Economic, Environmental, and Coal Market Impacts of SO_2 Emissions Trading Under Alternative Acid Rain Control Proposals

Prepared for:

Regulatory Innovations Staff
Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency

EPA Project Officer: Barry Elman

In Cooperation With:

Office of Program Analysis
U.S. Department of the Interior

DOI Project Officer: Indur Goklany

Prepared by:

ICF Resources Incorporated

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PREFACE

This report presents the findings of an analysis performed by ICF Incorporated for the Environmental Protection Agency (EPA) and the Department of Interior (DOI). The assumptions, findings, conclusions, and judgments expressed in this report, unless otherwise noted, are those of ICF Incorporated and should not be interpreted as necessarily representing the official policies of EPA, DOI, or other agencies of the U.S. government.

TABLE OF CONTENTS

FOREWORD

This analysis examines the impacts of various levels of emissions trading in the context of two representative proposals for reducing SO_2 emissions from electric utilities as part of an acid rain control program, and also in the absence of any such emission reduction program. The primary focus of the analysis is on utility emission levels, utility compliance costs and regional coal markets.

The analysis provides what should be viewed as upper bound estimates of the potential compliance cost savings and coal market effects that would result from each level of emissions trading examined. These estimates assume that utilities would achieve required emission reductions in a least-cost fashion, by pursuing the most economically efficient combination of emissions trades possible, subject to the constraints noted in the report. However, a range of practical considerations would likely serve to limit either the ability or the desire of utilities to engage in all of the emissions trades which are projected to occur in this analysis.

We call your attention to this and other caveats throughout the report, and especially in Chapter Three. In addition to discussing the caveats and uncertainties implicit in the analysis, Chapter Three also highlights a number of programmatic issues which would need to be addressed before any acid rain related emissions trading program could be implemented.

While this report presents and analyzes a range of emissions trading alternatives, it does not attempt to address all possible options. Nor does this report draw any conclusions regarding which, if any, emissions trading approach would be most suitable for an acid rain control program. Any decision regarding the appropriate level of emissions trading must take into account the manner in which such a program would be implemented and enforced, the magnitude of expected cost savings, the ramifications on regional coal mining activity, and a complex array of other technical, environmental and socioeconomic issues. This report is intended to provide useful information regarding several of these issues. It does not, however, set out to address all the issues relevant to the selection of a particular approach.

Executive Summary

EXECUTIVE SUMMARY

This report examines the ramifications of different levels of emissions trading (which allows aggregate emission reduction requirements to be achieved from multiple sources in the most economic manner, rather than by mandating uniform emission reductions from each source) in the context of two representative electric utility sulfur dioxide emission reduction proposals designed to control acid rain, and in the absence of any new control program. The two emission reduction proposals examined are S-316 (the Proxmire bill) and the 30 Year/1.2 Lb. proposal. Some of the key findings with respect to SO_2 emission reductions, utility compliance costs, and coal markets are presented in this summary. These findings are followed by a discussion of caveats and uncertainties that pertain to the reported results.

SO_2 EMISSION REDUCTIONS

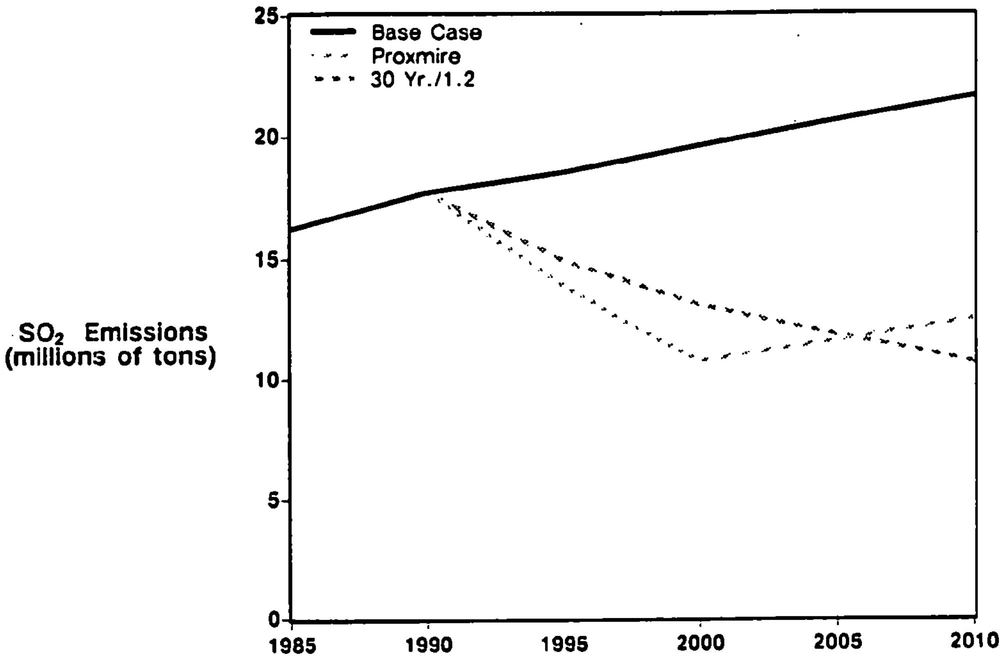
- Utility SO_2 emissions are forecast to increase steadily, from 16.3 million tons in 1985 to 21.7 million tons in 2010, under "Base Case" conditions (i.e., assuming no change in current emission control requirements).[1/]

- The Proxmire bill is forecast to reduce utility SO_2 emissions from Base Case levels by:

  -- almost 5 million tons by 1995
  -- about 9 million tons by 2000 and thereafter.

- The 30 Year/1.2 Lb. proposal is forecast to reduce utility SO_2 emissions from Base Case levels by:

  -- almost 4 million tons by 1995
  -- over 6 million tons by 2000
  -- about 11 million tons by 2010.

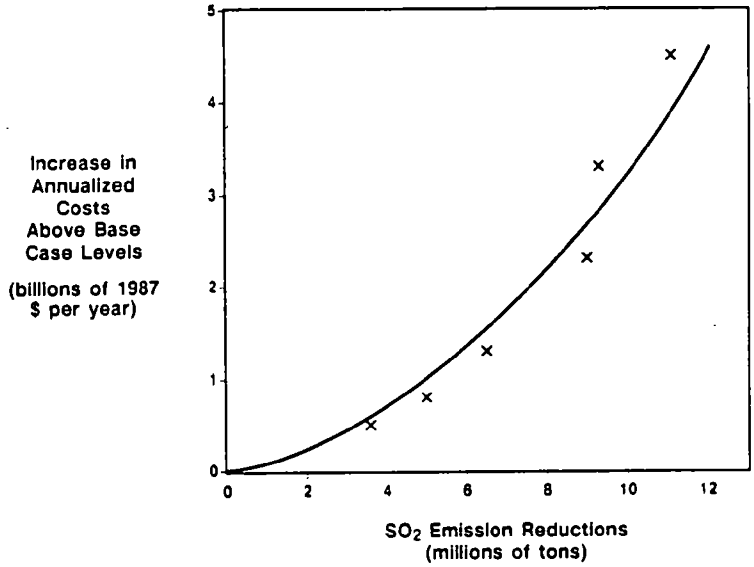


- Allowing emissions trading under these proposals would have no significant effect upon the overall amount or timing of emission reductions.

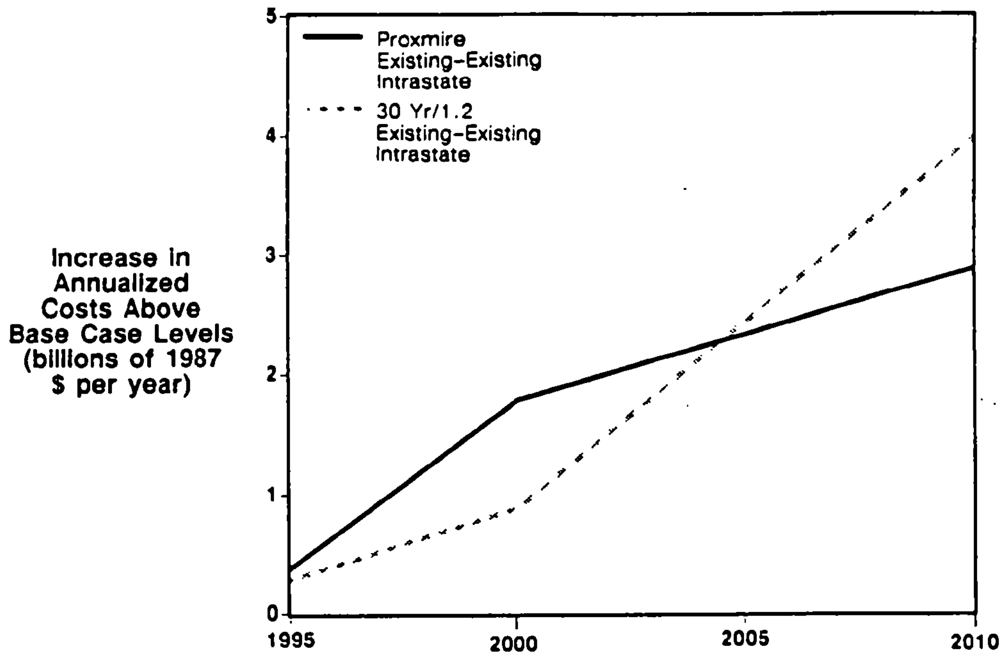
1/ Please note that these EPA Base Case forecasts were developed in early 1987; recent developments (e.g., state acid rain laws, SIP revisions, etc.) will be incorporated into a newer base case currently being developed by ICF for EPA. This would likely result in SO_2 emissions about 1.0 - 1.5 million tons lower than indicated by the EPA Base Case used for this study.

UTILITY COMPLIANCE COSTS

- As emission reduction requirements increase, annual compliance costs increase disproportionately. Assuming only intrautility emissions trading (among currently existing sources) for the proposals analyzed herein, costs increase rapidly as reduction requirements increase:



- Utility compliance costs under Proxmire and 30 Year/ 1.2 Lb. increase steadily over time, reflecting increasing emission reduction requirements over Base Case levels.



ECONOMIC BENEFITS OF EMISSIONS TRADING

- The Proxmire and 30 Year/1.2 Lb. proposals were analyzed under various emissions trading schemes to determine the economic effects of:

  -- increasing the geographic scope of trading (intrautility, intrastate, and interstate)

  -- allowing trading between new and existing sources.

- In addition, the Base Case was examined with existing-new trading and a 1.2 to 1 trading ratio (i.e., each ton of excess emissions must be offset by at least 1.2 tons of extra reductions elsewhere).

- The utility compliance costs associated with the alternative levels of assumed emissions trading under the analyzed proposals are presented below:

Increase in Utility Costs
Relative to Base Case Levels

	Annualized (billions of 1987 $/yr)			2010 Cumulative Capital (billions of 1987 $)	2010 Present Value (billions of 1987 $)
	1995	2000	2010		
Proxmire					
No Trades*	2-3	5-6	6-7	20-25	40-50
Ex-Ex Intrautility	0.8	2.3	3.3	9.7	19.6
Ex-Ex Intrastate	0.4	1.8	2.9	7.8	16.0
Ex-New Intrastate	0.4	1.7	0.9	-8.9	10.6
Ex-New Interstate	0.4	1.5	0.6	-11.1	9.0
30 Year/1.2 Lb.					
Ex-Ex Intrautility	0.5	1.3	4.5	10.1	17.9
Ex-Ex Intrastate	0.4	0.9	4.1	8.6	14.6
Ex-New Intrastate	0.4	0.5	3.6	2.0	11.7
Base Case					
No Trades	--	--	--	--	--
Ex-New Interstate	--	-0.7	-5.3	-25.8	-15.8

Ex-Ex: Trades between existing sources only
Ex-New: Trades between existing and new sources

* This case was not explicitly analyzed as part of this study; the rough estimates presented are based on previous analyses conducted for EPA.

- As shown in the table on page ES-4, the greatest single increment of cost savings associated with emissions trading is obtained when expanding the scope of trading from a "no trading" scenario (i.e., unit-by-unit compliance with uniform reduction requirements) to trading at the existing-existing intrautility level. Allowing even this relatively restricted form of trading reduces the annual compliance costs of an acid rain program by 30 to 60 percent.[2/]

- Increasing the geographic scope of emissions trading beyond the intrautility level would further reduce the utility cost impacts of both analyzed emission reduction proposals while achieving equivalent overall national emission reductions. By 2010, expanding the geographic scope of trading:

  -- from intrautility to intrastate further reduces present value costs by \$3.3-\$3.6 billion (or 20 percent), cumulative capital costs by \$1.5-\$1.9 billion (or 15-20 percent), and annualized costs by \$0.4 billion (or 10 percent).

  -- from intrastate to interstate further reduces present value costs by \$1.6 billion (or 15 percent), cumulative capital costs by \$2.2 billion (or 20 percent), and annualized costs by \$0.3 billion (or 30 percent).

- Permitting emission trades between existing and new sources (i.e., allowing new sources to be built without scrubbers as long as any resulting emission increases are offset by extra reductions at existing sources) would also reduce cost impacts associated with emission reduction proposals. As shown in the table on the opposite page, expanding the scope of intrastate trading to include new sources is projected to reduce present value costs to 2010 by \$2.9-\$5.4 billion (or 20-40 percent), cumulative capital costs to 2010 by \$6.6-\$16.7 billion (or 80-200 percent), and annualized costs in 2010 by \$0.5-\$2.0 billion (or 15-70 percent).

2/ No detailed modeling analysis was conducted in developing this estimate. Rather, this estimate is approximate and was derived from previous ICF analyses for EPA of acid rain proposals with no trading provisions. See, for instance, *An Economic Analysis of HR-4567: The Acid Deposition Control Act of 1986*, August 1986 (Default Case).

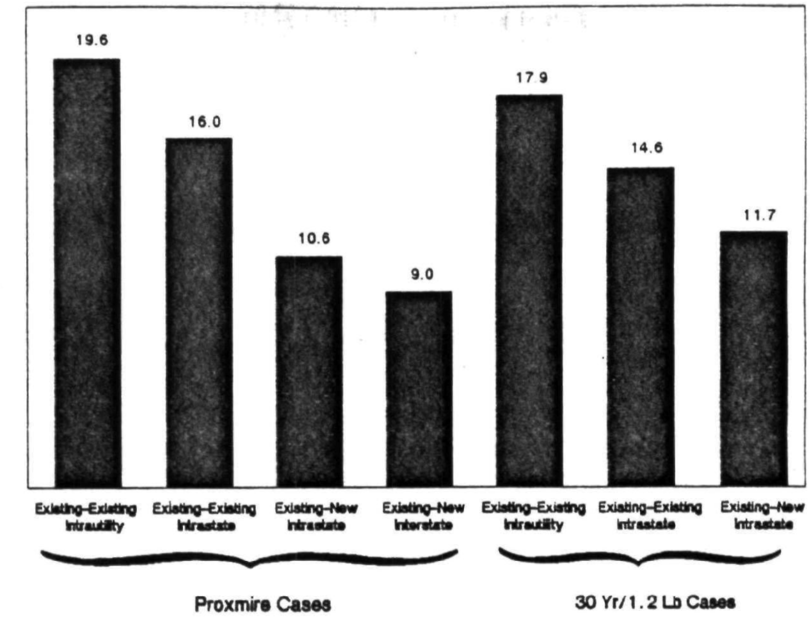
- The level of cost savings resulting from existing-new trades under the two analyzed emission reduction proposals depends significantly upon the amount of reductions that would be required. By 2010, the present value cost savings attributable to existing-new trading range from $5.4 billion (assuming about 9 million tons of reductions) to $2.9 billion (assuming about 11 million tons of reductions). Cumulative capital cost savings attributable to existing-new trading by 2010 range from $16.7 billion to $6.6 billion assuming about 9 million and 11 million tons of reductions respectively. Corresponding annualized cost savings range from $2.0 billion to $0.5 billion.

- Most of the savings associated with existing-new trades accrue in the later years of the analysis. By 1995, there would be few additional new coal plants on-line to take advantage of such trading opportunities, and annualized cost savings are less than $0.1 billion. By 2010, a large amount of new coal plants are forecast to be built, and annualized cost savings range from $0.5 - $2.0 billion (up to 70 percent savings).

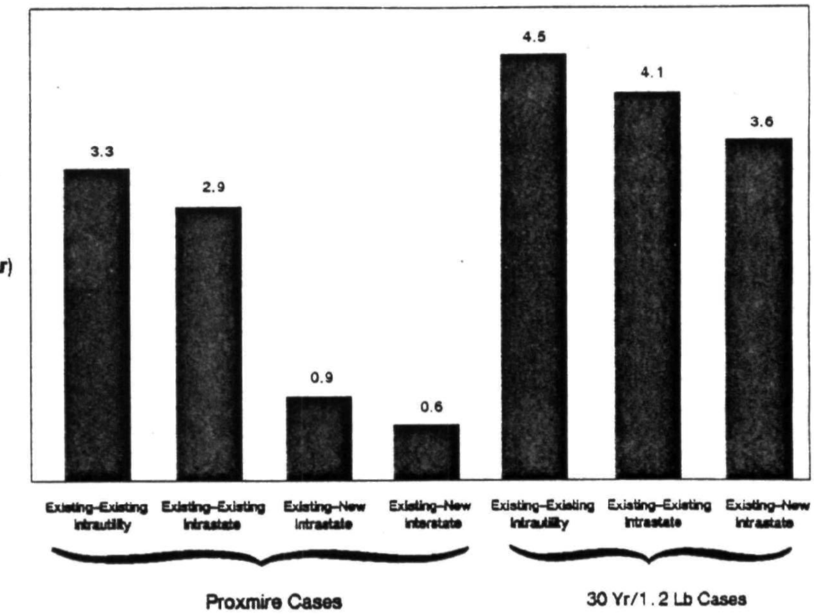
- Permitting existing-new trades under the Base Case (with a 1.2:1 trading ratio) would result in a small emission reduction by 2010 (about 1.4 million tons) with very substantial cost savings: $15.8 billion present value cost savings, $25.8 billion cumulative capital cost savings, and $5.3 billion annualized cost savings.

- As illustrated on the opposite page, the greatest economic savings could be provided by an emissions trading program which incorporates both increased geographic flexibility and existing-new trades. However, expanding the scope of trading opportunities would also increase the complexity and administrative burden of an acid rain control program, and would raise a number of additional issues which would need to be addressed before such a program could be successfully implemented.

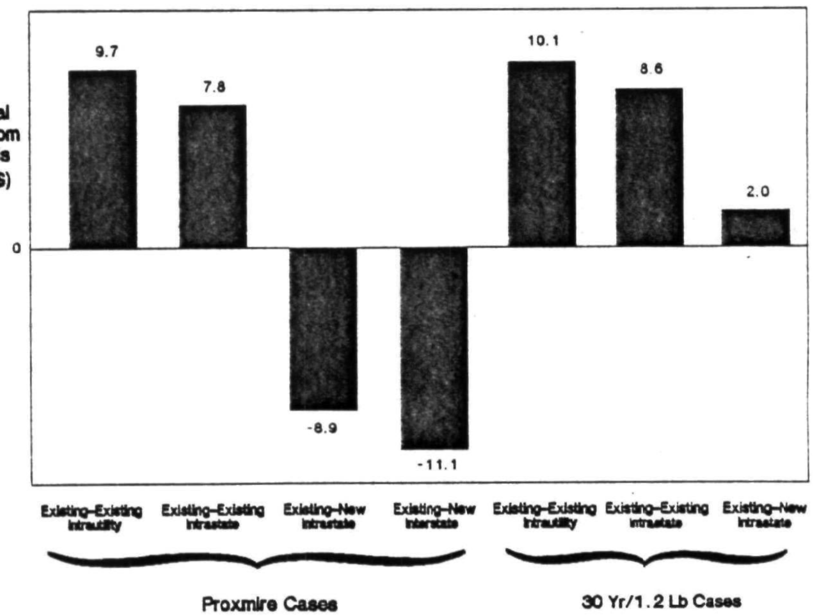
Increase in the Present Value of Costs Over the 1987-2010 Period Above Base Case Levels (billions of 1987 $)



Increase in Annualized Costs in 2010 Above Base Case Levels (billions of 1987 $/year)

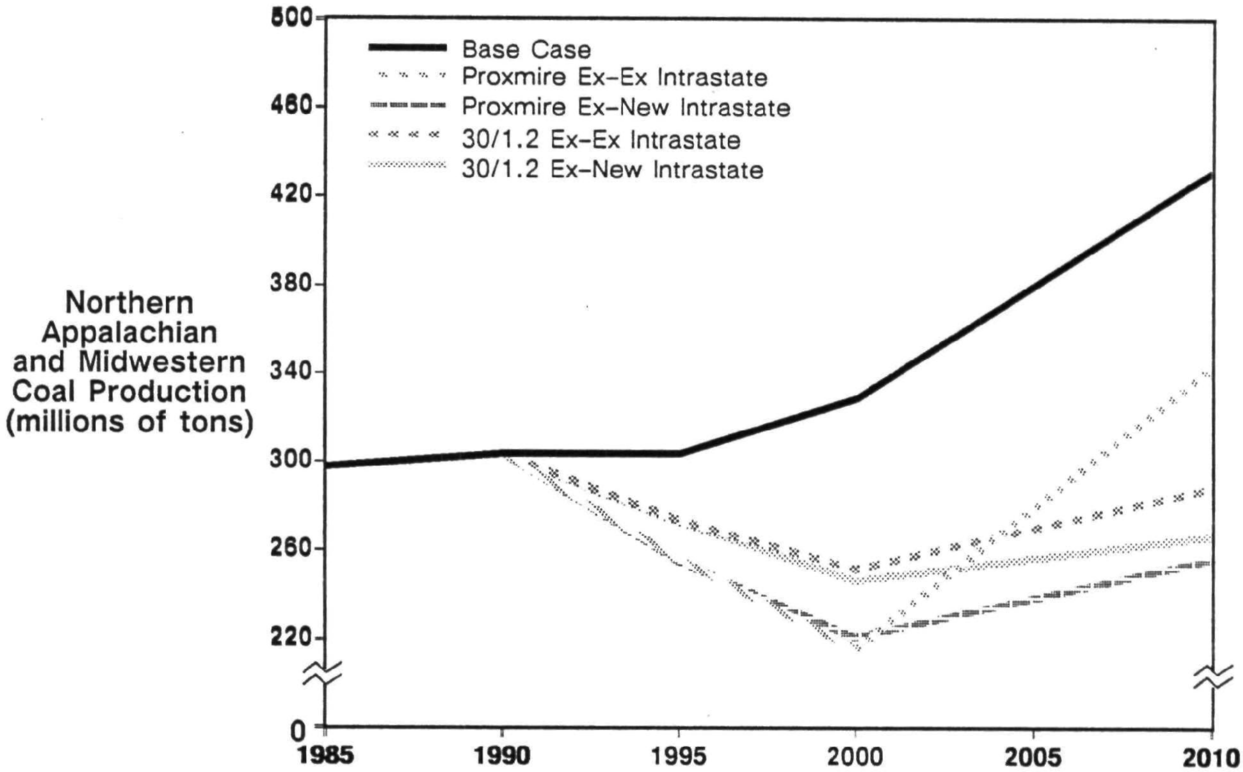


Change in Cumulative Capital Costs by 2010 From Base Case Levels (billions of 1987 $)



COAL MARKETS

Shifts in coal production away from high sulfur producing regions (i.e., Northern Appalachia and the Midwest) are forecast to increase as a result of the implementation of existing-existing trading under both the Proxmire and the 30 Year/1.2 Lb. proposals. Allowing existing-new trading increases the magnitude of such production shifts.



