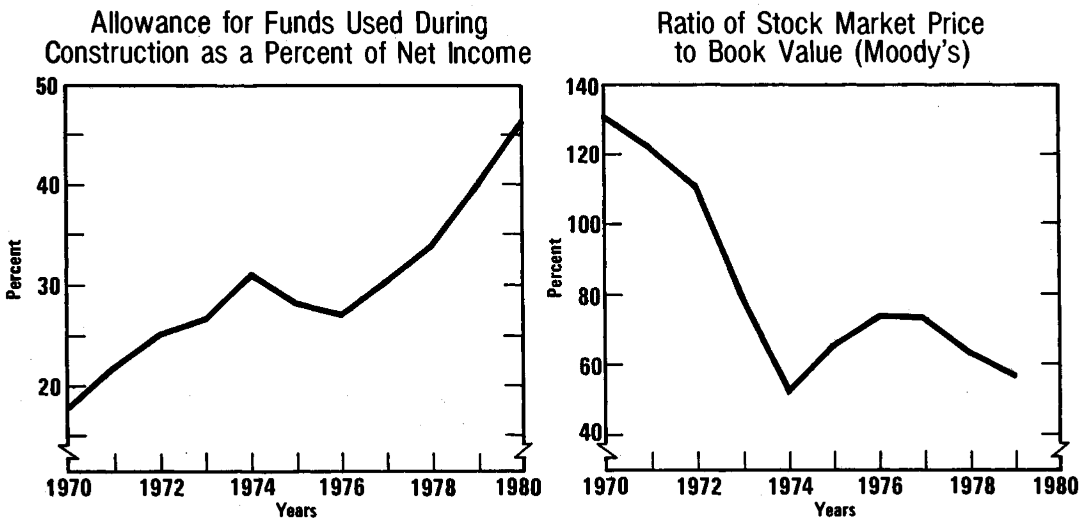
Treatment of Capital and Fuel Costs

Accounting procedures unique to the industry and imposed by PUCs have contributed to the financial difficulties of utilities, chiefly through regulations that increase the costs and risks of capital investment. Typically, a utility may include in its rate base only the costs of those facilities that the PUCs define as "used and useful", meaning that the costs for a new power plant--once requiring from five to eight years of construction and now requiring from eight to 12 years--cannot be recouped until the plant begins operation.

To offset the costs of building a new plant, an electric utility firm usually is granted an "allowance for funds used during construction" (AFUDC) account. This account represents a return--generally equal to the company's approximate cost of capital--on all "construction work in progress" (CWIP). Each year, the AFUDC account is treated as part of the firm's net income, though it does not represent real cash flow. Only when the plant is completed, and the AFUDC account is added to the plant's total rate base, can the utility realize a return on its investment. Before plant operation begins, however, the costs of construction must be borne solely by the company.

Since an AFUDC account represents noncash income, it can lower the quality of actual earnings. Furthermore, it can degrade the market value of the firm's stock, putting upward pressure on the costs of capital. Figure 2 shows trends in both the amount of AFUDC representing income and the ratio of market price to book value in stocks of the investor-owned

Figure 2.
Financial Trends in Investor Owned Electric Utilities According to Two Measures: 1970-1980



SOURCE: Adapted by CBO from H. L. Culbreath, "An Overview of the Financial Difficulties of the Electric Utility Industry," Statement by Edison Electric Institute before the House Committee on Energy and Commerce, Subcommittee on Energy, Conservation and Power (6 April 1981).

utilities--that is, the majority of utilities. In 1980, AFUDC accounted for 46 percent of reported after-tax income; three years earlier, the comparable figure was 30 percent. 1/

Unlike capital expenditures, escalating fuel costs may be quickly recovered under most PUC regulations. More than half of the nation's PUCs provide an automatic fuel adjustment clause to utilities within their jurisdictions. 2/ Under the fuel adjustment provisions, all or at least a major part of the cost increases of fuels may be reflected immediately in higher rates to consumers, with no need for a hearing or other administrative procedure. These provisions effectively protect utilities against the risks of reduced revenue from higher fuel costs.

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1. See Statement of H.L. Culbreath, for the Edison Electric Institute, "An Overview of the Financial Difficulties of the Utility Industry and the Impact on the Funding of Necessary Future Construction," given April 6, 1981, before the U.S. House of Representatives Committee on Energy and Commerce, Subcommittee on Energy, Conservation, and Power.

2. See National Association of Regulatory Utility Commissioners, "1979 Annual Report on Utility and Carrier Regulation" (October 1980).

The combined effect of detrimental regulatory treatment of capital investments and advantageous fuel adjustment clauses is to discourage replacement of expensive oil- and gas-fired capacity and older coal-burning facilities, typically meeting standards more relaxed than the current NSPS (see Chapter II). The short-term result is that construction of capital-intensive new plants, which are cleaner burning and more efficient, is delayed or postponed indefinitely. These twin outcomes do little to further the federal objectives of establishing a reliable future electricity supply and increasing the use of coal.

CONTRIBUTION OF AIR POLLUTION CONTROL COSTS TO INDUSTRY CAPITAL EXPENSES

In part because of increased demand for electricity, delays in construction, and steep rises in inflation, the utilities' expenditures for power plant construction have risen sharply over the last decade, exacerbating the capital-intensive nature of the industry. Though the total capacity growth of approximately 291 gigawatts in new coal-fired and nuclear capacity expected over the next 20 years is only moderate, the high cost of power plant construction will severely strain the industry. 3/ In 1970, electric utilities spent roughly $11 billion (in nominal dollars) for new equipment; by 1980, annual expenditures for new equipment had exceeded $29 billion. This 160 percent increase in annual capital investment, however, augmented total capacity by only 40 percent, and this trend is expected to continue. By the year 2000, expanding electrical capacity is expected to entail capital investments of more than triple the 1980 level (in nominal dollars), though capacity is anticipated to increase by only 44 percent overall.

Air pollution control costs are partially responsible for these escalations. In 1971, coal-fired power plants (equipped only with controls for particulate emissions) cost an average of $210 per kilowatt (in nominal dollars). In 1980, capital costs had risen to approximately $1,100 per kilowatt for a facility using wet scrubbing and to approximately $1,000 per kilowatt for a facility using dry scrubbing (in nominal dollars). (Chapter II describes these processes.) This represents a real cost increase of between 150 to 180 percent. Of this total, air pollution control requirements are responsible for approximately 25 percent, and cost escalations in basic materials and construction account for the remaining 75 percent.

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3. The breakdown of this projected total new capacity is 168 gigawatts of coal-fired generation and 123 gigawatts of nuclear power.

The Congressional Budget Office has estimated that deferring investments that would be made to meet the NSPS of 1978 would save the industry some $19.4 billion between 1980 and the year 2000. This savings would represent only about 6 percent of the estimated $320 billion needed for new coal-fired and nuclear capacity over the period and 11 percent of those expenditures needed solely for new coal-fired capacity ($176 billion). 4/

THE EFFECT OF AIR POLLUTION CONTROL COSTS ON THE ELECTRIC UTILITIES' FINANCIAL POSITION

The aggregate costs of air pollution, though high, appear not to be generally responsible for the utilities' worsening finances or for their difficulties in raising capital. The CBO's analysis of this issue, using bond ratings as a measure of creditworthiness, leads to the conclusion that the market perceives utilities that have invested in pollution control to have much the same financial soundness as the general population of electric utilities.

In an attempt to quantify the effects of pollution control investment on financial integrity, the CBO compared bond ratings of the 100 utilities listed by the investment firm Salomon Brothers against two subgroups (see Table 3). 5/ The first of the subgroups is a sample of 29 utilities that had 15 percent or more (that is, a high proportion) of their construction-work-in-progress accounts dedicated to environmental control equipment in 1979. The other subgroup, representing utilities with significant investment in flue gas desulfurization technology, consists of 21 companies, each with at least one scrubber system in operation.

Both of the subgroups in CBO's analysis--that is, those utilities with substantial financial commitments to pollution control--ranked generally better in terms of bond ratings than did the general population of 100 utilities. In fact, the scrubber group ranked best, with 62 percent of ratings at or above the straight "A" rating (shown in the table as A/A). Next in

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4. These data do not reflect costs of transmission and distribution.

5. The Salomon Brothers rating designations represent a compilation of bond ratings set by other investment firms, specifically Moody's and Standard and Poor's; hence the dual appearance of the Salomon Brothers listings. A Salomon Brothers "AAA/Aaa" listing reflects Standard and Poor's AAA bond rating and Moody's Aaa rating.

order was the group with 15 percent of construction-work-in-progress investments devoted to environmental commitments. The general population had the lowest distribution rated above A, with only 38 percent of ratings higher than the straight A rating. In both cases, the deviation of the subgroups' distributions from that of the general population are significant, suggesting that pollution control investments are more readily undertaken by financially sounder utilities. Using a second analytical approach, however, based on a random sample of utilities from the general population of 100 firms, the CBO found no statistical correlation between bond ratings and the ratio of total investment for construction-work-in-progress to the portion devoted specifically to environmental control.

To assess whether environmental control costs had affected the status of bond ratings over time, rather than only measure the ratings as of a specific date, the CBO also conducted a check of bond ratings between 1978 and 1980. In an examination of the same three groups displayed in Table 3, no significant pattern of rating changes emerged. The only group that had no upgradings during that period was the scrubber group, in which three firms with bond ratings below the A level were downgraded by one point or more. This same group, however, also contained some of the highest rated electric utilities.

The above results suggest that factors other than pollution control investment may more strongly influence the utilities' financial health as measured by bond ratings. Regulations enacted by public utility commissions appear to be a strong influence. According to various investigations (including another CBO study 6/), unfavorable regulations--those that prohibit or delay adequate return on capital investment--can be major factors in determining lower bond ratings, leading in turn to higher financing costs. One analysis, for example, reported that 90 percent of the utilities with low bond ratings--between A and BBB as set by Standard and Poor's--are outside of jurisdictions described as having "very favorable" regulatory climates. 7/ At the same time, only 13 percent of those utilities with strong bond ratings, as high as AA or AAA, were found to be within the jurisdictions with PUCs thought to have "unfavorable" regulations, as assessed by five investment firms.

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6. See forthcoming CBO paper on regulatory reform.

7. See Peter Navarro, "Electric Utility Regulation and National Energy Policy," Regulation, American Enterprise Institute Journal on Government and Society (January/February 1981).

TABLE 3. BOND RATING DISTRIBUTION OF 100 RATED ELECTRIC UTILITIES AND SAMPLE SUBGROUPS WITH INVESTMENTS IN ENVIRONMENTAL CONTROL (Percent distribution)

Bond Ratings a/ (Salomon Brothers Compilations)	All 100 Electric Utilities with Bond Ratings	Top 29 Utilities with Minimum of 15 Percent of CWIP b/ Funds Dedicated to Pollution Control	21 Utilities with Scrubbers in Operation
Aaa/AAA	1	None	4.8
Aaa/AA or Aa/AAA	1	3.4	4.8
Aa/AA	26	31	38.1
Aa/A or A/AA	10	10.3	14.3
A/A	32	31	28.6
A/BBB or Baa/A	8	3.4	None
Baa/BBB	19	20.7	9.5
Baa/BBB or Lower	3	None	None

SOURCES: Salomon Brothers, Industry Analysis, "Electric Utility Common Stock Market Data" (March 2, 1981); U.S. Department of Energy, Statistics of Privately Owned Utilities in the United States (October 1980); Environmental Protection Agency, EPA Utility FGD Survey: October-December 1980 (February 1981).

a. Double listings represent a range.

b. Funding for construction work in progress.

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Mitigating Factors--Federal and State Provisions

If the conclusion derived from the foregoing analysis is correct--that investments in pollution control do not adversely affect the financial performance of utility companies--then it is reasonable to ask why not. What factors can mitigate the high costs of efforts to meet emission standards? The CBO has explored two areas in which mitigating factors can be found: federal tax provisions, and certain aspects of federal and state regulations on ratemaking that specifically make allowances for environmental control costs.

Several federal tax programs that apply to the utilities work to ease the burden of pollution control costs. These include accelerated depreciation allowances (also called rapid amortization allowances), an investment tax credit, the availability of industrial development bonds (IDBs) to finance pollution control hardware, 8/ and the routine tax treatment of expenditures for working hardware as tax-deductible business expenses.

Under the accelerated depreciation provisions, which effectively constitute a tax subsidy, a power company with a generating plant that has been in operation since before 1976 may claim depreciated value for any pollution control improvement applied to that plant over a 60-month period, even though the actual useful life of the improvement may be considerably longer. Coupled with this provision, an investment tax credit of 10 percent, granted under the Tax Reform Act of 1978, can be used with the rapid amortization provisions, unless IDBs (discussed in more detail below) are used to finance expenditures, in which case only a 5 percent tax credit can be applied. These special provisions, helping older utilities to finance pollution control efforts, can enhance short-term revenues and offset overall financing costs.

Another avenue offering considerable tax advantages to new utilities investing in pollution control is available through the use of IDBs. Issued for a public purpose either by state or municipal governments or by local industrial development authorities, IDBs for pollution abatement can furnish long-term financing on which the interest to buyers is tax-free. This last feature allows a project financed with an IDB to cost the bond issuer less in interest than if a taxable form of financing were used. When the proceeds from a bond issue go toward a pollution control system, the owning firm pays all principal and interest to the bondholders, often through lease agreements. In effect, no municipal money is involved in such a transaction.

8. These are sometimes called pollution abatement revenue bonds.

If the municipality does guarantee payment to the bondholders, the IDBs are considered general obligation bonds of the municipality, whereas no such guarantee classifies the bonds as revenue issues that depend upon the funds generated by the benefiting firm.

Utilities appear to have relied more heavily on these IDBs than have any other industries; between 1971 and 1978, some 52 percent of all pollution abatement revenue bond monies went to utilities. The average cost of IDBs for pollution control hardware issued for the benefit of these same utilities was 5.97 percent, while the average cost of long-term debt to utilities for the years 1971 through 1978 was 7.98. Thus, the cost of capital from this form of financing was lowered by 2.01 percentage points.

Altogether, the use of these special tax allowances and IDBs (or other similar revenue bonds) can reduce utilities' pollution control costs significantly. A recent study that examined pollution control costs for electric utilities in a portion of the Ohio River Valley showed that air pollution control expenditures could be reduced by as much as 18 percent through full exploitation of these various allowances. 9/

Other provisions, notably certain federal and state rate-making rules on pollution control investments, can also be credited with a role in easing the burden on utilities of investing in pollution control hardware. Both the Federal Energy Regulatory Commission--which regulates interstate electricity rates--and more than half of all its state counterparts (the public utility commissions, which regulate intrastate rates) allow utilities to collect a return on part of or all investments for environmental construction-work-in-progress. 10/ (This allowance is distinct from the PUCs' typical prohibition against recovery of general construction costs, which utilities cannot incorporate in their rate bases until after the plant begins operation.) The advantage of this allowance is that it yields actual cash earnings for utilities on assets being constructed; it also obviates the crediting against income of a noncash allowance for funds used during construction--an accounting method that can erode earnings and hence stock and credit ratings. In general, the charging of construction-work-in-progress in the rate base can result in lower capital costs to the utility and lower lifetime

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9. See JACA Corporation, "The Economic Impact of Regulating Air Pollution in the Ohio River Valley," draft report prepared for the National Commission on Air Quality (December 1980).

10. See National Association of Regulatory Utility Commissioners, "1979 Annual Report."

electricity costs to the consumer. 11/ (This subject is discussed in greater detail in Appendix C.)

11. This discussion is confined to allowances already in existence before enactment of the Economic Recovery Tax Act of 1981 (P.L. 97-34). The potential benefits of the new law, which includes more liberalized depreciation allowances, on utility finances and cash flow have not been included in this analysis. For a discussion of potential benefits, see Donald W. Kiefer, "The Impact of the Economic Recovery Tax Act of 1981 on the Public Utility Industry," Congressional Research Service (January 15, 1982).

