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THE ROLE OF TECHNOLOGY
AND CONSERVATION IN
CONTROLLING ACID RAIN

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PREFACE

This Staff Working Paper by the Congressional Budget Office explores how improvements in technologies for reducing sulfur dioxide (SO_2) emissions and increased efforts by electric utilities to encourage conservation relate to reductions in SO_2 emissions and the cost of proposals for controlling acid rain. This study was conducted in response to three separate requests: from majority and minority members of the Senate Environment and Public Works Committee and its Subcommittee on Environmental Protection; from a separate group of 34 Senators; and from the Subcommittee on Natural Resources, Agriculture Research and Environment, of the House Committee on Science, Space, and Technology.

The paper was prepared in CBO's Natural Resource and Commerce Division by Marc Chupka under the supervision of W. David Montgomery and Roger C. Dower. Valuable comments and assistance were provided by Verdon Staines of CBO, Larry Parker of the Congressional Research Service, Robert Friedman of the Office of Technology Assessment, and Paul Portney and Hadi Dowlatabadi of Resources for the Future. The paper was typed by Patricia Joy.

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SUMMARY

Increased use by electric utilities of cheaper and cleaner technologies for burning coal or of conservation programs could reduce sulfur dioxide (SO_2) emissions and help lower the costs of controlling acid rain. The potential impact on SO_2 emissions or control costs is limited, however, by several factors, including the costs of improved technology relative to existing control measures, the current and future regulatory requirements governing SO_2 emissions, and the extent to which utilities are able to reduce the demand for electricity.

In this study, the Congressional Budget Office (CBO) constructed a base case of SO_2 emissions from electric utilities based on the costs of alternative technologies for burning coal. CBO then estimated how different assumptions about improvements in technology and enhanced utility-led conservation programs would affect SO_2 emission levels, relative to the base case. CBO also examined the relationships between these assumptions and the costs to utilities of complying with new regulations to control acid rain, and the effects on regional coal markets and on production of coal with varying sulfur contents.

IMPROVEMENTS IN TECHNOLOGY

New technologies for burning coal or controlling pollution will not lead to significant reductions in SO_2 emissions under current federal environmental regulations. Emissions of SO_2 from utilities originate chiefly from older coal-fired power plants that are subject to less stringent state regulations. Although utilities will invest in these plants as they near the end of their economic lives, the current regulations do not require them to install technologies for controlling emissions. Moreover, new coal-burning technologies, which would help reduce emissions from these sources, will remain more expensive than existing options that simply extend the life of these power plants. In the absence of new regulations, these plants will continue to emit SO_2 at current levels.

If concerns about acid rain lead to new and more stringent policies to reduce SO_2 emissions, improved technology might help lower the costs and lessen the impact on coal markets. In general, the extent to which this occurs will depend mainly on two factors: the cost of the technologies relative to existing measures for controlling SO_2, and the amount of regulatory flexibility granted to utilities to pursue nontechnological options for reducing emissions, such as switching to lower-sulfur coal.

If the costs of new technologies remain higher than conventional technology, then the new technologies would probably not be used. This is apt to be the case with technologies for "repowering" a plant--that is, partially replacing a plant with new coal-combustion technologies. On the other hand, the cost of retrofitting new technologies--that is, adding them to an existing coal-combustion technology--may be competitive with or below the cost of existing systems, such as scrubbers, for removing sulfur. The benefits provided by these technologies, however, will depend on the extent of their use.

If new regulations mandated the use of technology to control emissions, which would promote production of high-sulfur coal by allowing its continued use, any improvements (that is, reductions) in the cost of new technologies would translate directly into savings for the utilities required to adopt them. Even with such improvements, however, the overall costs of acid rain policies that mandate the use of technology would still be higher than the cost of more flexible policies, where less expensive measures for controlling SO_2, such as switching to lower-sulfur coal, are allowed. Under more flexible policies, retrofit technologies would not only have to cost less than scrubbers to be competitive, but would also have to cost less than switching to lower-sulfur coal. If these conditions are met, improved retrofit or scrubber technology could mitigate the loss in high-sulfur coal production that is associated with flexible control strategies. Repowering technologies are unlikely ever to be adopted under a flexible control strategy, or indeed in any scenario in which only moderate reductions in SO_2 emissions are required.

INCREASED USE OF UTILITY CONSERVATION PROGRAMS

Under current environmental regulations, conservation programs initiated by utilities are unlikely to lead to significant reductions in SO_2 emissions, even if the programs succeed in controlling the growth in demand for electricity. Utilities pursue conservation programs primarily to avoid or minimize the costs associated with building a new plant and to allow the continued operation of inexpensive older plants. New electrical plants, however, are relatively clean because of the stringent regulations governing SO_2 emissions from new coal-fired sources and the virtual absence of SO_2 emissions from plants fueled by natural gas. The net result of utility conservation efforts, therefore, is to defer the construction of new, less-polluting capacity.

Under new acid rain control policies, conservation programs may help lower utilities' compliance costs. Economic factors, however, favor continued operation of existing capacity, even under a relatively flexible control policy. Thus, conservation would simply defer the construction of cleaner but more expensive new capacity rather than reduce the use of existing capacity. Under control policies that limit the growth in emissions over time, such as a cap on emissions, the effects of conservation would be increased. Lowering the growth in demand for electricity would both defer new construction and reduce the additional control costs associated with an emission cap, since a cap would permit new sources of emissions only if emissions from some existing source were cut back. Nevertheless, the absolute costs of emission cap policies would still be greater than regulatory programs that allow emissions to grow.

CHAPTER I

INTRODUCTION AND OVERVIEW

Congressional efforts to reauthorize the Clean Air Act of 1970, as amended in 1977, have been frustrated by the national and regional economic implications of measures for controlling acid rain. Acid rain is a type of air pollution in which acidic compounds in the atmosphere fall to the earth's surface through the action of rain and gravity. By tightening the current regulations that govern sulfur dioxide (SO_2) emissions from coal-fired power plants--a primary cause of acid rain--legislative proposals to curb acid rain could add billions of dollars to the nation's costs of controlling air pollution and would have widely varying effects on coal production and employment in different regions of the country. Recent efforts by utilities and by state and federal governments to improve coal-burning technology and to promote conservation of electricity have been touted as reducing the need for acid rain controls or mitigating some of the costs and effects of regulatory control. This paper presents an economic framework for evaluating the potential contribution of improvements in technology and utility-led conservation efforts to reduce SO_2 emissions and thus reduce the costs of controlling acid rain.

THE CASE FOR TECHNOLOGY AND CONSERVATION

The costs and economic effects of regulatory programs that would reduce SO_2 emissions from coal-fired power plants depend on four major factors:

- The demand for electricity from these types of plants, which determines how much they will be used;
- The technology used for burning coal;
- The sulfur content and cost of the coal burned; and
- The type and costs of alternatives for controlling emissions that are allowed by the regulatory program.

Previous studies by the Congressional Budget Office (CBO) have highlighted the relationships between several of these factors--for example, the type of regulation and SO_2 control costs. Proponents of improved coal-burning technologies and of efforts to reduce the demand for electricity have argued, however, that earlier analyses by CBO and other organizations have failed to recognize fully the interaction of new technology and conservation efforts with the costs and effects of control measures. Specifically, some proponents have claimed that the development of improved, less expensive technology can lead to emission reductions under current regulations. Others have argued that the timing of acid rain control policies should accommodate the pace of technology development and thus lead to more cost-effective emission reductions. Supporters of increased efforts to conserve electricity have argued that such conservation programs will have the additional benefit of reducing SO_2 emissions.

The case for more explicit consideration of improved technology and conservation measures in the acid rain debate hinges on their potential ability to reduce SO_2 emissions and to do so at less cost than other methods. This paper evaluates these issues from two perspectives--under the current regulatory requirements of the Clean Air Act and under new proposals for controlling acid rain. Both perspectives require the construction of a base case for projecting emission levels. The base case for this analysis is developed in the first part of Chapter II and is used throughout the study.

OPPORTUNITIES FOR TECHNOLOGY AND CONSERVATION

The impact of improved technology on SO_2 emission levels or the costs of reducing emissions depends on its market potential; improvements in coal-burning technology can reduce emissions only if utilities decide to use the technology. The use of technology can be mandated by regulation, which virtually guarantees a market, or it can be left to the economic choice of utilities under more flexible regulatory regimes. In CBO's analysis of alternative regulatory scenarios, these regulatory approaches have very different implications for the likely market for and usefulness of new technologies in reducing emissions.

Energy conservation already occurs in the marketplace in response to higher electricity prices. In addition, utilities have begun recently to encourage their customers to invest in more efficient electricity-using equipment in an effort to reduce the need to build expensive new power plants. Proponents of conservation programs cite potential market failures as reasons why utilities--as well as federal and state governments--should consider programs that would further reduce the use of electricity. The market failures commonly cited include systematic underpricing of electricity resulting largely from rules under which regulatory commissions operate, and a "first-cost" bias under which consumers and other buyers of appliances and electricity-using equipment pay inadequate attention to the life-cycle savings that could accrue from conservation.

Conservation programs can reduce emissions only if they also reduce the amount of electricity generated in power plants that produce SO_2 emissions. Whether or not this reduction will occur depends on the choice utilities make between reducing their use of existing capacity and forgoing new capacity when demand for electricity declines. Conservation programs and the development of new technology affect emissions in very different ways, but utilities' decisions about investments in capacity have an important influence on the potential benefits (lower emissions, reduced costs, or both) from improvements in both.

Over the next 20 years, three main factors will define the environment within which investment decisions concerning coal-fired power plants will be made:

- o Current as well as proposed environmental regulations affecting SO_2 emissions may dictate investing in certain types of control technologies.
- o The aging capital stock of coal-fired power plants will require investments to maintain or expand capacity.
- o Growing demand for electricity will require new investments.

These factors are discussed below.

Environmental Regulation

The Clean Air Act imposes SO_2 emission controls on all coal-fired power plants. Most of these plants, however, were built before the act went into effect. These older sources are subject to regulations in State Implementation Plans (SIPs), which are typically much less restrictive than the uniform federal requirements for newly constructed plants, known as New Source Performance Standards (NSPS).

Many analysts believe that current SO_2 emissions are not controlled enough, however, in that those emissions contribute to significant environmental damage through acid rain. This view has spawned a multitude of proposals to change the regulations. Under many of these proposals, electric utilities would be forced to reduce emissions from SIP plants over roughly a decade. These reductions can be accomplished through a variety of methods, including:

- o Switching to lower-sulfur, and therefore "cleaner," coal;
- o Installing equipment to control emissions;
- o Partially or completely replacing older plants; and
- o Generating less electricity.

The range of abatement choices allowed by the regulatory approach taken may affect the opportunities for emerging technologies and conservation programs to reduce emissions or the costs of controlling acid rain. For example, some bills would require the use of emission control technologies, which could involve installing "retrofit" equipment or replacing part of an existing plant. This stipulation would reduce the cost advantage available to some utilities of switching to lower-sulfur coals, but is often proposed as a strategy to discourage shifts in regional coal production. Although technology requirements may increase the costs of controlling acid rain, it could also enhance the prospects for new technologies to play a role in reducing emissions.

Aging Capacity

The bulk of utility SO_2 emissions arise from older plants, many of which will require investments to continue to generate a reliable and sufficient supply of electricity. The options that utilities face include:

- o "Life-extension" projects to refurbish a plant, and

- o Partially or completely replacing a plant.

If the utilities choose a replacement strategy, the new plants would be subject to NSPS requirements and emissions would fall. The emerging technologies employed in the partial replacement strategy (called "repowering") could simultaneously reduce emission rates to NSPS levels and generate more power. Either replacement choice would reduce emissions under the current Clean Air Act, although utilities now favor the life-extension option. If utilities were to choose repowering in the future, however, the costs associated with lower levels of emissions might decrease, resulting in real benefits from improvements in technology.

Growing Demand for Electricity

In addition to maintaining existing capacity, most utilities will face increased demands for electricity over the next decade. Historically, such an increase has meant building new power plants. As an alternative, some utilities have recently instituted programs designed to lower consumer demand for electricity in an effort to avoid or postpone the costs of expanding capacity. In these programs, utilities encourage customers to purchase more efficient electrical devices such as appliances. If these programs succeed in reducing the amount of electricity generated in the future, the emission levels expected under current environmental regulations--and the costs incurred in meeting additional emission control requirements--could be lowered.