Regional coal mining employment trends largely follow regional coal production forecasts. Under either the Proxmire bill or the 30 Year/1.2 lb. proposal with existing-existing trading, the level of future coal mining employment declines significantly in high sulfur coal regions and increases in low sulfur coal regions. This effect is more pronounced under the existing-new trading cases. See table on page ES-9.

A relatively small amount of net national coal mining job slot losses (on the order of 2 percent of Base Case forecasted levels in 2010) are forecasted to result from the implementation of either the Proxmire bill or the 30 Year/1.2 Lb. proposal with existing-existing trading, as coal demands shift to lower sulfur Western coal mines that generally have higher productivities. Since these demand shifts are greater in the existing-new trading cases (because fewer plants are scrubbed), net coal mining job slot losses also are higher (on the order of 5 percent of Base Case forecasted levels in 2010).

Changes in Regional and National Coal Mine Employment (thousands of workers)

				Change in Job Slots Relative to Base			Change in Job Slots Relative to Base	
	Actual 1980	Actual 1985	Base 2000	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Base 2010	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New
Northern Appalachia	70	45	35	-8	-9	54	-7	-20
Central Appalachia	91	70	69	+12	+12	95	+8	+13
Southern Appalachia	12	9	6	--	--	9	-1	-2
Midwest	35	27	20	-8	-8	29	-12	-16
Rest of U.S.	23	20	24	+6	+6	47	+8	+14
TOTAL U.S.	231	170	154	+1	+1	235	-4	-11

The number of current mine workers who will actually lose their jobs will be less than the job slot losses shown above. Many currently employed miners will have retired or moved to other jobs by 2000 or 2010.

Job losses in other industries and additional adverse economic impacts would occur in regions that experience declines in coal mining employment. Conversely, other regions would experience more generalized job gains and enhanced economic activity as a result of increases in coal mining employment. Further, regional economies would be affected by changes in electricity costs associated with varying levels of emissions trading. None of these factors were assessed in this report.

CAVEATS AND UNCERTAINTIES

- This analysis estimates the emission reductions, compliance costs, and coal mining impacts associated with various levels of emissions trading in the context of two utility SO_2 emission reduction proposals. The results presented herein assume that utilities will achieve least-cost compliance with acid rain reduction requirements by pursuing all economic emissions trading opportunities. However, a range of technical, financial, programmatic and institutional considerations could serve to limit the ability or desire of utilities to engage in certain trades, especially trades beyond the existing-existing intrautility level. To the extent that full scale implementation of emissions trading (as envisioned in this analysis) is constrained by these considerations, the cost savings and other impacts projected herein would be reduced accordingly.

- A number of important issues must be addressed before any acid rain related emissions trading program could be initiated. These concern the structure of such a program, the manner in which it would be implemented and enforced, and its relationship to other environmental objectives (such as attainment of the National Ambient Air Quality Standards (NAAQS), the determination of best available control technology (BACT), and the prevention of significant deterioration (PSD) in areas which are already cleaner than the NAAQS). These issues are critical in determining how such a program would work in practice, how effective and reliable it would be in producing the required emission reductions, and the extent to which the forecasted savings would be realized. The assumptions and uncertainties related to these issues and other aspects of this study are discussed in Chapter Three.

- Note that these analyses were conducted using Interim 1987 EPA Base Case assumptions developed in late 1986. Recent trends in energy markets (e.g., declining scrubber costs, more likely availability of developing technologies, increasing mining productivity) could lead to somewhat different quantitative emission reduction, cost, and coal market impacts than presented herein (see Chapter Three). However, most of the qualitative effects of emissions trading on utility costs and coal markets would remain largely as discussed in this report.

Chapter One:
Introduction

CHAPTER ONE

INTRODUCTION AND BACKGROUND

Purpose of Study

Legislative interest in the "acid rain" issue has heated up significantly recently as part of a resurgence in public awareness of environmental concerns. Many acid rain control proposals have been developed in the past few years in search of a compromise that would be agreeable to all parties, by providing sufficient sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emission reductions to address the problem at a relatively low compliance cost and without major dislocations in regional coal production and employment.

One manner in which acid rain control proposals can be designed to keep compliance costs to a minimum is through the inclusion of "emissions trading" provisions. Emissions trading enables multiple sources to trade emission reduction requirements, so that overall emission reductions can be achieved at a lower cost. Emissions trading in the context of an acid rain control proposal can lower compliance costs significantly, while still preserving the required amount of overall emissions reductions.

There has been a noticeable trend towards consideration of certain emissions trading schemes (i.e., those permitting trades between sources within the same utility company or state) in conjunction with acid rain legislation. However, there are other trading options that offer even more economic flexibility but have yet to be considered in most legislative proposals. Few of the acid rain bills or proposals offered to date include provisions allowing the full interstate trading of emissions. Moreover, no acid rain bill has considered the possibility of exploiting the potential cost savings associated with trades between existing sources and new sources.

This study, performed by ICF at the request of the Environmental Protection Agency and the Department of the Interior, examines several emission trading schemes, including relatively unexplored emission trading possibilities such as wide-scale interstate trading and existing-new trades. These emission trading schemes are examined in the context of two prototypical acid rain control proposals -- the Proxmire bill (S-316, the Acid Deposition and Sulfur Emissions Reduction Act of 1987) and the 30 Year/1.2 Lb. emission reduction proposal -- as well as in the absence of any such reduction program. The report presents analyses of the potential economic, environmental, and coal market impacts associated with expanding the scope of emissions trading under these alternative control scenarios. Furthermore, this study identifies some of the major issues pertaining to the inclusion of emissions trading provisions, and in particular the allowance of existing-new and interstate trading.

This introductory chapter presents an overview and historical background on the subjects of acid rain and emissions trading. Chapter Two summarizes the major findings from the analyses of the different trading variants under the Proxmire bill and the 30 Year/1.2 Lb. proposal. Chapter Three presents a discussion of caveats and uncertainties pertaining to these analyses. Detailed numerical forecasts under a baseline reference case ("Base Case"), the Proxmire bill, and the 30 Year/1.2 Lb. proposal for the years 1995, 2000, and 2010 are presented in Appendices A, B, and C respectively. (Appendices B and C also provide detailed discussions of the Proxmire and 30 Year 1.2 Lb. forecasts respectively.) Appendix D presents a list of the assumptions used in the Base Case.

Only SO_2 emission reductions from U.S. electric utility powerplants and emissions trading among these sources were examined in this study, at EPA and DOI's direction. This report does not present forecasts of the economic and environmental impacts associated with the reduction or trading of utility NO_x emissions, nor with the reduction or trading of SO_2 and NO_x emissions from non-utility sources, but such impacts are not expected to be large relative to the impacts facing the utility sector in conjunction with SO_2 emissions. Nevertheless, these impacts warrant further study.

Further, it should be noted that the analyses presented in this report were conducted during 1987 and 1988 based on EPA Base Case assumptions developed in late 1986. (ICF is currently developing a new base case for EPA with updated assumptions.) Many trends exhibited recently in the energy industries (notably higher coal mining productivity, higher electricity demand growth, and lower pollution control technology costs) would likely lead to different baseline and control cost assumptions than employed in this study. Hence, some of the quantitative cost, emission, and coal production impacts of these emission reduction scenarios would likely be different than presented herein. However, most of the qualitative effects of emissions trading on utility costs and coal markets as discussed in this report would remain largely unaffected.

Background on Acid Rain

Acid rain, the acidification of natural atmospheric precipitation, is of concern because of potential adverse environmental impacts on natural ecosystems (including aquatic life, wildlife, vegetation, forests, and agriculture), materials (such as metals, wood, paint, and masonry), and general public health and welfare. In addition, the gaseous pollutants that are suspected to promote acid rain are also thought to be linked to certain atmospheric problems, such as local ozone buildup, suspended particulate matter and reduced visibility.

The effects of acid rain are thought to be magnified in ecosystems that are especially sensitive to increased acidity. Some such areas of the United States, upstate New York and New England in particular, have experienced deterioration of forest and aquatic life, which is believed by a number of scientists to be due to increasingly acidified rainfall. However, the rain that falls on the northeastern U.S. may not be acidified predominantly by local sources; acidified airborne moisture can travel for thousands of miles before falling to Earth. Because of this, acid rain is more than merely a local, or even national, concern. Areas of Eastern Canada have also witnessed similar environmental degradation, and claim that acid rain from the United States is the major source of these effects. Nonetheless, there is still controversy as to the true underlying cause of these effects, and it is possible that a number of stresses are at work. For example, some scientists believe local ozone problems rather than acid deposition may be the major cause of the observed stresses on forests in these areas.

It is generally believed that three main precursor pollutants, SO_2, NO_x, and volatile organic compounds (VOC), participate in the formation of acid rain. While only about forty percent of VOC emissions originate from man-made sources, man-made sources contribute the majority of SO_2 and NO_x emissions. For example, about 25 million tons of SO_2 is emitted annually in the U.S. from man-made sources (about 70% from electric generating powerplants), versus less than 500 thousand tons of annual natural SO_2 emissions. As for NO_x, 22 million tons are emitted annually in the U.S. from man-made sources (about one-third from powerplants), versus about 3 million tons per year from natural sources. The Ohio Valley region (Missouri, Illinois, Indiana, Kentucky, Ohio, West Virginia, Pennsylvania) contributes about 45 percent of national annual SO_2 emissions. Texas is the predominant NO_x emitting state, followed by California, Ohio, Pennsylvania, and Illinois. Emissions from these areas are carried long-distance by prevailing high-altitude wind currents to a number of Eastern states.

Because of concern about protecting local environmental conditions, five states (New Hampshire, Massachusetts, New York, Wisconsin, and Minnesota) have passed legislation in the past few years requiring curtailments or caps on statewide SO_2 (and, in some cases, NO_x) emissions. However, these states and others recognize that state laws can only be partially effective in reducing the impacts of acid rain. Because of acid rain's interregional (and international) nature, the debate concerning acid rain control has been and will continue to be focused on federal acid rain legislation. As a result, various proposals for reducing emissions, with attendant differences in forecasted regional economic impacts, have been put forth in Congress over the past few years.

Costs and Benefits of Acid Rain Control

Much of the controversy surrounding the acid rain issue stems from the regional differences in costs and benefits that would accrue under any acid rain control program. Those areas of the country with more sensitive aquatic ecosystems and/or mountainous terrains, and that are downwind of higher emitting states, are most likely to be deleteriously affected by continued acidic rainfall. These states (including, most prominently, New York and the New England region) would receive the greatest benefits from the implementation of federal acid rain legislation. On the other hand, those areas of the country that emit the highest quantities of the suspected precursor pollutants SO_2 and NO_x -- i.e., particularly states in the Ohio Valley area -- would incur the highest control costs under acid rain legislation (either as a result of switching to cleaner but more expensive fuels or installing pollution control technologies in order to reduce emissions). These costs would result in higher costs to electricity consumers (including residences, industries, and commercial establishments) which, in turn, would affect the economies of these areas. Further, regional economic activity, as related to coal production and coal mining employment, could be significantly affected under acid rain legislation, since high sulfur coal reserves and low sulfur coal reserves are not uniformly distributed across the country. Midwestern and some Eastern states with high sulfur coal deposits could experience reduced economic activity (due to reduced demand for these coals), while other Eastern states and many Western states with low sulfur coal reserves could show increases in economic activity (due to increased demand for lower sulfur coals). Thus, the costs and benefits of acid rain control would not coincide regionally.

A major obstacle in evaluating the attributes of acid rain legislation is that the benefits resulting from any program are extremely difficult to quantify. The negative effects of acid rain on the environment are problematic to isolate and to measure. Further, the mitigative effects of emission reductions on the environment are also quite difficult to assess. Finally, the value to society of improvements to the environment is also difficult to measure. What exactly is the social value of recreation, or of the opportunity to enjoy a pristine environment? In cases where human health may be concerned, what is the value of reduced mortality or morbidity? Some estimates of acid rain control benefits have been made, but are generally quite speculative given the aforementioned uncertainties.

While the benefits to society of acid rain legislation are difficult to quantify, the magnitude of direct costs to utilities is generally easier to estimate. Forecasted annual costs to electric utilities for most proposals (requiring 40-50 percent reduction in SO_2 emissions) range from about $2 billion to $6 billion. However, forecasted annual utility compliance costs for very stringent proposals (requiring 70 percent SO_2 emission reductions) have approached $14 billion. These cost estimates do not include any additional costs utilities might face in reducing NO_x emissions. By comparison, revenues for the entire U.S. electric utility industry in 1985 were about $150 billion. Other industrial sectors and mobile sources could also face significant costs to comply with potential acid rain legislation; however, under most proposed legislative initiatives, there would be relatively few reductions required from these sources, and thus costs would be low relative to those likely to be faced by utilities.

The indirect impacts and welfare losses due to acid rain controls could also be significant. Jobs may be lost in high sulfur coal mining communities of Northern Appalachia and the Midwest, and general economic activity in these regions of the country could suffer. Higher electricity prices to consumers as a result of emissions clean-up could have repercussions on national industrial and consumer activity, as well as on the international competitiveness of U.S. industry. There could also be opportunity costs associated with pollution control technology investments, since these capital expenditures could be put to use for other social or private investment purposes.

The costs and benefits of any acid rain control program are heavily dependent upon three factors: the level of required national emission reductions, the timing of the required emission reductions, and the regional distribution of the required emission reductions. The numerous proposals and bills issued over the past few years to deal with acid rain vary widely with respect to these three factors, and consequently would have quite different forecasted costs and benefits to the nation and to the affected regions.

Emissions Trading

One topic in the acid rain debate that has generated increasing interest is the notion of emissions trading. Through the use of emissions trading, it may be possible to achieve the desired level of emission reductions at lower cost. By allowing emissions trading, compliance with any emission reduction proposal would thus become less expensive. However, the level of air quality improvement would remain largely unaffected. Therefore, the cost-benefit ratio of the proposal would be improved (decreased costs for the same amount of air quality benefits) by the implementation of emissions trading.

The principle behind emissions trading is straightforward. Under the traditional command-and-control approach to environmental management, Congress, EPA, or a State regulatory agency assigns pollution control obligations to each individual source. This is generally accomplished by applying uniform emission limits or technology requirements to all sources that belong to common industrial source categories (e.g., existing coal-fired powerplants). While considerable analysis may be carried out to ensure that it is feasible for the sources in a given source category to meet the uniform requirements, the application of uniform standards can result in substantial cost inefficiencies. As control costs can differ significantly from source to source and from source category to source category, these variations in control costs make emissions trading economically desirable.

Instead of mandating fixed uniform emission reductions from each source, emissions trading permits the aggregate emission reductions to be achieved from sources in the most economic manner. Thus, those sources that are inexpensive to control can reduce emissions more than necessary. These extra emission reductions can then be traded to other sources that are more costly to control, allowing these latter sources to reduce emissions less than would be otherwise required, so long as the same level of aggregate emission reductions would be achieved.

The costs of compliance with emissions regulations are reduced as the scope of trading is broadened. Thus, uniform emission limits or caps imposed on a unit-by-unit basis are more costly and difficult to satisfy than permitting compliance on a utility company basis (and allowing the utility to use emissions trading in order to meet overall targets for its generating system in the lowest-cost manner). Similarly, an emissions trading scheme that restricts trades to an intrastate basis would offer fewer trading opportunities (and, hence, less potential cost savings) than would a scheme that permits emission trades across state lines. Further, a trading scheme which permits emission trades only between currently existing sources would be more restrictive, and compliance would be more costly, than a program that would sanction trades with new, future sources.

The amount of savings realized by emissions trading would also depend upon the nature of the specific emission control program enacted. In particular, there would be fewer opportunities for emissions trading, and consequently less savings, as the amount of emission reductions required by the control program increases. This is because, as emission reduction programs become increasingly stringent, almost all sources are required to pursue expensive compliance options. As a result, increased trading flexibility cannot lower costs as significantly.

Background History of Emissions Trading

The emissions trading concept was originally developed by EPA in 1976 in the form of an "offset" program for new industrial sources. This program (confirmed by Congress in 1977, and revised by EPA in 1980) ensures that the addition of new powerplants and other major stationary sources of emissions will not lead to violation of ambient air quality standards. In "non-attainment" areas (i.e., areas that fail to meet the National Ambient Air Quality Standards stipulated by the Clean Air Act), existing sources must make offsetting emission reductions to compensate for increases in emissions caused by the construction of any major new source. Usually, these offsets are obtained from other existing sources on the same site as the newly constructed source (i.e., "internal" offsets), although a number of offsets have involved the trading of emissions between different sites (i.e., "external" offsets). In total, approximately 2000 offsets have been approved throughout the country to date.

The notion of emissions trading was then expanded in 1979 to include trading between certain existing sources, thereby allowing for more cost-effective compliance with State Implementation Plans (SIPs) designed to attain and maintain ambient air quality standards. This "bubble" policy allows selected sets of existing sources that are located near each other and emit the same pollutant to be treated as though under a giant bubble. As long as total emissions under the bubble are not greater than the sum of the individual source emission limitations, and other environmental and programmatic requirements are met, an alternative combination of emission limitations for the individual sources is allowable. Thus, sources within the bubble with high control costs can emit more as long as other sources under the bubble emit less.

In its April 1982 Interim Emissions Trading Policy, EPA expanded the bubble program by allowing more widespread use of bubbles, as well as their adoption by states under EPA-approved "generic bubble rules." However a number of controversial issues arose in the course of implementing the 1979 and 1982 policies. These related to the possible interference of bubbles with air quality progress in nonattainment areas, as well as to a number of other technical and programmatic concerns.

EPA issued its Final Emissions Trading Policy in December 1986. The final policy incorporated special "progress requirements" for bubbles in nonattainment areas lacking approved SIPs (including all areas failing to meet the 1987 statutory deadline for attainment). In particular, it mandated that all bubbles approved in these areas must contribute to air quality progress by resulting in a net reduction in actual emissions of at least twenty percent. The final policy also clarified and tightened requirements for bubbles in other areas.

Since adopting its first bubble policy in 1979, over 50 bubbles have been approved by EPA, with approximate savings (based on industry estimates) of $300 million. Further, several states have adopted bubbles on their own by applying EPA-approved generic bubble rules. Approved bubbles at electric utility sources are presented in Table 1-1.

One of the more controversial developments in emissions trading practice has been the recent publication by EPA of a policy concerning the approval of bubbles at certain new sources. New Source Performance Standards (NSPS) compliance bubbles allow firms to meet NSPS by over-controlling one new NSPS facility in lieu of more costly control on another such facility. These NSPS compliance bubbles must produce actual reductions at least as great as those achieved by traditional unit-by-unit compliance. This policy has been instituted

TABLE 1-1

Approved Electric Utility Emissions Bubbles

Utility	Powerplant	City	State	Pollutant
Narragansett Electric	Manchester Street/ South Street	Providence	RI	SO_2
Kentucky Utilities	Green River	Muhlenberg	KY	SO_2
Tampa Electric	Gannon	Tampa	FL	SO_2
Burlington Electric	Moran	Burlington	VT	SO_2
Toledo Edison	Bay Shore	Oregon	OH	TSP
Central Illinois Public Service	Newton*	Newton	IL	SO_2

* NSPS Compliance Bubble

at Central Illinois Public Service Company's two Newton powerplant units as of 1987.[1/]

As implied above, the first step in developing an emissions trading proposal is to determine baseline emissions, or the level of emissions from which "increases" and "decreases" are measured. The Final Emissions Trading Policy contains detailed and elaborate criteria for determining baseline emissions from different types of emission sources in different types of air quality situations. It then must be demonstrated that the proposed trading scheme will not lead to local air quality violations. For bubbles involving SO_2 emissions, this generally requires the use of sophisticated ambient air quality dispersion models. The complicated procedures for determining baseline emissions and modeling air quality impacts reflect the technical and programmatic complexity of emissions trading in the context of a SIP compliance program. This complexity, combined with the controversy surrounding development of the emissions trading policy, has served as a deterrent to full utilization of the policy by the regulated community.