CHAPTER IV. PROMOTING RELIANCE ON COAL AND THE EFFECTS OF THE CLEAN AIR ACT

A major goal of U.S. energy policy to foster the nation's independence from foreign oil suppliers is to promote the burning of coal in electric power generators instead of oil or gas. Although the United States holds a full 31 percent of the world's recoverable reserves of coal, combustion of that fuel furnishes only about one-half of the nation's electricity, with oil and gas providing some 26 percent. (Nuclear and hydroelectric power account for the balance.) Thus, although exploitation of the coal resource has already risen appreciably, opportunities to replace far greater quantities of oil and gas still exist.

Both the Energy Supply and Environmental Coordination Act (ESECA) of 1974 and its successor, the Power Plant and Industrial Fuel Use Act (PIFUA) of 1978, were specifically designed to reduce oil and gas consumption in both new power plants and older facilities already capable of burning coal. Under the latter legislation, the PIFUA, the federal government can order that utilities operating generators that had at one time been converted from coal to oil reconvert those generators back to coal. In addition, utilities are effectively prohibited from burning oil or gas in new major power plants. Thus, a major goal of federal energy policy is also to encourage the accelerated replacement of gas- and oil-fired capacity with coal-burning plants.

Air pollution control policy, articulated by the federal government in the Clean Air Act and by state and local authorities in their own regulations (state implementation plans), can strongly influence the economics underlying the utilities' choices between reconversion of a power plant or its replacement, and continuing to rely on gas or oil. Replacement--involving major capital investment in new plants, which are subject to the act's 1978 NSPS is demonstrably expensive, as indicated by the analysis in the preceding two chapters. Desulfurizing flue gases by means of scrubbers, just one of the cost components entailed in meeting the 1978 NSPS, is an expensive but requisite technique. Reconversion is usually cheaper, since it rarely entails scrubbers. Reconversion has its own significant costs, however, including the possible need to upgrade the boilers and burners to use the particular coal involved, upgrade coal-handling equipment, and modify or replace particulate control devices.

This chapter examines the influence of the Clean Air Act and other factors on the economic choices for utilities between reconversion, replacement, or maintenance of existing oil- or gas-fired capacity. Results of the

Congressional Budget Office's analysis suggest that the costs of reconversion can be substantially less than continuing to burn gas or oil in coal-capable boilers; they also conclude that economic benefits associated with coal use are possible even with full replacement. At the same time, however, they point to oil prices as a strongly influential factor in the cost effectiveness of turning to coal to generate electricity. So long as the growth rate of world oil prices remains depressed, full replacement of oil- and gas-fired capacity may have difficulty proving its economic benefit. 1/

PREVAILING REGULATIONS FOR COAL CONVERSIONS

Distinct from new plants, which are uniformly subject to the federal NSPS of 1978, old plants that are candidates for reconversion can fall subject to a complex mix of federal and state regulations, including exemptions. Two types of reconversion projects are exempt from both NSPS and new source review under the act's "prevention of significant deterioration" program (see Chapter II and Appendix A): power plants ordered to convert to coal under the PIFUA of 1978, and voluntary reconversion of plants that were capable of burning coal before January 1, 1976. Most major utility reconversion candidates fall into these two categories. Both of these types of reconversions must meet the state emissions control requirements for coal-fired power plants of their same vintage, or they must comply with alternate regulations negotiated with the states and approved by the federal government (that is, the EPA). All other reconversions, while generally exempt from the 1978 NSPS, must undergo the PSD new source review process. Few if any reconversion candidates would fall under this latter category.

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1. Since early 1981, a strong downward pressure in world oil prices has occurred in response to excess production. Though residual oil prices have fallen in the spot markets, some by $7 per barrel from their peak price (approximately $34 per barrel), long-term contract prices remain high (approximately $33 per barrel). Analysts anticipate that revived economic growth in the United States and other countries will, by the mid- to late-1980s, spur a resumption of rising rates in world oil prices similar to those observed in the late 1970s. However, how long it will take for oil prices to regain their peak levels (in real terms) is unknown.

COST ANALYSIS--THE POTENTIAL BENEFITS OF RECONVERSION OR REPLACEMENT COMPARED TO CONTINUATION OF OIL OR GAS USE

To quantify and compare the economic effects of Clean Air Act regulations on power plant conversions, the CBO calculated the annual capital and maintenance costs of two possible reconversion cases and one replacement case. The lower-cost reconversion case, requiring no scrubber but using low-sulfur coal, would be completed at a capital cost of $150 per kilowatt. The higher-cost example, requiring a wet scrubber to meet assumed stricter state standards and burning high-sulfur coal, would be completed at a capital cost of $600 per kilowatt. 2/ The replacement example would require a capital cost of $1,160 per kilowatt. (All cases examined here were assumed to meet the applicable environmental standards. The two reconversion examples are assumed to meet all state and local regulations; the one replacement case is assumed to comply with the federal 1978 NSPS.)

The assumptions used in the analysis reflect upper-bound costs for both reconversion and replacement. In all cases, a 10 percent real rate of interest for capital investments was assumed, using a 15-year period for reconversion and a 20-year period for replacement (accounting for the possibly shorter operating life of a reconverted facility). The price of coal in all cases was assumed to rise at a real annual rate of 2.7 percent.

To allow comparison with the costs of using oil, the CBO also computed the operating costs of oil-fired capacity under two different assumptions regarding oil prices. (The maintenance of oil-fired capacity was assumed to entail no capital expenditures.) One assumption used was no real rise in oil prices; the other applied a constant 2 percent real rise over a 20-year period. The result yields not only a general comparison of electricity costs as determined by fuel, but also an illustration of the sensitivity of economic benefits from conversion and replacement to differing behavior of oil prices. This five-part comparison and an explanation of all underlying assumptions are displayed in Table 4.

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2. The range of reconversion costs were obtained from plant-by-plant reconversion estimates prepared by the Edison Electric Institute for use by ICF, Incorporated. See ICF, Incorporated, "A Preliminary Economic Analysis of Reconversion of Coal Capable Utility Boilers," prepared for the Edison Electric Institute (April 25, 1980).

TABLE 4. CAPITAL AND GENERATING COSTS FOR A 500-MEGAWATT OIL-FIRED, RECONVERTED OIL, AND NEW COAL-FIRED POWER PLANT

		In mills per kilowatt-hour			
Case	Capital (In dollars per kilowatt)	Annual Fixed Capital	Annual Operating	Fuel	Total Generating
A. Low Cost Conversion	150	3.2	7.5	26.6	37.3
B. High Cost Conversion	600	12.9	12.6	19.2	44.7
C. Replacement	1,160	22.2	10.1	19.2	51.5
D. Oil Plant with No Real Fuel Price Increase	None	None	2.0	48.4	50.4
E. Oil Plant with 2 Percent Fuel Price Increase	None	None	2.0	60.0	62.0

With either low- or high-cost plant reconversion, the generating costs of 37.3 and 44.7 mills per kilowatt-hour, respectively, are lower than current oil-plant generating costs of 50.4 mills per kilowatt-hour, even assuming no real rise in oil prices. 3/ In comparison, the replacement case of a new coal-fired power plant equipped with a scrubber (having a generating cost of 51.5 mills per kilowatt-hour) is cost effective only if oil prices rise by 2 percent in real terms over the next 20 years, resulting in an oil-plant generating cost of 62.0 mills per kilowatt-hour. The generating

3. These reflect generating costs only and do not include the costs of transmission and distribution.

TABLE 4. (NOTES ON ANALYTICAL ASSUMPTIONS)

A. No scrubber; low-sulfur coal burnt; average fuel cost over 20 years, starting at $38 per ton delivered price, rising at an annual real rate of 2.7 percent; 10 percent real financing costs for reconversion and particulate emissions control upgrading.

B. Wet scrubber; high-sulfur coal burnt; average fuel cost over 20 years, starting at $33 per ton delivered price, rising at an annual real rate of 2.7 percent; 10 percent real financing costs for reconversion, particulate emissions control upgrading, and scrubber retrofit.

C. New coal-fired plant with wet scrubber, high-sulfur coal burnt; fuel and financing costs same as Case B.

D. No capital outlays; fuel costs constant $31.50 per barrel for 20 years.

E. No capital outlays; average fuel cost over 20 years, starting at $31.50 per barrel, rising at an annual rate of 2 percent.

SOURCE: Congressional Budget Office.

cost of a new coal plant burning low-sulfur fuel also was calculated, assuming a construction cost of $975 per kilowatt. Interestingly enough, the resulting generating cost of 50.3 mills per kilowatt-hour (not shown in Table 4) is quite close to the replacement example of 51.5 mills per kilowatt-hour, which includes a scrubber.

Although full power plant replacement under these assumptions may not be economic unless oil prices begin to rise at some real rate from their 1980 levels of approximately $31.50 per barrel, it does become economic even assuming constant real oil prices if a 6 percent real interest rate, rather than a 10 percent rate, is applied. For analytical purposes, a 10 percent real rate of interest is often used in assessing effects of regulations and was used in these estimates both to allow comparison with other

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analyses and to demonstrate upper-bound costs. In practice, however, real rates of 6 percent or less more accurately represent true interest charges on capital for the electric utilities.

INHIBITING FACTORS

Although the Clean Air Act appears not to be a decisive factor in the economic advantages of reconversion, other factors do impede the rate at which reconversions can occur. These result from a combination of federal and nonfederal regulations.

Economic Constraints at the State Level

Underlying all other factors that may tend to discourage reconversion or replacement of oil- and gas-fired power plants are the financial condition of the individual utility and rate-making regulations imposed by the public utility commissions (see Chapter III). Many of the large oil-consuming utilities are in poorer financial condition than the general utility population and would face difficulty raising the necessary capital. Examination of a list of conversion candidates prepared by the Edison Electric Institute shows that only four (22.3 percent) of the 18 rated utilities on the list have higher than "A" ratings as reported by both Moody's and Standard and Poor's. 4/ In comparison, the general population of 100 rated utilities shown in Table 3 in Chapter III have 38 percent listed at ratings above A.

Compounding these difficulties are PUCs' decisions that discourage reconversion and replacement by delaying a return on investment for construction projects but providing, through fuel adjustment clauses, immediate relief from higher fuel costs (see Chapter III). These factors tend to perpetuate dependence on oil and gas. The net result of such constraints is a systematic bias against capital investment. A utility company that would experience a severe cash-flow problem while pursuing a conversion project may defer any such undertaking indefinitely. Nonetheless, some others, encouraged by the eventual prospect of savings from burning coal (even a high-cost reconversion plant of 500 megawatts can save roughly $1.4 million per month) have tolerated the short-term financial risks and proceeded with conversion plans.

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4. See Salomon Brothers, "Electric Utility Stock Market Data," Industry Analysis (March 2, 1981).

Administrative Impediments in the Clean Air Act

Many of the problems arising from the Clean Air Act can be characterized as administrative. Most reconversion projects fall under individual state emissions regulations, some of which are extremely strict as a result of encouraging oil consumption in place of coal in the 1960s and early 1970s for environmental reasons. Utility companies may seek to relax these state-imposed emissions limits in order to curb reconversion costs, often leading to long periods of negotiation between the utility, the state, and in some cases the EPA, which also has authority to enforce state plans. To arrive at a mutually acceptable emissions standard, the utility firm must submit a detailed description of the effects of the planned reconversion project on ambient air quality, including what measures will be taken to control emissions. The submission and review process is time-consuming and requires considerable technical expertise. Overall, both voluntary conversions and those mandated by federal regulations can involve two years or more of administrative effort before the start of conversion activities.

Because of inflation and deferral of cheaper energy-producing capacity, a utility planning conversion of a 500-megawatt generator costing $600 per kilowatt can lose $3.4 million a month (in nominal dollars) to such administrative delays. This may be compared to the monthly savings of $1.4 million (in nominal dollars) obtainable by that same conversion. Thus, though conversion to coal remains economically advantageous, some streamlining of the administrative requirements to speed implementation of conversion plans would enhance that advantage.

Technical Problems During Work in Progress

Once construction begins on a conversion project, technical problems can slow its progress. Late delivery of equipment and labor shortages can cost a firm some $3.5 million a month (in nominal dollars), assuming 30 percent completion of the project at the start of delay (again, assuming a 500-megawatt plant reconverted at $600 per kilowatt). The prospects of such delay once funds have been committed--postponing the anticipated savings of $1.4 million a month--can be particularly discouraging to firms in light of PUC regulations that generally prohibit recovery of capital investments for projects under construction.

THE IMMEDIATE PROSPECTS FOR CONVERSION

Despite these hindrances, many conversion projects are under way or planned. In a review of 14 utilities, the General Accounting Office reported that six firms were planning 25 reconversions, and two other companies had notified the Department of Energy that they plan to reconvert five additional units. 5/ Conversion of all 30 units would displace the use of some 190,000 barrels of oil per day. Potential for even greater oil displacement is projected by the Department of Energy, which estimates that as many as 520,000 fewer barrels per day of oil or gas equivalent might be consumed through conversions. 6/

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5. See General Accounting Office, "Financial and Regulatory Aspects of Converting Oil-Fired Units to Coal," report to the Chairman, Senate Committee on Energy and Natural Resources (November 21, 1980).

6. See Department of Energy, "Fuels Conversion Program Power Plant Profiles" (January 1981).

CHAPTER V. THE U.S. COAL MARKET AND THE CLEAN AIR ACT

To whatever extent the Clean Air Act influences the utility industry's use of coal, it may also indirectly affect the U.S. coal market. The analysis in this chapter assesses that indirect but important relationship, both as it appears to have operated thus far and as it may in the near future. As the facet of the Clean Air Act most influential to utilities, and in turn to the coal industry, the evolving new source performance standards (see Chapter II) governing gaseous and particulate pollutant emissions are a focal point of this analysis.

As background for evaluating the act's effects on coal markets, this chapter gives an overview of the nature of the coal resource and the factors that influence its purchase by electric utilities. The chapter then reviews the effects seen to date of the first NSPS of 1971. It then projects how the more rigid NSPS of 1978 are likely to influence the supply and distribution of coal through the year 2000.

THE NATURE OF THE U.S. COAL MARKET

The electric utility industry is the nation's largest user of coal, today accounting for some four-fifths of all domestic consumption. Roughly half of all U.S. electricity is now derived from coal. In 1979, some 550 million tons of coal went to utilities; by the end of this century, if current emissions standards remain in force, that figure should more than double, reaching an annual total of 1.2 billion tons. 1/ To meet this demand, coal production in nearly all regions is expected to rise. The actual distribution of this increase will probably not be uniform, however, and the Clean Air Act will have a role in altering the patterns of growth.

Despite the fairly uniform regional distribution of the nation's coal deposits--all but a few major geographic areas have at least some coal

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1. While the use of coal by electric utilities has been rising, demand in other sectors of the economy has been falling. Between 1970 and 1979, coal use by electric utilities rose some 65 percent but fell in all other industries, including steel making, by a combined 30 percent. Residential and commercial users account for only 1 percent of all coal purchases.

deposits--the market value of coal varies between and within regions. Two main characteristics affect the value of the delivered price of all coal:

- How it is mined--whether by deep-mining, which is typically the costlier method, or by surface techniques; and

- What distances it must travel from where it is produced to where it is used.

A third factor--sulfur content--is also influential, though of lesser importance, inasmuch as the demand for low-sulfur coal may be enhanced by emissions limits on sulfur dioxide. Energy content, another fuel-related value, has less influence on the price of coal at the mine than on the delivered price, since more volume of a low-energy-content coal must be shipped than of a high-energy-content coal. Aside from these factors, which can influence delivered price, the fuel value of different coals is essentially unvaried, since most new power plants can be designed to handle any particular coal chosen for long-term consumption.