CBO's Analytic Method

CBO investigated the relationship between these factors and improved technology and utility conservation programs in a three-step process. First, a base-case forecast of technology choices and, thus, SO_2 emission levels was developed by assuming current law and that utilities initiated no conservation efforts beyond those chosen in response to market prices. Second, CBO assessed the effects of less expensive technology and greater utility-sponsored conservation efforts on emission levels by allowing improvements in technologies (compared with the base case) and by relaxing the assumption concerning conservation efforts. Finally, the analysis allowed for changes in requirements for emission reductions to evaluate the effects of improved technology and conservation under different proposals for controlling acid rain.

THE ECONOMIC IMPLICATIONS OF CHOICES FACING ELECTRIC UTILITIES

Out of the set of investment choices defined by environmental regulation, aging capacity, and the rising demand for electricity, utilities must select a combination of technologies for generating power and controlling emissions, conservation programs, and coal types. The specific mix will vary among utilities, but most will attempt to select the least expensive approach.

While this objective is not always met, the goal of minimizing costs provides a useful guide for predicting utilities' future investment decisions. These decisions will produce a variety of outcomes, including emission levels, generation costs, and patterns of regional coal production that are central to the debate on acid rain. The value of improvements in technology and successful conservation efforts will be defined not simply by their existence or availability, but by how they affect these outcomes. The next two chapters provide additional detail regarding existing regulation, technology options, and conservation programs.

In Chapter II, CBO establishes a base case of technology choices and SO_2 emissions under current environmental regulations. The impact of new technologies on SO_2 emissions, costs, and coal production is then examined under new, more stringent regulatory policies. Chapter III discusses in detail the rationale for utility-led conservation programs--or "demand-side management." CBO conducted simulations under the assumption that conservation programs could eliminate the growth in demand for electricity between 1995 and 2000. Interpreting the results provides insight into the interaction between conservation and SO_2 regulation. The potential for utilities' conservation programs to reduce emissions and costs are explored under current regulations and under alternative, more stringent regulations that would require reductions of emissions in existing as well as new plants.

CHAPTER II

IMPROVED TECHNOLOGY

The production of electric power from coal has become more efficient and cleaner as a result of technological improvements. New combustion and emission control technologies continue to emerge as a result of public and private development efforts. Supporters of coal-burning technology programs argue that these endeavors will lead to reductions in sulfur dioxide (SO_2) emissions even in the absence of new control legislation. They further argue that new coal-burning technologies could reduce utilities' costs and promote regional production of high-sulfur coal under new regulations for controlling acid rain.

Technological advance alone will not necessarily reduce SO_2 emissions or lower the costs of controlling acid rain. Economic benefits arise only if electric utilities use the emerging technologies. Two major factors will determine demand by electric utilities for new coal-burning technologies:

- The investments required to continue generating electricity from older coal-fired plants; and
- The methods allowed to meet current or revised requirements for controlling emissions.

Utilities facing investments in aging capacity and emission controls, everything else being equal, will choose the least expensive alternative. This perspective suggests a useful distinction between technological *advance* and technological *improvement*. Technological advance describes engineering and technical progress that accompanies investment in the development of emerging technologies. Technological improvement occurs when technological advances become economically preferred to existing alternatives. Some new technologies are not used because they cost too much and because they are not required under current regulations. New policies for controlling acid rain could increase the use of emerging combustion and abatement equipment if their cost is competitive with that of conventional methods of pollution abatement.

CURRENT REGULATIONS AND THE CHOICE OF TECHNOLOGY

The market among electric utilities for coal-burning technologies has two segments. The construction of new plants constitutes the bulk of the demand for combustion, generation, and abatement equipment. This section focuses on the other segment: investments that utilities make at existing facilities in response to the declining performance of older coal-fired units. These plants define, in large part, the potential for technologically induced reductions of SO_2 emissions.

The Problem of Aging Capacity

As coal-fired power plants age, their performance declines: heat rates (the ratio of heat input to electricity output) increase, forced outages (periods of unavoidable shutdown and maintenance) become more frequent, and maximum available power is curtailed. The unit requires more fuel and repair, while generating less electricity. By the third decade of commercial service, these problems usually become serious enough for the utility to consider investments to return the plants to acceptable performance levels.

Beginning in the 1950s and continuing into the early 1970s, there was a massive increase of coal-fired capacity. These older units account for the bulk of SO_2 emissions and are the focus of most proposals to control acid rain. These sources were exempted from uniform federal emission standards--the New Source Performance Standards (NSPS)--established in the Clean Air Act of 1970. Instead, these plants are subject to State Implementation Plans (SIPs), under which states regulate individual sources to attain standards for local ambient air quality. Most SIP standards for SO_2 emissions are more lenient than the federal NSPS, and most are currently met without emission control technology.[1] Thus, investments in these older SIP plants provide a unique opportunity for cleaner coal-burning technology.

Investment Options to Maintain or Increase Capacity

Utilities have several options for investing in their aging plants. Demand for specific coal-burning technologies depends on which of these various investment options are selected. The differences in these options include the relative portion of an existing facility that would be replaced or modified, their effects on SO_2 emissions, the relative impact on generating capacity, their costs, and the regulations to which they would be subject. The investment options are grouped here into three main categories:

- **Life extension** or, more generally, plant improvement. These programs improve reliability, enhance combustion efficiency, restore capacity to its initial rating, and may prolong the plant's useful life for 20 years or more. Although life extension may marginally lower emission rates, overall SO_2 emissions could rise as a consequence of increased use of the plant over time. In cases where additional emission control is required, the utility could consider retrofitting abatement equipment. **Retrofit** technologies are used either to modify, but not replace, the existing coal-combustion equipment, or to remove sulfur from the coal-combustion gases. The most commonly used retrofit technology is called a "scrubber." The sole motive for retrofitting equipment is to reduce emissions, not to improve the plant or expand capacity. In fact, most retrofitting options reduce the net amount of electricity generated by an existing plant.

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1. Although the federal NSPS was promulgated in 1971 (and subsequently revised in 1978), several plants that commenced operation in the late 1970s are operating under SIP standards. These exceptions were allowed when construction was approved before 1971, but subsequent delays postponed commercial operation.

- **Repowering**, or partially replacing, the plant with new coal-combustion equipment. Although repowering costs more than life extension, it simultaneously lowers emissions and expands capacity. Repowering lowers costs compared with a brand new or "greenfield" plant by using existing land, structures, and transmission facilities, as well as by creating operating savings from new combustion technologies.

- **Replacing** the old plant by building a new one to maintain or expand capacity. Building a new plant is usually done in cases where an existing plant cannot be economically upgraded, retrofitted, or repowered. New coal-fired plants cost hundreds of millions of dollars and take roughly a decade to complete. A new plant would be subject to the more stringent NSPS and therefore must include technology that removes specified percentages of SO_2 from the combustion gases. The most common technology used is a flue gas desulfurization system called a "scrubber."

This list only considers the generating capacity of coal-fired utilities, and is not exhaustive. Other options available to utilities in responding to aging coal-fired capacity--for example, wholesale purchases of electricity from independent power producers or cogenerators, or construction of gas-fired capacity--might allow utilities simply to retire existing coal-fired plants.

The Costs of Investment Options

Holding aside the issue of availability of new technologies, the options to life-extend, repower, or replace a plant will compete on the basis of their relative costs. To assess the likely decisions utilities would make among these options, CBO developed a unit costing methodology to estimate the least costly investment options. The methodology and assumptions used by CBO closely follow those in a recent Department of Energy (DOE) study that examined three repowering technologies: atmospheric fluidized-bed combustion (AFBC), pressurized fluidized-bed combustion (PFBC), and integrated gasification combined-cycle plants (IGCC).[2] The appendix describes the various technologies and explains the methodology for computing comparative costs.

Two costs are calculated. The "unit cost" represents the cost of generating electricity at a specific plant, while the "system cost" adjusts the unit costs of life extension to include additional power generated from new plants. The system cost, therefore, attempts to put the costs of life extension and repowering on a more equal basis by explicitly including the new capacity gained through repowering.[3]

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2. See Department of Energy, Office of Fossil Energy, *The Role of Repowering in America's Power Generation Future* (December 1987). All costs cited in the DOE report are in 1985 dollars. Therefore, all comparisons in this section will be made in 1985 dollars.

3. System cost could also be called the cost avoided by repowering, when life extension and new construction are the alternatives. It is a weighted average of the cost of life extension and the cost of new capacity, with weights chosen to reflect the amount of additional capacity provided by a repowering project. Since different repowering options provide different increments to capacity, system cost will vary depending on which

Because the utilities have limited experience with the emerging technologies, estimates of capital and operating costs remain speculative. Lacking better data, CBO used the cost of the repowering technology and the assumptions about electricity generation in the DOE report. DOE's assumption regarding the capital costs of life extension--$357 per kilowatt (kw)--however, lies in the high end of commonly cited ranges. For example, the Office of Technology Assessment (OTA) cites a range of $200/kw to $400/kw for the capital costs of similar investments, while a study by the Electric Power Research Institute (EPRI) cites values between $150/kw and $300/kw.[4] A recent assessment of life-extension costs by the Energy Information Administration (EIA) arrived at a representative figure of $148/kw.[5] For its analysis, CBO assumed that life extension would cost $200/kw.

Estimates of Unit and System Costs. Under either cost basis, utilities would tend to choose the life-extension investment option over repowering or replacement because it is the least expensive (see Table 1). The unit cost of replacement capacity (56.0 mills per kilowatt-hour) is much higher than any other investment option, and the unit cost of repowered plants is substantially higher than the cost of electricity from a life-extended plant (31.5 mills per kilowatt-hour). When the unit costs are adjusted to reflect differences in capacity (system costs), the repowering options are still more expensive. In other words, the value of capacity gained by repowering an existing plant does not overcome the lower cost of life extension. Other factors could influence a utility's decision to repower or retrofit, but the cost comparisons nevertheless demonstrate the economic hurdles that such technologies face.

Alternative Assumptions. Under what conditions would utilities turn to something besides life extension under current policy? If the cost of repowering technologies fell, utilities would probably be more interested in acquiring them. The capital costs of IGCC, PFBC, and AFBC would have to fall to 80 percent, 50 percent, and 30 percent of their currently estimated costs to be competitive with life extension. Alternatively, if utilities imputed higher costs to building new capacity, the relative costs of repowering would fall. For example, according to DOE, the cost for new capacity is currently $1,285/kw. IGCC becomes competitive when the cost of new

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repowering option is being compared with life extension. Calculating the system cost in this way implicitly assumes that the additional capacity provided by life extension is required, so that repowering avoids the cost of new construction. This assumption puts repowering in the most favorable light possible, because if increased capacity is not needed, the only cost avoided by repowering would be the (lesser) cost of life extension.

4. See Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990s* (July 1985), p. 135. On p. 223, however, OTA cites $400/kw as a "most likely" estimate. The EPRI figures are from Appendix A of EPRI, "SO_2 Emissions Trend Analysis Sensitivity" (Coal Combustion Systems Division, Palo Alto, Calif., March 18, 1986).

5. See Department of Energy, Energy Information Administration, *Estimating the Capital Costs of Life Extension for Fossil-Fuel Steam Plants* (July 1988). The $148/kw estimate is a capacity-weighted national average for coal-fired plants, calculated as "overnight" capital cost in 1987 dollars per kilowatt. This calculation does not incorporate the costs of financing over the course of the project, or other contingencies sometimes included in comparisons of utilities' capital costs. Even if these factors are included, however, the capital costs are not likely to exceed $200/kw.

TABLE 1. UNIT AND SYSTEM COSTS OF GENERATING ELECTRICITY WITH SELECTED INVESTMENT OPTIONS (In 1985 mills/kilowatt-hour)

Investment Option	Unit Cost	System Cost of Life Extension[a]
Life Extension[b]	27.8	n.a.
Repowering		
Atmospheric fluidized-bed combustion[c]	45.2	31.5
Pressurized fluidized-bed combustion	43.4	34.3
Integrated gasification combined-cycle	50.0	45.6
Replacement	56.0	n.a.

SOURCE: Congressional Budget Office estimates based on Department of Energy (DOE) assumptions about technology costs and electricity generation.