Emissions Trading and Acid Rain Control

Emissions trading schemes in the context of acid rain legislation (i.e., legislation that would require reductions in SO_2 and NO_x emissions from current levels) could be structured quite differently than the trading programs currently in effect, and could, therefore, avoid many of the complexities and controversies of the current trading schemes. First, all current SIP requirements could remain in place under acid rain legislation, so that no increase in SIP emission limits at any existing units would occur. Thus, local non-attainment issues would not arise under an acid rain control program allowing emission trades among existing units because all required reductions, as well as all extra reductions available

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[1/] The Newton case is an interesting example. Unit 1, brought on-line in 1979, has an advanced scrubber (a type of SO_2 pollution control equipment) design that enables the unit to emit well below the original 1971 NSPS Subpart D restriction (1.2 lbs. SO_2/mmBtu with no minimum sulfur removal requirement) under which the unit is regulated. Unit 2, brought on-line in 1982 (also grandfathered in under the NSPS Subpart D regulations, and not regulated by the newer 1979 NSPS Da requirements stipulating a minimum level of sulfur removal through technological controls) was completed without a pollution control device. Central Illinois Public Service (CIPS) proceeded to petition EPA for a bubble at Newton; CIPS desired to burn less expensive local non-compliance (i.e., greater than 1.2 lbs. SO_2/mmBtu sulfur content) coal in unit 2 rather than using more expensive compliance coals from more distant mines, in exchange for increasing the scrubber's operating efficiencies at unit 1 and emitting at rates well below those required by the NSPS. EPA agreed, with the stipulation that the plant average emission rate not exceed 1.1 lbs./mmBtu (i.e., more restrictive than the NSPS for each individual unit). Therefore, the Newton bubble has <u>three</u> benefits: (1) more emission reductions are achieved than otherwise required through conventional stack-by-stack compliance with NSPS Subpart D, (2) overall compliance costs at the powerplant are reduced (by $22 million annually, according to CIPS estimates), and (3) local coal production and mining employment are enhanced.

for credit, would be above and beyond those required by SIPs for ambient attainment purposes. Further, an acid rain emissions trading scheme would focus on total atmospheric loadings of pollutants rather than on local ambient air quality attainment, so that trades can occur over a greater distance than typically associated with bubbles. Ambient air quality modeling of existing source trades (to assure equivalent localized ambient reductions) would be unnecessary because the law would mandate state or regional, not local, reductions. Determination of baseline emissions (to calculate the amount of emission reductions required or available for trade at each source) would become a simpler and less controversial process as well, because new, tighter, clearly defined emission limits or caps would be established for existing units under state acid rain control plans, and these would logically serve as the basis for determining baseline emissions for existing units engaging in trades. In the case of trades involving new sources, the continued operation of the New Source Review (NSR) program would ensure that any increases in emissions from new units as a result of a trade would not jeopardize applicable ambient air quality standards or Prevention of Significant Deterioration (PSD) increments. However, both the NSPS and NSR programs (as set out in the current Clean Air Act) would need to be explicitly modified in order to allow new source emission limits resulting from these programs to be satisfied through trading.

One possible method to implement emissions trading in the context of an acid rain control program would be to initially allocate to each source or utility an emission reduction requirement or an emission target or limit. Each source or utility would then be issued marketable emission permits corresponding to its emission target. Trades could take place through the exchange of emissions permits within a single utility or in a statewide or interstate emission trading marketplace. The price of emissions permits would be determined in the marketplace, and would be expected to approximate the marginal cost of reducing emissions -- the highest cost of reducing emissions in the utility system, state or interstate area.

Although certain institutional and administrative costs (such as data collection and verification, enforcement, and the operation of trading forums) would be imposed by the implementation of an acid rain emissions trading scheme, these costs would likely be small in comparison to the cost savings due to the increased flexibility offered through emissions trading. Furthermore, some of these costs would likely be incurred under any emission reduction proposal, irrespective of the extent of allowable emissions trading. For example, it would be necessary to monitor emissions from each source to determine compliance under any acid rain legislation implementation scheme, regardless of whether emissions trading was allowed or if uniform, unit-by-unit emission limits (i.e., no trading) were imposed.

Scope of Emissions Trading

Emissions trading schemes can vary by the geographic extent of allowable trades. While the aforementioned bubble and offset concepts usually correspond to emissions trading at the plant level (or, in some cases, groups of plants located in close geographic proximity), emissions trading under acid rain legislation could entail wider-level trading because of the broader state or regional (rather than localized) emission reduction targets. Specifically, trading in the acid rain context could be allowed to occur at the intrautility, intrastate, or interstate level.

While geographic boundaries offer one set of criteria to define the extent of emissions trading, the amount of emissions trading is also defined by the types or classes of sources involved. Trades among existing utility sources are perhaps most easily envisioned under an acid rain control program because the emission reduction targets under many such proposals are established at existing sources only (new sources often remain subject only to NSPS and other technology requirements applicable to new sources). However, trades between existing and new utility sources could also be considered. Such existing-new trades would allow new powerplants to be exempted from current NSPS emission regulations and other technology requirements (e.g., BACT applicable to new sources) requiring at least 70 to 90 percent sulfur removal from input coal, provided that any resulting emissions increase at these new sources be compensated by further emission reductions from existing sources.

A final factor in determining the extent of emissions trading is the trading ratio. A one-to-one trading ratio means that, for every ton of emission reduction generated by a "providing" source, one ton of emission reduction credit may be used at a "receiving" source. Adjusting the trading ratio can lead to net increases or decreases in the amount of emission reductions actually achieved in practice from levels otherwise required by the proposal. For instance, a 1.2:1 ratio would require the providing source to reduce emissions by 1.2 tons for each ton of emissions increase at the receiving source. An increase in the trading ratio will lead to more emission reductions (and hence more environmental benefits), but fewer trades (and hence less cost savings), than with an even one-to-one ratio.[2/]

Recent Acid Rain Proposals

As mentioned previously, several acid rain proposals have been put forth in the past few years. Table 1-2 chronologically presents some of the more prominent proposals devised during 1987 and 1988, and summarizes some of these proposals' key provisions.

Note that some of these proposals include language which allows emissions trading. This reflects widening acknowledgement that emissions trading has the potential to offer substantial economic cost savings at minimal environmental expense. This study aims to estimate quantitatively the value to any particular sulfur dioxide emission reduction proposal of various levels of SO_2 emissions trading, and discusses the salient issues and forecasted effects on utility costs, SO_2 reductions, and coal markets when considering alternative forms of emissions trading design.

2/ Trading among sectors (i.e., utility-industrial trades) has also been considered. One example of such inter-sectoral emission trading would be trading between copper smelters and utility powerplants in the Western states. Interpollutant trading (e.g., SO_2 with NO_x) could also be utilized, and has been considered in an earlier acid rain proposal. These trading approaches are not addressed in this analysis.

TABLE 1-2

Recent Acid Rain Proposals

Proposal	Date	Final Phase SO_2 Requirements	Trading Provisions
Proxmire (S-316)	Spring 1987	Statewide targets corresponding to a 1.2 lb./mmBtu average emission rate and 1980 fuel consumption.	Intrastate/Regional
30 Year/1.2 Lb.	Summer 1987	Unit-by-unit 1.2 lb./mmBtu limit upon reaching 30 years of age.	None
Gregg (HR-2498)	Summer 1987	Tax based on each unit's emission rate.	Not applicable
Mitchell (S-1894)	Winter 1988	NSPS upon reaching 40 years of age; Statewide emission targets to achieve 12 million tons of reductions below 1980 levels, allocated by state share of national 1980 unit-by-unit 0.9 lb./mmBtu "excess" emissions.	Intrastate only
Cooper (HR-4331)	Spring 1988	Reductions from SIP sources equal to historical statewide unit-by-unit 1.2 lb./mmBtu "excess" emissions.	Intrastate, with intrautility-interstate
Cuomo-Celeste	Summer 1988	Statewide average 0.9 lb./mmBtu limit, or 68% below 1980 levels.	Intrastate only
UMWA (Draft 4)	Summer 1988	Control technologies at all SIP units larger than 150 megawatts.	None
Mitchell Compromise	Summer 1988	Unit-by-unit 1.0 lb./mmBtu emission limit if larger than 100 megawatts and 1985 emission rate greater than 1.2 lb./mmBtu.	None
Bonker (HR-5562)	Fall 1988	Reductions from SIP sources equal 1980 statewide unit-by-unit 1.2 lb./mmBtu "excess" emissions; SIP emissions capped at 1985 levels.	Intrastate, with intrautility-interstate

NOTE: Unit-by-unit "excess" emissions refer to those emissions which resulted from a unit emitting in excess of the designated emission limit.

This report examines the utility SO_2 emission reductions, utility compliance costs, and coal market impacts of two of these recent acid rain control proposals (the Proxmire bill and the 30 Year/1.2 Lb. proposal) assuming alternative levels of emissions trading within the utility sector. A representative set of emissions trading scenarios were analyzed to determine the potential utility compliance cost savings that could accrue as the level of trading allowed becomes more expansive. With one exception, all cases presented herein were analyzed assuming a one-to-one trading ratio.

Chapter Two:
Findings

CHAPTER TWO

SUMMARY OF FINDINGS

This chapter summarizes the results of ICF's analyses of two alternative sulfur dioxide emission reduction proposals designed to control acid rain, the Proxmire bill and the "30 Year/1.2 Lb." proposal, as compared to a base case which assumes <u>no</u> federal acid rain legislation. In particular, this summary indicates the effects of changing the geographic scope and programmatic extent of emissions trading under these three scenarios. Electric utility SO_2 emission reductions, utility compliance costs, and coal market impacts are presented and discussed.

EMISSION REDUCTION SCENARIOS

Reduction Scenario	Total SO2 Reductions (Relative to Base Case)	SO2 Reduction Requirements/ Allocation Scheme
Base Case	1995: None 2000: None 2010: None	All units comply with current emission regulations. No federal acid rain legislation is assumed.
Proxmire	1995: About 5 mm tons 2000: About 9 mm tons 2010: About 9 mm tons	Aggregate emissions from SIP powerplant units in each of the 31-Eastern states are limited to the following emission targets: 1995: 2.0 lb. SO_2/mmBtu x 1980 total fuel consumption from all SIP powerplant units* 2000/2010: 1.2 lb. SO_2/mmBtu x 1980 total fuel consumption from all SIP powerplant units*
30 Yr/1.2	1995: About 4 mm tons 2000: About 6 mm tons 2010: About 11 mm tons	All units subject to a 1.2 lb. SO2/mmBtu limit (enforced on a 30 day average) upon reaching 30 years of age.

*Note: This is also known as a statewide 2.0/1.2 lb. "excess" emission reduction allocation.

EMISSION REDUCTION SCENARIOS

Two sulfur dioxide emission reduction proposals and a base case were examined as part of this study. The two emission reduction proposals examined were (1) an interpretation of S-316, the Acid Deposition and Sulfur Emissions Reduction Act of 1987 (hereafter referred to as "Proxmire"), and (2) the 30 Year/1.2 Lb. ("30 Yr/1.2") emission reduction proposal. These emission reduction cases were analyzed for the forecast years 1995, 2000, and 2010, and then compared to the Interim 1987 EPA Base Case ("Base Case") which reflects expected trends in utility sulfur dioxide emission levels, utility compliance costs and coal production assuming no changes in current environmental regulations. A description of these three cases is provided below:

- The Base Case assumes that all generating units would be required to continue to meet their sulfur dioxide emission limits as stipulated by current State Implementation Plans (SIPs) or New Source Performance Standards (NSPS), whichever are applicable. In addition, to the extent that state "acid rain" legislation has been enacted or future changes in powerplant SIPs have already been approved, the emission limits resulting from these changes are also assumed. Detailed Base Case specifications and assumptions are presented in Appendix D.

- Under Proxmire, emission reductions would be required in two stages from SIP units (i.e., non-NSPS units) in each of the 31-Eastern states. By 1993, (Phase I), aggregate emissions from all SIP units in each state would be required to meet a statewide emission target corresponding to a 2.0 lb.SO_2/mmBtu statewide annual average emission rate and 1980 fuel consumption from all SIP sources within the state. By 1998 (Phase II), aggregate emissions from these units would be required to meet a target corresponding to a statewide annual average emission rate of 1.2 lb.SO_2/mmBtu and 1980 fuel consumption from all SIP sources in the state. States would be responsible for procuring sufficient reductions from utility sources within the state to meet the mandated emission targets. The analyses presented in this report assume that states would allocate emission targets to SIP sources based on 1980 fuel consumption and a 2.0/1.2 lb. SO_2/mmBtu annual average emission rate. However, under Proxmire's "Default" provisions, if a state failed to develop an approvable plan for allocating reduction requirements, each individual unit within the state would automatically be required to meet a 1.2 lb. SO_2/mmBtu annual emission limit (i.e., no trading would be allowed).

- Under 30 Yr/1.2, all units would be required to meet current emission regulations until the thirtieth year of operation, at which time units would be required to meet a 1.2 lb. SO_2/mmBtu emission limit (on a thirty day rolling average). Because of the variability of sulfur in coal and the variability of scrubber performance, this is assumed to result in a 1.02 lb.SO_2/mmBtu annual average SO2 rate. Note that the "thirtieth year of operation" was based on powerplant vintage as of December 31 of the forecast year. Thus, a unit that initially came on-line at any time during 1970 would be considered to be 30 years old in 2000.

EMISSION TRADING SCENARIOS

Trading Scheme	Base Case	Proxmire	30 Yr/1.2
No Trading	X	X*	
Intrautility			
Existing-Existing		X	X
Intrastate			
Existing-Existing		X	X
Existing-New		X	X
Interstate (31-East/17-West)			
Existing-New	X**	X	

Note: "Existing" units, as defined herein, are those units in commercial operation by 1985, and are generally regulated under State Implementation Plans (SIPs) of the Clean Air Act. "New" units are those units which come (or came) on-line after 1985, and are required to meet NSPS Subpart Da regulations (which require 70-90 percent removal through SO_2 control technology -- i.e., scrubbers).

*/ No detailed analysis was conducted for the Proxmire No Trading case. Rather, estimates presented herein were derived from previous ICF analyses for EPA of similar acid rain proposals with no trading provisions.

**/ Assumes a 1.2-to-1 trading ratio.

The various cases, Base Case, Proxmire, and 30 Yr/1.2, were examined under several emission trading schemes which allow for different levels or degrees of trading flexibility. This included an assessment of trades within different geographic bounds. In order of increasing flexibility, these are:

- **Intrautility Trading.** Sources from within a utility holding company and situated in the same state are permitted to trade with each other to comply with a utility emission target. No trading between holding companies or across state lines is permitted.

- **Intrastate Trading.** Sources from different utility holding companies within a state can trade with each other to comply with a statewide emission target. No trading across state lines is permitted.

- **Interstate Trading.** Sources in the 31-Eastern states can trade with each other to comply with a 31-Eastern states emission target. A similar trading arrangement is assumed in the 17-Western states. No trading is assumed to be permitted between the 31-Eastern and the 17-Western states.

  Trades were also examined among different types of utility sources:

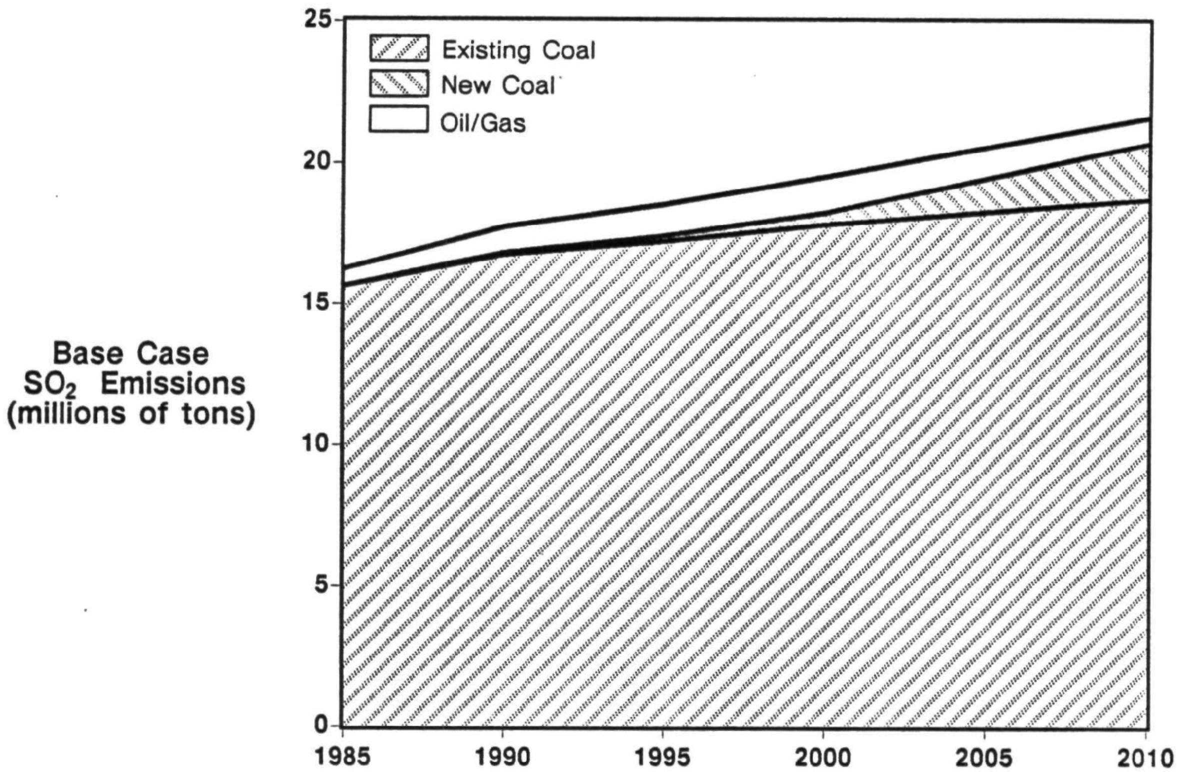
- **Existing-Existing Trading.** "Existing" powerplant units (generally subject to SIP requirements) can trade with other existing powerplant units to comply with new, tighter emission reduction requirements. However, each individual powerplant unit remains subject to its current SIP limits, so that no actual increase in emissions occurs at any unit as a result of trading.

- **Existing-New Trading.** "New" powerplant units can trade with existing units. New units which opt to trade with existing units are assumed to be exempted from NSPS Subpart Da regulations (which require a 1.2 lb. SO_2/mmBtu limit, and scrubbers to meet minimum percent SO2 removal requirements).[1/] However, any emission increases at new units above the actual level that would be emitted in a given year under NSPS Subpart Da (as forecasted in the Base Case) must be offset by extra reductions from existing units. Moreover, new units which obtain emission reductions from existing units must install controls in order to meet NSPS Subpart Da regulations as soon as the existing trading partners retire. Existing-new trading, in essence, enables new units to defer installation of NSPS Subpart Da control technologies only as long as cheaper offsetting reductions from existing sources are available.

One final factor examined in the emissions trading scenarios is the required trading ratio. In all but one of the cases, for every ton of qualifying emission reductions at a "credit providing" source, one ton of emission reductions could be foregone at a "credit receiving" source. In the Base Case with existing-new interstate trading, a 1.2:1 trading ratio was examined, thus requiring the providing source to reduce emissions by 1.2 tons for each ton of emission reductions foregone at the receiving source.

1/ For a discussion of additional technology-based requirements associated with New Source Review, and how they relate to the analysis of existing-new trading, see Chapter Three.

BASE CASE UTILITY SULFUR DIOXIDE EMISSIONS



BASE CASE UTILITY SULFUR DIOXIDE EMISSIONS

To determine the impacts of the emission reduction proposals and the effects of the various forms of emissions trading, an assessment is required of future emission trends assuming no changes in emissions regulations. The Base Case forecasts future utility emissions, assuming current emission regulations (and future changes in those regulations which have already been mandated), and uses EPA specified assumptions on electricity demand growth, oil prices, nuclear capacity, powerplant lifetimes, among other factors. A detailed list of Base Case assumptions is provided in Appendix D. The Base Case emission trends shown on the opposite page indicate the following:

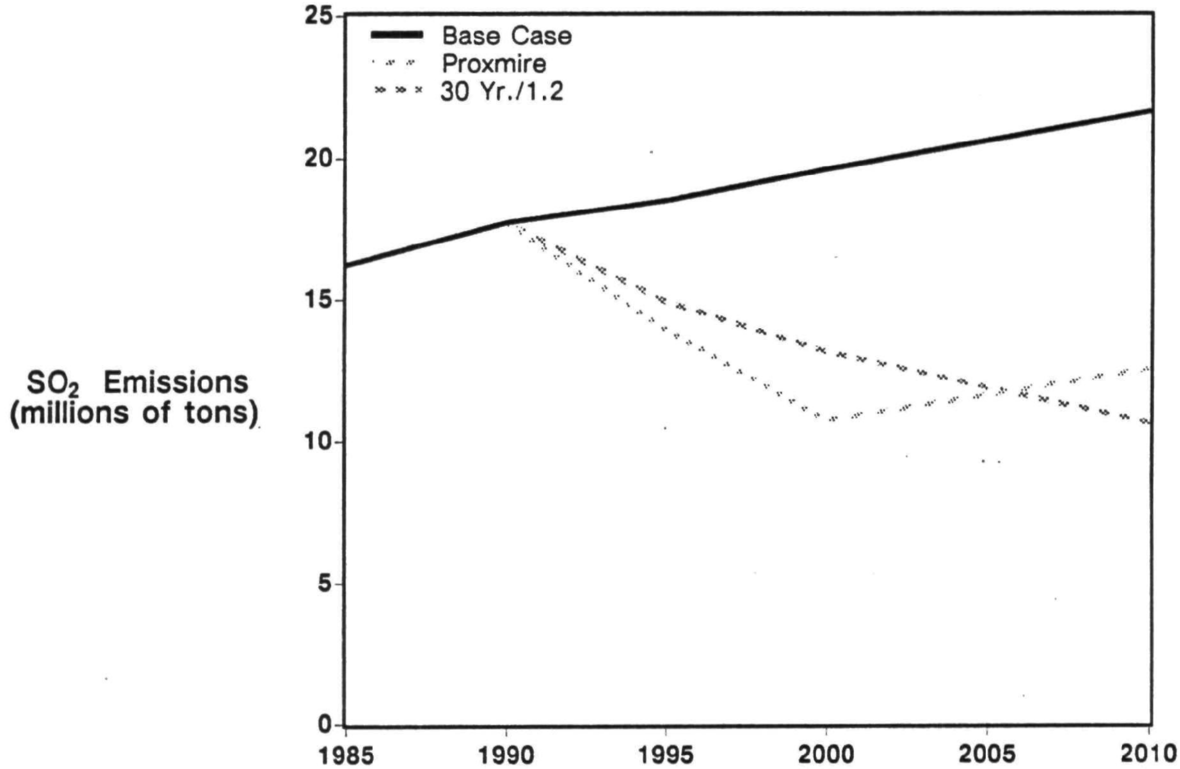
- Utility sulfur dioxide emissions are forecast to increase by 5.4 million tons (from 16.3 to 21.7 million tons) between 1985 and 2010.[2/]

- Most of the near-term growth in emissions is due to increased utilization of existing coal powerplants (as relatively few new coal and nuclear plants are scheduled to come on-line over the next decade, particularly after 1990) and due to increased use of oil relative to gas at oil/gas steam units (because gas prices are forecast to rise relative to oil as the current gas "glut" is reduced).