Regional Characteristics of Coal

In general, U.S. coal production can be divided into three regions: the area east of the Ohio and Mississippi rivers (particularly the Appalachian region); the Midwest (from the Mississippi to the western borders of Minnesota, Nebraska, Kansas, Oklahoma, and Texas); and the West. (See Figure 3.) Within all three regions, both deep- and surface-mining methods are used, though to different extents. In the East, the choice of mining method is roughly equally split between surface- (40 percent) and deep-mining (60 percent). In the Midwest and the West, however, far more surface- than deep-mining is done (see Figure 4). Because surface-mining is typically more productive, coal recovered by this method usually has a sizable cost advantage over coal from deep mines. 2/

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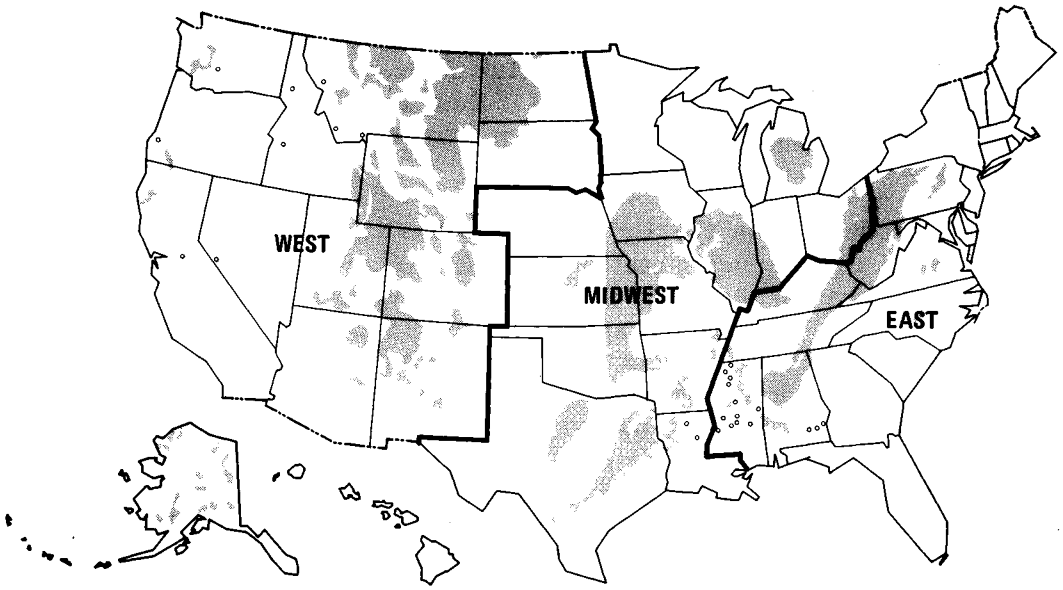
2. The location of the coal resource generally determines the recovery method used. Much Appalachian coal is buried in seams deep within mountains or hills; deep-mining is the only method available to recover much of this coal. For more superficial coal, large machines can remove the overlying soil (overburden), exposing the coal. This method, also called strip mining, tends to be more productive. In addition, because of the terrain involved and depth of overburden, many western surface mines are more productive than eastern surface mines, though other factors, such as the age of the mines, also can influence productivity.

Figure 3.

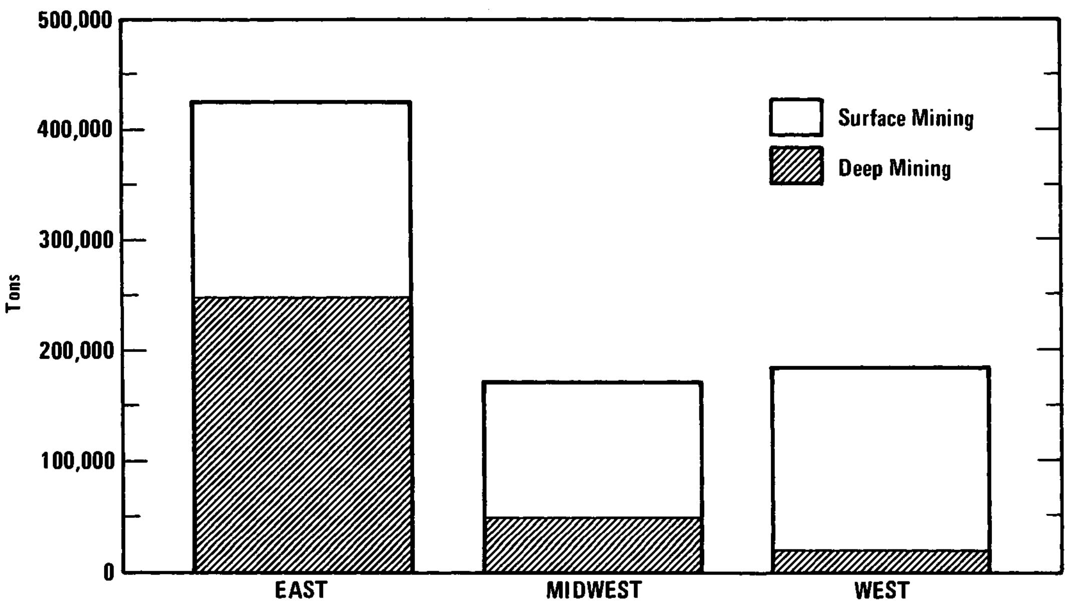
U.S. Coal Fields and Producing Regions



SOURCE: Adapted by CBO from The President's Commission on Coal, "Coal Data Book" (February, 1980).

Figure 4.

Total U.S. Coal Production by Region and Mining Methods: 1979



SOURCE: Adapted by CBO from U.S. Department of Energy, *Coal Production—1979* (April 30, 1981).

The regional pattern of coal's sulfur content also varies from region to region, and within particular regions. The East contains coals with sulfur contents ranging from below 1 percent to above 3 percent by weight. The Midwest offers little low-sulfur coal; most coal in that region is characterized by moderate- or high-sulfur contents, generally above 3 percent. The West has sizable reserves of low-sulfur coal; more than three-fourths of all western coal has a sulfur content below 1 percent. In contrast, the energy content of eastern and midwestern coal reserves is generally higher than in the West.

Coal production in the United States has been shifting slowly westward. In 1960, the producing states of the East accounted for 95 percent of total U.S. production. By 1970, the East's share of the market had declined to 85 percent and by 1979, to approximately 75 percent. 3/ The reasons for this trend are the high productivity of western surface mines, the growth in western energy consumption, and to some extent, the increased nationwide demand for low-sulfur coal to meet both state and federal environmental regulations. In the future, the revised federal emissions standards--the NSPS of 1978, with their implicit requirement of scrubbers on all new utility generators--may somewhat slow this westward trend in coal production, inasmuch as the current regulations provide little if any economic advantage to users of low-sulfur coal that is not locally produced.

Factors That Influence Choices of Coal Supply and Delivered Price

Although coal is produced in all three regions of the country, much coal, particularly western coal, is shipped to other geographic regions. Although under ideal conditions utilities would elect to burn local coal only, several factors often combine to influence them to do otherwise. Local mining costs, sulfur content, and the availability of a secure long-term supply often prompt utilities to buy coal produced in other areas, so long as they obtain the lowest delivered price for the fuel desired. The chief factor affecting utilities' coal purchasing decisions is the fuel's so-called free-on-board (FOB) price. The FOB price, coal's counterpart to oil's wellhead price, is its cost at the place of production, including mining and processing costs and producers' profit, but no transport cost.

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3. See Martin B. Zimmerman, The U.S. Coal Industry: The Economics of Policy Choice, the MIT Press (1981). The 1979 figure is based on the CBO analysis.

Mining method is the most significant factor affecting FOB costs. In general, surface mines are from two to three times more productive than underground mines, and coal from surface mines often sells for about one-half the price of coal from deep mines. In 1979, the average FOB value per ton of deep-mined coal was $32.76, while that of surface-mined coal was $17.58. 4/ To determine the delivered price of a particular coal, however, transporta-tion rates and distances hauled must be added to FOB costs.

Most coal moves by train. Rail haulage rates generally range from 10 to 30 mills per ton for each mile transported (termed a "ton-mile"). Higher rail rates predominate in the East, although in several western areas, rail rates have risen steeply over the last few years. At a cost of 15 mills per ton-mile, a haul of 300 miles can increase the FOB coal price by $4.50 per ton. For 1,000-mile hauls, $10 to $20 can be added to the price of each ton of coal. Though unusual in the East, where coal hauls average 300 miles, 1,000-mile hauls are not uncommon in the West.

Within a region, coal's delivered price is largely a function of the region's predominant mining method, since the value of local coal establishes the upper value for coal shipped from other areas. Delivered coal prices are highest in the East--where approximately half the coal is mined underground--ranging from $37 to $44 per ton. Delivered coal prices in the midwest are lower, ranging from $18 to $33 per ton, corresponding to the greater use of surface-mining methods in this area. Prices for coal delivered to western users, where surface-mining also predominates, are lowest, ranging from $14 to $18 per ton. 5/

Low mining costs, together with regulations encouraging the use of low-sulfur coal (such as stricter state standards on some older power plants and the 1971 NSPS on newer units) encourage the shipment of much western coal eastward. Most coal from western deposits happens to be low in sulfur content and because it is mostly surface-mined, tends to have lower FOB prices than eastern, deep-mined low-sulfur coal. As a result, western surface-mined low-sulfur coal is an attractive alternative to some buyers in the East and the Midwest in particular.

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4. See U.S. Department of Energy, "Energy Data Report," Coal Production-1979 (April 30, 1981).

5. See U.S. Department of Energy, Cost and Quality of Fuels for Electric Utility Plants--December 1980, Monthly Report (April 7, 1981).

Several factors limit the demand for western coal in the East and Midwest, however. For one, the East (notably Appalachia) holds large quantities of low-sulfur coals. Although much of this supply is mined (by either method) at a higher cost than western surface-mined coal, it is closer to many eastern purchasers and transportation costs thus can be lower. For eastern users, the costs of shipping western coal can often raise its delivered price above that for comparable low-sulfur eastern coal. Another major factor is the status of many sulfur dioxide regulations for old power plants. In many areas of the Midwest, the absence of strict sulfur dioxide regulations for many older power plants, allowing them to use indigenous surface-mined higher-sulfur coal, obviates the need to purchase low-sulfur coal from another region. Finally, through the imposition of a strict scrubbing requirement on all coal used in new power plants, the current NSPS provide little stimulus for increasing the import of low-sulfur coal.

THE 1971 NEW SOURCE PERFORMANCE STANDARDS AND U.S. COAL CONSUMPTION

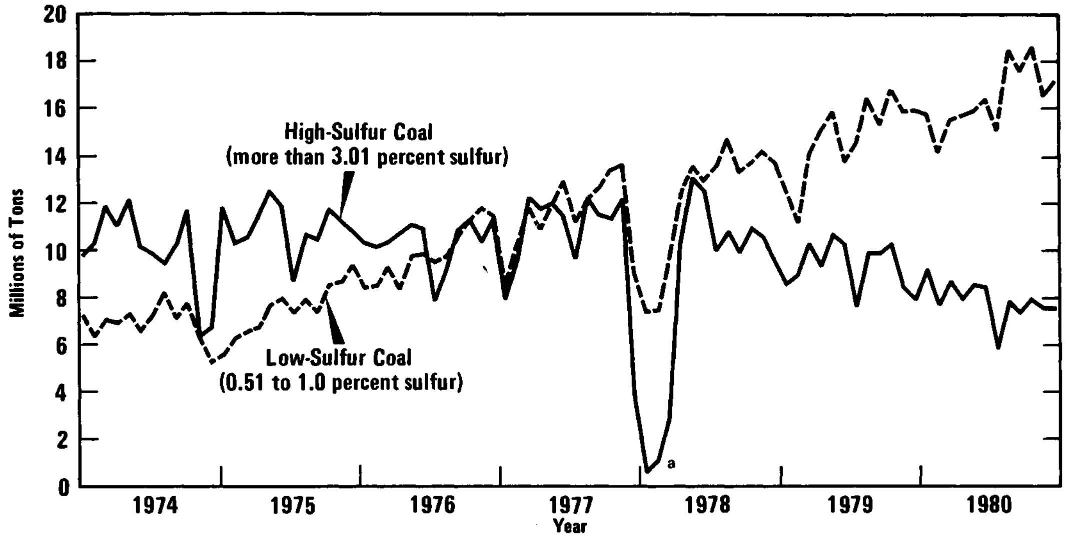
Concerns about distortions in U.S. coal markets shaped the Congress' revisions in 1977 of the Clean Air Act's new source performance standards. Under the old NSPS of 1971, utility companies could--and did--rely heavily on low-sulfur coal to meet mandatory mass pollutant emissions limits. (As stated in Chapter II, the maximum allowable amount of sulfur dioxide gas emitted from a steam boiler's stack was 1.2 pounds for every one million BTUs of fuel burnt.) Required only to meet this mass emissions limit by whatever method was economical, many utility managers elected to burn low-sulfur coal rather than install costly and still optional scrubbers; scrubbers were chosen rarely, usually in instances in which low-sulfur coal was not available within a reasonable distance.

From this apparent preference for low-sulfur coal under regulations promulgated in response to the Clean Air Act, the Congress concluded that two related distortions in need of correction existed: that demand for low-sulfur coal was gaining an edge over higher-sulfur coal; and that, accordingly, western coal could flood the market, displacing demand for eastern and more importantly, midwestern coal.

Data on the trend in demands for high- and low-sulfur coal tend to bear out these suppositions, but only partly (see Figure 5). The relative demand for low-sulfur coal did indeed grow during the late 1970s, coincident with the utilities' implementation of plans to meet the mass emissions limits

Figure 5.

Monthly Deliveries of Coal to U.S. Electric Utilities, by Sulfur Content: 1974-1980



SOURCE: Adapted by CBO from data provided by Data Resources, Inc.

[a] Drop coincident with mine workers' strike.

promulgated in 1971. 6/ At the same time, the rate of high-sulfur coal deliveries slackened. Though possibly related to one another and reflecting some displacement of high- by low-sulfur coal, these two trends cannot be construed as conclusive evidence of the Clean Air Act's effects. Other factors also have to be taken into account.

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6. By no means should the divergence of high- and low-sulfur coal demand in the late 1970s be taken as any indication of the effects of the revised NSPS of 1978. Because utilities' efforts at compliance with the revised NSPS are still very much on the planning or initial construction stages, the 1978 NSPS are unlikely to yield any measurable effects on fuel markets for another decade or more. Far more reasonable, though still tenuous owing to an insufficiency of data, is a possible correlation between the older NSPS and shifts in the coal market in the late 1970s and early 1980s. Even so, much of the perceived shifts may be attributable to tighter state regulations under the act limiting the emissions of some older power plants not covered by federal emissions standards.

Much of the increase in overall low-sulfur coal demand observed in the 1970s stemmed from the large increase in low-sulfur western coal consumption also observed during this period, an increase not necessarily in response to sulfur dioxide regulations and not necessarily resulting from regional shifts in the coal market. Though consumption of western coal rose by 145 percent between 1974 and 1979, the rise can be ascribed more to increased local consumption than to the attractiveness of western coal's low-sulfur characteristics to distant buyers. During those years, annual coal consumption in the West South Central, Mountain, and Pacific areas alone increased by 73 million tons; the nationwide increase for all coals during those years was 94 million tons. (Figures 6 and 7 outline the specific U.S. regions of coal supply and demand, which are also used in the coal market projections described in Appendix B.) At the same time, however, western coal shipments to midwestern consumers in Ohio, Illinois, and Indiana (the largest users of western coal east of the Mississippi) rose by only 10 million tons. 7/ For the most part, coal-burning utilities in those states continued to rely on local fuel, and of the total increase in national coal consumption between 1974 and 1979, less than 11 percent involved increased shipments of western coal to the three midwestern states. As stated above, mines in the East, notably in Appalachia, also yield significant amounts of low-sulfur coal. Thus, eastern suppliers too may have shared in the increased use of low-sulfur coal.

For the portion of low-sulfur western coal that was shipped east during the 1970s, mining costs may have been as strong an element as emissions regulations in stimulating its demand. As stated above, much low-sulfur coal, by virtue of being located in the West where surface-mining methods predominate, tends to incur relatively low recovery costs. Furthermore, western surface mines are more productive than many midwestern surface mines. In 1979, the average FOB price of surface-mined coal from Montana and Colorado ranged from \$9.76 to \$13.13 per ton, while that from Illinois, Indiana, and Ohio ranged from \$19.21 to \$21.13 per ton. 8/ Thus, this factor too may have contributed to the increased use of low-sulfur coal during the late 1970s.