NOTE: The unit cost is the cost of generating electricity at a specific plant. To put the costs of life extension and repowering on a more equal basis, the system cost adjusts the unit cost of life extension to include additional power generated from new plants.

n.a. = not applicable.

a. Assumes that replacement capacity is built and operated to generate the same amount of electricity as repowering options. The capacity expansion assumed for AFBC is 15 percent, PFBC is 30 percent, and IGCC is 170 percent.

b. The capital cost of life extension is assumed to be $200/kilowatt in these calculations.

c. Under alternative DOE assumptions concerning heat rates and operating costs for life extension compared with AFBC, the unit cost for life-extended plants is 29.4 mills/kilowatt-hour, and the system cost of life extension is 32.9 mills/kilowatt-hour. See the appendix for details.

construction exceeds $1,600/kw. However, replacement costs would have to be valued at $3,100/kw (for PFBC) and over $5,000/kw (for AFBC) in order for these technologies to compete with life extension. Unless repowering technologies perform much better than DOE expects, the economic potential for repowering appears limited by the low costs of life extension.

An increasing demand for electricity would not change the economics of repowering. Even if all the additional capacity for generating electricity gained by repowering is needed, utilities would choose new construction to meet these needs, at least on the basis of the cost estimates presented here. Other considerations, however, could play a role in utilities' choices between repowering and new construction. For example, difficulties in finding politically acceptable sites for new power plants could favor investments in repowering existing plants.

The Least-Cost Option: The CBO Base Case. Under current law, utilities have no incentive to install technologies that reduce SO_2 emissions in existing plants. For purposes of projecting future emissions, or estimating the cost of various acid rain control policies, the base-case assumption that utilities will prefer to perform simple life extension in the absence of regulatory changes appears warranted by the relative costs. If utilities choose to extend the lifetimes of coal-fired (and oil-fired) plants and increase the amount of electricity they generate, then emissions from existing sources would remain constant or even rise over the next decade. New coal-fired plants, even though well controlled, will also add emissions. Both of these factors contribute to the projected rise in SO_2 emissions from utilities in the CBO base case, from 17.6 million tons annually in 1990 to 20.1 million tons by 2000.

This projected increase in emissions would reverse the decline in utilities' emission levels experienced during the mid-1980s, which resulted from greater compliance with SIPs and low demand for electricity in regions with a large number of coal-fired plants. However, many states could maintain the federal air quality standard for SO_2 even if emissions increased (although a few states have chosen to control existing sources beyond federal requirements and others may follow), and an increasing demand for electricity is absorbing excess capacity in most regions. Given these projections, further reductions in SO_2 emissions and the potential contribution of improved technologies will not occur in the absence of regulatory change.

NEW REGULATIONS AND THE CHOICE OF TECHNOLOGY

The previous section suggests that in the absence of new regulations to control SO_2 emissions, neither existing nor emerging technology will further reduce SO_2 emissions. New legislation to control SO_2 could, however, change this outcome, particularly if it requires or encourages investments in technology. This section highlights how alternative approaches to controlling acid rain relate to the investment options that would reduce SO_2 emissions from existing plants, such as retrofitting scrubbers, emerging retrofit options, and repowering technologies. Acid rain control policies that explicitly require technology or are so stringent as to force utilities to use technological controls would encourage the use of existing retrofit technologies (scrubbers) rather than repowering technologies, but tend to be associated with higher overall control costs. Policies that allow utilities more flexibility in how they control emissions would encourage utilities to reduce emissions by using nontechnological and less expensive means, such as coal-switching (discussed below), rather than by investing in technological controls of any kind.

The Role of Technology in Acid Rain Control Policy

Most proposals to control acid rain would require utilities either to use "cleaner" lower-sulfur coal rather than high-sulfur coal--referred to as coal-switching--or to use technologies to reduce SO_2 emissions. Coal-switching is usually the cheaper alternative. The concern for the economic welfare of regions that rely heavily on the mining of high-sulfur coal, however, often motivates technology-based proposals. Generally, the greater the level of investment by utilities in technological controls, the more high-sulfur coal can be burned. Other proponents of technological controls view them as a way to insure large reductions in emissions, since scrubbers can remove high percentages of SO_2. Proposals that require annual reductions of 10 million to 12 million tons of SO_2 emissions, or that stipulate plant standards below one pound of SO_2 per million British thermal units (Btu), would force utilities to install scrubbers at many plants. Under these proposals, the ability of utilities to coal-switch becomes constrained by limited supplies of coal with a sulfur content low enough to meet these requirements.

Several approaches have been proposed either to force or to encourage the use of technology to reduce emissions. For example, placing limits on a plant's lifetime--that is, requiring existing plants to conform to the NSPS at some point--essentially accelerates the regulatory process by disallowing life extension unless technological controls are also installed. Plant lifetime limits could be imposed administratively by tightening the rules under which utilities can perform life extension and continue to maintain SIP regulatory status. Utilities currently may invest in life extension to up to 50 percent of the cost of replacing the unit before it is classified as "reconstructed," which invokes the NSPS. If this threshold were lowered, then utilities would still have some flexibility regarding the timing of life-extension programs, but would be forced to install technological emission controls when units are life-extended.

Alternatively, the Congress could dictate the standard that would apply and the age at which the plant would have to comply. This approach is simple and would steadily reduce emissions; but it is also characterized by slow progress toward emission goals and by relatively high costs, compared with policies that feature specific deadlines and allow nontechnological abatement--such as coal-switching--where it may cost less at a particular plant.

Policies directed at attaining targets for aggregate emission reductions by specific times can also encourage technological approaches by dictating their use or by making subsidies available to utilities that install technological controls. Compared with strict "polluter-pays" schemes that offer no subsidies but allow utilities flexibility in deciding how to reach the targets, however, restrictions or subsidies intended to force or encourage technological controls typically cost more.[6]

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6. See Congressional Budget Office, *Curbing Acid Rain: Cost, Budget, and Coal-Market Effects* (June 1986). In cases where capital subsidies encourage utilities to install technological controls where they otherwise would not, the costs are increased, even though the compliance cost borne by utilities is lowered by the amount of the subsidy.

Costs and Effectiveness of Technological Options
Under Policies Mandating Their Use

If SO_2 reduction policies are so stringent as to require the use of technology to reduce emissions, then the relative costs of the available technologies will dictate the utilities' decisions. The aggregate cost of such a policy can be calculated by multiplying the costs of the least expensive option (that achieves compliance) by the amount of technology required. Technological advance lowers the policy costs only when emerging technology costs less than the existing preferred compliance option. Under the estimates of technology costs used here, utilities are likely to respond to regulations that require technological controls at existing plants by using scrubbers and by life-extending the plant, not by repowering. Some repowering and alternative retrofit technologies are sufficiently close in cost to life extension and scrubbing that further improvements could prompt utilities to adopt them. The reduction in the cost of controlling acid rain, however, is likely to be small.

The capital costs of retrofitting scrubbers depends on a variety of site-specific factors such as the size and configuration of the existing plant, the level of control desired, the sulfur content of the coal burned, and the type of equipment chosen. No single estimate is likely to capture the actual cost faced by any one plant. DOE has estimated that the average cost of a scrubber is $300/kw. Alternatively, suppliers claim that capital costs for scrubbers have fallen below $200/kw.[7] The $250/kw in capital costs assumed in CBO's analysis is consistent with the EPRI study cited earlier. The $250/kw figure is also consistent with cost assumptions used in the analysis of flexible control policies presented later in this chapter.

Repowering. Under the assumed capital cost of $200/kw for life extension and $250/kw for a scrubber, the unit costs of repowering with PFBC or IGCC are nearly identical to an equivalent mixture of retrofitting and adding new capacity (as reflected by the system costs), while repowering with AFBC would cost more. These results are shown in Table 2. If the capital cost of IGCC rose by 2 percent, or PFBC by 4 percent, then they would cost more than retrofits and new capacity. Alternatively, if the capital cost of retrofitting a scrubber was $210/kw or less, the repowering options would still be more expensive. If these costs are representative, then conventional scrubbers could remain the abatement technology of choice, unless other factors are considered. Even in situations where the costs of alternative technology options are roughly equivalent, utilities are likely to favor the relative certainty of the proven design and performance of conventional alternatives.

A simple comparison of costs might mask important utility-specific or site-specific factors that could favor repowering in selected cases. For example, the wide variety of existing coal-fired plants may foster "niche" markets for repowering technologies under acid rain control policies. Nevertheless, there would have to be a large number of such markets for repowering options to lower significantly the costs of controlling acid rain.

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7. See Industrial Gas Cleaning Institute, "Acid Rain Control Briefing Document on Retrofitting Flue Gas Desulfurization Systems to Existing Coal-fired Boilers," (Washington, D.C., July 1987).

TABLE 2. UNIT AND SYSTEM COSTS OF GENERATING ELECTRICITY WITH SELECTED INVESTMENT OPTIONS AND SCRUBBERS (In 1985 mills/kilowatt-hour)

Investment Option	Unit Cost	System Cost of Life Extension with Scrubber[a]
Life Extension with Scrubber[b]	39.4	n.a.
Repowering		
Atmospheric fluidized-bed combustion[c]	45.2	42.6
Pressurized fluidized-bed combustion	43.4	44.1
Integrated gasification combined-cycle	50.0	50.3
Replacement	56.0	n.a.

SOURCE: Congressional Budget Office estimates based on Department of Energy (DOE) assumptions about cost and electricity generation.

NOTE: The unit cost is the cost of generating electricity at a specific plant. To put the costs of life extension and repowering on a more equal basis, the system cost adjusts the unit cost of life extension to include additional power generated from new plants.

n.a. = not applicable.

a. Assumes that replacement capacity is built and operated to generate the same amount of electricity as repowering options. The capacity expansion assumed for AFBC is 15 percent, PFBC is 30 percent, and IGCC is 170 percent. The loss of capacity when scrubbers are installed is assumed to be 2 percent.

b. The retrofit scrubber is assumed to add $250/kilowatt in capital costs to the life-extension project. Life extension alone is assumed to cost $200/kilowatt.

c. Under alternative DOE assumptions concerning heat rates and operating costs for life extension compared with AFBC, the unit cost for life-extended plants with a retrofit scrubber is 41.5 mills/kilowatt-hour. Consequently, the system cost of life extension with a scrubber is 44.4 mills/kilowatt-hour. See appendix for details.

Retrofitting Equipment. Given utilities' preference for life extension and scrubbers (if required), improvements in alternative retrofit technologies could lower emissions and reduce control costs. The appendix describes several emerging retrofit technologies that feature lower capital and operating costs than current scrubbers, but typically remove less SO_2 than scrubbers. Thus, in order to reduce emissions by the same amount, these technologies would have to be used in conjunction with medium- or low-sulfur coal, or be installed in more plants. For example, utility representatives have asserted that emerging retrofit technologies that remove between 50 percent and 70 percent of SO_2 would cost 25 percent to 40 percent less than a scrubber. On an equivalent emission-reduction basis, a technology that costs 40 percent less than a scrubber but attains only 70 percent removal would enjoy roughly a 25 percent cost advantage over scrubbers.[8] This figure is only approximate, but it provides a basis for estimating the potential impact of improved retrofit technologies on the costs of reducing acid rain. If the real costs of the desired mix of compliance technologies were reduced by 25 percent, then the aggregate costs of requiring their use would likewise fall by 25 percent. The changes in the costs of individual technologies can be used to estimate an upper bound of the overall savings expected from technological innovation under new acid rain control policies.

To illustrate the potential magnitude of cost savings, consider an acid rain control policy that requires plants to comply with the current NSPS as they reach age 30. Roughly 200 gigawatts of coal-fired utility capacity without scrubbers will be 30 years old by 2010. Assuming that all of this capacity were subject to an NSPS stringent enough to mandate technological controls costing 12 mills per kilowatt-hour (roughly equivalent to the difference in unit costs between life extension with and without a retrofit scrubber, as reported above), utilities would face additional costs of nearly $14 billion annually.[9] Emissions from these plants would be reduced from about 17 million tons annually to less than 4 million tons, but at an average cost of more than $1,000 per ton. In this situation, a 25 percent reduction in technology costs would save $3.4 billion annually. Under policies that put less emphasis on technology, of course, the economic gains would be considerably lower. Under current policy, for example, the gains from technology advances could easily be zero, as discussed above. To calculate the potential savings from improved technology, the next section examines flexible policies for reducing acid rain.