- After 2000, most of the increase in emissions comes from new coal powerplants. Nearly 200 gigawatts of coal capacity is forecast to be built between 2000 and 2010.

2/ Note that projections of future trends in emissions are uncertain and are dependent upon the specified base case assumptions shown in Appendix D. Recently, EPA had ICF analyze a "low emissions" base case which assumed very low growth in electricity sales, more existing plant retirements, significant amounts of repowering, and fewer new coal plants being built. Under these assumptions, emissions growth from utilities was forecasted to be flat, with SO_2 emissions totalling 16.9 million tons by 2005. See ICF report to EPA entitled Analysis of a "Low Emissions" Base Case and 10 Million Ton SO_2 Reduction Cases, September 30, 1988, for further detail.

SO2 EMISSION REDUCTIONS OVER TIME
UNDER PROXMIRE AND 30 YR./1.2



SO2 EMISSION REDUCTIONS OVER TIME UNDER PROXMIRE AND 30 YR./1.2 LB.

- Under the Proxmire cases, annual emission reductions below Base Case levels would total:

  - -- 4.6 million tons by 1995 under Phase I
  - -- about 9 million tons by 2000 and by 2010 under Phase II.

  Because there are no additional reductions required from existing sources after 2000, and because new plant emissions are not subject to additional controls (i.e., growth in overall emissions due to the addition of new sources is not capped), absolute emission levels increase under Proxmire between 2000 and 2010.

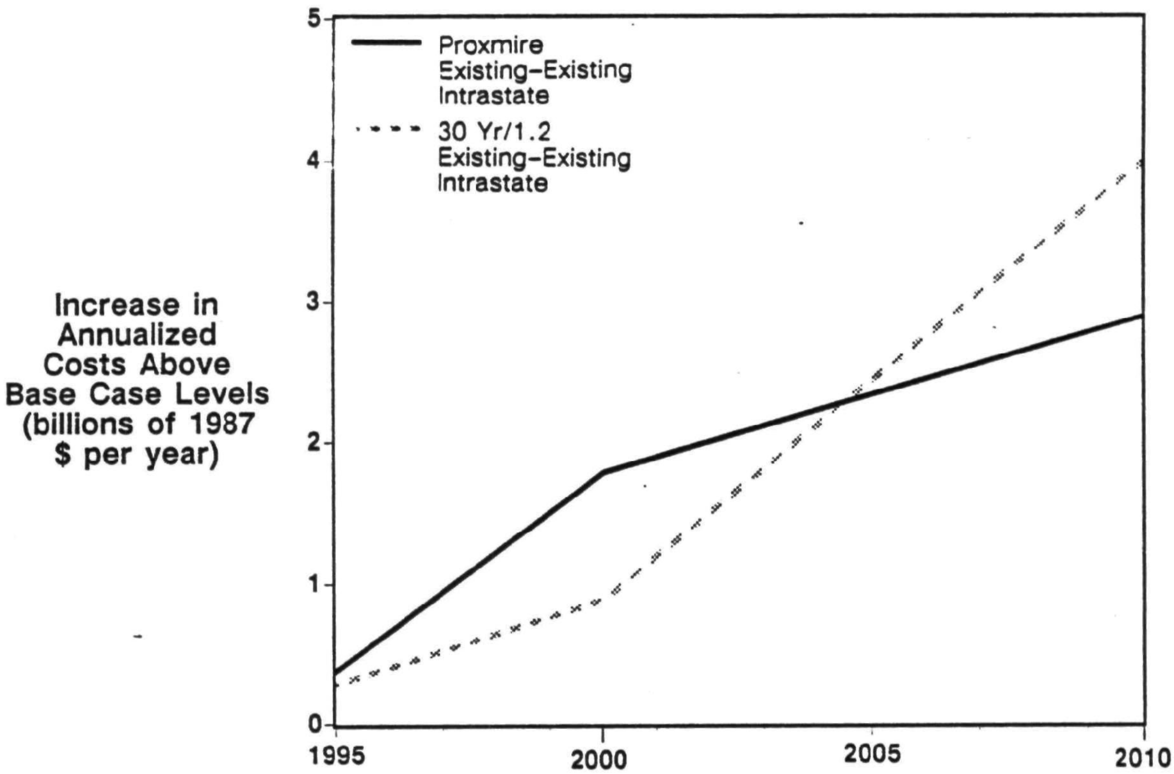
- Under the 30 Yr/1.2 cases, annual emission reductions below Base Case levels increase in magnitude over time:

  - -- 3.6 million tons of reductions by 1995
  - -- 6.4 million tons of reductions by 2000
  - -- 11.1 million tons of reductions by 2010.

  This occurs because the capacity which turns 30 years of age (and which is required to meet a 1.2 lb. emission limit) increases over time. In 1995, 73 gigawatts of coal capacity will be 30 years of age or older; by 2010, 175 gigawatts of coal capacity would be affected.

- Emission reductions required by either Proxmire or 30 Yr/1.2 would not change significantly as a result of implementing any of the alternative levels of emissions trading considered herein. This is because any increases in emissions at powerplant units (relative to levels specified under a "no trading" variant of the enforced acid rain program) must be counterbalanced by equivalent reductions (below "no trading" levels) at other units.

CHANGE IN ANNUALIZED COSTS OVER TIME



CHANGE IN ANNUALIZED COSTS OVER TIME

- The costs under Proxmire and 30 Yr/1.2 increase steadily with respect to the Base Case, reflecting the increasing emission reduction requirements over time. This trend is illustrated on the opposite page for the existing-existing intrastate trading cases.

  - In 1995, annualized costs increase by $0.4 billion under Proxmire and $0.4 billion under 30 Yr/1.2.

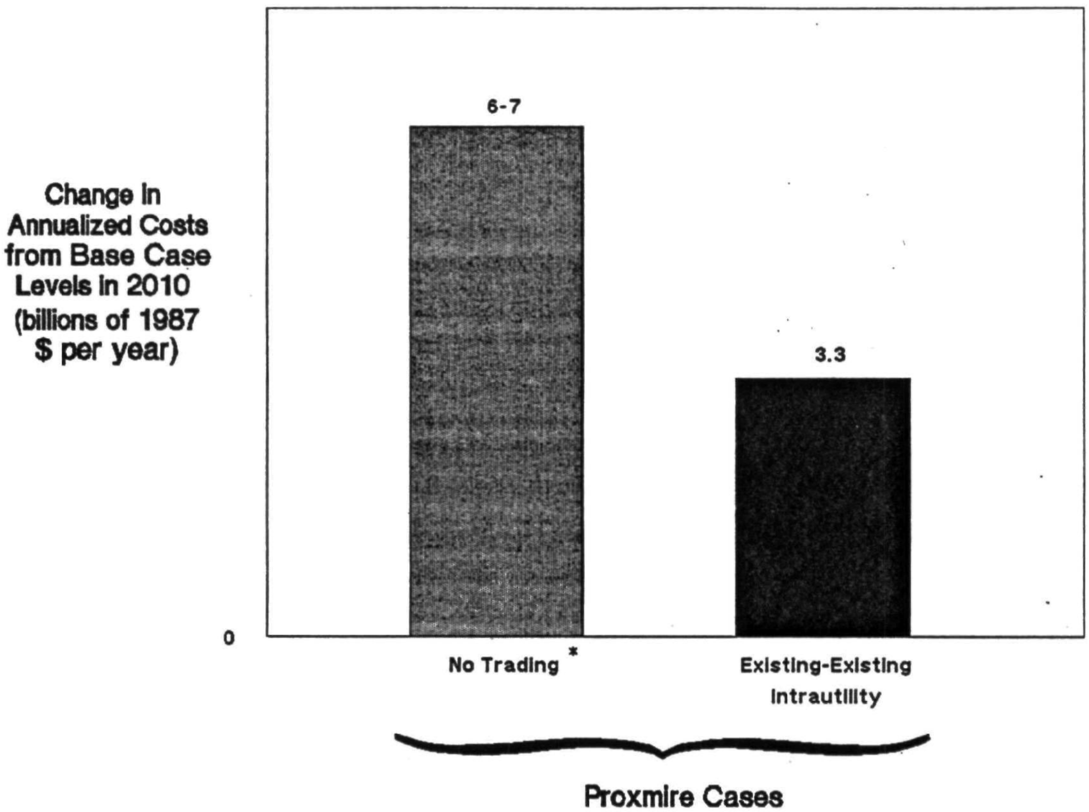
  - In 2000, annualized costs increase by $1.8 billion under Proxmire and $0.9 billion under 30 Yr/1.2.

  - In 2010, annualized costs increase by $2.9 billion under Proxmire and $4.1 billion under 30 Yr/1.2.

- The annualized costs under 30 Yr/1.2 are significantly higher than Proxmire by 2010 (about 40 percent greater for the existing-existing intrastate cases). This reflects greater reductions (about 20 percent more reductions) and increasingly higher costs per ton removed. As reduction requirements exceed 8 to 9 million tons, compliance costs increase rapidly, reflecting much higher marginal costs of achieving these reductions -- which generally are obtained through retrofitting of scrubbers.

- Although the 30 Yr/1.2 cases are more expensive in annualized cost terms than the Proxmire cases in 2010, the 30 Yr/1.2 existing-existing trading cases are less costly in present value terms than their Proxmire counterparts. This is because the reduction requirements of the 30 Yr/1.2 cases in the earlier forecast years (1995 and 2000) are less stringent, and therefore less costly, than the Proxmire requirements. Because these earlier forecast year costs are more heavily weighted in the present value calculations than costs from later years, the 30 Yr/1.2 cases have lower present value cost impacts than comparable Proxmire cases.

EFFECTS OF ALLOWING EXISTING-EXISTING INTRAUTILITY TRADING



* Note that the estimate presented here for the Proxmire No Trading case does not reflect any specific analysis conducted by ICF for EPA, but represents ICF estimates based on previous analyses of similar acid rain proposals with no trading provisions conducted by ICF for EPA.

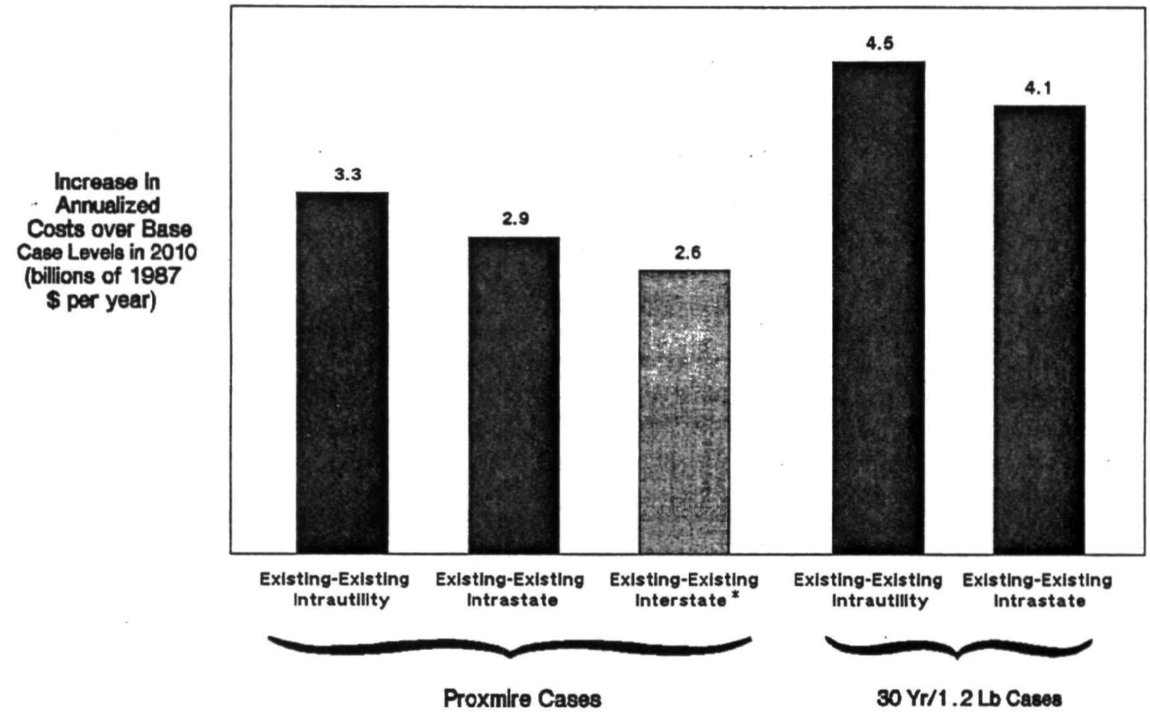
EFFECTS OF ALLOWING EXISTING-EXISTING INTRAUTILITY TRADING

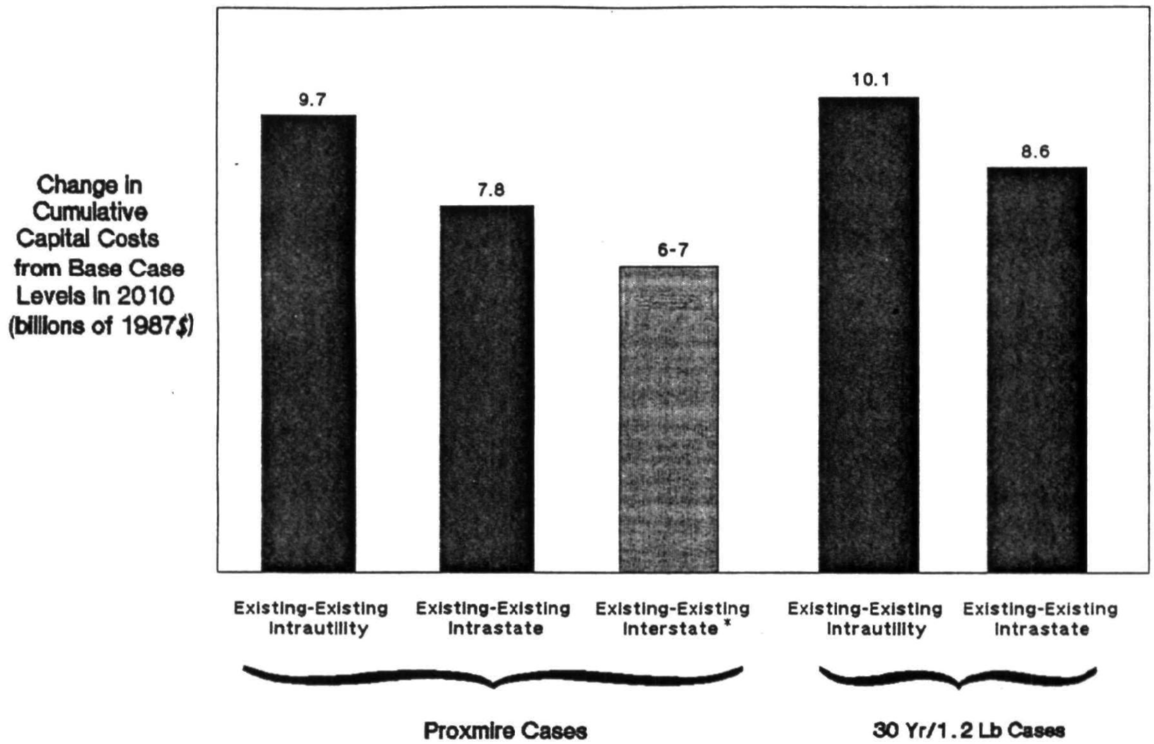
- The greatest single increment of cost savings associated with emissions trading is obtained when "expanding" the scope of trading from a "no trading" scenario (i.e., unit-by-unit compliance with uniform emission limits) to a scenario that allows trading at the existing-existing intra-utility level. Allowing even this relatively restricted form of trading reduces the annual compliance costs of an acid rain program by 30 to 60 percent.[3/]

- The cost savings associated with allowing even a limited level of emissions trading are large because the highest-cost compliance measures which would result under a no trading case can be avoided. Powerplant units which would have very high costs associated with meeting tighter emission limits (e.g., which would effectively have required scrubbers to be installed) can trade with units within the same utility which can make offsetting reductions at lower cost.

3/ No detailed modelling analysis was conducted in developing the Proxmire No Trading case estimate. Rather, the cost estimate for the Proxmire No Trading Case presented on the opposite page is approximate, and was derived from previous ICF analyses for EPA of acid rain proposals with no trading provisions. See, for instance, An Economic Analysis of HR 4567: The Acid Deposition Control Act of 1986, August 1986 (Default Case). The relative annual cost savings estimated above are also consistent with rough estimates made by ICF of a 30 Yr/1.2 No Trading Case.

EFFECTS OF GREATER GEOGRAPHIC TRADING FLEXIBILITY: ANNUALIZED AND CUMULATIVE CAPITAL COSTS





* Note that the estimates presented here for the Proxmire Existing-Existing Interstate trading case do not reflect the results of any specific analysis conducted by ICF for EPA, but represent ICF estimates based on the analysis of interstate trading in the Proxmire existing-new trading context, as well as previous analyses conducted by ICF for EPA.

EFFECTS OF GREATER GEOGRAPHIC TRADING FLEXIBILITY: ANNUALIZED AND CUMULATIVE CAPITAL COSTS

- Increasing the geographic scope of emissions trading reduces emission reduction costs. A greater geographic scope of trading results in more trading partners being available. This in turn allows more opportunities for powerplant units with relatively high cost reduction requirements to obtain emission reductions from powerplant units with relatively low cost reduction opportunities.

- The impact of greater geographic trading flexibility among existing sources on annualized costs is shown on the opposite page for 2010. A similar pattern of annualized cost savings due to increased geographic trading flexibility is forecast in 1995 and 2000, although the absolute cost savings are generally less than in 2010 because of lower overall reduction requirements and lower compliance costs in the earlier years. The annualized cost impacts in 2010 reflect:

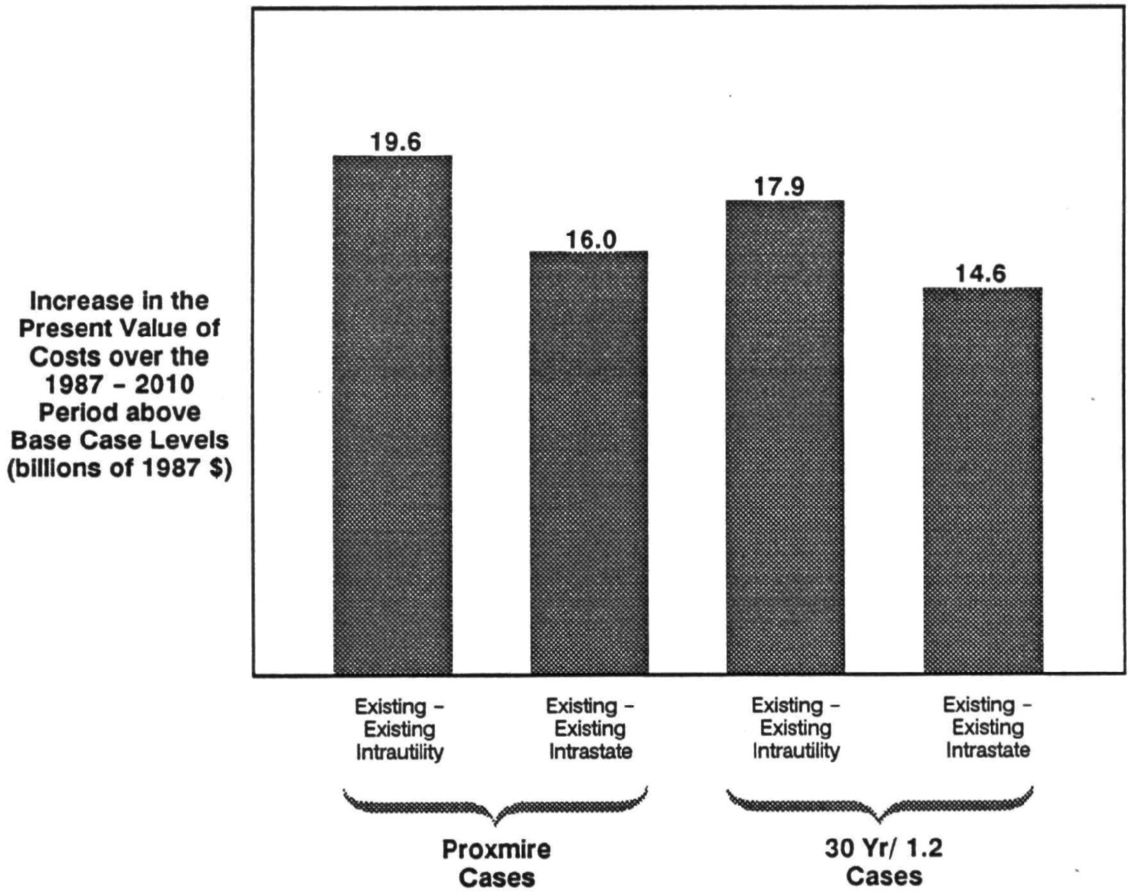
  -- An $0.4 billion cost savings associated with increasing the scope of trading from the intrautility level (i.e., restricted to within utility holding companies, with no trades allowed across state lines) to the intrastate level (i.e., permitting interutility, intrastate trading).