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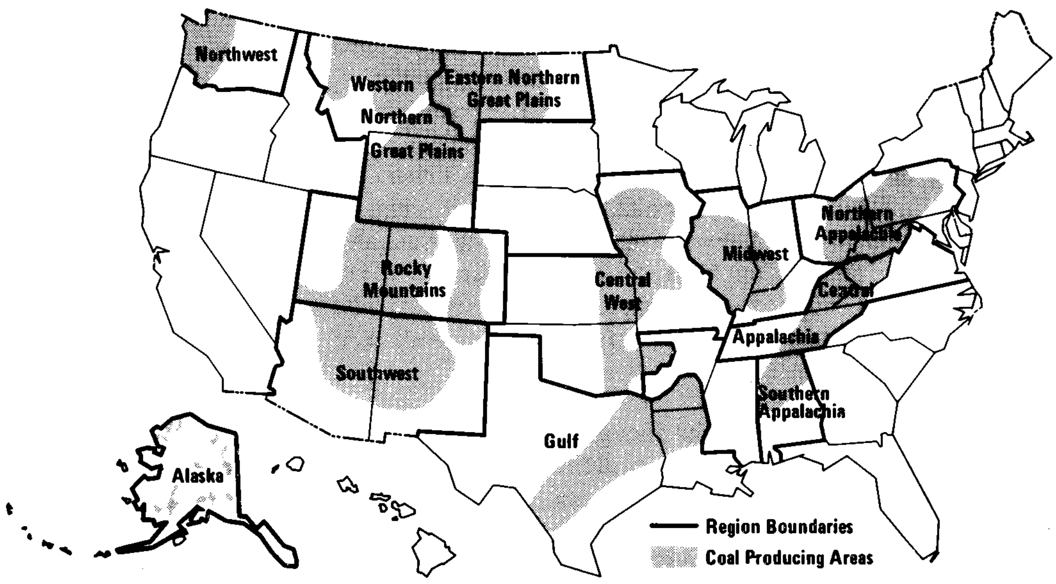
7. See U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Year 1978 (April 1979); see also, U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Year 1979 (April 1980).

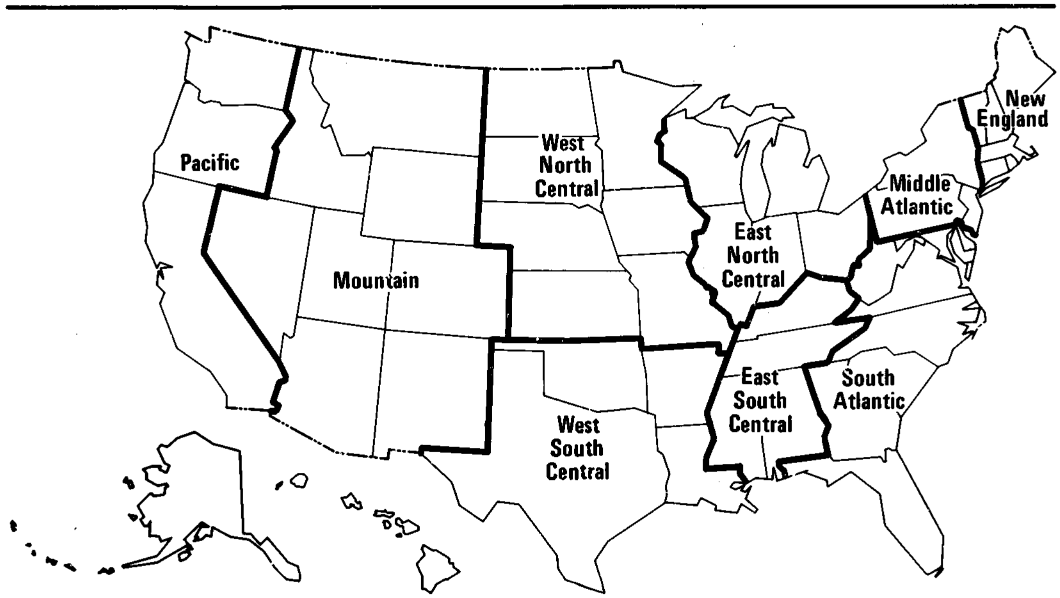
8. See U.S. Department of Energy, Coal Production-1979.

Figure 6.
U.S. Coal Supply Regions



SOURCE: Adapted by CBO from ICF, Incorporated.

Figure 7.
U.S. Coal Demand Regions



SOURCE: Adapted by CBO from ICF, Incorporated.

Though the nationwide demand for low-sulfur coal did rise during the 1970s, the characteristic of low-sulfur content does not appear to have caused that fuel's delivered price to be significantly higher than the delivered price for high-sulfur coals. Throughout the 1970s, the price of both high- and low-sulfur coal proceeded along roughly parallel upward paths (see Figure 8), with low-sulfur coal priced only slightly higher. The only anomaly in the pattern, also evident in the illustration of deliveries (Figure 5), occurred in 1978, coincident with a strike of mine workers against coal producers; though pronounced and causing a brief, inexplicable gain for high-sulfur coal over low-sulfur coal, this episode represents only a temporary disturbance on the otherwise quite regular course of both low- and high-sulfur coal prices. The fact of no significant difference between the delivered price of both coals suggests that buyers, at least in the 1970s, were willing to pay only a slight premium for low-sulfur content over the cost of locally available coals.

In conclusion, though increased demand for low-sulfur coal in the 1970s has occurred roughly simultaneous with implementation of utilities' plans to meet the 1971 NSPS, no firm correlation can be established, perhaps because the standards have not been in effect long enough. Nevertheless, the perceived potential for future distortions in the coal market prompted the Congress to take preventive measures in amending the Clean Air Act in 1977.

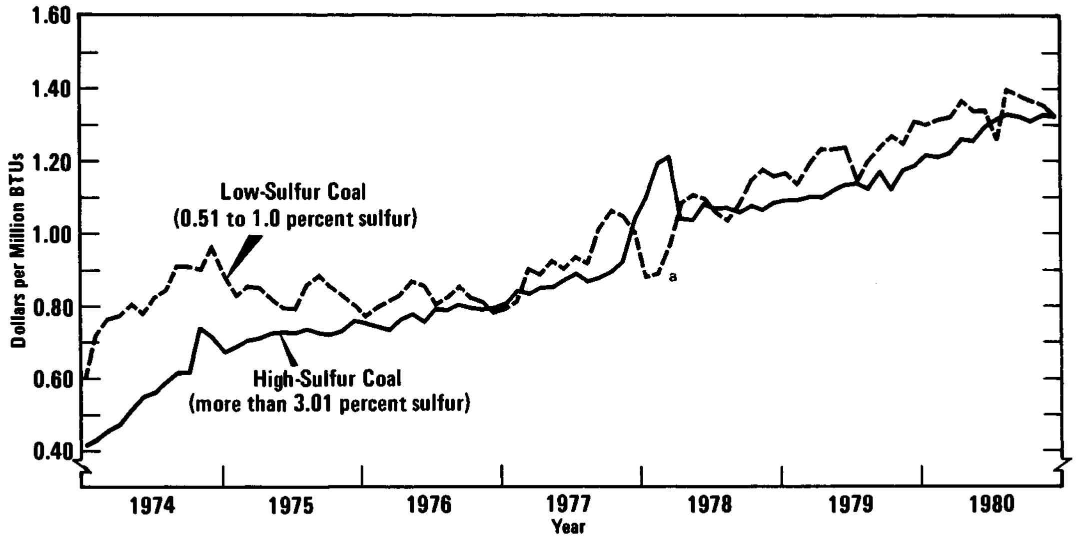
THE REVISED NSPS AND PROJECTIONS FOR U.S. COAL MARKETS

By requiring the installation of scrubbers in all new coal-burning generating plants, the revised NSPS of 1978 were designed to remove the attractiveness to utilities of using non-local low-sulfur coal. The requirement to remove a fixed percentage of sulfur dioxide when burning any type coal under the 1978 NSPS was designed to encourage the use of the cheapest coal available, usually a locally produced coal. In devising the new regulations, the EPA formulated projections through 1995 on the basis of a computer model simulation. 9/ The simulation indicated that, as a result of the proposed new standards, total pollutant emissions would be reduced through-

9. See ICF, Incorporated, "The Final Set of Analyses of Alternative New Source Performance Standards for New Coal-Fired Power Plants," prepared for the U.S. Environmental Protection Agency and Department of Energy (June 1979).

Figure 8.

U.S. Coal Prices, by Sulfur Content: 1974-1980



SOURCE: Adapted by CBO from data provided by Data Resources, Inc.

[a] Divergence coincident with mine workers' strike.

out the projection period, and that reliance on local coal would increase appreciably.

As part of a reexamination of the NSPS of 1978, the analysis in the remainder of this chapter attempts to assess what effects, if any, the revised NSPS will have on U.S. coal markets through the year 2000. Since the new standards were enacted, knowledge about scrubber costs, electricity growth, and coal supply has increased. To take account of this information in its analysis, the CBO requested ICF, Incorporated, a consulting firm specializing in coal-market information, to examine the effects of the 1978 NSPS on the basis of new assumptions developed by the CBO. ICF was chosen to conduct the modeling because it operates one of the most detailed coal and utility emissions models available, and because that model continues to be used by the EPA and other researchers to determine the effect of alternative standards on the utility and coal industries.

The purpose of the modeling was to establish a baseline of reasonable expectations for current policy with regard to three sets of issues: What quantity of air pollutant emissions can be expected from the utility sector through the year 2000? What are likely to be the annual and cumulative costs of the standards limiting these emissions? And what consumption and regional production levels of different coal types may be anticipated? (This same model is used in the analysis in Chapter VI that compares alternative emissions standards for sulfur dioxide--the most influential emissions limit--against this baseline and against each other.) The remainder of this chapter focuses on two aspects of the third issue: What type of coal is likely to be used within each consuming region, and where will that coal originate? The analysis is based on the assumption that the current NSPS will remain in force. (Appendix B details the assumptions and the methodology used.)

In the year 2000, the majority of projected new coal-fired capacity--that is, plants subject to the current NSPS--will be in the West South Central area and Atlantic seaboard states. Almost 100 gigawatts (60 percent) of the 168 gigawatts of new coal-fired electric capacity anticipated will be located in these areas (see Table 5). The area seen to experience one of the lowest growth rates in new coal-fired capacity is the southern Midwest (encompassing the East South Central area); the sizable commitment to new nuclear power in that region will tend to lower the Midwest's growth in coal-fired capacity, though recent nuclear plant cancellations may result in greater projected coal-fired capacity.

With regard to the sulfur content of coal burnt by new plants subject to the current NSPS, the pattern of overall consumption established late in the 1970s is expected to continue. Low-sulfur coal (generating less than 1.2 pounds of sulfur dioxide per million BTUs) is projected to meet roughly 60 percent of all new coal-fired utility demand by the year 2000. Much of that consumption is seen to occur in the Mountain and West South Central regions (36 percent), where low-sulfur coal naturally predominates; and the South Atlantic region (24 percent), where low-sulfur coal is available from Central Appalachia. Hence, the low-sulfur coal consumed in these regions will come largely from local supplies. In the East, North, and South Central areas of the Midwest, however, where low-sulfur coal is not mined, low-sulfur coal will supply approximately 60 percent of the regional demand in the year 2000 in power plants covered by the NSPS. Most of this supply will probably come from the West, indicating an accelerated trend toward western coal supplies. The growth in midwestern coal production (see Table 6), however, also indicates that many new power plants will choose to burn the locally produced high-sulfur coal under the NSPS.

Three western areas are projected to experience significant increases in total coal production. In the Rocky Mountain states, production is seen to rise by 578 percent; in the Southwest, it should rise by 468 percent; and in the Western Northern Great Plains, by 268 percent. These sizable growth rates are attributed partly to consumption by users in the West and West

TABLE 5. PROJECTED REGIONAL GROWTH IN COAL-FIRED ELECTRICITY, TO YEAR 2000

Region	Total 20-Year Growth in Coal-Fired Capacity (In gigawatts)	Total Projected Annual Coal Consumption (In millions of tons)	Percent Increase in Consumption from 1979
East (New England and Middle and South Atlantic)	44.2	290	110
East North Central	25.5	241	50
East South Central	3.6	88	23
West North Central	11.8	134	82
West South Central	54.2	275	535
West (Mountain and Pacific)	25.0	146	134
Total	164.3	1,174	114

SOURCE: CBO/ICF analysis.

South Central regions, and partly to increasing demand in the Midwest and East. In the year 2000, western coal will supply approximately 21 percent of all coal burnt by both new and old utilities east of the Mississippi. The majority of coal used in these areas, however, will still be supplied by midwestern and eastern (primarily Appalachian) producers.

These data indicate some important trends in coal markets. Most important, coal production is seen to rise in all U.S. regions, most notably in the western areas. The exception is Southern Appalachia; a slowing of production in Appalachia is to be expected, since these eastern reserves have been mined for longer periods and are declining in productivity.

Also important is the increasing amount of western coal shipped east by the year 2000. In 1979, eastward shipments of western coal are esti-

TABLE 6. REGIONAL COAL PRODUCTION FOR 1979 AND PROJECTED TO THE YEAR 2000 (In millions of tons per year)

Region	Base Year Production (1979)	Total Projected Annual Production	Percent Increase
Northern Appalachia	187	331	77
Central Appalachia	213	342	61
Southern Appalachia	24	21	-13
Midwest	131	252	92
Central West	14	17	21
Gulf	26	119	358
Eastern Northern Great Plains	14	44	214
Western Northern Great Plains	104	383	268
Rocky Mountains	27	183	578
Southwest	25	142	468
Northwest/Alaska	5	33	560
Total	770	1,867	142
Total Western Coal Shipped to Eastern Utilities	22a/	127	477

SOURCE: CBO/ICF analysis.

a/ Estimate obtained from data in U.S. Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution, Calendar Year 1979.

mated to have been some 23 million tons; by the year 2000, these are projected to be 127 million tons--an increase of more than 450 percent. (Most western coal shipped east comes from Powder River Basin in Montana and Wyoming and goes to Ohio, Indiana, and Illinois.) This increase can be compared to growth in overall coal production, which is estimated to rise by 142 percent over approximately the same period. Thus, even under the current NSPS, with their intent to promote reliance on local resources, western coal penetration of the midwestern and eastern markets is seen to increase substantially throughout the remainder of this century.

To a large extent, the increase of western coal sales in midwestern markets is projected because inexpensively mined--hence low-priced--western coal can be shipped long distances and still retain a competitive edge over local coal supplies. For example, it is estimated that in the year 2000, a Wyoming Powder River coal shipped 1,000 miles to Indiana at 20 mills per ton-mile--achieving a delivered cost of $1.64 per million BTUs--will still underprice a locally produced Indiana coal shipped 100 miles at a delivered cost of $1.68 per million BTUs. 10/ However, this slight competitive edge is highly sensitive to transportation rates, which, if they rise higher than projected, can result in much higher delivered prices for Western coals shipped long distances.

The different control requirements for high- and low-sulfur coal also are expected to have some influence, though a small one, on U.S. coal markets. The lower control requirement of 70 percent for low-sulfur coal (instead of 90 percent) was originally established in recognition of the higher marginal cost of reducing sulfur dioxide from coals already low in sulfur content. This lower control requirement, however, is expected to provide a small cost advantage to some users of non-local low-sulfur coal. For example, the total cost differential of scrubbing a high-sulfur midwestern coal versus that of scrubbing a low-sulfur western coal is roughly 4.5 mills per kilowatt-hour, or approximately $8.70 more per ton than using the low-sulfur western coal. (This estimate is based on a 500-megawatt power plant burning western coal with a heat content of 10,000 BTUs per pound.) This differential would favor the purchase of low-sulfur coal over an equivalent-cost high-sulfur coal within an approximate radius of 500 miles. Such differentials are not large enough, though, to cause large-scale distortions in the U.S. coal market.

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10. Because Wyoming Powder River coal and Indiana Interior Basin coal have different energy contents, their delivered price reflects the total cost of buying and shipping the equivalent amount of fuel energy, expressed as one million BTUs.

Mining costs and transportation rates remain the major determinants of coal selection under the current standards, while low sulfur content is only a small influence. In this respect, the current standards should eliminate only a portion of the perceived encouragement to use non-local coal supplies. In the next chapter, the effects of alternate standards are examined and compared to the current standards to determine what effect, if any, different sulfur dioxide emissions limits may have on total emissions, on the costs of compliance, and on the production and distribution of coal.