Costs and Effectiveness of Technological Options Under Flexible Control Policies

While it is not possible to describe and model all of the different proposals that have been made to curb acid rain, two "generic" approaches can be used to highlight the interactions between improved technology and the effects of acid rain control policy on costs, emissions, and the coal market. A commonly espoused goal of legislation to control acid rain is to reduce annual SO_2 emissions by 10 million tons from 1980

8. Testimony of Dr. Richard Balzhiser before the Subcommittee on Energy Research and Development, Senate Committee on Energy and Natural Resources, S. Hrg. 100-388, April 2, 1987.

9. This calculation makes the simplifying assumption that all capacity is operated at 65 percent.

levels over roughly a decade's time (assumed here to be the year 2000). Depending on how emission goals are expressed, and on the type of sources that are included in the goals, however, policies could affect the electric utility sector in significantly different ways. In this report, electric utilities are assumed to be responsible for the entire 10 million ton reduction, and the difference between policies is confined to the exclusion or inclusion of sources that began operation after 1980. A one-time "rollback" policy excludes newer sources, and an emission "cap" policy includes them.

The key difference between a cap and a rollback policy is the total emissions ultimately reduced. Electric utilities emitted roughly 17.4 million tons of SO_2 in 1980. A reduction of 10 million tons by 2000 would restrict emissions to 7.4 million tons in that year. Under a one-time rollback policy, the resulting level of utility emissions in 2000 (and beyond) is the sum of 7.4 million tons from old sources plus whatever emissions arise from new sources. Under a cap, the 7.4 million tons becomes an absolute target because all sources are included. To operate, new sources must seek offsets--that is, emission reductions equivalent to that source's projected emissions--from existing sources, and the level of control applied to sources that existed in 1980 must be tightened more than under a rollback policy. Since total emissions from utilities are projected to grow by nearly 3 million tons between 1980 and 2000, a cap policy would result in actual emission reductions of nearly 13 million tons (including some offsets), while the rollback policy would reduce emissions by only 10 million tons, compared with projected emission levels in 2000.

Conventional Technology. CBO used a model of electric utilities and the coal market developed by the Energy Information Administration to predict utilities' SO_2 control costs and SO_2 emissions under the two control policies. This model, called the National Coal Model Version 7 (NCM7), determines the least costly response by utilities to alternative policy scenarios.[10] Utilities are granted complete flexibility in responding to the emission targets. The model incorporates one abatement technology, the costs of which are based on conventional retrofit scrubbing equipment.

The overall control costs are higher and emission reductions are greater under the cap policy than under the rollback policy because of the projected rise in emissions under the base case. Table 3 shows the emissions and annual control costs in 2000 associated with the two policies. The rollback would cost utilities an additional $4.1 billion annually, and the cap would cost $7.1 billion (in 1988 dollars).[11]

The geographic distribution of emission reductions and control costs under the two policies is also different. Compared with the rollback, the cap policy is particularly expensive in relatively "clean" states located in the West or Southwest regions where offsets are quite expensive to achieve. Although few of these states would have to reduce emissions from existing plants under the rollback policy, maintaining 1980 emission levels under the cap can become very expensive if coal-

10. See Congressional Budget Office, *Curbing Acid Rain*, for a detailed description of this approach using an earlier version of the model (NCM5).

11. When comparing annual emissions and costs in the year that initial compliance is attained, the distinction between the rollback and the cap is essentially semantic: a 12.8 million ton rollback from 1980 emission sources would achieve the same emission reductions as the 10 million ton emission cap if both are attained by 2000.

TABLE 3. ANNUAL SO_2 EMISSIONS AND CONTROL COSTS IN 2000 UNDER A 10 MILLION TON ROLLBACK AND A 10 MILLION TON CAP, WITH CURRENT TECHNOLOGY

Region	SO_2 Emissions (Thousands of tons)			SO_2 Control Costs (Millions of 1988 dollars)	
	Base Case	Rollback	Cap	Rollback	Cap
New England, New York, and New Jersey	1,046	743	534	406	513
Mid-Atlantic	3,177	1,341	1,239	1,197	1,441
South Atlantic	5,069	2,595	2,026	727	944
Midwest	7,069	2,636	2,182	1,301	1,562
Southwest	1,198	1,048	407	108	1,910
Central	1,578	697	555	192	248
North Central, West, and Northwest	1,100	790	492	185	492
U.S. Total	20,148	9,850	7,435	4,115	7,110

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The regions are based on U.S. Federal Regions. CBO has combined New England with the New York/New Jersey Federal Region; the North Central, West, and Northwest Federal Regions (excluding Alaska and Hawaii) also are combined. The regions, and the states they comprise, are: New England, New York, and New Jersey (Maine, New Hampshire, Vermont, Massachusetts,Connecticut, Rhode Island, New York, New Jersey); Mid-Atlantic (Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware); South Atlantic (Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida); Midwest (Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio); Southwest (Texas, New Mexico, Oklahoma, Arkansas, Louisiana); Central (Kansas, Missouri, Iowa, Nebraska); North Central, West, and Northwest (Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado, California, Nevada, Arizona, Washington, Oregon, Idaho).

fired generation is expected to increase. Under the rollback, utilities' control costs are concentrated in regions where their emission rates have historically been high: the Midwest, South Atlantic, and Mid-Atlantic regions.

Improved Technology. CBO conducted a simulation of the NCM7 to illustrate the role that emerging technology might play by the year 2000 under programs to control acid rain. The emergence of an improved retrofit technology was depicted in the model as a 50 percent reduction in the base-case capital cost of retrofitting a scrubber.[12] The assumed 50 percent decline in the capital costs is roughly equivalent to a 25 percent decline in the overall cost of using abatement technology.

Because the NCM7 does not distinguish between different SO_2 control technologies, this 25 percent reduction can be interpreted as the emergence of either improved retrofit technologies that remove more SO_2 or, simply, less expensive scrubbers. In either case, the model's structure would simply retrofit more capacity in proportion to either the lower percentage of SO_2 removed or the lower costs of the scrubber. Although the simulation's results might underestimate the amount of capacity retrofitted with improved technologies, the aggregate cost and coal-market effects would not be significantly biased.

Under either the rollback or the cap, the assumption of lower capital cost for retrofitting abatement equipment reduces the overall annual cost of the policy, encourages the use of technology, and eases the losses for high-sulfur coal production attributed to control policies. Table 4 displays the policy simulation results in the year 2000, under the base-case assumptions and with improved technology. Compared with the costs of current technology (shown in Table 3), less expensive retrofit equipment would reduce annual control costs by \$0.5 billion under the 10 million ton emission rollback and by \$1.0 billion under the 10 million ton emission cap.

These results suggest that ambitious targets for emission reductions would create a market for technology that would be very sensitive to changes in the prices of technology. The assumed 25 percent reduction in technology cost increases the demand for technology by more than 73 percent with the rollback (32.0 installed gigawatts compared with 18.5 gigawatts) and by 44 percent with the cap (56.0 gigawatts compared with 38.9 gigawatts). The increased demand for technology suggests that commercial returns to developing improved retrofit equipment could be high: the additional 13.5 gigawatts to 17.1 gigawatts of retrofitted capacity represent between \$2.0 billion and \$2.5 billion in additional equipment orders.

Effects on the Coal Market. Improved technology could mitigate to a significant degree the losses in coal production attributed to flexible control policies. Table 5 displays estimates of steam coal production for the years 1990 and 2000 under the base case in the particularly vulnerable states, which can be grouped into two regions: the Midwest and Northern Appalachia.[13] The Midwest region includes Illinois, Indiana, and western Kentucky; the Northern Appalachia region comprises Maryland,

12. The base-case capital costs of retrofitting scrubbers in the NCM7 range from \$240/kw to \$280/kw, depending on the region.

13. These production estimates include only steam coal, which is burned in utility and industrial boilers, and exclude the metallurgical coal used in making steel.

TABLE 4. ANNUAL SO_2 EMISSIONS AND CONTROL COSTS IN 2000 UNDER A 10 MILLION TON ROLLBACK AND A 10 MILLION TON CAP, WITH IMPROVED TECHNOLOGY

Region	SO_2 Emissions (Thousands of tons)			SO_2 Control Costs (Millions of 1988 dollars)	
	Base Case	Rollback	Cap	Rollback	Cap
New England, New York, and New Jersey	1,046	696	534	352	440
Mid-Atlantic	3,177	1,341	1,238	1,134	1,206
South Atlantic	5,069	2,586	2,026	489	740
Midwest	7,069	2,637	2,181	1,163	1,306
Southwest	1,198	1,048	407	95	1,759
Central	1,578	692	555	189	218
North Central, West, and Northwest	1,100	790	492	172	468
U.S. Total	20,148	9,790	7,433	3,595	6,138

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The regions are based on U.S. Federal Regions. CBO has combined New England with the New York/New Jersey Federal Region; the North Central, West, and Northwest Federal Regions (excluding Alaska and Hawaii) also are combined. The regions, and the states they comprise, are: New England, New York, and New Jersey (Maine, New Hampshire, Vermont, Massachusetts,Connecticut, Rhode Island, New York, New Jersey); Mid-Atlantic (Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware); South Atlantic (Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida); Midwest (Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio); Southwest (Texas, New Mexico, Oklahoma, Arkansas, Louisiana); Central (Kansas, Missouri, Iowa, Nebraska); North Central, West, and Northwest (Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado, California, Nevada, Arizona, Washington, Oregon, Idaho).

TABLE 5. PROJECTED STEAM COAL PRODUCTION FROM NORTHERN APPALACHIA AND THE MIDWEST IN 1990 AND 2000 UNDER THE BASE CASE (In millions of tons)

	Coal Type		
Region	Low Sulfur	Medium Sulfur	High Sulfur
	Production in 1990		
Northern Appalachia	7.2	64.0	82.6
Midwest	6.4	21.9	95.6
Total	13.6	85.9	178.2
	Production in 2000		
Northern Appalachia	21.9	96.2	115.4
Midwest	9.7	35.3	89.8
Total	31.6	131.5	205.2

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The Northern Appalachia region comprises Maryland, Ohio, Pennsylvania, and northern West Virginia; the Midwest region includes Illinois, Indiana, and western Kentucky.

Ohio, Pennsylvania, and northern West Virginia. Together, these regions account for more than 80 percent of the high-sulfur coal produced in the United States, and less than 10 percent of low-sulfur coal produced in 2000 under the base case and all policy simulations. Table 6 shows the effects of the two control policies on regional coal production under alternative assumptions about technology. In the aggregate, losses in regional coal production are roughly halved under either policy, assuming that utilities can choose less expensive abatement equipment. This reduction occurs without either mandating technological controls or, as is sometimes proposed, offering subsidies for retrofitting equipment.

Technological Options and Their Long-Term Implications for Emission Reduction Strategies

Over the longer run, the potential market for new abatement technologies under future acid rain control policies could be affected, in part, by two factors. First, demand for new technologies could be limited by the number of plants that choose to retrofit conventional equipment in order to achieve the initial targets for emission reductions. Plants that install scrubbers would no longer be candidates for new control technologies. This is not likely to be a significant limiting factor under the acid rain control programs considered here. Even assuming a 25 percent reduction in the costs of technology, the CBO simulations project that utilities would retrofit less than 30 percent of the unscrubbed coal-fired capacity.

Second, demand for new technologies will be affected by the emission reduction requirements that exist after the initial emission targets are met. Under the rollback policy, no new requirements for emission reductions are placed on existing sources. Thus, little demand would develop for new technologies regardless of their cost or advantages in reducing emissions. Under the emission cap policy, however, the incentives for development and deployment of technological controls could be permanent and continue beyond the initial compliance date, since adding controls to existing plants is one way to gain emission offsets for new capacity. Analyses of emission caps show they are expensive to maintain over time, since the additional offsets must be achieved at increasingly costly sites. The continued improvement of retrofit technologies and, perhaps, new repowering options could help reduce these expected high costs.

Repowering may eventually become a more attractive option under emission caps, since a repowering project could simultaneously expand capacity and provide the required offsets. This result would depend, however, on the investment decisions made by utilities to achieve near-term reductions. Utilities can respond to emission caps initially in two ways. On the one hand, they can concentrate on controlling emissions through technological means at older plants--life-extending these units and retrofitting conventional or improved equipment--while switching coals at newer plants. This strategy would leave relatively newer plants without technological controls--increasing the chance that by the time that these plants require investments in capacity, repowering technologies would be available at competitive costs. On the other hand, the utility could retrofit the newest plants with conventional technologies and switch fuels at older plants. This strategy might cost less in the short run, but would leave many older plants facing investments in capacity and potential emission controls in a shorter time frame.