  -- An additional $0.3 billion cost savings associated with permitting interstate trading (i.e., trades allowed across the 31-Eastern states and across the 17-Western states, but not between these two broad regions) versus intrastate trading. (While no explicit existing-existing interstate trading case was analyzed, the annualized cost savings associated with expanding trading to the interstate level was estimated based on the difference in costs between intrastate and interstate trading in the existing-new trading context. In addition, previous analyses conducted by ICF for EPA of existing-existing interstate trading cases revealed similar cost savings.[4])

- Greater trading flexibility also leads to lower cumulative capital expenditures by utilities, generally because less scrubbers are built. Increasing the scope of trading from the intrautility to intrastate level is forecasted to reduce cumulative capital costs by 15 to 20 percent. Increasing the scope of trading further to the interstate level is forecasted to reduce cumulative capital costs (by 2010) by an additional 10 to 20 percent.

4/ See, for instance, "Preliminary Analysis of 'Proxmire-Equivalent' Reductions Allocated Across the Continental U.S. Based on Total 1980 Utility Sulfur Dioxide Emissions from SIP Powerplants," July 1, 1987.

EFFECTS OF GREATER GEOGRAPHIC TRADING FLEXIBILITY: PRESENT VALUE OF COSTS

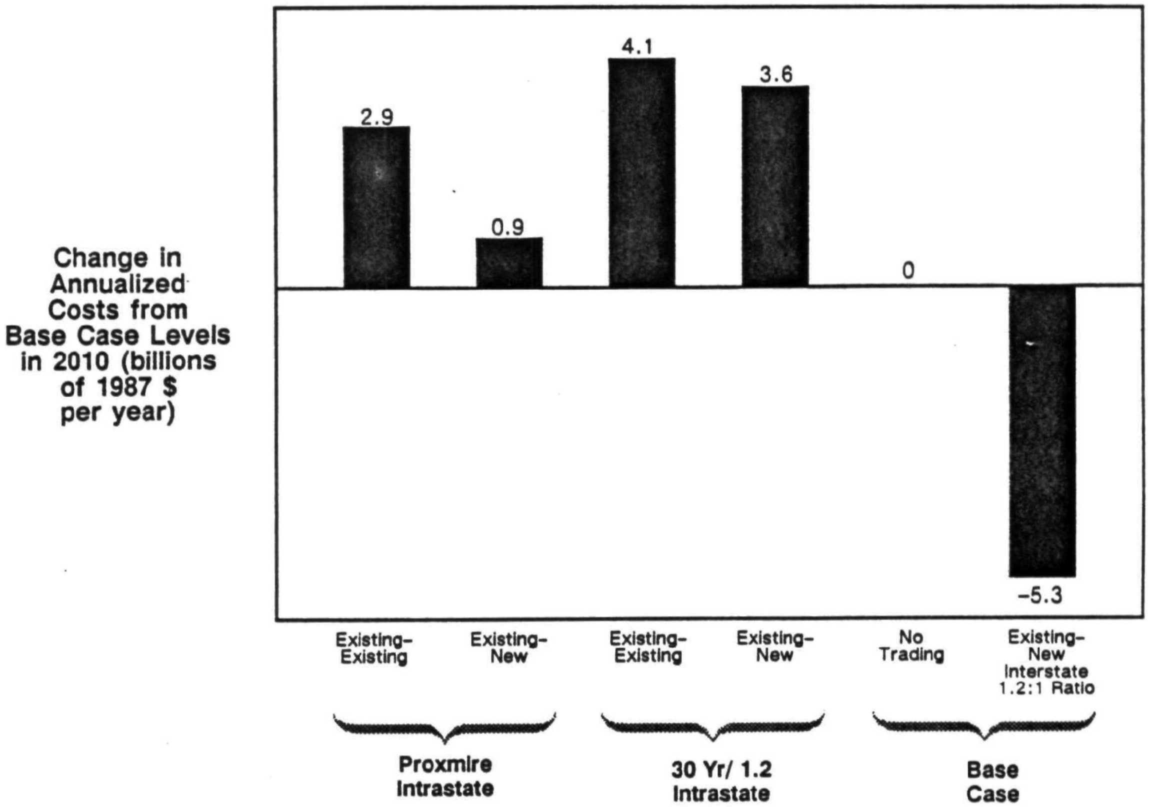


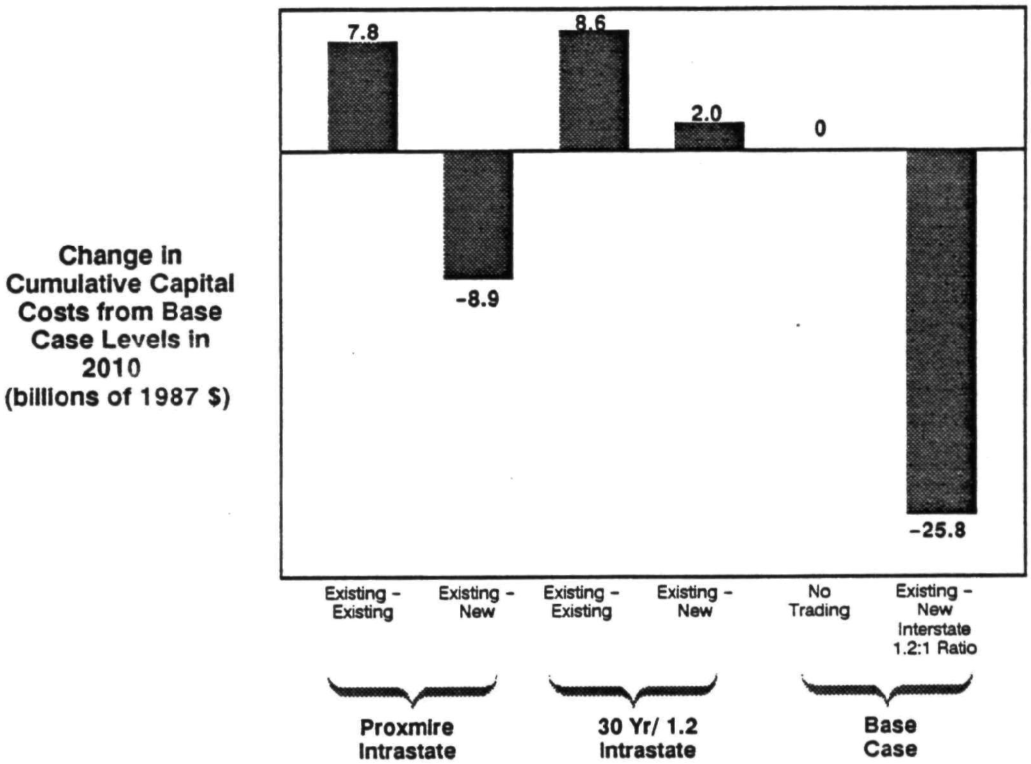
EFFECTS OF GREATER GEOGRAPHIC TRADING FLEXIBILITY: PRESENT VALUE OF COSTS

- Changes in the present value of costs reflect the changes in annualized costs incurred over the forecast period (i.e., through 2010) discounted back to 1987 using the utilities' real discount rate.

- Similar to the changes in annualized costs (discussed on page 2-15), the present value of costs is reduced as trading flexibility increases. The present value of costs is reduced by approximately 20 percent when allowing intrastate trading instead of intrautility trading; in contrast, annualized costs by 2010 are reduced by only about 10 percent (as shown on page 2-14). The present value of costs is reduced to a greater extent since relative cost savings due to intrastate trading (i.e., cost savings as a percentage of compliance costs) are higher in the near-term (which are weighted more heavily in present value calculations) than in the long term. This is because relatively fewer opportunities for cost savings through intrastate trading are available by 2010 as emission requirements become more stringent.

EFFECTS OF EXISTING-NEW TRADING:
ANNUALIZED AND CUMULATIVE CAPITAL COSTS





EFFECTS OF EXISTING-NEW TRADING: ANNUALIZED AND CUMULATIVE CAPITAL COSTS

- The cost savings associated with expanding the scope of emissions trading to permit trades between "existing" sources and "new" sources is also significant. With existing-new source trades, new powerplants no longer are required to meet NSPS Subpart Da and thus can be built without scrubbers.[5/] This is permitted as long as any resulting emission increases above the actual levels projected for these new sources under the Base Case (i.e., assuming the operation of scrubbers designed to meet NSPS-Da) are offset by further reductions at existing units. Because the cost savings associated with building a new plant without a scrubber ($1000-2000 savings per ton increase in emissions) are far more substantial than the cost of offsetting these increases at an existing plant through coal switching (about $100 to $400 per ton removed), the net cost savings of building a new plant without a scrubber and switching coals at existing units are considerable.

- The value of existing-new trading is inversely related to the amount of emission reductions required. This is primarily because the marginal costs of emission reductions at existing plants increase as more emission reductions are required. By 2010:

  - Under the 30 Yr/1.2 intrastate case with existing-new trades, emission reductions total 11.1 million tons, with net annualized cost savings of about $0.5 billion and cumulative capital cost savings of about $6.6 billion relative to the 30 Yr/1.2 intrastate case with existing-existing trading.

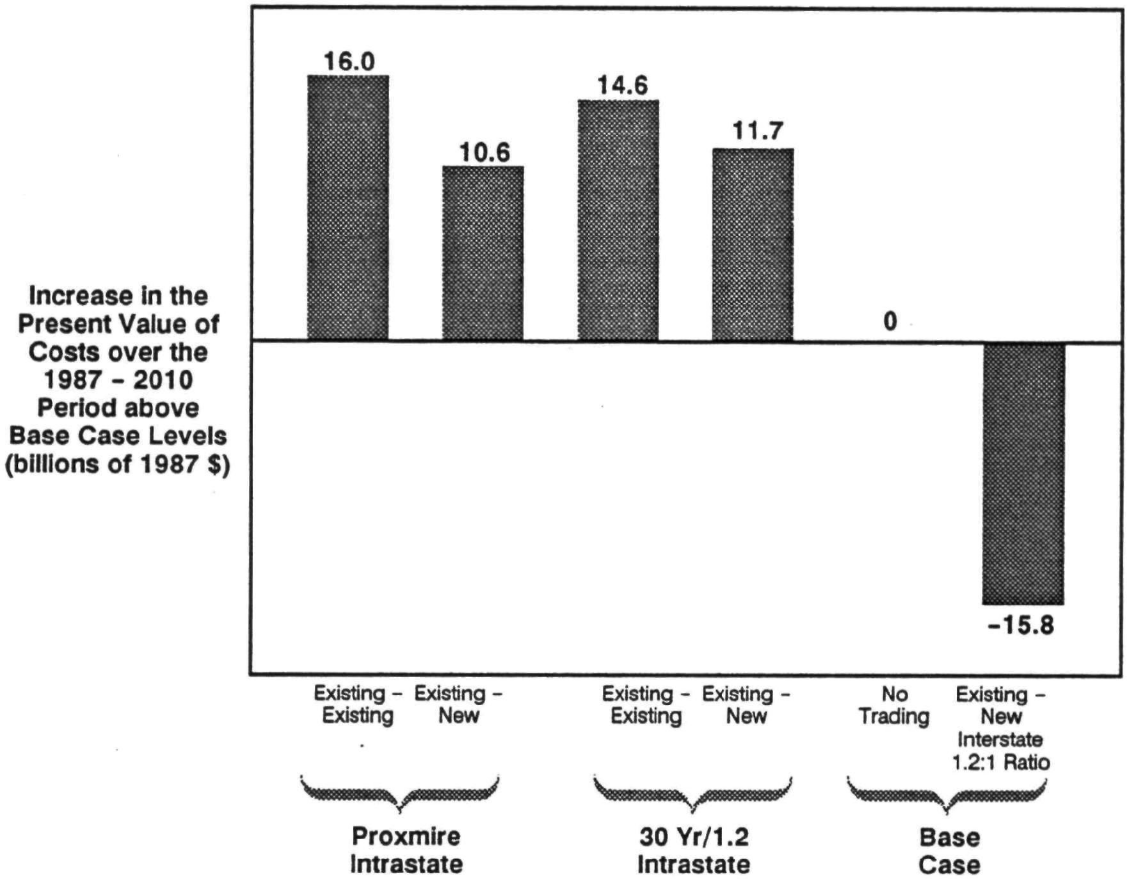
  - Under the Proxmire intrastate case with existing-new trades, emission reductions equal 9.1 million tons, with greater net annualized cost savings of $2.0 billion and greater cumulative capital cost savings of about $16.7 billion relative to the Proxmire intrastate case with existing-existing trading.

  - Under the Base Case with existing-new trades (1.2:1 trading ratio), net emission reductions total only about 1.4 million tons, with very substantial net annualized cost savings of $5.3 billion and very substantial cumulative capital costs savings of about $25.8 billion relative to the Base Case with no trades.

- In 1995 and 2000, the value of existing-new trades is less significant than in 2010, reflecting fewer new sources being able to take advantage of existing-new trades. By 1995, only a few new coal plants subject to current NSPS regulations are forecast to be constructed (beyond those plants already partially completed). By 2000, about 27 gigawatts of new coal plants are forecast to be built (beyond those already partially completed), versus about 225 gigawatts of new coal capacity in 2010.

5/ For a discussion of additonal technology-based requirements associated with New Source Review (i.e, Best Available Control Technology and Lowest Achievable Emission Rate), and how they relate to the analysis of existing-new trading, see Chapter Three.

EFFECTS OF EXISTING-NEW TRADING:
PRESENT VALUE OF COSTS



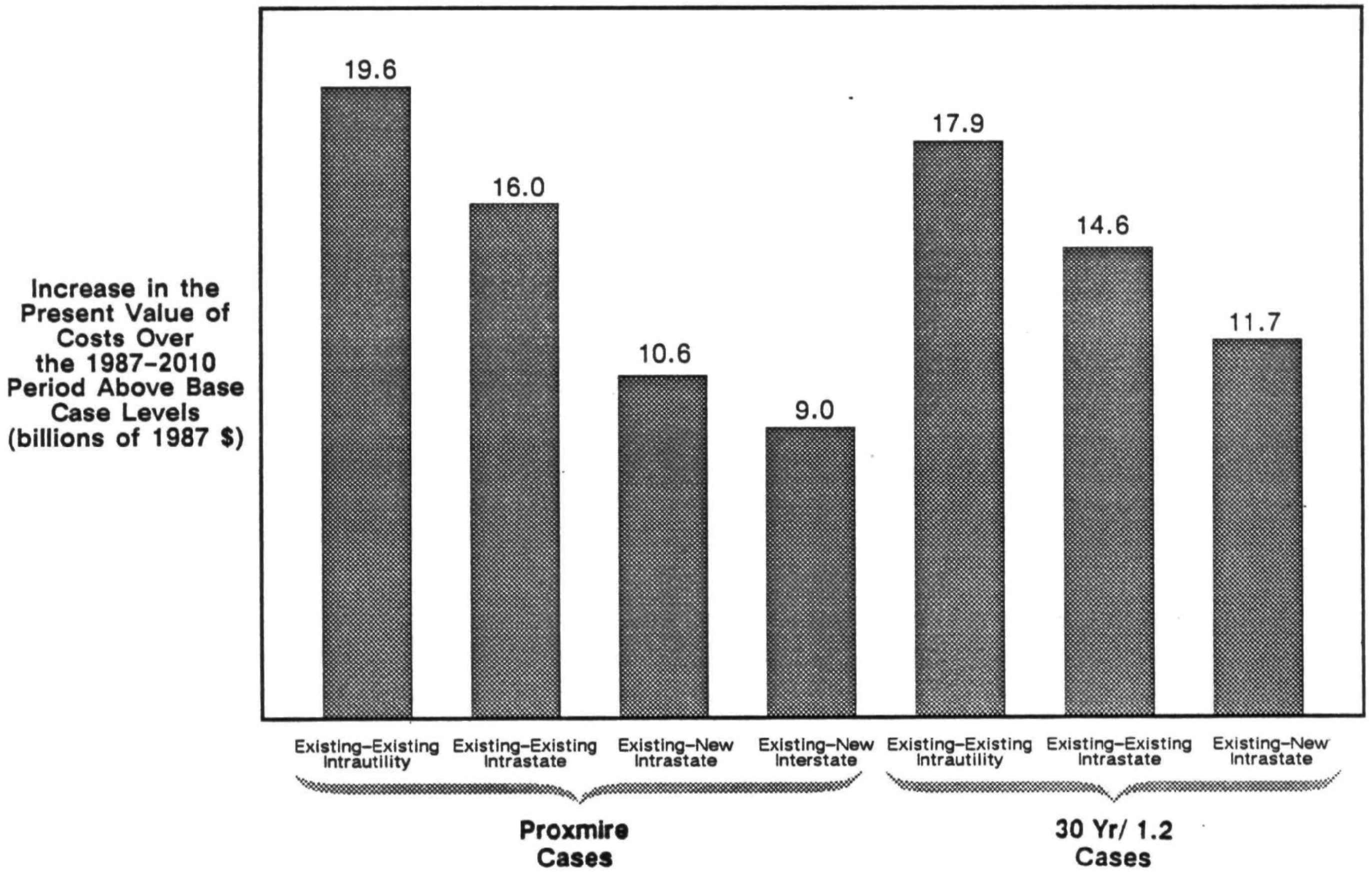
EFFECTS OF EXISTING-NEW TRADING:
PRESENT VALUE OF COSTS

- Expanding emissions trading to allow existing-new trades reduces the present value of costs substantially, by approximately 20 percent under the 30 Yr/1.2 case and about 35 percent under the Proxmire case, relative to the cost of the same emission reduction proposals with only existing-existing trading. Under Proxmire, this reflects relatively low annualized cost savings in the early years (about 2 percent in 1995 and about 7 percent in 2000) and much higher savings (about 70 percent) by 2010. Under 30 Yr/1.2, this reflects relatively higher annualized cost savings in the earlier years (about 55 percent in 2000) and smaller savings (about 10 percent) by 2010.

- Allowing existing-new trades reduces the present value of costs of Proxmire more significantly than 30 Yr/1.2 because the net annualized cost savings in 2010 under Proxmire are much greater than the net annualized cost savings under 30 Yr/1.2.

- Note that 1987 Interim EPA Base Case scrubber cost assumptions were used in these analyses. More recent studies indicate that up-to-date scrubber cost assumptions would likely be somewhat lower. Lower scrubber cost assumptions would reduce the forecasted compliance costs of the emission reduction cases, and would reduce the value (i.e., cost savings) of existing-new trading to a certain extent.

CHANGE IN PRESENT VALUE OF COSTS
WITH INCREASED TRADING FLEXIBILITY



CHANGE IN PRESENT VALUE OF COSTS WITH INCREASED TRADING FLEXIBILITY

- The changes in the present value of costs indicate significantly lower costs as trading flexibility increases:

  - -- Allowing existing-existing intrautility trading versus no trading can reduce the present value of costs by 30 to 60 percent ("no trading" case not shown on the opposite page).

  - -- Allowing intrastate trading further reduces costs by 20 percent, as compared to allowing only intrautility trading.

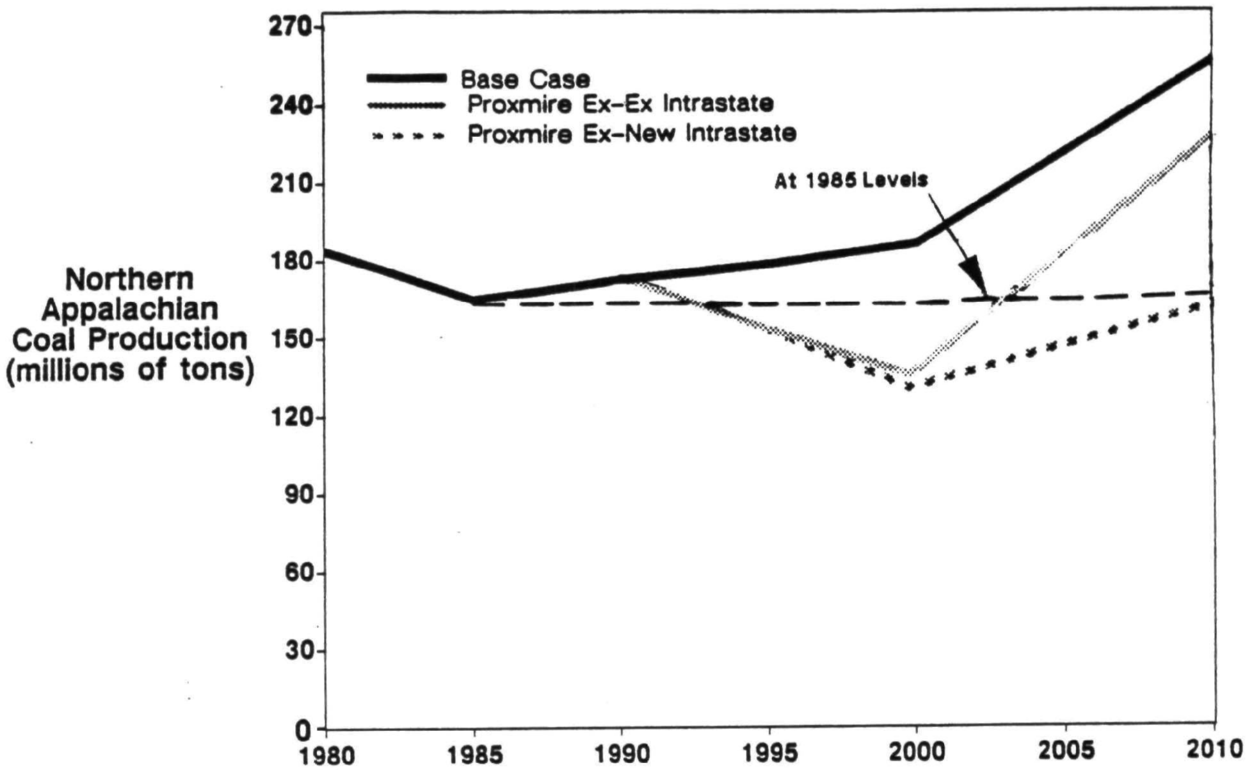
  - -- Allowing interstate trading saves an additional 10 to 20 percent, as compared to allowing only intrastate trading.