CHAPTER VI. CHOICES FOR NEW SOURCE PERFORMANCE STANDARDS

The Congress is now considering possible changes to the Clean Air Act, and the debate will almost certainly include a reexamination of the new source performance standards. This chapter outlines various possible courses of action with respect to the NSPS, altering only the way they restrict emissions of sulfur dioxide. The analysis focuses primarily on three aspects of the alternative approaches:

- Total projected emissions of sulfur dioxide under each option;
- The costs of each alternative to the electric utility industry and to consumers; and
- The production and distribution of U.S. coal.

ALTERNATIVE EMISSIONS STANDARDS

To provide a framework for Congressional consideration of the Clean Air Act, the CBO has projected the possible outcomes of four alternative standards for the NSPS that became effective in 1978. Being current law, though subject to change through EPA review at intervals of four years or less, the 1978 NSPS are treated as one basis against which the alternatives are measured; comparison of each alternative against the others is equally important, however, and is a critical part of the analysis. The four alternatives to current law that the CBO has analyzed include one option that would be a reversion to the NSPS of 1971, a second and third that would alter the imposition of percentage reductions for sulfur dioxide that are stipulated in current law, and a fourth that would allow a balance of sulfur dioxide emissions control between old and new sources to achieve the same level of control as would the current NSPS. Descriptive details of these four options are given on the following pages; the essential characteristics are summarized in Table 7. 1/

1. The model used to project the effects of the options is described in Appendix B.

TABLE 7. SUMMARY OF CURRENT AND ALTERNATIVE EMISSIONS STANDARDS

Current Law and Options	Mass Emissions Limits (In pounds of sulfur dioxide per million BTUs of fuel consumed)
Current Law—New Source Performance Standard of 1978 a/	1.2 pound ceiling 0.6 pound floor
Option I—Revert to 1971 New Source Performance Standard a/	1.2 pounds
Option II—Achieve 70 Percent Emissions Control and Set an 0.8 Pound Floor for Sulfur Dioxide Emissions a/	1.2 pound ceiling 0.8 pound floor
Option III—Achieve 90 Percent Emissions Control and Set a 0.6 Pound Floor for Sulfur Dioxide Emissions a/	1.2 pound ceiling 0.6 pound floor
Option IV—Constrain Total Emissions Growth by Balancing Sulfur Dioxide Emissions Control Between Old and New Sources	New plant must meet current NSPS emissions level if no tradeoff used; if emissions are reduced at an existing plant new plant may increase its emissions beyond current NSPS level by same amount

a/ Applies to new or modified sources only.

Option I. Revert to the New Source Performance Standards of 1971

Reenactment of the 1971 NSPS, as described in Chapter II, would require coal-fired utility plants to limit emissions of sulfur dioxide gas to 1.2 pounds for every one million BTUs of fuel burnt. (For brevity, the

TABLE 7. (Continued)

Required Percentage Reduction Level	Comments
90 percent for emissions between floor and ceiling; 70 percent or more if emissions are below floor	Requires all coal to be scrubbed regardless of sulfur content
None	Allows low-sulfur eastern and western coal to be used without scrubbing
70 percent for emissions between floor and ceiling; none required if emissions are below floor	Allows much western and some eastern coals very low in sulfur content to be used without scrubbing
90 percent for emissions between floor and ceiling; none required if emissions are below floor	Eliminates scrubbing for some low-sulfur western coals; reduces scrubbing for most western and some eastern coals
Same as current law if no emissions trading used; none or variable when trading used, depending on reduction needed to meet constraints	Limits projected emissions to those calculated under current law; allows new and old facilities within a state to decide individual control levels so long as the limit on total emissions is not violated

SOURCE: Congressional Budget Office

following text expresses such a standard as 1.2 pounds SO_2 per million BTUs.) An electric utility subject to this standard could comply either by using low-sulfur coal without sulfur dioxide emissions controls (a scrubber), or by using a scrubber and burning a cheaper higher-sulfur coal. The primary distinctions of this standard over its successor are that it leaves scrubbers optional and that it does not require a set percentage reduction of potential sulfur dioxide emissions.

Option II. Achieve 70 Percent Emissions Control and Set a 0.8 Pound Floor for Sulfur Dioxide Emissions

This alternative would scale down the current standards' requirement that utilities control sulfur dioxide emissions by 90 percent when burning high-sulfur coal; it would also eliminate the current requirement to use scrubbers in plants burning very low-sulfur coal. It would call for scrubbing (or another technique that can desulfurize flue gases) only if emissions were above a maximum control level, or "floor", set at 0.8 pounds SO_2 per million BTUs. No control requirement would be specified for emissions below this floor. Above the floor, sulfur dioxide emissions would have to be reduced by at least 70 percent, and in no case could emissions exceed the 1971 NSPS ceiling of 1.2 pounds SO_2 per million BTUs. Under this option, much western coal and some eastern (notably Appalachian) coal could be burnt without scrubbers.

Option III. Achieve 90 Percent Emissions Control and Set a 0.6 Pound Floor for Sulfur Dioxide Emissions

Though retaining the current NSPS requirement of 90 percent sulfur dioxide emissions control for utilities using high-sulfur coal, this option would lower the current control requirement for some low-sulfur coals and eliminate it entirely for others. The alternative would stipulate that sulfur dioxide emissions be reduced by at least 90 percent if they are between 0.6 and 1.2 pounds per million BTUs of fuel consumed, a requirement similar to the current standard. Unlike the current standards, however, no control requirements would be specified for emissions below 0.6 pounds SO_2 per million BTUs. Under this alternative, only some western coals could be burnt without scrubbers, although the control requirement for the remaining low-sulfur western and eastern coals would be significantly relaxed.

Option IV. Constrain Total Emissions Growth by Balancing Sulfur Dioxide Emissions Between Old and New Sources

Two features are unique to this option: first, it would operate on a state-by-state basis within a general, nationwide framework; and second, it could affect old sources as well as new ones. Total future sulfur dioxide emissions within each state would be limited to levels projected under the current NSPS, allowing operators of new and old utility plants within each state to meet the overall emissions limit by using any combination of measures. Thus, the alternative would allow new plants to increase their emissions above NSPS permitted levels, so long as commensurate emissions reductions occurred at existing sources within the same state. This is commonly termed "emissions trading," or "new source bubbling." 2/ For purposes of the CBO analysis, because western states contain few old coal-fired facilities, emissions trading was treated as permissible only in the 31 states east of the Mississippi River. All other new power plants were assumed to be required to meet current state or federal NSPS requirements, whichever was lower. (Limiting the analysis to the 31-state region reduced computation time and costs but not accuracy.)

Under such a plan, a utility planning a new plant would first determine the quantity of new emissions the contemplated plant would contribute to the area's atmosphere after complying with the current NSPS; this would establish a baseline for trading. That plant could then increase its sulfur dioxide emissions by a measured amount above the baseline, so long as emissions from one or more already existing sources were reduced by an equal amount. In this procedure, overall incremental emissions would be held to current NSPS levels, but the burden of control could be distributed between utilities operating new and old sources. For purposes of analysis, emissions trading was treated as being limited to intrastate areas, assuming that such a plan would not allow negotiation over state boundaries; this assumption tended to produce results showing higher costs than plans allowing emissions trading between states. 3/ It was also assumed that this option would allow new sources to trade emissions allowances with an existing source only so long as the latter continued to operate. 4/

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2. "Bubbling" is a calculating procedure that envisions each state as having an enclosing overhead bubble within which the utility emissions of that state are contained; additions and subtractions of pollutant emissions are treated as occuring within the confines of that bubble.

3. Administration of this option would probably be complex and perhaps somewhat costly in terms of both money and time. Because the administrative mechanics of implementing this plan are purely conjectural, this analysis disregards any potential such costs the option might entail.

4. Should the existing facility be retired, the new source would have either to apply the tradeoff to another existing facility in the region or reduce its own emissions by the amount originally slated for trading.

COMPARISON OF ALTERNATIVE EMISSIONS STANDARDS

For a continuation of current law and each of the alternative emissions standards outlined, the CBO projected sulfur dioxide emissions, costs, and coal use.

Effects on Emissions and Control Costs

The highest growth in sulfur dioxide emissions from new coal-fired power plants would be allowed under Option I, increasing total utility emissions from an annual 17.6 million tons in 1979 to 22.8 million in the year 2000. 5/ Both the current standards and Option IV would limit total emissions to 21 million tons by the year 2000, the lowest increase of all the alternatives. Total emissions under the other choices--Options II and III--would tend to fall between these upper and lower bounds. Table 8 shows total projected emissions of all the alternatives examined, including the current standards. 6/

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5. As stated in Chapter II, these increased emissions would accompany the addition of 168 gigawatts of new coal-fired electrical capacity anticipated.

6. Four cautions must be noted, however, when comparing the costs and projected emissions. First, the current NSPS and Option IV could yield the lowest level of future sulfur dioxide emissions. This does not give a measure of the health effects or costs of allowing pollutant levels to rise beyond the current standards; whether any analyis could assess these effects from such small differences in projected emissions is doubtful. Second, if new sources using emissions tradeoffs from existing plants were allowed to retain the higher emissions limits after the existing plants were retired, the bubbling approach could leave a dirtier generation of new plants than would be allowed under the current NSPS; however, this analysis assumes that regulations under Option IV would not permit this. Third, the long operating life of most electric plants--usually about 50 years--suggests that most existing sources that could be useful for emissions offsets (as under Option IV) would continue to operate through the year 2010, after which a sharp drop in utility emissions could be expected because of the surviving generation of cleaner plants. Since the surviving plants would be required to lower emissions to reach the original standards, then the predicted cost effectiveness over the life of the plants could drop (that

Power plants subject to neither of the Clean Air Act's NSPS can emit twice to six times the volume of sulfur dioxide than do plants that are regulated under the standards. Therefore, emissions from facilities not subject to either standard dominate the projections shown in Table 8. New plants under the most stringent national standards--the current NSPS--will contribute only 1.6 million of a total projected 21 million tons of sulfur dioxide emissions in the year 2000. Similarly, even under the most lenient standards--Option I--new plants will contribute only 4 million of a total 22.8 million tons of sulfur dioxide in the year 2000. The difference between the emissions projected for new units under current law and Option I is only 2.4 million tons. In both cases, roughly eight-tenths of all sulfur dioxide emissions would arise from units in existence during the early 1970s--that is, those facilities subject to neither NSPS. This disparity is attributable primarily to the higher emissions rates associated with older sources. For example, the average emissions rate in the year 2000 from a power plant that is subject to neither of the act's emissions standards is estimated to be 2.6 pounds SO_2 per million BTUs, compared to an average emissions rate of 0.4 pounds SO_2 per million BTUs for plants operating under the stringent 1978 NSPS.

Judgments about cost effectiveness can be made from comparing the costs incurred by reducing sulfur dioxide emissions from the highest projected levels--in this case, 22.8 million tons by the year 2000 under Option I. Under the current NSPS, sulfur dioxide removal is projected to cost $2,411 a ton. Removal costs under Option II would be $1,929 a ton. Option III--by far the most expensive choice according to this measure--would incur a removal cost of $3,400 a ton. Option IV, in sharp contrast, would permit sulfur dioxide removal at only $550 a ton at the end of the projection period.

Option IV would offer the utilities the greatest economic efficiency, because it would permit fuel-switching as a substitute for scrubbers;

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6. (continued)
is, become more expensive per ton of sulfur dioxide removed), depending on the cost of the new control technique chosen. Finally, the mandatory installation of scrubbers under the current NSPS provides a form of insurance against increased levels of sulfur dioxide emissions that could result from the burning of high-sulfur coal, under possible emergency situations. For these reasons, only partial conclusions about the full benefits of each alternative relative to cost can be drawn in this study.

TABLE 8. TOTAL PROJECTED SULFUR DIOXIDE EMISSIONS AND COMPARISON OF COST EFFECTIVENESS UNDER CURRENT LAW AND ALTERNATIVE STANDARDS

Emissions Under Current Law and Alternative Standards	Total Nationwide Sulfur Dioxide Emissions (In millions of tons per year)			Incremental Cost of Sulfur Dioxide Reductions Below 1971 NSPS (In 1980 dollars per ton reduction)	
	1979	1990	2000	1990	2000
Current Law					
Total	17.6	20.7	21.0	1,800	2,411
New Sources	None	0.4	1.6		
Option I a/					
Total	17.6	21.1	22.8	N/A b/	N/A b/
New Sources	None	0.8	4.0		
Option II					
Total	17.6	21.0	22.1	None	1,929
New Sources	None	0.6	2.8		
Option III					
Total	17.6	21.1	21.9	None c/	3,400
New Sources	None	0.4	2.0		
Option IV					
Total	17.6	20.7	21.0	900	550
New Sources	None	0.4	2.5		

SOURCE: CBO/ICF analysis.

a. Incremental cost of sulfur dioxide emissions reduction represents cost of control beyond these standards.

b. Not applicable.

c. No significant emissions reduction is achieved beyond Option I, although annual costs are increased by $360 million.

switching to a lower-sulfur coal at existing power plants to reduce the control requirements for new plants would lower annual costs while achieving the same emissions reductions as the current NSPS. For example, switching an existing 500-megawatt plant from a high-sulfur coal at 3.33 pounds SO_2 per million BTUs to a medium-sulfur coal at 1.66 pounds SO_2 per million BTUs could reduce emissions at a rate of $431 per ton removed. By contrast, a new plant of comparable size but equipped with a scrubber may incur costs of $1,230 for each ton of sulfur dioxide removed beyond the level that would be required under Option I.

Measures of cost effectiveness can only be taken as rough gauges of economic efficiency, however. For example, although the current NSPS cost less per ton of sulfur dioxide removed than would Option III, they are actually more expensive in terms of capital and annual charges (the next section examines these costs). They remove more sulfur dioxide, however, and hence are less costly per ton removed. Thus, consideration of these options should include total costs as well as costs per ton.

Cost Effects on the Utility Industry

Annual costs of air pollution regulations to the utility industry are a function of two factors: the capital and operating costs of pollution control equipment and the increased premiums associated with purchasing and shipping low-sulfur coal.

Capital Costs. In general, the capital requirements of each alternative are roughly proportional to the amount of scrubber control needed. The current NSPS are projected to involve the greatest capital outlay, approximately $33 billion between 1980 and 2000 (see Table 9); that large capital expense is attributable for the most part to the need to install scrubbers to meet the standards.

At the other end of the spectrum, capital outlays for the moderate amount of optional scrubbing entailed in meeting the NSPS of 1971 (Option I) are projected to total only $14 billion over the 1980-2000 period.

The two choices that stipulate emissions floors (Options II and III) would reduce the overall costs of scrubbing by eliminating mandatory desulfurization for very low-sulfur coals and by allowing many coals to meet the emissions floor with only moderate reduction levels (70 percent and less). High-sulfur coals in both of these options would still need to be scrubbed by either 70 percent (Option II) or 90 percent (Option III), affecting primarily the midwestern and Atlantic seaboard states; in both cases, the

TABLE 9. PROJECTED COST EFFECTS ON THE UTILITY INDUSTRY OF ALTERNATIVE EMISSIONS STANDARDS

	Current Standards	Option I	Option II	Option III	Option IV
Cumulative Capital Requirements (In billions of 1980 dollars)					
1990	8.30	3.90	4.50	4.10	6.60
2000	33.40	14.00	14.60	17.10	14.70
Projected National Scrubber-Equipped Capacity (In gigawatts)					
1980	45.70	45.70	45.70	45.70	45.70
1990	81.60	55.80	59.00	55.30	73.00
2000	213.50	73.30	77.40	87.30	123.40
Approximate Annual Costs (In billions of 1980 dollars)					
1980	5.35	5.35	5.35	5.35	5.35
1990	8.10	7.38	7.38	7.74	7.74
2000	14.10	9.76	11.11	12.82	10.75
Nationwide Average Generating Costs of Air Pollution Control (In 1980 mills per kilowatt-hours)					
1980	2.34	2.34	2.34	2.34	2.34
1990	2.57	2.34	2.34	2.46	2.46
2000	3.43	2.37	2.70	3.12	2.62

SOURCE: CBO/ICF analysis.

use of an emissions floor requiring no further control would tend to reduce significantly the amount of scrubbing needed in the western states. The capital costs for Option II and III are estimated to total between $14 and $17 billion for the 1980-2000 period.