TABLE 6. EFFECTS OF ACID RAIN CONTROL POLICIES ON PROJECTED STEAM COAL PRODUCTION IN 2000 UNDER ALTERNATIVE TECHNOLOGY ASSUMPTIONS (In millions of tons)

Region	Coal Type		
	Low Sulfur	Medium Sulfur	High Sulfur
PRODUCTION UNDER THE BASE CASE			
Northern Appalachia	21.9	96.2	115.4
Midwest	9.7	35.3	89.8
Total	31.6	131.5	205.2
PRODUCTION UNDER A 10 MILLION TON ROLLBACK			
Conventional Technology			
Northern Appalachia	38.0	67.2	92.8
Midwest	13.8	58.8	65.3
Total	51.8	126.0	158.1
Improved Technology			
Northern Appalachia	34.9	73.7	99.5
Midwest	12.5	58.4	75.6
Total	47.4	132.1	175.1
PRODUCTION UNDER A 10 MILLION TON CAP			
Conventional Technology			
Northern Appalachia	37.7	65.4	63.0
Midwest	14.4	54.2	47.0
Total	52.1	119.6	110.0
Improved Technology			
Northern Appalachia	32.2	65.3	86.5
Midwest	11.9	56.5	67.9
Total	44.1	121.8	154.4

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The Northern Appalachia region comprises Maryland, Ohio, Pennsylvania, and northern West Virginia; the Midwest region includes Illinois, Indiana, and western Kentucky.

CHAPTER III

CONSERVATION

Utilities could respond to the high costs of constructing new capacity to meet increased demands for electrical services by encouraging consumers to use electricity more efficiently. Such conservation efforts would constrain demand and limit the need for utilities to generate more electricity, thereby reducing the need to expand capacity. Reducing the amount of electricity generated would also lower sulfur dioxide and other emissions from the combustion of fossil fuels. Proponents of energy conservation have argued that any effort to further reduce SO_2 emissions should explicitly consider this link between SO_2 emissions and utility-sponsored conservation programs. These programs tend to affect new, less-polluting plants, however, which limits the programs' contribution to emission reductions under the current Clean Air Act or new measures to control acid rain.

THE USE OF CONSERVATION PROGRAMS BY ELECTRIC UTILITIES

Utilities try to select the least expensive combination of generation, transmission, and construction of new capacity to meet rising demands for electricity with adequate reserve margins. In recent years, however, some utilities have begun also to consider methods of influencing the demand for electricity through programs that encourage consumers to use less electricity. These programs are commonly referred to as "demand-side management," or DSM. Although DSM may involve different types of activities, this report focuses on utility conservation programs--programs sponsored by utilities to reduce the overall demand for electricity.[1]

The new emphasis on integrating decisions about electricity supply and demand (often called "least-cost utility planning") has been a response to financial conditions experienced by utilities in the 1970s and early 1980s. During that period, many utilities were saddled with excessive debt (especially those with partially finished but unneeded nuclear plants), lowered bond ratings, excess capacity, and increasingly contentious decisions by state public utility commissions (PUCs) regarding the amount of committed investment that could be recovered by raising

1. Other DSM objectives include reducing demand at specific times during the day ("peak-clipping"), shifting peak demands to off-peak times ("load-shifting"), or increasing overall generation, either at specific times ("valley-filling") or at all times ("strategic load growth"). For an explanation of DSM concepts, see Electric Power Research Institute, *Impact of Demand-Side Management on Future Customer Electricity Demand* (Palo Alto, Calif.: October 1986).

electricity rates.[2] Growth in demand for electricity, once fairly predictable, had increasingly become a source of uncertainty for utilities. Given their precarious financial position, utilities became extremely reluctant to commit financial resources to satisfy potential but uncertain future capacity requirements associated with uncertain demands for electricity. Unlike other business concerns, however, utilities cannot reduce sales (by limiting the supply of electricity) in order to avoid high-cost production (generation), since investor-owned electric utilities accept an obligation to provide an adequate supply of electricity to meet consumer demand under the rates set by the PUC. Under these conditions, utility conservation programs came to be viewed as a means of reducing the financial risks of building new capacity to meet an unpredictable future demand for electricity.

From this perspective, utility conservation programs are a potential alternative to building a new plant or expanding existing capacity. In a typical utility conservation program, utilities subsidize (through planning assistance, energy audits, rebates, or interest-free loans) more efficient electricity-using devices. More efficient devices can deliver the same level of electricity services--light, heat, or mechanical power--while using less electricity. If enough customers purchase efficient equipment in response to these incentives, then demands for electricity will fall--or at least will not rise as quickly. These gains from efficiency become a source of electricity "supply" that can be used to satisfy new demands for electricity services, and enable utilities to avoid the costs of building expensive new plants.

To encourage utilities to pursue conservation programs, some PUCs have compensated utilities for lower sales of electricity and the costs of conservation programs by allowing electricity rates to rise. If electricity consumption by program participants is reduced by a greater percentage than rates are increased, then total electric bills for these customers will remain below previous levels. A successful utility conservation program, therefore, can simultaneously reduce the cost of energy to consumers and provide net income to utilities. In order to regulate the distribution of potential gains and losses from conservation, however, PUCs also subject these programs to a variety of ratemaking rules. The most important of these rules concerns the relative financial welfare of participants and nonparticipants. For example, some PUCs apply a "no losers" test to utility conservation programs: that is, consumers not included, or who elect not to participate, cannot be subject to higher electricity rates. Such restrictions can limit the development of these programs.

The record for utility conservation programs thus far has been mixed, with some notable successes and some disappointing results.[3] These programs continue to evolve and will probably become more effective as experience is gained in designing, implementing, monitoring, and evaluating the individual projects. Moreover, the value of conservation programs to utilities may increase as they face

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2. See Congressional Budget Office, *Financial Condition of the U.S. Electric Utility Industry* (March 1986) for an overview of the conditions faced by utilities over the last decade.

3. For an overview of early DSM conservation programs, see Robert F. Hemphill and Edward A. Meyers, "Electric Utility Conservation Programs: Progress and Problems," in John D. Sawhill and Richard Cotton, eds., *Energy Conservation: Successes and Failures* (Washington D.C.: The Brookings Institution, 1986).

the need to expand the supply of electricity and the capacity to generate it in order to accommodate the projected increases in demand for electricity during the 1990s. In fact, some PUCs have begun to encourage these programs in lieu of conventional responses to rising demand.

CURRENT REGULATIONS AND UTILITY CONSERVATION PROGRAMS

Using the National Coal Model Version 7 (NCM7), CBO examined a conservation scenario that assumed an increased reliance on utility conservation programs. CBO's analysis substitutes into the NCM7 an assumed reduction in demand for electricity. Specifically, the "conservation case" assumes zero growth in demand for electricity between 1995 and 2000, implying that utility conservation programs could offset the increased demand between 1995 and 2000 projected in the CBO base case. The assumed reductions in demand of around 340 billion kilowatt-hours (kwh) annually is equivalent to a reduction in total projected demand in 2000 of 10 percent, and of roughly 15 percent of demand in 1985.

The Conservation Case

This conservation case, based on zero growth in demand between 1995 and 2000, represents an attractive target for utility programs that are aimed at reducing the need to expand capacity. The simulation results, however, do not depend on the timing of reductions in demand. Equivalent demands for electricity in 2000 could result from conservation efforts that cut the anticipated growth rate in electricity demand throughout the 1990s from 2.7 percent to 1.6 percent. Moreover, the "conservation" growth rate could also occur under a variety of scenarios regarding economic performance, industrial and demographic shifts, and the status of energy markets during the 1990s.

Another important assumption in the CBO conservation case is that electricity sales decline proportionately over all four load categories represented in the model: base, intermediate, seasonal, and daily peak. This feature is consistent with CBO's interpretation of DSM conservation as an alternative to building expensive new generating capacity. (Other DSM programs, such as peak-clipping or load-shifting, are consistent with shorter-run objectives of reducing the cost of generating electricity from the existing capacity.) Furthermore, CBO's assumptions about conservation are most likely to help reduce SO_2 emissions, since generation is reduced at all times. Emissions might increase, however, under alternative DSM programs. For example, load shifting could increase emissions if generation is shifted from relatively clean units designed to meet peak demands to "dirtier" units that meet base loads. This latter point emphasizes the fact that utilities do not employ DSM specifically to reduce emissions or sales, but to reduce or avoid costs.

Finally, since the CBO conservation case simply assumes lower demand for electricity, care must be exercised when comparing these results with the base case. What appears as a cost saving to the utilities is actually a shifting of costs to the purchasers of energy-efficient electrical devices and appliances--electricity users who are not represented in the model. The relative magnitude of these costs--electricity generation costs avoided compared with demand-side investments incurred--will determine the overall efficiency of conservation activities. The distribution and timing of the actual cost savings could be quite different under a variety of DSM approaches, and would depend on the PUC's apportionment of the cost burden and the efficiency savings between ratepayers and shareholders.

Effects of the Conservation Case on Costs and Emissions

Simulation of the CBO conservation case suggests that utility conservation programs alone are a relatively ineffective method of controlling SO_2 emissions. Tables 7 and 8 display the changes in electricity demand and SO_2 emissions in the year 2000 as a result of assuming that growth in demand could be eliminated by 1995. Under current law, annual SO_2 emissions in the year 2000 would be about 2 percent (or 400,000 tons) less with conservation; in other words, the 10 percent reduction in projected electricity demand translates into a 2 percent reduction in utilities' overall SO_2 emissions.

The rather small reduction in emissions under the conservation case is consistent with the assumed rationale for utility conservation programs. Within the NCM7, conservation postpones the need to build new capacity and encourages the continued operation of older facilities. Existing coal-fired plants remain the cheapest way of generating electricity, and they contribute the majority of SO_2 emissions under either scenario. New plants--including NSPS coal-fired plants along with gas-fired combustion turbines and combined-cycle units--emit very little SO_2. In the CBO base case, these plants are built to meet a growing base load or to satisfy higher peak demand, both of which are limited under the conservation case. SO_2 emissions are only slightly reduced when these plants are not built.

Conservation remains a fairly diffuse method for reducing emissions because the reduction in demand for electricity does not necessarily target the plants that produce the greatest amount of emissions per unit of electricity produced. Instead, utilities that attempt to minimize costs reduce the amount of electricity generated from plants that produce the most expensive electricity. To the extent that the dirtiest plants do not also produce the most expensive electricity, conservation alone will have limited effects as an environmental policy.

Other air pollutants emitted by utilities would experience a more proportionate reduction under the conservation case. Nitrogen oxides would be reduced by 630,000 tons (roughly 7 percent of emissions projected in 2000), while carbon dioxide (CO_2) emissions would decline by 260 million tons (roughly 10 percent of emissions projected in 2000). The reduction in CO_2 emissions is based on an 8 percent decline in the amount of energy provided by coal, a 7 percent decline in oil use, and a 29 percent reduction in natural gas burned. Limitations of conservation as an emission reduction policy again emerge, since a large percentage of the reduction is borne by gas-fired plants, which emit less CO_2 than coal-fired plants.

According to the NCM7, utilities would save more than $24 billion in 2000 under the conservation case--$17.5 billion in operating and fuel costs, and $6.9 billion

TABLE 7. REDUCTIONS IN ELECTRICITY DEMAND AND SO_2 EMISSIONS IN 2000 ACHIEVED UNDER THE CONSERVATION CASE

Region	Electricity Demand (Billions of kilowatt-hours)			SO_2 Emissions (Thousands of tons)		
	Base Case	Conservation Case	Percentage Reduction	Base Case	Conservation Case	Percentage Reduction
New England, New York, and New Jersey	319	280	12.2	1,046	960	8.2
Mid-Atlantic	340	305	10.1	3,177	3,135	1.3
South Atlantic	711	637	10.4	5,069	4,936	2.6
Midwest	621	558	10.1	7,069	7,027	0.6
Southwest	524	476	9.2	1,198	1,188	0.8
Central	163	148	9.2	1,578	1,575	0.2
North Central, West, and Northwest	651	587	9.8	1,011	917	9.3
U.S. Total	3,329	2,993	10.1	20,148	19,738	2.0

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The regions are based on U.S. Federal Regions. CBO has combined New England with the New York/New Jersey Federal Region; the North Central, West, and Northwest Federal Regions (excluding Alaska and Hawaii) also are combined. The regions, and the states they comprise, are: New England, New York, and New Jersey (Maine, New Hampshire, Vermont, Massachusetts,Connecticut, Rhode Island, New York, New Jersey); Mid-Atlantic (Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware); South Atlantic (Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida); Midwest (Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio); Southwest (Texas, New Mexico, Oklahoma, Arkansas, Louisiana); Central (Kansas, Missouri, Iowa, Nebraska); North Central, West, and Northwest (Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado, California, Nevada, Arizona, Washington, Oregon, Idaho).