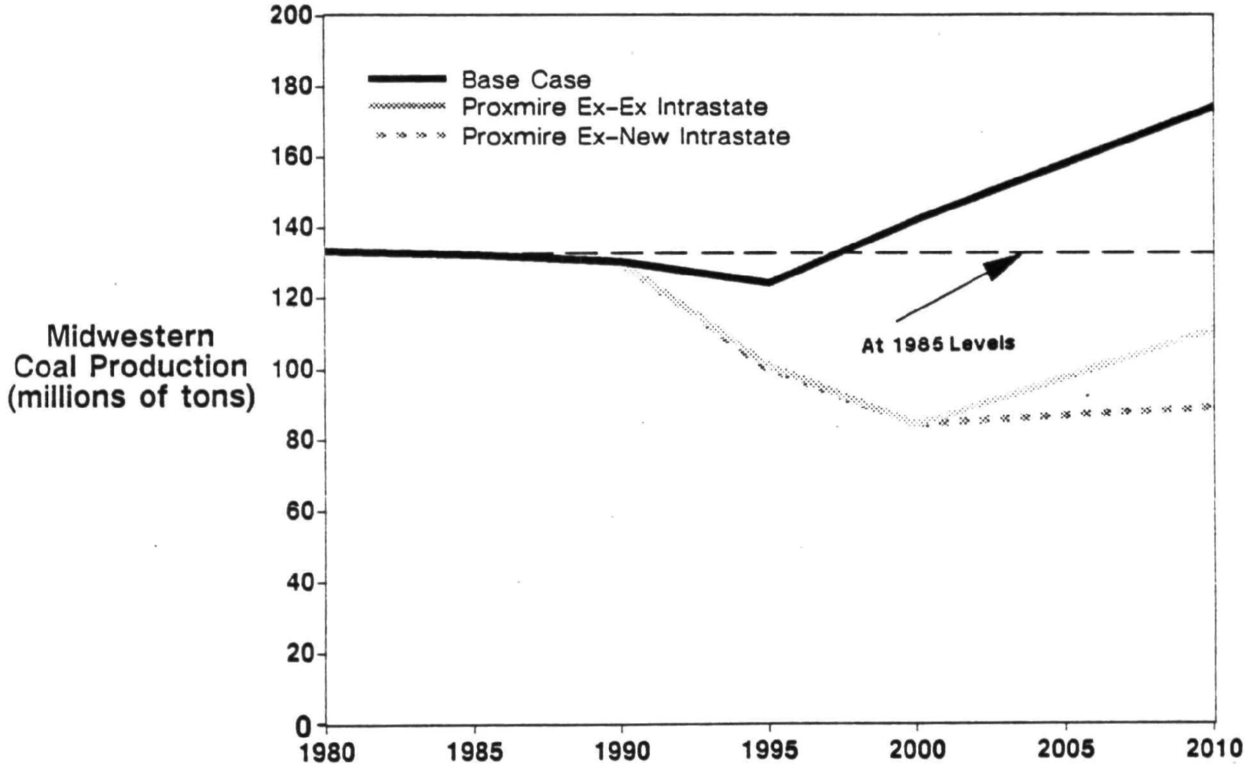
  - -- Expanding trading to allow existing-new trades reduces costs by 20 to 40 percent, as compared to allowing only existing-existing trades.

- The maximum present value cost savings result from maximum emissions trading flexibility. Existing-new interstate trading opportunities enable roughly 50 percent present value savings over an existing-existing intrautility emissions trading program. Total savings of an existing-new interstate trading program may approach 80 percent when compared to a no trading situation.

- However, as the degree of trading flexibility increases, so too would the programmatic complexity and administrative burden of an acid rain control program. The effect would be greatest for a program that combined interstate and existing-new emission trades. Increased trading flexibility would also raise a number of additional design, implementation, and enforcement issues that would need to be addressed before such a program could be successfully implemented.

REGIONAL COAL PRODUCTION





REGIONAL COAL PRODUCTION

- Coal production in high sulfur regions declined during the early 1980s as new nuclear plants were brought on-line, electricity demand growth was slow, and emissions regulations were tightened in certain states. High sulfur coal production is forecast to grow only slowly through the mid-1990s in the Base Case, as existing coal capacity is gradually utilized more to meet growing electricity demand. High sulfur coal production is forecast in the Base Case to expand rapidly after 2000 as new scrubbed high sulfur coal plants are brought on-line.

- Under the Proxmire cases, national coal production levels remain relatively unaffected, but there will be significant shifts in regional coal production. High sulfur coal producing regions, including the Midwest (Illinois, Indiana and Western Kentucky) and Northern Appalachia (Pennsylvania, Maryland, Ohio and Northern West Virginia), lose coal production as utilities shift from higher sulfur to lower sulfur coals in order to meet the emission reduction requirements. High sulfur coal production is reduced significantly below both current and Base Case levels by 1995 and 2000. After 2000, the addition of new coal plants and the absence of additional reduction requirements at existing plants results in an increase in high sulfur coal production. However, production still remains well below forecasted Base Case levels and, in the Midwest, production remains well below current levels as well.

- Similar coal production impacts are exhibited in the 30 Yr/1.2 forecasts, although there are less shifts away from higher sulfur coals by 1995 and 2000 because fewer reductions are required, and more shifts by 2010 because more reductions are required.

- Allowing existing-new emission trading results in further increases in low sulfur coal production at the expense of high sulfur coal production. This occurs because (1) utilities choose to build new <u>unscrubbed</u> powerplants which use low or medium sulfur coals in lieu of new <u>scrubbed</u> powerplants which are forecast in the Base Case to use higher sulfur coals in some instances, and (2) in order to offset emission increases at new powerplants, utilities must further reduce emissions from existing powerplants, usually through increased fuel switching.

CHANGES IN REGIONAL AND NATIONAL COAL MINE EMPLOYMENT
(Thousand Workers)

	Actual 1980	Actual 1985	Base 2000	Change in Job Slots Relative to Base: Proxmire In-State Ex-Ex	Change in Job Slots Relative to Base: Proxmire In-State Ex-New	Base 2010	Change in Job Slots Relative to Base: Proxmire In-State Ex-Ex	Change in Job Slots Relative to Base: Proxmire In-State Ex-New
Northern Appalachia								
Pennsylvania	36	22	18	-5	-5	30	-3	-12
Ohio	15	9	5	-2	-2	7	-2	-3
Maryland	1	1	--	--	--	--	--	--
Northern W. Va.	18	13	12	-1	-1	18	-2	-5
TOTAL	70	45	35	-8	-9	54	-7	-20
Central Appalachia								
Southern W. Va.	36	24	24	+4	+4	33	+3	+4
Virginia	16	13	13	+2	+2	18	+2	+3
Eastern Kentucky	35	30	29	+5	+6	41	+4	+6
Tennessee	4	3	3	--	--	4	--	--
TOTAL	91	70	69	+12	+12	95	+8	+13
Southern Appalachia								
Alabama	12	9	6	--	--	9	-1	-2
TOTAL	12	9	6	--	--	9	-1	-2
Midwest								
Illinois	18	14	13	-7	-7	17	-8	-10
Indiana	5	5	2	--	--	4	-2	-2
Western Kentucky	12	8	5	-1	-1	8	-2	-4
TOTAL	35	27	20	-8	-8	29	-12	-16
Rest of U.S.	23	20	24	+6	+6	47	+8	+14
TOTAL U.S.	231	170	154	+1	+1	235	-4	-11

COAL MINING EMPLOYMENT

- While overall national coal production under the Base Case is forecasted to increase at a relatively high rate of growth (roughly 2 percent per year between 1985 and 1995), national coal mining employment grows at a much slower rate (and, in fact, declines overall by 1995). This is because of (1) the expected continuation of productivity improvements (i.e., more coal produced per miner), due to advances in technology and increasingly efficient work forces, and (2) expected shifts in production towards higher productivity (i.e., less labor intensive) mines in the West.

- Regional coal mining employment impacts under Proxmire and 30 Yr/1.2 are similar to the regional coal production impacts discussed earlier, with declines in high sulfur regions and increases in low sulfur regions, relative to Base Case levels.

- Expanding the geographic scope of trading under Proxmire and 30 Yr/1.2 to the intrastate or interstate level is forecasted to have relatively small effects on regional and national coal mining employment, beyond the employment impacts of Proxmire and 30 Yr/1.2 with only intrautility trading.

- Through 2000, the option of existing-new trading is forecasted to have relatively minor effects on coal mining employment (beyond those resulting from existing-existing trading), as few new coal plants that can utilize such trading opportunities are forecasted to be built. By 2010, however, significant shifts in regional coal mining employment are forecasted under existing-new trading.

- Nationally, coal mining employment in 2010 under existing-new trading falls by 11 thousand (5 percent) relative to the Base Case, as compared to a drop of 4 thousand (2 percent) with just existing-existing trading. The additional reduction in employment associated with existing-new trading occurs because (1) many new plants are built without scrubbers, resulting in decreased coal consumption (because unscrubbed powerplants are more efficient), and (2) new plants use more lower sulfur coals, much of which is from Western mines of higher productivity.

- Note that the losses in mining employment relative to Base Case levels that are estimated herein (i.e., "job slot" losses) reflect losses in the number of coal mining jobs. They do <u>not</u> reflect the number of existing miners who will lose their jobs. Some of the job slot losses represent opportunity losses (i.e., new jobs that are forecasted to be created under the Base Case but not under the emission reduction scenario examined). Moreover, many of the currently employed coal miners may retire or change jobs voluntarily prior to 2000 or 2010. Accordingly, the number of miners actually thrown out of work under an acid rain program would likely be considerably lower than the "job slot" losses shown on the opposite page. Further, it should be noted that the shifts in coal mining employment discussed herein, while significant (gross job slot losses of up to 38 thousand jobs), are eclipsed by the losses that have occurred in the industry over the 1980-85 period (61 thousand job slot losses).

NET AND GROSS MINING JOB SLOT LOSSES

	Change From Base Case: 2010		Change:
	Proxmire Intrastate Existing-Existing	Proxmire Intrastate Existing-New	Existing-New vs. Existing-Existing
U.S. Net Mining Job Slot Losses (thousand workers)	-4	-11	-7
U.S. Gross Mining Job Slot Losses (thousand workers)	-20	-38	-18
U.S. Total Gross Job Slot Losses (Including Non-Coal Mining Jobs)	?	?	?
Utility Annualized Compliance Costs (billions of 1987 $/yr)	+2.9	+0.9	-2.0

NET AND GROSS COAL MINING JOB SLOT LOSSES

- Net national coal mining job slot losses discussed on page 2-27 reflect the losses in overall U.S. coal mining employment. While this is an important measure of coal mining employment, it does not indicate the extent of regional job losses or dislocations. This concept is represented by gross coal mining job slot losses (or the sum of regional mining job slot losses).

- Gross coal mining job slot losses in the U.S. under Proxmire are roughly 17-18 thousand workers by 2000 with either existing-existing or existing-new trading at the intrastate level.[6/] By 2010, this range increases significantly: 20 thousand job slots are lost under existing-existing trading versus 38 thousand job slots under existing-new trading. In other words, there are 18 thousand more gross job slot losses assuming existing-new trading by 2010. Because annualized utility compliance costs are forecasted to be $2.0 billion higher under existing-existing trading than under existing-new trading by 2010, the cost per gross coal mining job slot saved by restricting trading to the existing-existing level can be roughly estimated at $100,000 per year. However, as discussed below, the cost per total gross job saved (including non-coal mining jobs) could be quite different.

- Gross coal mining job slot losses presented herein indicate only a portion of the total gross job losses or dislocations which could occur as a result of regional mining employment losses. Other jobs dependent upon local mining activity could also be lost as a result of mine shutdowns, and could lead to a significantly larger number of total gross job losses. In addition, lost investments in mines that are closed, in firms that are adversely affected by coal mining job losses, and in regional infrastructure abandoned (particularly in mining towns which experience severe economic hardship due to mine shutdowns) could also be significant, and have not been estimated herein. On the other hand, lower electricity costs resulting from existing-new trading (as opposed to existing-existing trading) would result in higher regional economic activity in many parts of the country. Furthermore, there would likely be new jobs created to support increased mining activity in regions which experience coal production and mining employment gains. These impacts were also not assessed herein.

6/ These analyses were conducted using 1987 Interim EPA Base Case mining productivity assumptions developed in late 1986. However, recent trends in mining productivity have indicated higher productivity growth than assumed in these analyses. Higher assumed productivity growth would result in lower future base case employment forecasts, and smaller impacts on forecasted employment under Proxmire and 30 Yr/1.2, since productivity at incremental mines would be higher.

CAVEATS AND UNCERTAINTIES

Many assumptions and uncertainties underlie the findings presented in this chapter concerning the effects of emissions trading under alternative acid rain control proposals. Of particular importance are those factors that relate to the implementation of intrastate, interstate or existing-new trades. These are discussed in detail in Chapter Three. Some of the key assumptions and uncertainties are noted below:

- The analyses presented herein assume that the emissions baseline for determining "extra" reductions at existing powerplant units under the Proxmire and 30 Yr/1.2 proposals would be the new, tighter emission targets imposed under these emission reduction proposals. For new powerplant units, the baseline was assumed to be the actual emissions that would result from NSPS-Da requirements, as projected under the Base Case. In the case of existing-new trades, it was also assumed that new units that rely on emission reductions from existing units must develop other existing trading partners or install scrubbers (or other equivalent controls) once the existing units retire.

- The results presented in this report assume that utilities will achieve compliance with emission reduction requirements in least-cost fashion, by pursuing the most economically efficient combination of emissions trades possible, subject to noted constraints. However, a range of technical, financial, programmatic, and institutional considerations would likely serve to limit either the ability or the desire of utilities to engage in all of the emission trades which are projected to occur, especially in the case of trading beyond the existing-existing intrautility level. To the extent that full scale implementation of emission trading (as envisioned in these analyses) is constrained by these considerations, the cost savings and other impacts presented herein would be reduced accordingly.

Also discussed in Chapter Three are the assumptions made in these analyses regarding a number of other important emissions trading issues. These pertain to the structure of an emissions trading program and the manner in which it would be monitored and enforced. They also pertain to the relationship between emission trading and other environmental objectives, such as attainment of the National Ambient Air Quality Standards (NAAQS), determination of best available control technology (BACT), and prevention of significant deterioration (PSD) in areas already attaining the NAAQS. These issues are critical in determining how an emission trading program would work in practice, how effective and reliable it would be in producing the required emission reductions, and the extent to which the projected savings would be achieved.

There are also many analytical assumptions and uncertainties of note that do not relate solely to the use of emissions trading. These include cost and technology assumptions for SO_2 control options, site-specific constraints affecting alternative emission reduction strategies, and major assumptions incorporated into the Base Case (such as electricity demand growth rates, oil and gas prices, coal mining productivity, etc.). These assumptions have very important effects on the utility cost and coal market impacts presented herein. These assumptions and uncertainties are also addressed in Chapter Three.

CHAPTER THREE

CAVEATS AND UNCERTAINTIES

This chapter discusses a number of caveats, assumptions and uncertainties which have important effects on the findings of this analysis, including:

- Implementation Assumptions and Uncertainties Regarding Emission Trading - This section discusses the assumptions and uncertainties associated with the implementation of emission trades, particularly those trades between existing and new sources. This includes issues regarding administrative and transaction costs, the determination of baseline emissions, powerplant retirements, PSD and new source review, monitoring and enforcement, and barriers to implementation.

- Sulfur Dioxide Control Assumptions - This section presents generic scrubber costs, describes site-specific retrofit scrubber costs, and discusses assumptions regarding such issues as new control technologies, removal efficiencies and scrubber lifetimes, and the impacts of these assumptions on emission reduction costs and on the value of existing-new plant trades.

- Site-Specific Constraints Affecting Alternative Reduction Strategies - This section discusses the site-specific costs and constraints that can significantly affect individual powerplant compliance decisions.

- Base Case Assumptions - This section highlights some key EPA Base Case assumptions, such as electricity growth rates, world oil and gas prices, powerplant lifetimes, and coal mining productivity and reserves.

- Restricting Utility Forecasts Between Scenarios - This section identifies key variables (such as gas consumption, interregional power flows, and new coal and nuclear powerplant builds) that are restricted in the emission reduction cases to Base Case levels.

- Direct Costs and Near-Term Constraints Not Analyzed - This section identifies certain costs of the emission reduction cases that were not analyzed, such as oil and gas price changes associated with changes in utility fuel demands.

- Indirect Costs Not Measured - This section discusses the indirect costs of the emission reduction cases that were not analyzed. These include the administrative and transaction costs of emissions trading, the indirect and regional economic impacts associated with the different control options, the costs of abrogating long-term coal contracts, and the opportunity costs of capital due to increased investments in control technologies.

IMPLEMENTATION ASSUMPTIONS AND UNCERTAINTIES REGARDING EMISSIONS TRADING

A number of assumptions were made regarding emission trades between utility sources, and in particular between existing and new sources. Further, there are important caveats and implementation uncertainties associated with these emission trades:

- <u>Administrative and Transaction Costs</u> - Emission trades between individual powerplant units and, in certain cases, between utilities and across state lines, would likely result in additional administrative costs for establishing regulatory mechanisms to oversee and enforce the trades. Transaction costs (including brokerage-type commissions and costs to utilities for preparing new operating permit applications) could also be incurred if an emissions trading program were established. These administrative and transaction costs were not estimated as part of this analysis but could be significant. To the extent there are transaction costs, the amount of emissions trading and net cost savings associated with trading as estimated for this analysis would be reduced.

- <u>Baseline Requirements</u> - In permitting emissions trading between "existing" powerplant units under the Proxmire and 30 Yr/1.2 proposals, the emission baseline from which relative increases and decreases in emissions were calculated was each existing unit's allocated emission target (under the respective emission reduction proposal). For example, under Proxmire, each "existing" SIP unit was subject to an emission target corresponding to a 2.0 lb. SO_2/mmBtu emission rate (Phase I) or a 1.2 lb. SO_2/mmBtu emission rate (Phase II), and its historical 1980 fuel consumption. In the case of the 30 Yr/1.2 proposal, Base Case projected fuel consumption and a 1.02 lb. SO_2/mmBtu annual average emission rate served as the basis for calculating each existing SIP unit's emission target.

  For "new" units, forecasted "actual" emissions from the Base Case (assuming the application of NSPS requirements) were used as the baseline for trading. Under the Base Case, most new units scrubbed low or medium sulfur coals, resulting in relatively low forecasted actual emission rates. The average emission rate forecasted in the Base Case by 2010 for new coal powerplants is 0.3 lb. SO_2/mmBtu (on an annual average).

  However, in implementing specific existing-new trades under an actual acid rain control program, it would be difficult to define baseline emissions for new units in terms of forecasted actual emissions. Baseline requirements for new units would likely have to be related in some way to source-specific allowable emissions or based on some other objective criterion, such as average actual emission rates associated with applicable new source control requirements (e.g., a common baseline for all new units, reflecting average new source emission rates, or different baselines for different subcategories of new units based on geographic location and other criteria).

To the extent that these baseline levels are established closer to the maximum emission rates allowable for new units (i.e., 0.6-0.8 lbs. SO_2/mmBtu, which are typical annual average rates for high or very high sulfur coals subject to the 90 percent total removal requirement), the number of existing-new trades and the associated cost savings would be greater than forecasted herein, but fewer emission reductions would result. To the extent much lower emission rates were used to establish baseline requirements for new plants, there would be less existing-new trades and hence lower cost savings, but more emission reductions would be achieved.

Powerplant Retirements -- Powerplant retirements can have a very important impact on the value of emissions trading (especially existing-new trading) since they partly determine how many new plants are built, as well as how many existing plants are available to engage in trades. In this analysis, few coal burning units are assumed to retire through 2010 (the forecast horizon of this study), given the 60-year lifetime assumption for coal-fired units and the fact that few existing coal units were built before 1950. Hence, powerplant retirements constitute a relatively insignificant factor in this analysis. (For a discussion of the effects of powerplant retirements in the long-term, see Very Long Term Impacts of Existing-New Trades, below.)

The treatment of emission reductions resulting from powerplant retirements (i.e., the extent to which they are considered creditable for purposes of trading) can also have a very important impact on the results of this analysis.

For existing-new trades under the Proxmire bill and the 30 Yr/1.2 Lb. proposal, it was assumed that powerplants that engage in emission trades must develop other "existing" trading partners or install controls to meet new source requirements on-site once the initial trading partners retire. For existing-existing trades under the 30 Yr/1.2 Lb. proposal, it was also assumed that powerplants that engage in trades must obtain reductions from other partners or reduce further from on-site once the initial trading partners retire. To the extent that sources were allowed to continue to rely on emission reductions from existing powerplants beyond their retirement, there would be more emission trades and lower costs. There would also be higher emissions because no further emission reductions would be required to replace reductions from retired plants.

In contrast, for existing-existing trades under the Proxmire bill, this analysis assumed that powerplant retirements did receive emission reduction credits. As existing powerplants retire, the overall emission target that must be met across all existing plants does not change or is not reduced to account for fewer existing sources. However, this interpretation of the Proxmire bill has minimal effects on the resulting forecasts because of the few powerplant retirements by 2010.

- Technology Requirements Under NSPS - EPA has twice promulgated an NSPS for electric utilities. The original NSPS, promulgated in 1971, imposed a uniform national emission limit of 1.2 lb. SO_2/mmBtu. This limit could be met either by using low sulfur coal, or by using any combination of high, medium, and low sulfur coal in conjunction with add-on control technology. In most cases, the use of low sulfur coal provided the least-cost method of compliance, and add-on controls were generally not installed.

  The new NSPS (Subpart Da), promulgated pursuant to the Clean Air Act Amendments of 1977, was conceived in part to counter long-term potential adverse impacts to high sulfur coal producing regions associated with the original NSPS. By stipulating that (in addition to meeting the 1.2 lb. SO_2/mmBtu standard) a fixed percentage of SO_2 emissions must be removed from input coal burned at new coal powerplants, NSPS Subpart Da effectively mandates the use of scrubbers. NSPS Subpart Da has the effect of (1) requiring more emission reductions from new units than under the original NSPS, and (2) making high sulfur coal use more economic at new units relative to the original NSPS.