Option IV would require scrubbing only in instances in which a new source could not find an old one to serve as a trading partner with which to balance emissions allowances. Because of the high degree of emissions control mandated in this latter option, more scrubbing is envisioned than for Option I (at roughly the same capital expense) although much less than for the current standards.

Generating Costs. The current NSPS would result in the highest expected annual cost ($14 billion in the year 2000), while Option I would result in the lowest ($10 billion). Option IV would entail lower annual costs after 1990 ($11 billion per year by the year 2000) once significant coal-fired capacity growth had begun in the East, where the most existing capacity is available for cost-effective emissions trading purposes (see Table 9).

The current NSPS would have the highest generating cost associated with pollution control primarily because of the current fixed and variable charges of using scrubbers. The 3.43 mills per kilowatt-hour charge in 2000 (shown in Table 9) under the current standards would translate into approximately $1.72 for a monthly electricity use of 500 kilowatt-hours. This represents approximately 6 percent of the average residential electricity charge recorded in 1980. 7/

Option I would exact the lowest average generating costs for emissions control--2.37 mills per kilowatt-hour. This cost is not projected to change appreciably through the year 2000, largely because the proportion of present scrubber-equipped capacity compared to total capacity would not change significantly. In addition, though the standards under Option I would encourage use of low-sulfur coal, and thus could slightly raise annual operating costs, that increase would be insignificant when averaged over total electricity production. Overall, the utilities' operating costs for air pollution control would rise by less than 5 percent.

The two alternatives that set emissions floors, Options II and III, would involve average generating costs higher than under Option I but lower than under the current standards. This cost would occur because both scrubber and low-sulfur coal use under both options would fall somewhere between that under Option I and the current standards. The price of and demand for low-sulfur coal would be lower than under Option I but higher than under

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7. See U.S. Department of Energy, 1980 Annual Report to Congress (April 1981).

current NSPS; conversely, the scrubbing costs of both Options II and III would be lower than under the current NSPS but higher than under Option I.

Aside from Option I, Option IV would result in the lowest generating cost for pollution control--2.62 mills per kilowatt-hour in 2000. At the same time, Option IV would also achieve the lowest projected emissions levels. The combination of low cost and high emissions control would occur because many old sources would switch to low- or medium-sulfur coal as an economical method for curbing emissions and reducing the burden of emissions control at newer sources (through emissions trading). When the older units used for emissions trading retired, however, the annual generating costs of Option IV might rise. Assuming normal plant retirement rates, however, this rise would not likely occur until after the year 2010.

Other Cost Factors. The sensitivity of electricity costs to other factors besides pollution control--notably fuel transport--is important. To test this sensitivity, the CBO also examined the influence of continued real increases in rail rates (in addition to the generic assumptions outlined in Appendix B). In assessing Option I, the CBO assumed high rail rates; the results showed that if rail rates rose an additional 15 to 25 percent in real terms during the 1985-1990 period, the incremental (that is, real) cost to electricity users in the year 2000 would be 5.34 mills per kilowatt-hour--up 128 percent over the present rate of 2.34 mills per kilowatt-hour and higher than the rate resulting from either the current standards or from any other option. Interestingly, the higher transportation costs could stimulate an increase in the numbers of scrubbers built for new plants under Option I, since high-sulfur coal use with scrubbing would become more economical in many cases than shipping low-sulfur western coal to the Midwest.

Coal Consumption and Production

Because of the long lead time that precedes a new coal-fired power plant's becoming operational, effects associated with any emissions control strategy initiated today would not be observable until the mid- to late-1990s. Accordingly, coal-market effects in the year 2000 would best indicate the influence of standards enacted now as alternatives to the current law 1978 NSPS.

Coal Consumption. Coal consumption by electric utilities generally determines the production patterns of all U.S. coals. Under each of the options analyzed here, as well as under current law, total coal consumption by the utilities is seen to be divided roughly between the western and eastern halves of the country in the year 2000. The West South Central region (see Figure 7 in Chapter V) would experience the highest growth in total consumption, from 43 million tons per year in 1979 to between 254 million tons under Option I to 275 million tons under current law (see Table 10). These figures delineate the upper and lower bounds of growth projected for that region. This pattern is consistent with the region's expected high growth in coal-fired capacity (see also Table 5 in Chapter V). The interregional differences in total coal consumption primarily reflect small variations in capacity use and "energy penalties" associated with scrubbing; thus, the current NSPS, in requiring scrubbers on all new coal-fired plants, show the highest forecast of total coal consumption. 8/

Although overall coal consumption is not significantly influenced by standards, the quantity of low-sulfur coal used is affected. For example, because Option I would have a more lenient control standard than the other options and would not mandate scrubbers, most utilities subject to this standard would choose to burn low-sulfur coal; in the year 2000, more than half of all coal consumed by utilities would be low-sulfur coal (see Table 10). 9/ At the opposite extreme, the current NSPS, by requiring scrubbers, would discourage consumption of low-sulfur coal where it was not locally produced. In the year 2000 under the current NSPS, only 40 percent of the coal consumed by utilities would have a low sulfur content, reflecting less eastern and midwestern consumption of low-sulfur coal than would occur under Option I. Options II and III, by permitting compliance with emissions floors, would also spur the consumption of low-sulfur coal, though to a lesser extent than Option I. Similarly, Option IV, by promoting emissions trading, would increase low-sulfur coal consumption, since that fuel could be used in both new and old facilities to achieve relatively inexpensive emissions reductions.

Coal Production. Where coal is produced and how production is affected by different emissions standards are other important questions. Regardless of which of the options examined here were chosen, the western states would experience the highest growth in coal production over the next two decades. The major reason for this is not so much the amount of

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8. The use of scrubbers requires power, which must be supplied by the utility. Thus, the greater amount of scrubbing employed, the more coal consumed to meet overall electricity demand. (See Appendix B on scrubber assumptions.)

9. For the purposes of this discussion, low-sulfur coal is assumed to produce less than 1.2 pounds sulfur dioxide per million BTUs.

TABLE 10. UTILITY COAL CONSUMPTION IN 1979 AND PROJECTED FOR THE YEAR 2000, BY REGION (In millions of tons per year)

Region	Baseline Consumption (1979) a/	Current Standards		Option I	
		Total Consumption	Percent Low-sulfur	Total Consumption	Percent Low-sulfur
East	208	290	41	291	48
East North Central	160	241	21	243	35
East South Central	72	88	21	90	28
West North Central	74	134	33	128	46
West South Central	43	275	49	254	79
West (Mountain and Pacific)	62	146	47	146	67
Total	619	1,174	40	1,152	51

(continued)

NOTE: Boundaries of regions displayed in Figure 7.

a/ Percent of total 1979 low-sulfur coal consumption is not available.

eastern and midwestern demand for western coal arising from each option, as it is the expected high growth in western coal-burning capacity. Beyond the West's high projected use of local coal supplies, the choice of emissions standards can, however, influence the West's share of the eastern markets. The Midwest, with its deposits of high- and moderate-sulfur-content coal, is the area most vulnerable to standards that encourage consumption of low-sulfur coal.

Continuation of the current standards, which, by design, should mitigate the economic advantage of low-sulfur coal as a means to control emissions, would result in relatively high production forecasts for the Midwest (a 92 percent growth in production by the year 2000) and the lowest projected eastward shipment of western coal (127 million tons). In contrast, Option I

TABLE 10. (Continued)

Option II		Option III		Option IV	
Total Consumption	Percent Low-sulfur	Total Consumption	Percent Low-sulfur	Total Consumption	Percent Low-sulfur
290	48	292	37	290	46
242	34	242	31	242	20
89	28	88	18	89	24
130	47	128	39	132	36
260	76	263	74	268	57
149	65	146	59	149	55
1,160	50	1,159	44	1,146	42

SOURCE: Baseline 1979 consumption from U.S. Department of Energy, Bituminous and Subbituminous Coal and Lignite Distribution, Calendar Year 1979 (April 21, 1980).

would encourage the use of low-sulfur coal; this choice would reduce the expected growth rate in midwestern coal production to 76 percent and raise the quantity of low-sulfur western coal shipped east to an annual 151 million tons by the year 2000 (see Table 11). (This amount would be higher were it not for the large quantity of low-sulfur coal available from Northern and Central Appalachian mines--see Table 12.)

Both western production and eastward shipment would rise as a result of policies that put a premium on coal with a sulfur content below 1.2 pounds sulfur dioxide per million BTUs--coal that, despite Central Appalachian reserves, is not abundant in the East. Thus, Option II would foster the eastward movement of large quantities (164 million tons in 2000) of western coal; such transported coal would help users to meet this option's floor of

0.8 pounds sulfur dioxide per million BTUs without scrubbing (see Table 10). As a result of lowering the floor to 0.6 pounds sulfur dioxide per million BTUs, as in Option III, however, the supply of coal usable without scrubbing would become limited primarily to that mined in the Rocky Mountain and Western Northern Great Plains regions. This would restrict the total eastward import of western coal to an annual 145 million tons in the year 2000. Furthermore, the limited availability of western coal that can meet the standard of Option III without scrubbing, plus the costs of transport, and the emissions floor requiring no further control would all tend to encourage the use of local high-sulfur coal in the Midwest. The result would lead to production levels in the Midwest similar to those encouraged by the current standards (see Table 11). 10/

Compared to the current standards, Option IV would increase western coal production but would not give rise to so high a demand for low-sulfur coal as the other alternatives (see Table 12), since medium-sulfur coal would often supplant high-sulfur coal. High-sulfur coal production in the Midwest would be lower than under the current standards but somewhat higher than under Option I. This small increase could be expected to result from greater use of existing plants with scrubbers and from emissions trading in some areas that allow a few plants to burn high-sulfur coal without scrubbers. (This latter situation might not be desirable, and an emissions ceiling for new sources could be used to prevent it; such a ceiling was not included in these estimates.)

Substitution of medium- for high-sulfur coal (not shown in the tables) also would be high under Option IV, since this approach would allow utilities to meet acceptable emissions limits at nominal expense; burning medium-sulfur fuel would remain appreciably cheaper than resorting to scrubbers. Use of low-sulfur coal, however, would remain the chief strategy to reduce emissions under Option IV, and demand for western coal for eastern utilities

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10. Because most midwestern coal is surface-mined and hence cheaper than most Appalachian coal, which is deep mined, some Appalachian coal production would be displaced by midwestern coal. This would allow midwestern coal production levels in Option III to remain as high as under current standards, even though more western coal actually would be shipped eastward. Without the very low emissions floor of Option III, however, the cost to eastern users of purchasing and scrubbing a midwestern coal would be higher than buying a low-sulfur coal from nearby Appalachia (coal that must be scrubbed even to meet very low emissions floor), and midwestern coal production levels would fall.

would rise to 149 million tons per year--higher than under the current standards but lower than all others except Option III.

Sensitivity to Flue Gas Desulfurization and Other Cost Assumptions. To whatever extent that the costs of flue gas desulfurization technology drop, the demand for low-sulfur coal would also fall. This effect would be particularly pronounced under any alternative standards that emphasize scrubbers or any similar sulfur dioxide control method. On the other hand, if the cost of using low-sulfur coal increased, scrubber capacity also would rise. For example, the amount of low-sulfur coal shipped east is affected by rail costs; if rail rates are assumed to rise 15 to 25 percent between 1985 and 1990 (as stated earlier, under modified assumptions for Option I), only 94.3 million tons of western coal would be shipped east in the year 2000. This is a reduction of almost 57 million tons from that originally predicted for the same alternative. The high rail rates would force eastern and midwestern coal users to turn to the higher-priced but nearer low-sulfur Appalachian coal and to use scrubbers, so that cheap local high- and medium-sulfur coals could be burnt while meeting a standard of 1.2 pounds sulfur dioxide per million BTUs. In this respect, increased rail costs alone would be responsible for greater shifts in coal production and distribution than would be the expected changes resulting from any of the emissions control alternatives considered.

CONCLUSIONS FROM THE ANALYSIS

The CBO projections suggest that alternative emissions standards for new electricity sources can yield nominally different levels of sulfur dioxide emissions at widely divergent costs. Adopting Option I--that is, reverting to the NSPS of 1971--would be the least effective in controlling new emissions, resulting in 22.8 million tons of sulfur dioxide from utilities by the year 2000. In comparison, the current NSPS are projected to achieve sulfur dioxide emissions levels 8 percent lower, but at an average cost of $2,411 for each ton of sulfur dioxide eliminated. The two alternatives with emissions floors, Options II and III, each would entail significantly lower capital costs than the current NSPS, but neither would be highly cost effective in reducing emissions. Option II would lower emissions by 3 percent from the previous NSPS at a cost of $1,929 per ton of sulfur dioxide removed, while Option III would lower emissions by 4 percent, but at a cost of $3,400 per ton. Finally, Option IV, with its emissions trading feature, would achieve the same quite high degree of emissions control as the current 1978 standards do, but at an average cost of only $550 for each ton of sulfur dioxide reduced beyond the levels forecast for Option I.

TABLE 11. REGIONAL COAL PRODUCTION FOR THE YEAR 2000 UNDER EACH ALTERNATIVE (In millions of tons per year and percent increase over base year)

Region	Base Year Production (1979)	Current Standards		Option I	
		Production	Percent Increase	Production	Percent Increase
Northern Appalachia	187	331	77	316	69
Central Appalachia	213	342	61	359	69
Southern Appalachia	24	21	-13	21	-13
Midwest	131	252	92	231	76
Central West	13	17	31	19	46
Gulf	26	119	358	82	215
Eastern Northern Great Plains	14	44	214	44	214
Western Northern Great Plains	104	383	268	409	293
Rocky Mountains	27	183	578	199	637
Southwest	25	142	468	131	424
Northwest and Alaska	5	33	560	32	540
Total	769	1,866	143	1,843	140
Total Western Coal Consumed by Eastern Utilities	22 a/	127	477	151	586

(continued)

a/ See U.S. Department of Energy, Bituminous Coal and Lignite Distribution, Calendar Years 1978 and 1979 (December 21, 1979 and April 21, 1980).

TABLE 11. (Continued)

Option II		Option III		Option IV	
Pro- duction	Percent Increase	Pro- duction	Percent Increase	Pro- duction	Percent Increase
312	67	302	61	314	68
350	64	356	67	354	66
20	-17	20	-17	20	-17
234	79	254	94	239	82
16	23	15	15	16	23
94	262	87	235	112	331
45	221	45	221	45	221
401	286	385	270	402	287
216	700	231	756	180	567
132	428	126	404	148	492
32	560	32	540	33	560
1,852	141	1,853	141	1,862	142
164	645	145	559	149	577

SOURCE: CBO/ICF analysis.

TABLE 12. ESTIMATED LOW SULFUR COAL PRODUCTION IN 2000, BY REGION (In millions of tons per year)

Region	Current NSPS	Option I	Option II	Option III	Option IV
Northern Appalachia	20.8	24.1	37.1	31.8	29.2
Central Appalachia	203.7	224.9	207.9	217.7	206.7
Southern Appalachia	3.4	3.4	2.9	2.9	3.4
Midwest	0.5	0.4	0.5	0	0.5
Central West	5.1	6.1	4.7	4.4	5.0
Gulf	None	None	None	None	None
Eastern Northern Great Plains	1.4	1.4	1.4	1.8	1.4
Western Northern Great Plains	214.0	268.0	265.4	247.0	245.3
Rocky Mountains	122.7	138.7	161.2	180.4	124.7
Southwest	79.7	84.3	85.3	77.5	82.4
Northwest/Alaska	21.4	21.4	21.4	21.4	21.4
Total	672.7	771.3	787.8	784.9	720.0

SOURCE: CBO/ICF analysis.

NOTE: Figures on base year production not available.

The low cost per ton of Option IV highlights two important points:

- Emissions from older sources not covered by any emissions standards will dominate national emissions through the year 2000 and beyond--hence the rather narrow margin within which emissions abatement projections fall; and

- The least costly control measures now available are those that involve substituting lower-sulfur coals at existing sources now using high-sulfur coals.