TABLE 8. OPERATING AND PERFORMANCE CHARACTERISTICS OF THE ELECTRIC UTILITY SECTOR IN 2000 UNDER THE BASE CASE AND THE CONSERVATION CASE

	Base Case	Conservation Case
Sales (Billions of kilowatt-hours)	3,329	2,993
Generation (Billions of kilowatt-hours)	3,659	3,292
Capacity Built Between 1995 and 2000 (Gigawatts)		
Coal-fired	33	17
Gas-fired	51	6
Emissions (Millions of tons)		
Sulfur dioxide	20.1	19.7
Nitrogen oxide	8.9	8.3
Carbon dioxide	2,484	2,225
Annual Cost (Billions of dollars)		
Variable (Operation, maintenance, and fuel)	108.8	91.3
Annual Capital	11.6	4.8
Total	120.4	96.1

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

in annual capital expenses forgone (or postponed).[4] Since these savings do not include the costs to utilities or consumers of undertaking the conservation measures, it is difficult to assess the net effect on consumers or utilities. Technical studies suggest that many electricity customers have not taken advantage of opportunities to use electricity more efficiently. Thus, the potential for increased efficiency may be sufficiently valuable to induce utilities to examine methods of tapping it. The effectiveness with which utility programs can translate the estimated potential into actual net economic gains remains promising, but uncertain.

Effects of the Conservation Case on the Coal Market

As discussed in previous chapters, the impact of policies for controlling utilities' SO_2 emissions on regional coal production remains an important issue. Successful conservation efforts will lower coal production to the extent that coal-fired generation is avoided. Of particular interest is the potential effect on production in the Midwest and Northern Appalachia regions, where most of the nation's high-sulfur coal is produced.

Under the conservation case, the anticipated growth in coal production between 1990 and 2000 would be reduced (see Table 9). The effect is negligible on production of low-sulfur coal, would moderately curtail the high growth in production expected for medium-sulfur coal, and would nearly erase the anticipated growth in production of high-sulfur coal during the decade because fewer NSPS coal-fired plants would be built. The requirement that all new plants use scrubbers renders the choice of coals essentially neutral with respect to sulfur content; many utilities would obtain cheap, locally mined, high-sulfur coal to fuel their new plants. However, the market for high-sulfur coal would be constrained by conservation programs that successfully limit construction of new coal-fired plants.

NEW REGULATIONS AND UTILITY CONSERVATION PROGRAMS

While utility conservation programs appear to have a limited effect on emissions in the absence of new SO_2 regulations, they may lower the control costs. The extent to which these programs can help lower the costs of new control policies in the year 2000 is shown under the 10 million ton rollback and the 10 million ton cap introduced in the previous chapter.

Effects of the Conservation Case on Costs and Emissions

Conservation would have only a small effect on emission reductions under new acid rain control policies, but would lower utilities' control costs. Under the 10 million ton rollback policy, national SO_2 emissions in 2000 would be 9.8 million tons under the CBO base case, and slightly less--9.4 million tons--under the CBO conservation

4. The annual cost totals--$120.4 billion in the base case and $96.1 billion with conservation--are not equivalent to the total annual cost of producing electricity in the year 2000, since they would not include previous investment in capacity.

TABLE 9. PROJECTED COAL PRODUCTION FROM NORTHERN APPALACHIA AND THE MIDWEST IN 1990, AND IN 2000 UNDER THE BASE CASE AND THE CONSERVATION CASE (In millions of tons)

Region	Coal Type: Low Sulfur	Coal Type: Medium Sulfur	Coal Type: High Sulfur
PRODUCTION IN 1990			
Northern Appalachia	7.2	64.0	82.6
Midwest	6.4	21.9	95.6
Total	13.6	85.9	178.2
PRODUCTION IN 2000 UNDER THE BASE CASE			
Northern Appalachia	21.9	96.2	115.4
Midwest	9.7	35.3	89.8
Total	31.6	131.5	205.2
PRODUCTION IN 2000 UNDER THE CONSERVATION CASE			
Northern Appalachia	21.8	92.5	99.1
Midwest	8.9	29.9	84.6
Total	30.7	122.4	183.9

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The Northern Appalachia region comprises Maryland, Ohio, Pennsylvania, and northern West Virginia; the Midwest region includes Illinois, Indiana, and western Kentucky.

case (see Table 10). Under the 10 million ton cap, national emissions in 2000 are 7.4 million tons with or without conservation--that is, they are constrained by the cap (see Table 11). The annual costs to utilities of controlling SO_2 emissions under the rollback policy would be \$3.6 billion with conservation, a savings of \$0.5 billion compared with the SO_2 control costs of \$4.2 billion without conservation. Under the cap policy, annual SO_2 control costs would drop by \$0.9 billion--from \$7.1 billion to \$6.2 billion--with conservation.

The simulation results presented here do not suggest a very strong relationship between the near-term costs of new controls on emissions and utility conservation programs. Conservation activities at levels assumed here do not contribute to more dramatic savings in SO_2 control costs for the same reason that conservation alone does not produce significant reductions in emissions. The sources most affected by slightly slower growth in the demand for electricity are NSPS coal-fired sources and gas-fired peaking units, all of which are relatively clean. The primary determinant of the cost of controlling SO_2 emissions is still the level of control applied to existing state-regulated coal-fired sources dispatched as base-load or cycling units; the operation of these plants is not fundamentally affected by the assumed reductions in demand.

This point can be reinforced by recalling the unit cost figures developed in the last chapter. As shown in Tables 1 and 2, electricity is more expensive to generate from a coal-fired replacement plant (56.0 mills/kwh) than from a life-extended plant (27.8 mills/kwh), even if the latter includes a scrubber (39.4 mills/kwh). Since switching to lower-sulfur coal is usually less expensive than retrofitting, the SO_2 control options analyzed here increase the average costs of generating electricity, but do not affect the marginal cost of adding capacity that is avoided by eliminating the growth in demand. Thus, utilities with successful DSM programs would still control emissions from existing plants and forgo building new plants when faced with requirements to reduce emissions in the near term. Conservation is unlikely to affect substantially the costs of controlling SO_2, since most of these costs are associated with controls on existing plants.

Given the magnitude of potential savings relative to the costs, some analysts have argued that the net gains from utility conservation programs could finance the additional SO_2 control costs associated with an emission reduction policy. (As calculated before, gross annual savings to electric utilities of \$24 billion are possible if growth in demand for electricity were eliminated, while net savings would depend on the costs of implementing the conservation programs.) These savings could exceed the \$4 billion to \$7 billion in annual control costs associated with new acid rain control programs. Of course, these savings from conservation are independent of the need for acid rain controls. If cost-effective conservation occurs in concert with acid rain policy, then consumers or utilities would still be forced to give up the economic gains from conservation to pay for the costs of achieving environmental policy goals.

<u>Effects of the Conservation Case on Coal Markets</u>

The effects of utility conservation programs and acid rain control policy on coal production could be especially severe in the high-sulfur coalfields of the Midwest

TABLE 10. ANNUAL SO_2 EMISSIONS AND CONTROL COSTS IN 2000 UNDER THE BASE CASE AND THE CONSERVATION CASE, WITH A 10 MILLION TON ROLLBACK POLICY

Region	SO_2 Emissions (Thousands of tons) Base Case	Conservation Case	SO_2 Control Costs (Millions of 1988 dollars) Base Case	Conservation Case
New England, New York, and New Jersey	743	629	406	342
Mid-Atlantic	1,341	1,295	1,197	904
South Atlantic	2,595	2,554	727	763
Midwest	2,636	2,486	1,301	1,182
Southwest	1,048	1,044	108	140
Central	697	656	192	159
North Central, West, and Northwest	790	738	185	114
Total	9,850	9,402	4,155	3,606

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The regions are based on U.S. Federal Regions. CBO has combined New England with the New York/New Jersey Federal Region; the North Central, West, and Northwest Federal Regions (excluding Alaska and Hawaii) also are combined. The regions, and the states they comprise, are: New England, New York, and New Jersey (Maine, New Hampshire, Vermont, Massachusetts,Connecticut, Rhode Island, New York, New Jersey); Mid-Atlantic (Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware); South Atlantic (Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida); Midwest (Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio); Southwest (Texas, New Mexico, Oklahoma, Arkansas, Louisiana); Central (Kansas, Missouri, Iowa, Nebraska); North Central, West, and Northwest (Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado, California, Nevada, Arizona, Washington, Oregon, Idaho).

TABLE 11. ANNUAL SO_2 EMISSIONS AND CONTROL COSTS IN 2000 UNDER THE BASE CASE AND THE CONSERVATION CASE, WITH A 10 MILLION TON CAP POLICY

Region	SO_2 Emissions (Thousands of tons) Base Case	Conservation Case	SO_2 Control Costs (Millions of 1988 dollars) Base Case	Conservation Case
New England, New York, and New Jersey	534	534	513	422
Mid-Atlantic	1,239	1,239	1,441	1,008
South Atlantic	2,026	2,025	944	1,072
Midwest	2,182	2,182	1,562	1,321
Southwest	407	407	1,910	1,917
Central	555	555	248	215
North Central, West, and Northwest	492	492	492	275
Total	7,435	7,434	7,110	6,231

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The regions are based on U.S. Federal Regions. CBO has combined New England with the New York/New Jersey Federal Region; the North Central, West, and Northwest Federal Regions (excluding Alaska and Hawaii) also are combined. The regions, and the states they comprise, are: New England, New York, and New Jersey (Maine, New Hampshire, Vermont, Massachusetts,Connecticut, Rhode Island, New York, New Jersey); Mid-Atlantic (Pennsylvania, Maryland, West Virginia, Virginia, District of Columbia, Delaware); South Atlantic (Kentucky, Tennessee, North Carolina, South Carolina, Mississippi, Alabama, Georgia, Florida); Midwest (Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio); Southwest (Texas, New Mexico, Oklahoma, Arkansas, Louisiana); Central (Kansas, Missouri, Iowa, Nebraska); North Central, West, and Northwest (Montana, North Dakota, South Dakota, Wyoming, Utah, Colorado, California, Nevada, Arizona, Washington, Oregon, Idaho).

and Northern Appalachia regions. Unlike most acid rain control policies, under which the projected growth in regional coal production is reduced but not reversed, a 10 million ton emission cap implemented in concert with conservation efforts would actually lower coal production by the year 2000 in these two regions from 1990 levels. Estimated overall production in both regions for 1990 is 277.7 million tons (from Table 9), while the 10 million ton cap policy with conservation yields an estimated 266.8 million tons for 2000 (see Table 12). If conservation efforts effectively eliminate NSPS plants as a source of growth in demand for high-sulfur coal, an acid rain policy would have to place greater emphasis on SO_2 control technology to maintain production levels of that type of coal.

Long-Term Emission Caps and Conservation

The near-term differences between the rollback and the cap policies--in terms of the savings in SO_2 control costs attributed to the conservation program--is primarily a function of the level of control. Under the cap policy, additional controls are applied to existing plants to offset the expected increase in emissions from plants that begin operation between 1980 and 2000. Beyond the year 2000, the difference in control costs between a rollback and a cap would widen as the demand for electrical services grows. DSM conservation could become a valuable strategy for controlling emissions if a permanent emission cap were adopted.

Analyses of long-run emission caps under growing demand for electricity generally find that utilities' costs rise, as increasingly costly control measures are applied to existing plants. DSM programs, however, could defer both the costs of additional emission controls and the construction of new plants and thus become a preferred abatement option. Nevertheless, increased demand for electricity would still mean additional costs for utilities--costs that would have to be met by additional investment in conservation or by new capacity and additional emission controls at existing sources to offset emissions. Over the long run, emission caps enhance the value of conservation primarily by raising the overall costs of adding new capacity, which would include securing emission offsets from existing plants. Thus, conservation helps reduce the high costs expected from emission caps, but overall costs associated with maintaining the emission cap will rise in any event.