  For the existing-new trading envisioned in this analysis to be possible, statutory and regulatory amendments would be required in order to eliminate the scrubber requirements, and to allow the emission reductions associated with NSPS Subpart Da to be met by means of fuel switching and trades with existing sources.

  Since any emission increases from new sources above the levels they would have been forecasted to emit (assuming the operation of scrubbers designed to meet NSPS Subpart Da) must be offset by extra reductions from existing units, the overall level of emission reductions resulting from NSPS Subpart Da would not change because of existing-new trading. Further, as noted in Chapter Two, utility costs would be reduced. However, as also discussed in Chapter Two, existing-new trading would result in significant shifts in coal production and coal mining employment from high sulfur coal producing regions to low sulfur coal producing regions.

- Other Technology-Based Requirements Under NSR - In addition to NSPS, new powerplant units may be subject to other technology-based requirements under New Source Review (NSR).[1/] The NSR program mandates that major new units locating in areas attaining the ambient air quality standards apply Best Available Control Technology (BACT). Most areas of the country are currently designated "attainment" for SO_2, and virtually all new powerplant units are expected to be located in these areas. BACT is determined on a case-by-case basis for individual units following a detailed evaluation of alternative control options, but must be at least as stringent as NSPS. As with NSPS, the current NSR regulations would need to be modified to allow BACT requirements to be satisfied by trades with existing sources.

  Because it is difficult to estimate BACT requirements for future unplanned coal units, actual Base Case emissions for unplanned units were forecast based on current or expected emission requirements for planned coal units, and were used as the baseline for new units engaging in trades. For a number of states, state NSPS limits or BACT requirements were assumed to be more stringent than NSPS Subpart Da. Nevertheless, it is likely that future BACT determinations in these as well as other states will commonly result in tighter emission limits than assumed for new unplanned coal units in this analysis. To the extent that tighter BACT requirements would result in lower actual emissions, Base Case emissions would be lower, and additional compensating reductions from existing sources would have to be provided in the existing-new trading cases in order to achieve the same overall emission reductions as under the current NSR program.

  However, tighter BACT requirements would raise the marginal cost of emissions control at new sources, thereby increasing the cost savings enabled by each existing-new trade -- even with actual emissions under BACT used as the baseline. Since further existing-new trading opportunities would also be created, the total savings resulting from existing-new trading could be somewhat higher than estimated herein. Therefore, to the extent that the actual emissions forecasted in this analysis for unplanned new units (based on BACT/NSPS for planned coal units) are greater than the actual emissions that would result from future BACT requirements, a more conservative (i.e., lower) estimate of the value of existing-new trades would result.

1/ New units constructed at an existing plant may avoid the requirements of NSR by offsetting their emissions with reductions at other units within the plant, such that no significant increase in "net" plantwide emissions occur. This regulatory procedure is called "netting."

- Ambient Air Quality Standards/PSD Increments - For this analysis, existing-existing trades were permitted only if SIP emission limits continued to be met (and hence ambient air quality standards were not violated).[2/] For existing-new trades, it was assumed that new units would not be required to meet NSPS or BACT control requirements on site, but would be located such as not to violate ambient air quality standards, Prevention of Significant Deterioration (PSD) increments, or other local air quality requirements. Most new units engaging in existing-new trades under the Proxmire or 30 Yr/1.2 proposals are forecasted to use low sulfur coals without scrubbing, and thus are not very likely to violate these requirements.

  The average annual emission rates forecasted in 2010 for new units that trade with existing units under the Proxmire and 30 Yr/1.2 existing-new trading cases are 0.8-0.9 lb. SO_2/mmBtu. While the emission rates at new units engaging in existing-new trades are forecast to increase significantly (from a Base Case average of 0.3 lb. SO_2/mmBtu), nearly all of these units (94 percent under Proxmire intrastate, 97 percent under Proxmire interstate, and 100 percent under 30 Yr/1.2 intrastate) would still satisfy the requirements of the original 1971 NSPS (1.2 lbs. SO_2/mmBtu on a 30-day average). Moreover, any emission increases relative to current NSPS and BACT requirements would have to be offset by extra reductions at existing units, and these offsetting reductions would often be made at other units in the same plant or in the same general vicinity. Due to these considerations, and to the fact that background levels of SO_2 are generally expected to decline significantly in most parts of the country under Proxmire or 30 Yr/1.2, local air quality constraints are not (in most cases) expected to be a limiting factor in the implementation of existing-new trades under these emission reduction proposals.

  Local air quality constraints are more likely to be a limiting factor under the Base Case with existing-new trading and a 1.2 to 1 trading ratio. Under this scenario, the average annual emission rate forecasted by 2010 for new units that trade with existing units is 1.6 lbs. SO_2/mmBtu. Only 61 percent of the new units that trade would satisfy the original NSPS, while 33 percent are forecasted to have emission rates of 2.8 lbs. SO_2/mmBtu or higher. Even under this scenario, however, the majority of new units that engage in existing-new trading are not expected to face air quality constraints, because of low sulfur coal use, offsetting reductions from nearby units, or a combination of these factors. There may be, however, a much greater incentive for utilities to locate new units at or near existing powerplants.

2/ It should be noted that the emissions "increases" that would be allowed at existing powerplants as part of a trade are not increases above allowable SIP levels. Rather, they are increases relative to the new, tighter limits that would be imposed under the acid rain control program in a unit-by-unit (no trading) framework, and would be compensated by further reductions from other sources beyond their new, tighter limits.

To the extent that local ambient air quality constraints would serve as a limiting factor in the implementation of individual existing-new trades under Proxmire, 30 Yr/1.2, or the Base Case, these constraints could often be overcome (while still preserving most of the cost savings associated with trading) by using even lower sulfur fuels for the units in question, down-scaling the size of the units, or siting them in an alternative location.

It should also be noted that the long-term economic growth management goals of the PSD program (i.e,. maximizing the availability of air quality increment over the long-run) would not be jeopardized by existing-new trading, since existing-new trades cannot extend beyond the lifespan of the existing source, and new sources would be required to meet NSPS and BACT requirements on-site once existing source trading partners retire.

Nevertheless, for existing-new trades to occur, local communities would have to accept a new unscrubbed unit with higher emissions in exchange for additional reductions at existing units. The existing units providing extra reductions would not necessarily be located at the same plant or general vicinity as the new unit, but could be located at other distant powerplants and even in other states. Given the general difficulties in siting new polluting sources, and given that well over 100 scrubbers have now been installed, it could be difficult to convince local communities to accept a new powerplant unit without a scrubber.

With these considerations in mind, further review and analysis is necessary to fully assess the extent to which ambient air quality standards, PSD increments, and other local air quality requirements might reduce the amount and value of existing-new trading, particularly in the long term (i.e., beyond 2000).[3]

3/ In addition to local air quality issues, issues related to the generation and disposal of solid waste can also be important in the siting of new powerplants. However, solid waste issues have not been considered in this analysis.

- Structure of an Acid Rain Program - An emissions trading program could be structured in a number of ways under an acid rain control proposal. These relate to the manner in which emission reduction requirements are initially allocated and the procedures for reallocating emission reduction requirements over time.

  For example, an acid rain control proposal could mandate that uniform emission reduction requirements be initially allocated to sources on a unit-by-unit basis. Intrautility, intrastate or interstate trading could then be accomplished by allowing two or more units to alter their allocations in tandem, so long as the same amount of overall reductions are provided. Each trade would be approved by the appropriate regulatory agency (or agencies), so that the legally binding emission limits for each source can be revised. While the specific limits applicable to the sources would change as a result of the trade, each source would continue to be subject to its own enforceable limit.

  Alternatively, the initial emission reduction requirements could be allocated in the form of a utility, statewide or regional emission reduction requirement or emission cap. Under this approach, the utility or state would be given discretion in initially allocating unit-by-unit reduction requirements, as well as in reallocating them in the future. Reduction requirements for the individual units would be allowed to change (or "float") freely over time without case-by-case regulatory review, as long as the overall utility, statewide or regional reduction requirements are met.

  The modeling methodology and assumptions used in the analyses presented herein are consistent with both of these general approaches for allocating emission reduction requirements. Utility, statewide, or regional emission targets were derived from emission reduction requirements stipulated in the Proxmire bill and the 30 Yr/1.2 proposal, and then imposed in ICF's Coal and Electric Utilities Model (CEUM) for utility sources to satisfy in a least-cost manner (i.e., analogous to the "floating" bubble approach) in each forecast year. However, the five/ten year periods between the forecast years shown herein should be more than adequate time for the revision procedures of a more formal allocation/reallocation system involving case-by-case regulatory reviews to occur, and the results of the modeling efforts should therefore be representative of this approach as well.

- <u>Monitoring and Enforcement</u> - This analysis assumes that an acid rain related trading program could be designed to be fully enforceable so that the emission reductions projected herein would be reliably obtained. Monitoring and enforcement procedures would have to be designed to ensure compliance on whatever time scale is necessary. One way of accomplishing this would be to mandate the use of continuous emissions monitors, which would provide an effective means of monitoring and enforcing reduction requirements. Such an approach would be particularly important in the case of a "floating" bubble (discussed above), and would alleviate the special difficulties associated with simultaneously measuring emissions from all units in order to determine compliance with an overall emissions cap.

  Special concerns, however, may arise with respect to the ability to enforce future retrofit requirements under existing-new trading. As existing source trading partners retire and new unscrubbed units would be required to retrofit control equipment, utilities may attempt to assert that installation of expensive scrubbers (or equivalent controls) would cause economic hardship or, because the once new units have a shorter remaining life, that such controls would no longer be cost-effective. However, these concerns can be mitigated by requiring new units, as a condition for trading, to preserve retrofit space and waive all equity arguments in light of the savings realized through trading. These concerns can be further mitigated by incorporating into an acid rain control bill severe statutory penalties for failure to meet retrofit control obligations.

- <u>Barriers to Implementation</u> - While the trading schemes analyzed in this report have the potential to reduce costs significantly, the extent to which such cost reductions would be realized in practice would depend upon the degree to which trading mechanisms can be successfully implemented. A number of technical, economic, administrative, and institutional considerations may serve to limit trading activity under an emission reduction program. For example:

  -- While state public utility commissions (PUCs) and state environmental agencies are both concerned with economic and environmental factors, the purview of state PUCs is economic and financial issues, while the primary focus of state environmental agencies is pollution control. Emission trades involve elements of both, and will require a greater degree and a different type of cooperation than currently practiced.

  -- Utility managers and operators may be reluctant to engage in trading, due to uncertainty about the regulatory treatment of revenues and costs associated with trades.

  -- Imperfect and incomplete information on other potential trading partners and on source emission levels may inhibit or prevent full exploitation of emission trading opportunities.

  -- The time allowed for the state or utility planning process under some acid rain control proposals may not be sufficient for trading arrangements to be completed before federal approval of particular control strategies is required.

  -- As discussed above, ambient standards, PSD increments, and other local air quality requirements can prevent the approval of existing-new trades in certain situations, or require new sources to take additional steps (e.g., using even lower sulfur fuels) in order to effectuate an existing-new trade.

  A number of approaches exist to overcome some of these implementation problems. Nevertheless, the extent to which trading activity is constrained by such impediments will be critical in determining the degree to which the savings forecasted in this analysis will be achieved.

- Very Long Term Impacts of Existing-New Trades - This analysis examined the impacts of existing-new trades through 2010, but did not assess the impacts beyond 2010. After 2010, many existing powerplants are likely to retire and the value of existing-new trades would decline, as fewer existing unit trading partners would be available. By 2040, all existing units would retire (assuming a 60 year lifetime), and new units which did not install scrubbers (i.e., because they purchased emission reductions from existing units) would have to install controls in order to meet NSPS and BACT.

  Existing-new trading can thus be thought of as an optional program for deferring installation of a scrubber as long as cheaper equivalent reductions from existing sources are available. The costs of installing a scrubber or equivalent controls at new sources will ultimately be faced by those utilities opting to engage in existing-new trades, and these post-2010 costs were not addressed herein. Further, to the extent costs of retrofitting controls at already built facilities would be greater than installing controls at these facilities when they were new, total costs could be somewhat greater. However, if new facilities were built such that a scrubber could be added at a late date (e.g., by designing and leaving in the appropriate space during construction), then retrofit costs would be minimized. Moreover, by deferring the installation of hardware, the utility could benefit from potential development and deployment of alternative, lower cost control technologies. In any case, the deferral option provided by existing-new trades is likely to be attractive to utilities because future capital expenditures are more heavily discounted than current investments.

SULFUR DIOXIDE CONTROL EQUIPMENT COSTS AND ASSUMPTIONS

Sulfur dioxide control costs, removal efficiencies, retrofit factors, scrubber types, and new control technology assumptions have important impacts on the forecasted costs and coal production of the various emission reduction cases and, in particular, the value or net cost savings associated with existing-new trades. The costs of retrofitting a scrubber at an existing unit are shown in Table 3-1. The costs of scrubbers plus particulate control equipment at new powerplants meeting NSPS Subpart Da regulations (70 - 90 percent required total removal including washing credits and a 1.2 lb. ceiling, all enforced on a 30 day average) are shown in Table 3-2. The costs of particulate controls at new unscrubbed plants (e.g., new plants which obtain emission offsets from existing plants) are shown in Table 3-3. The costs, removal efficiencies, and other assumptions are discussed below:

- <u>Costs</u> - The level of retrofit scrubber costs will affect the forecasted costs of reducing emissions from existing sources. Higher or lower scrubber costs will accordingly raise or lower the forecasted cost impacts.

  The costs of scrubbing a new powerplant have a substantial impact on the net cost savings associated with existing-new trades. Lower scrubber costs would tend to reduce the net cost savings associated with existing-new plant trades since the savings associated with <u>not</u> scrubbing these plants would be lower. Higher new plant scrubber costs would result in greater net cost savings associated with existing-new trades.

  The relative costs of scrubbing high versus lower sulfur coals could influence forecasted coal production. Many new plants are forecasted to scrub lower sulfur coals because the costs of scrubbing lower sulfur coals are lower than scrubbing high sulfur coals in order to meet NSPS. If the costs of scrubbing lower sulfur coals were more expensive (relative to scrubbing high sulfur coals) than assumed currently, more medium or high sulfur coals might be scrubbed, potentially resulting in more high sulfur coal production in the Base Case.

  In general, lower scrubber costs would result in a reduction in the costs and would alter forecasted coal production. Lower scrubber costs would induce powerplants to retrofit more scrubbers and scrub higher sulfur coals rather than switching to low sulfur coals. High sulfur coal production would likely benefit. Higher scrubber costs would have the opposite but less significant effects because relatively few scrubbers are forecast to be retrofitted in most of the emission reduction cases examined herein.

TABLE 3-1

RETROFIT SCRUBBER COSTS FOR
EXISTING UTILITY POWERPLANTS (1.1 FACTOR)

	Sulfur Level						
	Very Low	Low	Low-Medium	Medium	High-Medium	High	Very High
Scenario Specifications							
A. Annual SO2 Emission Limit (lbs./mmBtu)	0.16	0.22	0.34	0.25	0.33	0.50	0.67
B. Annual SO2 Removed (lbs./mmBtu)	0.64	0.86	1.32	2.25	3.00	4.50	6.00
C. Percent Removal	80%	80%	80%	90%	90%	90%	90%
D. Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet	Wet
Scenario Cost (early 1986 $'s)							
A. Capital ($/kw)	207.40	210.90	224.90	238.70	246.10	261.90	270.50
B. O&M							
-- Fixed ($/kw-yr)	5.67	5.78	5.95	9.63	9.98	10.42	10.75
-- Variable (mills/kwh)	1.49	1.68	1.97	1.89	2.04	2.28	2.50
C. Capacity Penalty (%)	1.54	1.54	1.60	1.96	2.06	2.22	2.38
D. Energy Penalty (%)	2.56	2.21	2.76	4.42	4.51	4.68	4.70
E. Reliability Penalty (%)	2.70	2.70	2.70	2.70	2.70	2.70	2.70

Sulfur Level	Lbs. SO2/mmBtu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.34-5.00
Very High Sulfur	More than 5.00

Dry: Spray Dryer Flue Gas Desulfurization (FGD) System
Wet: "Wet" Limestone FGD System

Source: EPA estimates. Capital and fixed O&M costs shown above reflect a retrofit factor of 1.1 (i.e., the capital cost of retrofitting a scrubber is 1.1 times the capital cost of installing a scrubber at a new powerplant, and the fixed O&M cost is 1.075 times the O&M cost of a new scrubber reflecting a ten percent escalation for three-quarters of the fixed O&M costs). Most existing powerplants have higher retrofit costs. Powerplants with no plant-specific estimates were treated as follows:

Size	Capital Cost Relative to a New Scrubber	Fixed O&M Cost Relative to a New Scrubber
Greater than 400 Mw	110%	107.5%
Between 150 and 399 Mw	140%	130.0%
Less than 150 Mw	200%	175.0%

TABLE 3-2

POLLUTION CONTROL COSTS FOR NEW UTILITY POWERPLANTS
(Scrubbers and Particulate Control Equipment)

	Sulfur Level						
	Very Low	Low	Low-Medium	Medium	High-Medium	High	Very High
Capital Costs (early '86 $/kw)	181.20	185.20	193.60	277.00	279.80	283.60	292.60
Fixed O&M Costs (early '86 $kw/yr)	4.91	5.00	5.13	9.36	9.80	10.20	10.54
Variable O&M Costs (early '86 mills/kwh)	1.42	1.61	1.92	1.92	2.10	2.35	2.55
Energy Penalty (%)	2.23	2.07	2.31	4.41	4.60	4.83	4.93
Capacity Penalty (%)	1.51	1.52	1.57	1.94	2.15	2.39	2.53
Reliability Penalty (%)	2.7	2.7	2.7	2.7	2.7	2.7	2.7
Scrubber Type	Dry	Dry	Dry	Wet	Wet	Wet	Wet
Particulate Control	BH	BH	BH	ESP	ESP	ESP	ESP

Sulfur Level	Lbs. SO2/mmBtu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.34-5.00
Very High Sulfur	More than 5.00

Dry: Spray Dryer FGD System
Wet: "Wet" Limestone FGD System
BH : Baghouse
ESP: Electrostatic Precipitation

TABLE 3-3

POLLUTION CONTROL COSTS FOR NEW UTILITY POWERPLANTS
(For New Plants Built Without Scrubbers)

	Sulfur Level						
	Very Low	Low	Low-Medium	Medium	High-Medium	High	Very High
Capital Costs (early '86 $/kw)	82.80	82.80	82.80	82.80	62.10	48.30	48.30
Fixed O&M Costs (early '86 $kw/yr)	2.25	2.25	2.25	2.25	0.77	0.61	0.61
Variable O&M Costs (early '86 mills/kwh)	0.40	0.40	0.40	0.40	0.14	0.11	0.11
Energy Penalty (%)	0.95	0.95	0.95	0.95	0.21	0.21	0.21
Capacity Penalty (%)	0.95	0.95	0.95	0.95	0.21	0.21	0.21

Sulfur Level	Lbs. SO2/mmBtu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.34-5.00
Very High Sulfur	More than 5.00

Dry: Spray Dryer FGD System
Wet: "Wet" Limestone FGD System
BH : Baghouse
ESP: Electrostatic Precipitation

The scrubber cost assumptions used in the EPA Base Case were developed in the early 1980s using the TVA/EPA scrubber model. Recent analyses performed by ICF on behalf of EPA employ scrubber cost assumptions that are 40 percent lower in capital costs and 25 percent lower in O&M costs than the aforementioned EPA Scrubber cost assumptions. This was done on EPA's request in order to bring the scrubber cost assumptions more in line with current industry estimates.

- Retrofit Factors - Unit-specific retrofit factors ranging from 1.1 to 2.0 were used in this analysis to capture the difficulties and constraints inherent in retrofitting a scrubber on an existing unscrubbed powerplant. All capital costs were escalated by these factors, but only three-quarters of fixed O&M costs, the portion directly related to maintenance, were escalated. Other costs, such as operating and landfill labor and supervision, were not considered to be significantly affected by spacing limitations and congestion problems (i.e., those factors which result in higher retrofit costs). Differences among units in scrubbing costs have important impacts on selected compliance options. These site-specific retrofit factors were developed for EPA on a unit-by-unit basis for the 200 highest emitting powerplants in 1980. For other powerplant units, alternative estimates were used based on unit size. (See Table 3-1).

  Table 3-4 shows the retrofit factors for existing unscrubbed coal capacity under current EPA assumptions. Currently, there are 81 gigawatts of utility coal-fired powerplants with retrofit costs assumed to be 10-20 percent higher than the costs of a new scrubber. About 59 gigawatts of this capacity is non-NSPS capacity.

  Higher or lower retrofit factors than assumed herein will accordingly raise or lower the forecasted cost impacts, and will result in different powerplants retrofitting scrubbers.

- Scrubber Types Assumed - Conventional limestone "wet" scrubbers and spray dryer "dry" scrubbers were assumed for this analysis. Wet scrubbers are most commonly used, although dry scrubbers are being increasingly used at newer powerplants. Based on the scrubber cost assumptions, wet scrubbers are more cost-effective than dry scrubbers to retrofit on existing plants burning high and medium sulfur coals, in light of the assumption

TABLE 3-4

DISTRIBUTION OF POWERPLANT CAPACITY BY RETROFIT SCRUBBER COST FACTORS [4/] (GW)

	Retrofit Factor Categories[5/]			
	1.1-1.2	1.3-1.6	1.7-2.0	Total
Unscrubbed Coal Capacity (Gw)	81.0	59.7	67.8	208.5

that baghouses also would have to be installed if dry scrubbers were retrofitted. Dry scrubbers are more cost-effective in those rarer instances when existing plants are retrofitted with scrubbers using lower sulfur coals.

For new powerplants, the total costs (including fuel costs) of installing dry scrubbers plus baghouses are generally cheaper than wet scrubbers plus electrostatic precipitators (ESPs), even when taking into account the higher prices for low sulfur coal (which is used at powerplants with dry scrubbers).