With regard to effects on the utilities' financial requirements, the results indicate that the current NSPS are the most capital-intensive choice; they also entail the highest annual costs because of fixed and variable charges associated with scrubbers. Options II and III, with their greater reliance on low-sulfur coal as a means to achieve emissions control, would result in lower capital requirements; they also involve generally lower annual costs, although utilities would remain vulnerable to fuel and transport cost escalations. Control levels equivalent to the current NSPS could be achieved by Option IV, and at a significantly lower cost; the burden of control would be more evenly distributed among new and older facilities.

In light of the current costs of control technology and the abundance of low-sulfur western coal, emissions standards for new sources can alter traditional patterns of coal supply and demand. In particular, limiting sulfur dioxide emissions without requiring scrubbers for all coal types, as under Option I, would tend to increase the market share that low-sulfur coal holds. That, in turn, could raise the volume of shipments of western coal to the Midwest and East, as eastern low-sulfur coal costs rise and supplies in certain instances shrink. Nothing short of a mandatory scrubbing, as under current standards, could slow--and only slow--this eastward penetration. Both Options II and III, by eliminating scrubbing for only some coals (those found mostly in the West), would also raise the amount of western coal shipped East. No matter what emissions standard are in force, midwestern and some eastern coal production would remain vulnerable to the lower cost and rapidly growing production of western coal. Mitigating circumstances that would help encourage coal production in the East, and in particular, the Midwest, are higher-than-expected rail rates over the next two decades and significantly lower costs than anticipated for flue gas desulfurization technology. The latter would entail technological breakthroughs or improvements now being studied but not yet foreseen.

Finally, the analysis points to some difficult choices for the Congress in assigning priorities, since minimizing sulfur dioxide emissions, utility costs, and losses in midwestern coal production cannot all be done simultaneously. To hold emissions to their lowest levels and protect midwestern coal production, the current standards are the best choice. If, however, reducing the capital burden on utilities is given equally high priority, then Option III--which lowers capital needs by roughly half, raises emissions only slightly, and yields relatively high midwestern production forecasts—becomes a more preferable choice. If both emissions control and cost are high priorities, but safeguards for midwestern coal production are not, then the best alternative is Option IV. Finally, if cost is the chief concern, then Options I and II, which would promote the use of low-sulfur coal though allowing greater emissions growth than the current standards, are the most suitable policy choices.

APPENDIXES

APPENDIX A. EFFECTS OF THE PSD PROGRAM

The CBO analysis of the Clean Air Act's potential influence on the electric utilities includes assumptions about the effects of "prevention of significant deterioration" (PSD) provisions. Though probably smaller than the effects of the new source performance standards, and difficult to quantify separately from them, the effects of the PSD provisions are still of interest. The following analysis reviews the estimated influence of the PSD program on emissions, power plant siting, and construction schedules. Only the effects of the PSD program on emission limits were included in the projections (see Appendix B), since other costs, such as administrative requirements, are believed to be insignificant.

EFFECT ON EMISSIONS LIMITS

In a recent study, the National Commission on Air Quality has concluded that the case-by-case "best available control technology" review process under the PSD program has often resulted in emission limitations stricter than would have been required by NSPS or state implementation plans. 1/ According to the commission, all PSD permits issued between April 1978 and November 1979 showed that nine out of 16 permits issued for power plants during that period contained control requirements significantly more stringent than the NSPS. These tighter requirements will lead to 20 percent reductions in sulfur dioxide emissions and 25 percent reductions in particulate emissions beyond levels allowed under the NSPS. (The means of compliance for these facilities is unknown, but it probably will often involve additional scrubbing or lower-sulfur fuel.) Because these control levels were established before 1979, however, much of their cost to the industry should be captured in the analyses in Chapter II.

Because the current NSPS require such a high degree of control, situations in which the PSD regulations result in significant additional emissions control should be rare. The exceptions concern possible requirements of up to 90 percent control on sulfur dioxide emissions for plants burning low-sulfur coal, rather than the requisite 70 percent. This situation

1. See National Commission on Air Quality, To Breathe Clean Air, Final Report (March 1981).

could occur in areas desiring to limit emissions further and protect air quality; examples may be Wyoming and New Mexico, which already require more than 70 percent control on some power plants firing low-sulfur coal. No evidence suggests, however, that BACT levels stricter than NSPS will be established with any frequency in the future for most regions.

EFFECTS ON POWER PLANT SITING

An important concern is whether the Clean Air Act imposes non-economic, institutional constraints on the construction of new generating capacity. Compliance with both PSD regulations and national ambient air quality standards can pose operational limitations on a power plant at a particular site. Such limitations can restrict how much capacity can be built in certain areas.

The EPA reports that both the 1971 and revised 1978 NSPS for utilities allow a 1,000-megawatt coal-fired boiler to operate in a Class II PSD area, assuming no appreciable background concentrations or other sources nearby, and relatively flat terrain. 2/ Under these conditions, one large plant complying with the 1971 NSPS would leave little if any 24-hour PSD increment (see Table 2 in Chapter II), while the same plant complying with the 1978 revised NSPS would consume approximately half of the 24-hour increment, usually the most limiting standard. Compliance with either emissions standard would not allow a facility of this size to be located either in or near a Class I area. Thus, in certain circumstances, such as where the terrain is mountainous, contains Class I areas, and other nearby sources, compliance with NSPS might not be sufficient to protect the Class II increments, and further emissions control or moving to another site might be necessary. If emissions control proved too costly, or if an alternate site were not available, the new plant would not be built.

Both the national commission and the National Academy of Sciences report that the major constraints on power plant siting from PSD regulations involve the presence of "complex" (mountainous) terrain and Class I areas near or surrounding the potential site. 3/ In the West, Class I areas

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2. Terrain that is not flat tends to confine and thus concentrate pollutant emissions.

3. See National Commission on Air Quality, To Breathe Clean Air, and National Academy of Siences, On Prevention of Significant Deterioration of Air Quality, National Academy Press (1981).

(National Parks and certain national monuments) represent the greatest potential constraint, at times perhaps limiting development within a 100-kilometer radius. In the East, Class II areas and the presence of other sources of pollutants pose the greatest potential for siting constraints. Both the commission and national academy also conclude that such constraints are specific to certain sites and are difficult to quantify generically; moreover, they point out that other legislation besides the Clean Air Act severely restricts development in many Class I areas, thus making it difficult to assign growth limitations in Class I areas to the Clean Air Act alone. Finally, alternative sites are usually available, thus allowing a plant to be built somewhere. Much less certain is the incremental cost of relocating a power plant early in its planning process.

Only two applications for PSD permits have been denied, both involving permits for coal-fired power plants near Class I areas. After submission of additional information, one was approved with minor modification. The other power plant eventually received a permit after adopting more stringent controls to reduce total sulfur dioxide emissions by 95 percent. The actual incremental cost of achieving this additional control is unknown.

EFFECTS ON CONSTRUCTION SCHEDULES AND RESULTING COSTS

Between 1970 and 1980, average power plant construction times increased from four to seven years. The reasons most often cited involve the numerous operating licenses and permits required by various laws enacted over the last decade. The Clean Air Act is responsible for one of the more complex permit processes, and thus it is a suspected contributor to protracted construction schedules.

The PSD regulations entail certain explicit and implicit time-consuming tasks. Strictly interpreted, the regulations can require one-year's air quality monitoring data for the permit application. Time is also taken up in developing permit submissions, probably six months. In addition, the reviewing agency is then allowed one year either to approve or reject the permit application. Thus, assuming the permit is approved, up to 30 months can elapse before construction begins.

In practice, the time necessary to obtain a PSD permit varies widely, but it is usually less than 30 months. Table A-1 shows the time spent in the various stages of obtaining a permit, based on a survey of PSD permits issued according to the requirements of the Clean Air Act's 1977 amendments. Before embarking on the early stages of the permit process, a utility

TABLE A.1 PROCESSING TIME SPENT FOR NEW SOURCES BEFORE AND DURING PSD REVIEW

Process Sequence	Median Number of Days	90th Percentile a/	95th Percentile a/
Initial Contact to Initial Submission	42	440	487
Initial to Final Submission	57	298	319
Final Submission to Permit Issue	157	323	328
Initial Submission to Permit Issue	271	463	528
Initial Contact to Permit Issue	333	612	634

SOURCE: See Dames and Moore, "An Investigation of Prevention of Significant Deterioration (PSD) and Emission Offset Permitting Processes," prepared for National Commission on Air Quality (Revised December 1980).

a/ Upper quartiles; 90 percent and 95 percent of permits were processed in these numbers of days or fewer.

applicant typically contacts the agency to determine whether monitoring is required, and if so, how much and what control requirements may be imposed. If the critical permit stages, including monitoring, are assumed to occur between initial contact and permit issuance, then it is clear that total processing time is usually completed within a year, although delays of up to two years can occur in rare instances.

The reasons for the relatively shortened time needed to obtain a permit compared to what theoretically can elapse probably involve the short median time an agency spends on reviewing a final permit and determining how much monitoring to require. The short processing time for final permits is evidenced in Table A-1 as usually consuming less than six months.

With regard to monitoring, the same study responsible for the data in the table found that reviewing agencies required actual on-site monitoring data for particulate matter and sulfur dioxide in only 17 and 15 percent of all cases, respectively. In the other instances, either monitoring was not required, or existing state and local data collected by public agencies were available and accepted.

With regard to the costs associated with increased lead times for construction, it is important to distinguish between time requirements that can be incorporated into the overall planning process and those that fall outside of this schedule, thus resulting in delay. Table A-1 indicates that the overall time required to obtain a PSD permit can cover one to two years but more commonly involves one. If the one year usually required to obtain a permit can be partially or totally absorbed within other planning requirements, such as selection of final design and equipment specifications prior to construction, then delay is reduced to less than one year.

Table A-2 presents estimates of project cost increases for a six month, 12-month, 18-month, and 24-month delay in construction start-up. These estimates include the costs associated with inflation as well as those associated with extended use of obsolete capacity (identified in the table as energy replacement), in this case, a 500-megawatt oil-fired plant.

TABLE A-2. ESTIMATED COSTS OF DELAYS IN CONSTRUCTION START-UP OF A NEW 500-MEGAWATT COAL-FIRED POWER PLANT (In millions of dollars)

	Six-Month Delay	12-Month Delay	18-Month Delay	24-Month Delay
Energy Replacement	4.3	8.6	13.0	17.4
Inflation	25.0	50.0	78.0	104.0
Total	29.3	58.6	91.0	121.4

SOURCE: Congressional Budget Office.

The average increase in normal project lead-time associated with the Clean Air Act is estimated to be six months, which translates into some $29.3 million for the example given in Table A-2. This estimate assumes that approximately one year of permit preparation and review is necessary, of which half falls outside the normal planning schedule necessary for project start-up. Adding the costs of a full monitoring network for sulfur dioxide, nitrogen oxide, and particulate emissions, and necessary air quality analysis costs for developing a permit (a total cost of approximately $140,000) results in a possible total cost increase of $29.4 million for the example given. For comparison, CBO estimated that a change in the interest rate or weighted cost of capital from 10 to 11 percent could result in a total project cost increase of $101 million.

APPENDIX B. ANALYTICAL ASSUMPTIONS AND METHODOLOGY

To arrive at forecasts of pollutant emissions, changes in capital and annual costs, and coal market effects, the CBO used a detailed linear programming model developed by ICF, Incorporated. The key assumptions, including scrubber costs, were supplied by CBO for use in the simulations. A review of the assumptions and methodology used follows.

DESCRIPTION OF ASSUMPTIONS

Table B.7, at the end of this appendix, defines the major assumptions used in the modeling effort. Tables B.1 through B.4 present the estimated costs used in the analysis of scrubbers for different coal types. These costs are based on a recent Tennessee Valley Authority study, Technical Review of Dry FGD Systems and Economic Evaluation of Spray Dryer FGD Systems (EPA-600/7-81-014) and the information contained in EPA Utility FGD Survey: October-December 1980, (EPA-600/7-81-021a). The costs of the basic units include all equipment and materials needed to transfer the flue gas from the boiler to the stack, as well as collection and disposal of sludge and fly ash residues. The estimates in the tables also reflect a small expected increase in the real costs of equipment and operation between 1980 and 1985, the starting point used for the simulations. Table B.5 displays estimated costs of upgrading particulate control equipment necessary when switching from high-sulfur to low-sulfur coal, as simulated for computation for Option IV.

The costs presented in these tables give rough approximations of the cost-penalty involved; only a case-by-case analysis of actual fuel-switching situations could provide an accurate estimate. Such information was not available for this report.

METHODOLOGY

The effects of the assumptions and alternative standards were estimated using the ICF Coal and Electric Utilities Model (ICF/CEUM). The model simulated key attributes of the coal and electric utility industries by year and by region. For the coal industry, forecasts were made of coal consumption by sector, production by mining method, supply prices, coal

TABLE B.1. CURRENT NSPS

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.24	0.36	0.5	0.5	0.67	0.89
	(Percent Pollutant Control)					
Design Control Efficiency	70	70	70	90	90	90
Actual Control Efficiency	68	68	69	84	86	86
Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	144	145	146	228	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	2.15	2.39	2.68	3.9	4.37	4.8
	(Percent)					
Capacity Penalty	1.52	1.54	1.58	2.23	2.45	2.61
Energy Penalty	2.36	2.38	2.42	3.47	3.85	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

TABLE B.2. OPTION I—EMISSIONS CAP OF 1.2 POUNDS OF SULFUR DIOXIDE PER MILLION BTUs OF FUEL CONSUMED

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.76	1.14	0.8	1.0	1.0	1.0
	(Percent Pollutant Control)					
Design Control Efficiency	0	0	Part a/	70	80	90
Actual Control Efficiency	0	0	50	68	79	84
Scrubber Type	NA	NA	Dry	Dry	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	71	123	148	207	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	0.1	0.1	1.77	3.64	4.2	4.8
	(Percent)					
Capacity Penalty	0	0	1.12	1.8	2.24	2.61
Energy Penalty	0	0	1.71	2.81	3.48	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

a/ "Part" indicates 70 percent control of portion of flue gas.

TABLE B.3. OPTION II—ACHIEVE 70 PERCENT EMISSIONS CONTROL AND SET A 0.8 POUND FLOOR

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.8	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.8	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.76	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.76	0.62	0.64	1.0	1.0	1.0
	(Percent Pollutant Control)					
Design Control Efficiency	0	Part a/	Part a/	70	90	90
Actual Control Efficiency	0	50	60	68	80	84
Scrubber Type	NA	Dry	Dry	Dry	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	119	134	148	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs--Fixed and Variable	0.1	1.32	2.15	3.64	4.22	4.8
	(Percent)					
Capacity Penalty	0	1.04	1.37	1.81	2.45	2.61
Energy Penalty	0	1.61	2.1	2.81	3.58	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

a/ "Part" indicates 70 percent control of portion of flue gas.

TABLE B.4. OPTION III—ACHIEVE 90 PERCENT EMISSIONS CONTROL AND SET A 0.6 POUND FLOOR

Item	Variable					
	(Coal Type in Pounds SO_2 Per Million BTUs Consumed)					
Raw Coal	0.6	1.2	1.76	3.92	6.67	8.89
Delivered Coal	0.6	1.2	1.67	3.33	5.0	6.67
Coal to Scrubber	0.57	1.14	1.59	3.16	4.75	6.33
Annual Sulfur Dioxide Limit	0.54	0.50	0.50	0.50	0.67	0.89
	(Percent Pollutant Control)					
Design Control Efficiency	0	70	70	90	90	90
Actual Control Efficiency	0	58	70	85	86	86
Scrubber Type	NA	Dry	Dry	Wet	Wet	Wet
	(Dollars per Kilowatt)					
Total Costs for SO_2 and Particulate Control	71	145	146	228	231	235
	(Mills per Kilowatt-Hour)					
Operation and Maintenance Costs-- Fixed and Variable	0.10	2.22	2.69	3.9	4.37	4.8
	(Percent)					
Capacity Penalty	0	1.54	1.58	2.23	2.45	2.61
Energy Penalty	0	2.22	2.43	3.50	3.85	4.01

SOURCE: Congressional Budget Office

NOTES: All costs based on a 500-megawatt power plant generating 5,500 hours per year. Amortized capital costs not included; all O&M costs are first-year costs. Costs expressed in mid-1980 dollars.