These long-run incentives would operate without regard to the specific compliance deadlines for the initial emission reductions. Near-term investments in conservation would still provide higher returns under the emission cap if new capacity and, eventually, additional emission controls are avoided. Therefore, an emission cap would encourage utility conservation programs regardless of the schedule of emission reductions.

Of course, policies that would encourage or dictate much larger decreases in demand for electricity--such as the goals expressed in proposals designed to address aggregate CO_2 emissions--could have much larger effects on future SO_2 control costs and emission levels. This study assesses the role for utility-led conservation, where reductions in the growth of demand for electricity represent a viable target for conservation efforts. If regulations or price incentives substantially reduced the demand for electricity from current levels, rather than just slowing the rate of growth, the reductions in emissions and eventual control costs could be substantial. The costs

TABLE 12. EFFECTS OF ACID RAIN CONTROL POLICIES ON PROJECTED STEAM COAL PRODUCTION FROM NORTHERN APPALACHIA AND THE MIDWEST IN 2000, UNDER THE BASE CASE AND THE CONSERVATION CASE (In millions of tons)

Region	Coal Type: Low Sulfur	Coal Type: Medium Sulfur	Coal Type: High Sulfur
PRODUCTION UNDER A 10 MILLION TON ROLLBACK			
Base Case			
Northern Appalachia	38.0	67.2	92.8
Midwest	13.8	58.8	65.3
Total	51.8	126.0	158.1
Conservation Case			
Northern Appalachia	36.1	64.5	64.5
Midwest	12.7	58.4	55.1
Total	48.8	122.9	119.6
PRODUCTION UNDER A 10 MILLION TON CAP			
Base Case			
Northern Appalachia	37.7	65.4	63.0
Midwest	14.4	54.2	47.0
Total	52.1	119.6	110.0
Conservation Case			
Northern Appalachia	36.1	63.1	54.9
Midwest	12.5	58.4	41.8
Total	48.6	121.5	96.7

SOURCE: Congressional Budget Office, based on simulations of the National Coal Model Version 7.

NOTE: The Northern Appalachia region comprises Maryland, Ohio, Pennsylvania, and northern West Virginia; the Midwest region includes Illinois, Indiana, and western Kentucky.

of achieving absolute reductions in demand would likely be larger than the costs associated with the conservation programs that simply halt the growth in demand.

Other Analyses of Conservation and Emission Control Costs

Two recent studies have suggested that aggressive conservation programs would lead to larger reductions in both emissions and costs than those estimated by CBO.[5] Those studies rely on significantly higher estimates or assumptions of the efficacy of conservation programs in reducing demand. Comparing these studies with the results presented here shows that the reduction in control costs is highly dependent on the amount of demand reduction presumed.

At one end of the continuum is the Center for Clean Air Policy (CCAP) study, which examines the American Electric Power utility and the Tennessee Valley Authority (TVA). The CCAP analysis employs a modeling approach similar to the NCM7 and assumes that conservation could hold demand for electricity at 1985 levels through 2000. However, the growth in demand for electricity nationwide since 1985 has been substantial--well over 10 percent thus far--and shows little sign of diminishing. Utility-sponsored conservation approaches, therefore, are less likely to return demand to the 1985 level. The assumption of zero growth in demand for electricity over a 15-year period leads to predictions of substantially lower emission levels and lower control costs under new control policies. For the American Electric Power utility, conservation lowered emissions in 2000 by 17 percent, and control costs were reduced by 40 percent; for the Tennessee Valley Authority, conservation achieved sufficient reductions in emissions to eliminate additional control costs.

The dramatic reductions in SO_2 emissions attributed to conservation in the TVA system relied on the assumption that additional nuclear generation (two plants restored to service, one plant initially placed in service) would more than satisfy the growth in demand for electricity. When conservation eliminates this growth, the analysis assumes that this nuclear capacity is still brought into service, and coal-fired generation is commensurately reduced. This situation of having nuclear plants available is not representative of other utilities. In addition, under alternative and plausible assumptions, the TVA might be inclined to continue to generate from the existing coal-fired units and sell surplus electricity in the wholesale power market.

The American Council for an Energy Efficient Economy (ACEEE) study represents an intermediate case between the CCAP and CBO assumptions about demand: between 1985 and 2005, conservation programs reduce the growth in demand for electricity from an annual rate of 1.7 percent to 0.9 percent, or roughly by half. In the ACEEE case, conservation directly reduces SO_2 emissions by about 10 percent without additional controls. Under a targeted reduction in emissions of 55 percent (attained by the year 2000), the direct control costs are reduced by

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5. See American Council for an Energy Efficient Economy, *Acid Rain and Electricity Conservation* (June 1987), which focuses on the East Central Area Reliability (ECAR) power pool region that spans much of the Midwest and Northern Appalachia regions. Another study, *Acid Rain: Road to a Middleground Solution*, by the Center for Clean Air Policy (July 1987), examines the American Electric Power (AEP) and Tennessee Valley Authority (TVA) systems.

roughly 40 percent--from \$3.6 billion to \$2.2 billion in present value terms under the ACEEE assumptions about conservation.[6]

Taken together, these studies suggest that the relative contribution of conservation to the reductions in both emissions and control costs under acid rain policies depends on the assumptions about the reduction in demand. With modest reductions in demand, conservation efforts alone neither significantly reduce SO_2 emissions nor substantially lower control costs. If generation of electricity is more sharply reduced, attaining the targets for emission reductions might cost much less if expensive SO_2 emission controls could be avoided at the margin. Greater reductions in demand, however, require more costly investments in conservation. Utilities responding to acid rain control policies would have to strike a balance between the costs of a conservation program and the magnitude of the control costs they could potentially avoid.

Finally, acid rain control policies would neither prevent nor deter utilities from pursuing cost-effective DSM conservation programs. While certain approaches such as emission caps may increase the returns from successful conservation efforts, the potential gains from casting the regulations in order to maximize the contribution of conservation should be weighed against the resulting total costs of expressing SO_2 emission requirements in those ways. The results presented here suggest that the existing incentive for utility conservation programs--that is, the potential for avoiding the costs of constructing new plants and generating more electricity--is much stronger than any further incentive associated with avoiding some of the costs of controlling SO_2.

6. Unlike the CCAP and CBO approach, the ACEEE study constructs a conservation scenario based on technical and economic assumptions regarding the operation of a DSM program, and accounts for the cost of conservation activities in its estimates.

APPENDIX

UTILITIES' INVESTMENT CHOICES

FOR EXISTING PLANTS

This appendix is divided into two main sections. The first section describes the choices available to utilities for investments in continued operation of existing coal-fired plants. The second section develops a simple methodology to calculate the cost of investment alternatives; selected results of these calculations were reported in Chapter II. In addition to documenting the results, the underlying equations provide a way to repeat the calculations using other financial assumptions or new information about technology costs or expected performance.

TECHNOLOGIES FOR EXISTING PLANTS

As power plants age, their performance declines: heat rates (the ratio of heat input to electricity output) increase, forced outages (periods of unavoidable shutdown and maintenance) become more frequent, and maximum available power is curtailed (capacity is derated). Thus, an aging plant requires more fuel and services less of the annual demand for electricity. By the third decade of commercial service, these problems become serious enough for utilities to consider alternative investments to meet their capacity needs. A number of options are available to utilities that wish to avoid building a new plant to generate the power previously supplied by the existing plant. These options range from relatively modest improvement programs to extensive repowering options that may be commercially available within the decade.

Life Extension and Retrofitting Controls

Utilities have recently initiated investment programs to allow specific plants to continue operating at about their original performance levels. These programs, known as life-extension programs, improve both productivity (by lowering the heat rate, reducing forced outages, and increasing the rated capacity) and longevity (by allowing the plant to operate at specified levels beyond its expected lifetime). Depending on a plant's condition and the goals of the improvement project, these programs typically cost between $100 and $400 per kilowatt.

If new sulfur dioxide (SO_2) controls are desired in addition to these improvements, conventional and emerging control equipment could be retrofitted as part of a life-extension program. Utilities can perform the life-extension and retrofitting activities separately, and have done so in cases where scrubbers were retrofitted to meet initial compliance with State Implementation Plan (SIP) standards. As average boiler age increases, however, the option to retrofit without making simultaneous (or at least subsequent) life-extension investments becomes the exception rather than the rule. If retrofit equipment is deemed necessary in the future, utilities would almost certainly extend the life of the plant in order to match the life of the boiler with that of the new control equipment. Finally, retrofitting during a life-extension project could be less expensive than performing separate investment programs at different times.

Both emerging and conventional retrofit technologies are based on similar principles. Sulfur-bearing gases that result from coal combustion are combined with a reagent--a calcium- or sodium-based sorbent. The products of this chemical reaction can be removed as sulfur-containing solids, preventing the release of gaseous SO_2 into the atmosphere. The one important difference between retrofit techniques is the location of the reaction and where the precipitate is eventually removed.

Conventional scrubbers shunt the flue gas to a separate reaction vessel to be combined with the reagent, reheat the cleaned gas in some cases, and return the gas to the flue and out the smokestack. Wet scrubbers remove the precipitate as a moist solid, while dry scrubbers rely on the particulate control equipment to remove the by-products. The estimated capital costs of retrofitting wet scrubbers range from $150 to over $300 per installed kilowatt. This range encompasses differences in site-specific factors such as the boiler's age, size, and configuration, as well as the scrubber system's performance and reliability. Annual operating costs for wet scrubbers designed to remove 90 percent of SO_2 from high-sulfur coal range from about 5 mills to over 10 mills per kilowatt-hour. Capital and operating costs for dry scrubbers are somewhat lower, but dry scrubbers tend to remove a lower percentage of SO_2.

Many emerging technologies, however, treat combustion gases before they reach the flue--that is, with the newer technology, the sorbent is injected into the boiler itself. These technologies take several forms: limestone injection multistage burner (LIMB) uses equipment that controls fly ash to remove the resulting particles from the flue gas; the slagging combustor also places the sorbent into contact with the coal during the combustion phase, but the by-products (in the form of molten ash, or "slag") drop to the bottom of the boiler for removal; and in-duct sorbent injection introduces the sorbent compound at a later combustion phase, at or near the exhaust ductwork.

The newer retrofit technologies may have several advantages compared with conventional scrubbers. First, some existing plants are difficult to retrofit with scrubbers because of space limitations and the design of the boiler, and newer technologies may require less space. Second, several emerging technologies can significantly retard formation of nitrogen oxides (NO_x), whereas conventional scrubbers remove only SO_2. Third, they cost less to buy and to operate. The capital costs of utility-scale LIMB, slagging combustors, and in-duct sorbent injection are projected to be in the range of $50 to $150 per kilowatt, with operating costs between 2 mills and 10 mills per kilowatt-hour. Although conventional scrubbers will probably remain cost-effective for the largest plants, the newer technologies may find markets in small- to medium-size utility boilers.

Unfortunately, the emerging options may not remove as high a percentage of SO_2 as wet scrubbers (90 percent), diminishing their economic advantages in many cases. LIMB and in-duct sorbent injection could remove as much as 50 percent to 70 percent of SO_2, and slagging combustors could remove up to 90 percent. The costs to remove SO_2 using these technologies ranges from $200 to $800 per ton. Although this cost compares favorably with conventional scrubbers in some cases, any advantages will depend on the degree of emission control specified in new legislation.

Repowering Options

The most promising repowering technologies for the next decade are atmospheric or pressurized fluidized-bed combustion boilers (AFBC and PFBC, respectively), and integrated gasification combined-cycle (IGCC) plants. A fluidized-bed combustor suspends in the air the coal and reagent mixture in a combustion boiler. The sulfur is bonded to the reagent and falls to the bottom of the boiler for removal. The AFBC is available for small industrial and utility boilers, and larger-scale AFBC repowering projects have been completed by Northern States Power and Colorado-Ute Electric Association. Potentially more efficient than AFBC, PFBC could be commercially available within a decade, and a PFBC repowering demonstration project is under way at a mothballed American Electric Power generating unit in Ohio.

An IGCC plant converts coal into a medium-Btu gas using a pure oxygen process, removes the sulfur and other impurities from the gas (yielding marketable sulfur and nontoxic slag), then burns the gas in a combined-cycle generator for maximum efficiency. The current IGCC removes 95 percent to 99 percent of impurities from fuel gas--more than current scrubbers. Although an IGCC plant is at least as expensive as a new conventional plant to build and run, construction and operation can proceed in modular fashion when natural gas is available at the site before the coal gasifier is built. The only IGCC plant currently operating is the 100-megawatt "Cool Water" plant, built as a new commercial demonstration project near Daggett, California.

The available information indicates that the capital costs of a repowering project lie between the cost of a life-extension program that includes retrofitting scrubbers, and the cost of building a new plant at the scale of the expanded and repowered plant. The Department of Energy (DOE) estimates that the capital cost for AFBC would be $759 per kilowatt (based on expanded capacity), while repowering with PFBC would cost $818 per kilowatt. Capital costs of IGCC--at $1,156 per kilowatt--is nearly as expensive as building a conventional coal-fired plant equipped with a scrubbers, which DOE assumes would cost $1,285 per kilowatt (all figures in 1985 dollars).[1]

These cost estimates of repowering technologies should be viewed as quite speculative, because of limited experience with the technologies themselves plus the uncertainty about what other components of the existing plant would be replaced. Comparing the cost of repowering with other options is also complicated by additional factors that are not easily condensed into summary cost figures. For example, average capital costs are often expressed in units of expanded capacity, complicating any comparisons with options that do not expand the capacity of an existing plant. The next section develops a method to adjust for this factor.

1. See Department of Energy, Office of Fossil Energy, *The Role of Repowering in America's Power Generation Future* (December 1987), referred to as the DOE repowering study.

The relationships between technology, regulatory requirements, and utility costs are quite complex--both at the individual utility level and when viewed in the aggregate. Technology can be used to reduce emissions at older plants in three ways: life-extend the plant and retrofit with abatement technology, repower the plant, or replace the plant with new capacity. Utilities make these choices based on the total costs.

Generation Costs: An Analytical Approach

The costs of alternative technologies are subject to considerable debate. Part of the debate reflects inherent uncertainty over the eventual cost and performance of emerging technologies. But much of the confusion can be traced to the various ways in which cost data are presented. The costs of alternative technologies may be expressed as capital and variable costs (without reference to performance characteristics or the amount of power produced); may be presented as the cost of generating electricity, which depends on a multitude of financial, accounting, and engineering assumptions; or may be expressed as dollars per unit of emissions removed.

Life-Extension, Retrofitting, and Replacement Costs. The cost of generating electricity has two basic components: variable costs and capital costs (see Appendix Table 1). The variable costs (those that vary with respect to the amount of power generated) are fuel costs and operation and maintenance (O&M) costs. The per-kilowatt cost of fuel depends on the efficiency with which the equipment produces electricity from fossil fuel (expressed by the heat rate) and the price of the fuel. Operation and maintenance costs reflect the materials and labor--such as chemical reagents for pollution control, disposing of ash and spent reagents, and routine repair--used to keep the plant functioning.

Capital costs can be levelized--that is, transformed into annual cost streams--using a capital charge rate to represent the fraction of the investment that is considered a cost in a given year. A simple capital charge rate might reflect just an asset's lifetime and interest rate; but, in utilities' decisionmaking, the concept is normally extended to reflect depreciation schedules and federal, state, and local property taxes. Multiplying the capital charge rate by the installed capital cost gives the annual capital cost. Dividing annual capital costs by the amount of electricity generated by the plant yields the capital cost portion of generation on a per-kilowatt-hour basis. This cost is added to variable costs (expressed in mills per kilowatt-hour) to give the levelized "busbar" cost of generating electricity.[2]

2. "Busbar" cost is the cost of electricity that leaves the plant; it does not include transmission and distribution (T&D) losses typically experienced at roughly 10 percent. Busbar costs adjusted for T&D losses are not equivalent to electricity rates, however. In constructing revenue requirements, public utility commissions' ratemaking rules incorporate the generation cost and the rate of return on investment. These revenue requirements are then apportioned to various classes of customers through electricity rates.

APPENDIX TABLE 1. CALCULATING THE COSTS OF GENERATING ELECTRICITY

Generation Cost = Variable Cost (VC) + Levelized Capital Cost (LCC)

Variable cost calculated as

$VC = O\&M + FC$
$FC = (HR \times FP)/1{,}000$

Where

O&M = Operation and maintenance (mills per kilowatt-hour)
FC = Fuel cost (mills per kilowatt-hour)
HR = Heat rate (Btu per kilowatt-hour)
FP = Fuel price (dollars per million Btu)

Levelized capital cost is calculated as

$LCC = (ANC/Gen) \times 1{,}000$
$ANC = Cap \times CCR$
$Gen = 8{,}760 \times Capfac$
$Gen_{repo} = 8{,}760 \times Capfac \times (1 + Inc)$

Where

ANC = Annual capital cost (dollars per kilowatt)
Cap = Installed capital cost (dollars per kilowatt)
CCR = Capital charge rate ($0 < CCR < 1$)
Gen = Annual Generation (kilowatt-hours)
8,760 = 365 x 24 (hours per year)
Capfac = Capacity factor ($0 < Capfac < 1$)
Gen_{repo} = Annual generation from repowered plant (kilowatt-hours)
Inc = Percent increase in capacity from repowering/100

SOURCE: Congressional Budget Office.

NOTE: Btu = British thermal unit.

These estimates of the costs of generating electricity reflect a host of financial and engineering assumptions. For example, cost comparisons of technological costs can be especially sensitive to capital charge rates and to assumed rates of use during the year. Capital charge rates will vary depending on the underlying financial assumptions and the expected economic life of alternative technologies.[3] The capacity factor is the percentage of the hours in a year that a given unit can or will operate. As capacity factors increase, capital costs are spread over more units of annual output, decreasing the capital cost share of each kilowatt-hour of electricity.

Repowering Costs. The cost of generating electricity outlined in Appendix Table 1 can be extended to place repowering on a comparable basis with conventional life extension or retrofit technologies. Since repowering is a substitute for both life extension and building new capacity, the estimated generation costs should be adjusted to reflect increases in capacity. This distinction is captured in the concepts of "unit" cost and average "system" cost of alternatives. The unit costs reflect the total cost of generating one kilowatt of electricity from a particular plant. System costs implicitly credit a repowered plant with its increased electricity as compared with a life-extended or retrofitted plant. (And system costs can also be calculated to include a "penalty" in cases where retrofit technologies such as scrubbers decrease the plant's available power.) The unit cost of the repowered plant should be compared with the system cost of alternative investment options to account fully for the differences in capacity between repowering and the other technologies. This comparison reflects the costs of life-extending plus adding existing plant and new generating capacity equivalent to the additional capacity gained by repowering. Costs are therefore compared while holding constant the amount of electricity generated.[4] These calculations are displayed in Appendix Table 2.

The unit and system costs reported in Chapter II are constructed primarily from data contained in the DOE repowering study. Repowering is assumed to increase the capacity of an existing plant by 15 percent for AFBC, by 30 percent for PFBC, and by 170 percent for IGCC, while a retrofit scrubber decreases the capacity of an existing plant by 2 percent. Assumptions regarding the performance and costs of individual technologies--heat rates, O&M costs, and capital costs--are taken from

3. For example, the DOE repowering study assumed a capital charge rate of 13.4 percent for investments in existing plants; the Environmental Protection Agency (EPA), in its models of utilities' decisionmaking, currently uses 9.0 percent for retrofit scrubbers. Therefore, DOE's annual capital cost for a retrofit scrubber would be 50 percent higher than the EPA's annual costs for identically priced equipment. The National Coal Model results reported elsewhere in this study assume a capital charge rate of 10 percent.

4. These system costs are a capacity-weighted average of the life-extended (or life-extended with retrofit) costs and the added capacity, evaluated at the costs of a new plant. Using capacity, rather than annual operation, as a weight implicitly assumes that capacity factors are identical among different technologies. If capacity factors vary, then annual operation would provide appropriate weights.

APPENDIX TABLE 2. EQUATIONS FOR CALCULATING THE SYSTEM COSTS OF LIFE-EXTENSION OPTIONS FOR COMPARISONS WITH REPOWERING OPTIONS

$SC_{le} = (GC_{le} + (Inc \times GC_{new}))/(1 + Inc)$

$SC_{le+ret} = (GC_{le+ret} + ((Inc+Pen) \times GC_{new}))/(1 + Inc)$

Where

SC_{le} = System cost for life extension (mills per kilowatt-hour)

GC_{le} = Unit cost of generation from life-extended plant (mills per kilowatt-hour)

Inc = Percent increase in capacity from repowering/100

GC_{new} = Unit cost of generation from new plant (mills per kilowatt-hour)

SC_{le+ret} = System cost for life extension with retrofitted scrubbers (mills per kilowatt-hour)

GC_{le+ret} = Unit cost of generation from life-extended plant with retrofitted scrubbers (mills per kilowatt-hour)

Pen = Capacity penalty for retrofit ($0 < Pen < 1$)

SOURCE: Congressional Budget Office.

Figure 3-2 of the repowering study.[5] Assumptions that apply to all options--capital charge rates (13.4 percent for investments in existing plants and 12.2 percent for investments in new coal-fired capacity), capacity factor (65 percent), and coal price ($1.87 per million Btu)--are taken from Figure 4-1.

Other factors could be considered by utilities in deciding whether to repower, but these factors are not fully captured in summary cost figures. One such factor is the projected need for additional generating capacity. The implicit assumption that repowering displaces the need to construct expensive new coal-fired capacity is the key difference between the unit and system costs. Alternatively, if investments in demand-side management (DSM) conservation programs could satisfy the additional demand for electricity, then the costs of these programs should be reflected in the unit and system cost estimates. If, for example, the necessary efficiency investments could be purchased at the unit costs of repowering, then the repowering option could be compared with the others using the unit cost estimates. In this special case, the cost of generating electricity from new capacity becomes irrelevant, and the costs of alternative technologies can be compared independently of scale. Other factors that utilities might consider include additional regulatory interactions with the public utility commissions, and operating characteristics such as flexibility in the choice of fuel, the properties of disposable wastes, and flexibility in trading off electricity generation levels with production efficiency.

Cost of Removing Emissions. Another commonly cited measure of cost--costs per unit of SO_2 removed, usually expressed in dollars per ton--helps assess the relative efficiency of alternative approaches to controlling acid rain. It can facilitate comparisons among coal-switching options and emission control technologies that have different costs and performance characteristics, including conventional scrubbing equipment and emerging retrofit technologies.

The usefulness of this measure to guide utilities' decisions among competing investment options, however, is limited. Utilities will not necessarily choose technologies based on average or marginal (per-ton) cost of emissions removed, but rather on the total costs of reducing emissions. For example, technologies that remove a high percentage of pollutants at a low average cost may not be chosen if they control emissions to a level far beyond that required. A more expensive method (on a per-ton basis) that reduces the required amount at lower total cost (because fewer tons are removed) could be less costly to the utility.

This example can be extended by noting the current lack of price differences between coals with different sulfur content. For utilities with access to inexpensive low- to medium-sulfur coal, a least-cost control strategy could involve combining the use of medium-sulfur coal with an ostensibly higher-cost technology (on a dollar-per-ton-removed basis) rather than choosing a lower-cost (per ton) technology and burning a higher-sulfur coal.

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5. Figure 3-2 of the repowering study includes alternative assumptions about heat rates and O&M costs for life extension (with and without a retrofit scrubber) for comparison with AFBC. The unit and system costs reported in Tables 1 and 2 of this report are calculated under the assumptions listed for the PFBC and IGCC comparisons, with alternative AFBC comparisons given in the footnotes to these tables.

Furthermore, estimates of dollars per ton of SO_2 removed can vary substantially for given technologies. For example, costs for conventional scrubbers have been reported in the range of $300 to $1,500 per ton of SO_2 removed, depending on the equipment employed, the size of the boiler, and, in particular, the sulfur content of the coal burned--with the dirtiest coals generating the lowest cost per ton. If the sulfur content of coal is held constant for the comparisons among alternative technologies, then the usefulness of the cost-per-ton-removed measure may be improved.

These examples indicate the drawbacks of using a cost-per-ton-removed measure to make inferences about the ultimate demand by utilities for specific technologies. As a matter of policy evaluation, however, the cost of emissions removed is an appropriate measure for comparing the overall efficiency of regulatory approaches. When alternative programs achieve different levels of emissions, information about the average or marginal cost of emissions reduced represents an important measure of cost-effectiveness.