TABLE B.5. ESTIMATED COST PENALTIES IN OPTION IV ASSOCIATED WITH FUEL SWITCHING (Per kilowatt of capacity)

Initial Coal by Pounds SO_2 Per Million BTUs	New Coal Types by Pounds SO_2 Per Million BTUs Consumed					
	0.8	1.2	1.76	3.92	6.67	8.89
0.8	x	x	x	x	x	x
1.2	20	x	x	x	x	x
1.76	30	20	x	x	x	x
3.92	60	30	20	x	x	x
6.67	60	60	30	20	x	x
8.89	60	60	60	30	20	x

SOURCE: Congressional Budget Office.

NOTE: No scrubbers are assumed to figure in this estimate.

distribution, and transportation costs by mode. For the electric utility industry, forecasts were made of generation, changes in emissions, fuel use (including coal by type), and changes in costs for capital, fuel, operation and maintenance, and pollution control for alternative standards.

The model generates a least-cost equilibrium solution using a standard linear programming formulation, which simultaneously balances supply and demand requirements for each region of the United States. This equilibrium solution reflects a wide variety of conditions affecting both the coal and electric utility industries, including both governmental policies and non-governmental factors. The results are summarized regionally in terms of production, consumption, and prices for coal for utilities. These provide the basis for estimating other impacts, such as capital requirements and environmental effects.

The CEUM links the coal and electric utilities industries. The electric utility sector in the model is structured in such a way as to minimize total generation and distribution costs. The model forecasts economic capacity expansion and dispatch. The model can operate existing capacity of various plant types and/or build new capacity. Further, it can operate capacity in any of four local categories--base, cycling, seasonal peaking, and daily peaking. It is designed to build and operate capacity of various plant types in the various load categories such that the total of fuel, capital, and operations costs is minimized.

Different pollution control regulations (for sulfur dioxide and other pollutants) that apply to specific types of plants in different jurisdictions are explicitly modeled. For older sources, actual state emission limitations are used. For sources subject to NSPS, either the federal standards or assumed PSD or state limit is used, whichever is lower (see Table B.6). Hence, consumption of any one coal type depends on its price relative to other coal types and other compliance alternatives. Rather than merely minimizing delivered coal costs, the model minimizes the total costs of generating and distributing electricity.

The current NSPS and all alternatives were simulated as follows. All existing sources were assumed subject to the applicable state and local standards contained in the State Implementation Plan (or PSD determination, if lower), and all new sources were subject to the alternative federal emissions standards being examined, except when those would be superseded by more stringent state regulations in effect as of 1980. Option IV was modeled similarly, except that new sources were permitted to increase emissions above current NSPS levels if equivalent reductions of sulfur dioxide (beyond levels regulated by the SIP) were obtained at one or more existing sources. In all cases, the least-cost solution for electricity production was simulated.

Table B.7 outlines the assumptions used in the model simulation analysis.

TABLE B.6. PREVENTION OF SIGNIFICANT DETERIORATION ASSUMPTIONS FOR SPECIFIED STATES (In pounds of sulfur dioxide per million BTUs consumed)

	State New Source Emissions Standards	Assumed Federal PSD Emissions Limit
Montana	1.20	1.20
Wyoming	0.20	0.20
Colorado	0.40	0.20 a/
New Mexico	0.34	0.34
Utah	0.12/1.20	0.20 a/
Arizona	0.80	0.20 a/
Nevada	1.20	0.20 a/
North California	0.13	0.13
South California	0.13	0.13

SOURCE: Congressional Budget Office.

a/ Denotes states where assumed PSD limit is more stringent than state standards.

TABLE B.7 MAJOR ASSUMPTIONS USED IN CBO/ICF ANALYSIS

Parameter	Base Case	Comment
Energy and Economic Conditions		
GNP (Percent per year real growth	1980 - 1985 = 2.9 1985 - 2000 = 3.0	Modified from recent CBO economic forecasts.
World Oil Prices (1980 dollars)	1985 = 37.29 1990 = 41.17 1995 = 45.46 2000 = 50.19	Higher oil prices encourage the substitution of coal for oil by electric utilities, within assumed financial and institutional constraints. Estimates of future oil prices assume a 2 percent per year real escalation in price, which is based on recent CBO forecasts.
Natural Gas Prices and Availability	As estimated by ICF Gas Models	
Electric Utility Energy Demand		
Electricity Growth Rate (Percent per year)	1979 - 1985 = 3.2 1985 - 1990 = 2.7 1990 - 1995 = 2.7 1995 - 2000 = 2.7	Growth rates for electricity are expected to remain well below pre-1980 historical averages. This is consistent with Wharton Economic Forecasting Assumptions (WEFA) and ICF analysis of the electricity markets
Nuclear Capacity	1985 = 78 1990 = 121 1995 = 141 2000 = 175	Since coal is a substitute for nuclear power in generating electric power, variation in nuclear capacity levels leads to variations in national coal production forecasts. The estimates are based on a unit-by-unit review.
Substitution of Coal for Oil and Gas	Reconversions assumed and accelerated replacement allowed but deterred by capital cost penalty and state limits.	Current and projected oil and gas prices indicate it is economic to substitute coal for oil and gas in substantial proportions, but institutional and financial constraints make this unlikely to occur. In the base case, about 18 gigawatts of conversions are assumed. The accelerated replacements of oil and gas units with new coal units are inhibited by adding capital cost penalty to the cost of a new coal unit and by limiting the amount of new coal capacity in key states--California, Texas, Louisiana, and Florida.

(continued)

TABLE B.7 (Continued)

Parameter	Base Case	Comment
Power plant and Industrial Fuel Use Act		The off-gas provision is not in effect, but the base-year gas use rule remains in 1985 only with the base year quantity defined as the maximum use during 1970s. Oil and gas-fired combined cycle are prohibited for new power plants.
Utility Capital Costs per kilowatt (1980 dollars)	Coal = About 850 Nuclear = 1,020-1,254 Turbine = 223-235	Capital costs for new power plants are based on the most recent (1979) technical data developed by EPRI. They include a total real escalation of 12 percent between 1978 and 1985, as modified by CBO.
Non-Utility Coal Demand		
Industrial Coal Use (Per million tons)	1985 = 80 1990 = 117 1995 = 171 2000 = 225	Based on recent ICF analysis.
Steam Coal Exports (Per million tons)	1985 = 40 1990 = 84 1995 = 120 2000 = 196	Long-term estimates of export demands for steam coal are based on recent ICF in-depth analysis of the export markets.
Metallurgical Coal Use (Millions of tons)		
Export	1985 = 51 1990 = 56 1995 = 58 2000 = 60	Export demand for metallurgical coal is assumed to decline from abnormally high levels in 1980, and then increase only slightly. Metallurgical exports are assumed to be primarily low-sulfur, high-Btu coals.
Domestic	1985 = 73 1990 = 67 1995 = 66	Domestic use of metallurgical coal is expected to decline due to the sluggish growth of the U.S. steel industry and continued process changes that reduce the use of coke per ton of product.

(continued)

TABLE B.7 (Continued)

Parameter	Base Case	Comment
Synfuels (Coal input in millions of tons)	1985 = 7 1990 = 24 1995 = 82 2000 = 139	Estimated demand for coal-derived synfuels in 1985 has been reduced from earlier forecasts to reflect a reduced government role in promoting commercial synfuels production and a project-by-project assessment of announced plans.
Residential and Commercial Coal Use	1985 = 8 1990 = 9 1995 = 10 2000 = 11	Residential and commercial coal use is expected to increase slowly. Residential and commercial demand is assumed to be limited to low- and medium-sulfur coals.
Financial Parameters		
Inflation Rate (Percent per year)	1980 - 2000 = 8.0	The annual inflation rate is assumed to be 8 percent per year, consistent with recent CBO forecasts.
Discount Rates (Percent per year)	Coal Mine = 14.48% Utility = 12.61%	These nominal rates are based on a 6.0 percent real rate for mining and a 4.27 percent real rate for utilities.
Coal Transport Rates— Rail, Barge, and Truck (Percent total real escalation)	1979 - 1985: East = 25.0% West = 25.0%	Transportation rates are estimated to increase in real terms through 1985 as allowed under the Staggers Rail Act.
Mining Costs (Dollars total real escalation)	1980 - 2000: Capital = 0.0% Labor = 0.0% Materials = 0.0%	Capital, labor, and materials are assumed to remain constant in real terms. Productivity increases are assumed to offset any real cost escalation.
Other		
Federal Leasing Policy	Enough	It is assumed that enough coal will be leased by 1985 and later to avoid artificially driving up market prices.
Air Pollution Regulations	Most recent federal and state rules.	Controls on utility emissions of SO_2, NO_x, and TSP are subject where applicable to federal NSPS, revised NSPS and PSD rules; or to state SIP rules if more stringent.

APPENDIX C. FINANCIAL EFFECTS OF DIFFERENT ACCOUNTING METHODS FOR CONSTRUCTION WORK IN PROGRESS

Particular accounting methods used by the electric utilities can influence the financial condition of the industry and the costs of producing power. They can also affect the industry's costs to meet the Clean Air Act's NSPS.

The most significant regulation pertaining to utility finances is the state public utility commissions' treatment of "construction work in progress." In most instances, utilities may not earn returns on CWIP investments before their new facilities are fully operational. To account for the lost revenue a firm incurs while a facility is being built, the state PUC usually allows a utility to establish an "allowance for funds used during construction" account. This account essentially represents the value of total CWIP capitalized each year at a rate of return set by the commission. The capitalized annual CWIP appears as income for accounting purposes, but it is not realized as cash until the facility is service. When the facility does begin operation, the capitalized AFUDC is added to the total investment, forming the rate base. The rate base is then depreciated over the operating life of the facility, with the utility earning an annual return on the undepreciated portion. Although the utility is ultimately allowed to earn a fair return on its construction costs, it must borrow or otherwise maintain its cash flow in the interim.

Table C.1 compares the finances of a new 500-megawatt plant under three different accounting and pollution control hardware assumptions. Each facility is assumed to have begun construction in 1980 with expected start-up in 1987. The first facility includes a scrubber as part of the total plant, and its rate base is calculated to include AFUDC. The second facility also has a scrubber, but the utility is allowed to earn a return on its CWIP investment before plant start-up. The third facility has no scrubber, and similar to the first facility, its rate base includes AFUDC. The calculations assume either all or none of the facility is subject to CWIP or AFUDC, depending on the case.

Figure C.1 shows the electricity cost curves for each plant over its lifetime. Both plants using AFUDC in the rate base do not start charging for electricity until the first year of operation. The plant using CWIP, on the other hand, begins adding a small charge to existing electricity costs during the years of construction. This added charge from passthrough of

TABLE C.1. FINANCIAL COMPARISON OF A NEW 500-MEGAWATT POWER PLANT UNDER DIFFERENT ACCOUNTING AND POLLUTION CONTROL HARDWARE ASSUMPTIONS (In millions of dollars)

	Plant and Scrubber with AFUDC (In Rate Base)	Plant and Scrubber with CWIP (In Rate Base)	Plant with No Scrubber, AFUDC (In Rate Base) c/
Total Plant in Rate Base Start-up (nominal dollars) a/	1,195	892	933
Total Interest During Construction (nominal dollars) a/	303	124	229
Cost to Consumers Over Life of Plant (1980 dollars) b/	86,542	64,394	68,020

SOURCE: Congressional Budget Office.

a/ Interest rate, AFUDC, and return on rate base calculated at 13.74 percent.

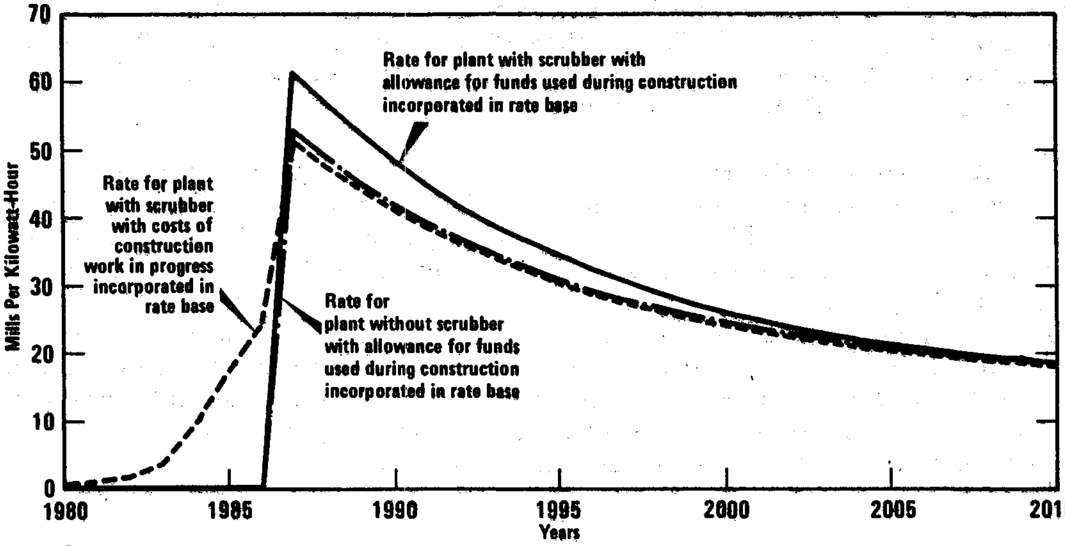
b/ Discount rate used was 10 percent over 25 years.

c/ Life cycle costs of this facility also include higher fuel cost for low-sulfur coal.

CWIP to existing electricity costs would result in high electricity rates during the years preceeding plant start-up. As Table C.1 shows, however, both plants using AFUDC as an accounting procedure have larger rate bases, higher interest costs, and greater electricity costs over the life of the plant than the facility obtaining a return on CWIP, which is assumed to offset a portion of its annual investment during construction.

Figure C1.

Projected Electricity Rates Under Different Accounting Assumptions: 1980-2010



SOURCE: Congressional Budget Office.

NOTE: Transmission and distribution rates not included.

It is important to note that the cost of AFUDC to a plant with a scrubber is approximately equal to the cost of the scrubber itself. The present value difference in total investment (with interest) of the first two plants shown in Table C.1 is equivalent to $184 per kilowatt-hour. This cost is approximately equal to a wet limestone scrubber without particulate controls.

The reason AFUDC is employed as an accounting procedure primarily involves the reluctance of state PUCs to force present consumers to subsidize the rates of future consumers. Though over the long term, utilities and ratepayers enjoy lower costs when CWIP is incorporated in the rate bases, the prospect of yearly rises in electricity rates before a plant's start-up remains an unattractive option to most PUCs.

A recent survey reveals that many states allow some CWIP in the rate base, but such treatment is not uniform, and the average amount allowed is only approximately 20 percent. 1/ In the survey, 44 state PUCs, accounting

1/ General Accounting Office, "Construction Work in Progress Issue Needs Improved Regulatory Response for Utilities and Consumers" (June 23, 1980).

for $38 billion out of the $42.5 billion of total CWIP in 1978, provided information on their treatment of CWIP. In these 44 states, 23.4 percent of CWIP was allowed in the rate bases. The range of CWIP allowed in rate bases nationwide was between 21 and 23 percent in 1978. This 21 to 23 percent figure may be misleading, since state PUCs often employ an "AFUDC-offset" when CWIP is allowed in the rate base. This offset essentially subtracts part of the real income generated by CWIP and replaces it with AFUDC accounting income.

Although AFUDC represents only one accounting procedure that can adversely affects the financial condition of a utility, it is perhaps the most important one. As AFUDC increases as a percent of total revenues, the quality of a utility's earnings diminishes. This reduction in the quality of earnings is perceived negatively by the investment community, which, in turn, becomes reluctant to continue lending, resulting in increased cost of capital for utilities. A 1 percent rise in interest rates can add $25.6 million to the total cost of a new 500-megawatt facility. Such potential costs and those actually associated with financing a utility subject to AFUDC largely overshadow the cost of most air pollution controls.