- Scrubber Lifetime - For this analysis, it was assumed that retrofit and new scrubbers would have a useful lifetime of 30 years. Given the limited operating experience with scrubbers and retrofit applications to date, it is uncertain how long retrofit scrubbers are likely to last and/or what additional costs might be required to keep them running for 30 years. To the extent retrofit scrubbers have a shorter useful lifetime than 30 years, the annual capital charges and total costs incurred would be higher.

4/ Retrofit factors represent the percent increase of capital costs and three-quarters of fixed O&M costs for retrofit scrubbers relative to the costs of new powerplant scrubbers. Hence, a powerplant in the 1.2 retrofit factor category which retrofits a scrubber will experience 20 percent higher capital costs and 15 percent higher fixed O&M costs than the costs of new scrubber.

5/ Eight categories are used in the analysis. The total number of plants and capacity reflect the top 200 emitting powerplants evaluated for EPA plus all other existing unscrubbed capacity (on-line as of end-1985) which could potentially be affected by retrofit scrubbers. Note that this capacity includes unscrubbed NSPS capacity, which comprises a significant portion (22.4 Gw) of the 1.1-1.2 retrofit categories.

- Removal Efficiencies - A maximum annual average removal efficiency of 90 percent was assumed for retrofit "wet" scrubbers and a maximum of 80 percent was assumed for "dry" scrubbers. Assuming greater scrubber removal capabilities (at a reasonable cost) might result in more reduction through scrubbing and less through coal switching. This could result in greater high sulfur coal production. Assuming a lower maximum removal efficiency (such as 85 percent for "wet" scrubbers) would have the opposite effects.

- New Control Technologies - New sulfur dioxide control technologies were not assumed for this analysis. New "retrofit" control technologies (such as sorbent injection) could result in lower costs for meeting emission reduction requirements. Some view new emission control technologies as quite promising, and believe that they are likely to be available for use by utilities by 1995 at significantly lower costs than conventional scrubbers. However, given the limited operating experience and uncertainty surrounding the costs and performance of new control technologies, it is unlikely that many utilities would pursue this option by 1995. By 2000 or 2010, new emission control technologies are likely to be more promising however.

  On balance, the assumption of no new control technologies or no control technology improvements by 1995 is probably conservative and the assumption of new technologies in 2000 or 2010 is even more conservative. To the extent some improvements do occur, the costs of the emission reduction cases would be lower. On the other hand, the value or net cost savings of existing-new plant trades could be less with new technologies. This is because new control technologies could also be used at new plants (if the minimum 70 percent removal could be achieved), This would result in lower costs--but less net savings--associated with avoiding the percent removal requirement at these plants by negotiating existing-new plant trades.

SITE-SPECIFIC CONSTRAINTS AFFECTING ALTERNATIVE EMISSION REDUCTION STRATEGIES

Site-specific limitations exist which will affect the ability of specific units to pursue certain alternative emission reduction strategies. For this particular analysis, plant-specific retrofit scrubber costs and coal switching costs have been captured through specific constraints in ICF's Coal and Electric Utilities Model (CEUM). The forecasted cost and coal production impacts under the emission reduction cases will be affected by these assumptions, as outlined below:

- Retrofit Scrubbers - As discussed earlier, unit-specific retrofit factors were applied to the cost of a new scrubber in order to account for site-specific difficulties in retrofitting scrubbers on existing powerplants.

- Coal Switching Costs - Coal switching costs were developed by ICF for EPA and included in this analysis. These estimates were used in this analysis to capture approximately the added coal transportation capital costs (e.g., refurbishment of existing or the building of new rail spurs) and coal handling capital costs (e.g., new rotary dumpers, dethawing equipment, etc.) that specific powerplants would incur if they shifted to lower sulfur coals. About 15 gigawatts of powerplants are estimated to incur significant costs if they shift to lower sulfur coals. Of these, 11 gigawatts incur costs associated with refurbishing existing rail spurs and upgrading coal handling equipment. The remaining 4 gigawatts of capacity might have to construct entirely new rail spurs and purchase new coal handling equipment. The cost estimates are shown in Table 3-5 for 200 and 500 megawatt powerplants. These estimates tend to be conservatively high. Powerplants requiring new rail lines (especially smaller ones) might find it more economic to unload coal off trains, reload it onto trucks and then transport it to the plant. To the extent that this is true, switching costs would be lower than noted herein. Higher or lower coal switching costs influence which powerplants choose to switch coals and how much fuel switching occurs relative to retrofit scrubbing, although only a relatively limited amount of capacity is affected by these constraints.

TABLE 3-5

COAL SWITCHING COSTS
(early 1986 $/kw)

	Plant Size	
	200	500
Medium Cost - Refurbishing Existing Rail Lines and Coal Handling Equipment[6/]	115	70
High Cost - Constructing a New Rail Spur, Purchasing New Coal Handling Equipment[7/]	265	130

Source: ICF estimates

6/ Assumes 15 mile spur refurbishment at $1 million/mile.

7/ Assumes 15 mile spur construction at $3 million/mile.

SITE-SPECIFIC CONSTRAINTS AFFECTING ALTERNATIVE EMISSION REDUCTION STRATEGIES

- Utility System Constraints - For any utility, system operating constraints such as area protection and specific unit turn-down rates limit a utility's flexibility to change the operation of its powerplants. Such an assessment could be made through the use of ICF's utility-specific capacity planning and dispatching model (IPM-Integrated Planning Model). However, the development of such constraints were beyond the scope of this study, and hence no such constraints were incorporated.

- Particulate Control Equipment Upgrade Costs - Particulate upgrade costs for powerplant units switching to lower sulfur coals were developed for EPA to capture approximately the added electrostatic precipitation equipment costs incurred because of the inherent high resistivity of ash from lower sulfur coals. The equipment is upgraded most commonly through the installation of a flue gas conditioning system (injection of sulfur trioxide into the flue gas) or by increasing the plate collection area. The costs presented in Table 3-6 are average costs, which assume 75 percent of the units that switch to lower sulfur coals will install flue gas conditioning, while the remaining 25 percent will add new plate area. Particulate upgrade costs influence which units choose to switch coals and how much fuel switching occurs relative to retrofit scrubbing.

- Mine-Mouth Powerplants - Mine-mouth powerplants (or plants burning only local coals) often have limited coal handling and transportation facilities. These limitations are captured to a certain extent in CEUM by requiring some local coal to be supplied to the utility sector. These quantities are relaxed over time so that CEUM is free to substitute non-local coals in increasing proportions, if this is more economic.

TABLE 3-6

PARTICULATE REMOVAL EQUIPMENT UPGRADE COSTS FOR EXISTING UTILITY COAL-FIRED POWERPLANTS SWITCHING TO LOWER-SULFUR COALS
(early 1986 $/kw)

	Coal Used After Switching					
Original Coal Used	Very Low	Low	Low Medium	Medium	High-Medium	High
Low	11	.	.	.	.	.
Low-Medium	12	10	.	.	.	.
Medium	14	12	10	.	.	.
High-Medium	15	14	12	10	.	.
High	17	15	14	11	8	.
Very High	17	15	14	11	8	4

Sulfur Level	Lbs. SO2/mmBtu:
Very Low Sulfur	Less than 0.80
Low Sulfur	0.80-1.08
Low-Medium Sulfur	1.09-1.66
Medium Sulfur	1.67-2.50
High-Medium Sulfur	2.51-3.33
High Sulfur	3.34-5.00
Very High Sulfur	More than 5.00

Note that for the above assumed particulate upgrade costs:

> Costs are applied to all existing powerplants which shift to lower-sulfur coals.
>
> Costs are also applied to existing powerplants which retrofit scrubbers and shift coals.

Source: Energy Ventures Analysis estimates developed for EPA.

SITE-SPECIFIC CONSTRAINTS AFFECTING ALTERNATIVE EMISSION REDUCTION STRATEGIES

- Long-Term Contracts - Existing long-term contracts may restrict the flexibility of utilities to switch to different coals under various regulatory alternatives. To the extent that public information on these contracts is available, these contracts were incorporated within CEUM. Similar to the constraints for mine-mouth plants, these are relaxed over time, reflecting the known duration of these contracts. In addition, fifty percent of these contracts for medium or higher sulfur coals were assumed to be abrogated under the emission reduction cases, reflecting the exercising of "force majeure" provisions. Aside from these constraints and this modelling treatment, no costs were included in this analysis for abrogating existing or newly negotiated long-term coal contracts.

- Boiler Specifications - Certain boiler types (primarily cyclones or wet-bottom pulverizers) require the use of low-ash fusion coals. There is a relative scarcity of low-sulfur, low-ash fusion coals, particularly in Appalachia and the Midwest. In an attempt to capture this scarcity, wet-bottom and cyclone boilers were restricted from shifting to low-sulfur coals. There are a few existing unscrubbed plants with wet-bottom boilers or cyclone burners and low sulfur dioxide emission limits. These units were presumed to have obtained sufficient reserves of low-sulfur, low-ash fusion coal to continue to meet their emission limits and were not restricted from using low-sulfur coal.

- Coal Rank Specifications - Existing coal-fired powerplant units designed to burn bituminous coals were not permitted to shift to lower rank coals (e.g., from bituminous to subbituminous) unless such plans have already been announced. Because of the design of the boilers and particulate removal equipment of these powerplants, burning lower rank coals typically results in capacity deratings, increased forced outage rates, and higher operating costs. At present, little reliable information is available to estimate these costs. Further, these costs are likely to be very site- and boiler-specific. To avoid these problems, all existing units designed to burn bituminous coals were restricted to bituminous coals when considering shifting coal supplies unless, as mentioned above, plans to this effect have already been announced. To the extent that subbituminous coal compliance options prove to be economic, the increase in Western regional coal production would be spread among more regions and the cost impacts would decrease.

- Coal Transportation - ICF estimates coal rail rates as the long-run variable costs of rail transportation. This cost-based rate is the lowest rate a railroad would offer to avoid losing the traffic. The use of cost-based rates will result in forecasting the correct compliance coal option (i.e., the least-cost option). However, the actual rate the railroad will charge will generally be just less than the next-best alternative --which may be another carrier, another mode, coal from another region, or another fuel. Where the markets are competitive, the rate will be quite close to the cost-based rate. However, where little competition exists, this charge may be higher than the cost-based rate, up to the cost of the next-best alternative.

  In economists' terms, this difference between the cost-based rate and the actual rate is not a "cost to society" but a "wealth transfer" from utility ratepayers to railroad stockholders or ratepayers (depending on Interstate Commerce Commission regulations). The costs presented in the EPA Base Case and changes in costs presented under the emission reduction cases thus represent "costs to society". Costs to utility ratepayers could be higher in some but not all circumstances. However, rates between the carrier's costs and the costs of the next-best alternative have little or no effect on the source of the transported coal. [6/]

  In general, recent ICF analyses (including detailed examination of rail costs and rates to the AEP and TVA utility systems, as well as examination of costs and rates to other utilities and individual plants) suggest that many rail rates are close to long-run variable costs. Further, the number of "captive" powerplants (i.e., powerplants with little or no transportation competition) has dwindled in the past several years as rail deregulation and market forces in the coal industry has fostered considerable competition among railroads. This trend is expected to continue. Also, most "captive" powerplants are generally located in the West and/or are already using lower sulfur coals. Thus, the implications of using cost-based rates for these plants are relatively insignificant when analyzing electricity rate impacts under the emission reduction cases.

6/ See memorandum to Rob Brenner, EPA entitled "Transportation Rate Assumptions for Coal Market Modeling," June 26, 1984; see also memorandum to Rob Brenner entitled "Response to Comments Received on July 26, 1984 Memo entitled 'Transportation Rate Assumptions for Coal Marketing Modelling,'" April 5, 1985.

ICF's assessment of long-run variable costs is based on engineering analyses of rail, barge and truck costs. These costs have been developed for and reviewed by a number of railroads and electric utilities. The cost estimates are regularly compared with tariffs and contract announcements in order to ensure the reasonableness of the estimates. Nonetheless, the estimates should be still viewed as approximate to any specific movement.

BASE CASE ASSUMPTIONS

As noted in Chapter One, EPA specified a base case for this analysis. EPA Base Case assumptions are presented in Appendix D. Important assumptions pertaining to forecasted emissions and cost impacts are discussed below. Note that the EPA Base Case used in this study was originally analyzed in early 1987, incorporating assumptions developed in late 1986. More up-to-date assumptions (e.g., higher electricity/High Oil levels, higher coal mining productivity, lower oil and gas prices, etc.) would likely lead to some important changes in the quantitative forecasts. However, the general qualitative results presented herein likely would not change appreciably.

- Electricity Growth Rates - Lower electricity growth rates would lower the utilization of some existing powerplants in the Base Case and would lower Base Case sulfur dioxide emissions. This would also lower the emission reductions required under the Proxmire and 30 Yr/1.2 scenarios, and thus would lower the costs of meeting the targeted emissions levels under the cases examined. On the other hand, lower electricity growth rates would reduce the number of new coal plants built in the future, and thus would lower the amount of net cost savings associated with permitting existing-new source trades. Higher growth rates (as evidenced recently) would tend to have the opposite effects.

- Nuclear Capacity, Availability and Lifetimes - EPA assumed for this analysis that nuclear capacity would be built based on current utility plans and schedules. This includes the assumption that all existing TVA nuclear units would be brought back on-line. In the longer term (after 1995), no additional new nuclear capacity is assumed to be built and nuclear plants begin to retire (a 35 year lifetime was assumed). The nuclear capacity and retirement assumptions have an important impact on the amount of new coal plants built (particularly after 2000), and hence the amount of existing-new trading opportunities and the net cost savings associated with these trades. Also, future emission levels, required reductions and utility costs would be affected.

  In addition, the availability of nuclear plants is assumed to improve by 1995. Nuclear capacity factors were assumed to increase from current levels of about 60 percent to 67 percent by 1995. This increase in capacity factors assumes that low capacity factors experienced currently -- resulting in part from increased Nuclear Regulatory Commission (NRC) scrutiny following the accident at Three Mile Island in 1979 and other technical problems -- will be resolved and there will be relatively few new NRC regulatory requirements.

Lower estimates of the future availability of nuclear plants would have similar impacts as reducing assumed nuclear capacity, and would result in increased utilization of existing fossil fuel powerplants and more construction of new coal powerplants. Base Case emission forecasts would be higher, and required reductions from existing plants and costs would also be higher, although not significantly. More new coal-fired powerplants would be built, and the net cost savings of existing-new trades would be greater. Higher nuclear estimates would have the opposite effects.

- Fossil Powerplant Lifetimes - Fossil powerplant lifetimes and assumed retirements will have an important effect on the amount of new coal plants built, the amount of existing capacity available for trades, and thus existing-new trades. The EPA Base Case assumes that all fossil steam units are refurbished when the units reach 30 years of age, and that such refurbishment activity extends the useful life of these units by an additional 30 years. EPA's 60-year lifetime assumption was based on several factors. While history suggests that a fossil steam powerplant will retire after roughly 40 to 50 years of service if no major life extension efforts are pursued, utilities are currently refurbishing many existing powerplants (and will likely refurbish many more powerplants in the future). This is primarily because of the lower costs and risks associated with refurbishing existing capacity in lieu of building new powerplants. Electric Power Research Institute estimates suggest that refurbishment activities could extend the life of a powerplant by about 20 years, and that perhaps as many as three-quarters of the fossil steam units would be plausible candidates for life extension. Based on these and other estimates, EPA has assumed a 60-year average lifetime. Some units may in fact have their lifetimes extended well beyond 60 years, while other units less suited to refurbishment may be retired earlier (possibly without any refurbishment efforts at all).

  This assumption should be investigated further. This should include assessments of the potential scope of powerplant refurbishments and review of those that might not be suitable for refurbishment (e.g., units with supercritical boilers or units which have been frequently cycled are not likely to be refurbished because of the greater operating stresses which such units have experienced).

- <u>Advanced Generating Technologies and Cogeneration</u> - New plant technologies and cogeneration will have important impacts on the amount of new coal-fired powerplants built and thus the amount and value of existing-new plant trades. Innovative electricity generation technologies such as solar, geothermal, wind, advanced combined cycle, combined cycle gasification, and fluidized bed combustion (FBC) units, are incorporated into the EPA Base Case to the extent that such units have been planned (e.g., the Ocean States Power combined cycle project in New England) or are in operation (e.g., Black Dog 2 of Minnesota and Nucla of Colorado FBC units). The most significant penetration of new plant technologies is likely to be in the burgeoning area of small power production or cogeneration. Estimates of new technologies in this area are also explicitly incorporated into the forecasts.

- <u>World Oil Prices and Gas Prices</u> - EPA Base Case world oil prices and gas prices have an important long-run effect on the amount of new coal capacity built (in lieu of new oil/gas plants). Lower long-term oil and gas prices would reduce the amount of new coal plants built (and thus the amount of existing-new trades). Oil and gas prices by 1995 are unlikely to have a very significant impact on the utilization of existing coal plants versus oil or gas plants. The EPA Base Case assumes $24 per barrel prices in 1995 in 1987 dollars. Even with prices at $13-17 per barrel in 1995, most existing coal-fired powerplants would still be dispatched ahead of oil/gas steam plants, and hence sulfur dioxide emissions from existing sources would be affected only to a limited extent. Further, even at this oil price range, the costs of switching from coal to oil or gas are still likely to be much higher than other compliance options, and therefore will have relatively little impact on the cost and coal production impacts of the cases. Oil prices significantly below $13 per barrel could lead to the back-out of coal by oil and gas in some areas and greater cost-effectiveness associated with switching from coal to oil or gas use to reduce emissions. This could have large impacts on costs and coal production forecasts.

- Availability of Very Low Sulfur Coal Reserves - The cost and availability of very low sulfur coal reserves (i.e., below 0.8 lbs. SO_2 per million Btu) are an important factor in assessing the cost and coal production effects of achieving emission reductions and, importantly, in achieving cost effective existing-new trades. In analyzing the 30 Yr/1.2 cases, ICF conducted additional analysis of the costs and availability of very low sulfur bituminous coal reserves. This assessment was based on discussions with low sulfur coal producers throughout the U.S., a review of published geologic data in candidate regions, and analysis of electric utility coal shipments over the past 15 years. This preliminary assessment determined that effectively no very low sulfur coal reserves are located in the East; significant quantities can be found in the West. It must be stressed that, given the very short period of time over which this analysis was conducted, this assessment was quite preliminary and not comprehensive. Further analysis is needed to fully examine the costs, availability and quality of very low sulfur Eastern and Western reserves, and to develop modelling treatments more appropriate for these scarce resources.

- Availability of Import Coals - This analysis did not assess the potential penetration of import coals in the East. Given the relatively high transportation costs to ship Western very low sulfur coals to the Gulf and Atlantic states, import coals (particularly those with very low sulfur content, such as Colombian coals) could prove to be very competitive. The extent to which foreign coal use is enhanced and domestic production reduced by the emission reduction requirements of these proposals should be the subject of additional analysis.

- <u>Coal Mining Productivity</u> - A key component of coal supply, and thus coal prices, is coal mining productivity (measured as tons produced per machine shift for new deep mines, tons per man-day for new surface mines, and tons per man-year for existing deep and surface mines). For most of the 1970s, productivity declined due to new health and safety regulations, new state and federal strip mine regulations, 1974 United Mine Workers Association union work rules, an influx of younger and inexperienced workers, and deteriorating labor-management relations. However, productivity has improved dramatically since 1978. In particular, between 1982 and early 1986, deep mining productivity increased at a 10 percent annual rate, while surface mining productivity grew by 5 percent annually. Estimates of the future gains in coal mining productivity (i.e., tons per worker-year) have an important impact on the costs of producing coals and hence future coal prices. For the EPA Base Case, gains in productivity were expected to continue. To the extent there are larger gains, coal prices (and thus the costs of coal switching) would generally be lower. Further, coal mining employment levels would also be lower. Smaller gains would have the opposite effects.

  For the EPA Base Case, it is expected that productivity in the industry will continue to improve at about a 3 percent per year rate for deep mines and at a 2 percent per year rate for surface mines, reflecting an assessment of historical data and underlying long-term trends on productivity gains and technological improvement. This rate of the growth in productivity will be offset somewhat by annual real wage increases. Given the recent historical evidence, this rate of annual productivity growth is likely to be achieved if technological efficiency gains continue at their current pace and if no major institutional changes (i.e., no unexpected regulations) are enacted. In fact, recent ICF assessments would suggest higher assumed rates of productivity growth than were used in the EPA Base Case. Historically, coal mining productivity has grown by about 5-10 percent per year between 1986 and 1988 (since the development of the EPA Base Case in 1986).

RESTRICTING UTILITY FORECASTS BETWEEN SCENARIOS

In analyzing the emission reduction cases, certain activities were held at forecasted Base Case levels. This was done to facilitate comparison of costs and emissions between scenarios.

- Gas Consumption - was held at Base Case levels for utilities. To the extent utility users can shift to more gas, utility compliance costs could be lower. However, the effect of this increase in demand for gas on gas prices could increase national consumer costs substantially. Lower gas prices than assumed herein for the EPA Base Case (as recent analyses might suggest) would have an important effect on forecasted base case emission levels, and hence on utility compliance costs and the value of emissions trading under an acid rain control program.

- Electricity Transmission - was constrained to the interregional flows which were forecast to occur in the Base Case. If powerpool arrangements of long-term transmission agreements permit changes in these flows, the forecasted costs of the emission reduction cases could be moderately reduced, especially in the West. Additional cost reductions could accrue if additional power could be imported to the U.S. from Canada. The extent to which the emission reduction cases might create incentives for greater interregional transmission flows from Canada has not been explored in this analysis.

- Coal and Nuclear Powerplant Builds - were also held to Base Case levels. Different powerplant builds would affect the forecasted changes in costs, though only slightly.

DIRECT COSTS AND NEAR-TERM CONSTRAINTS NOT ANALYZED

Some of the direct costs of the emission reduction alternatives were not measured for this analysis. These potential costs could be significant, but their exact magnitude is uncertain. These costs were beyond the scope of this particular analysis, although they have been the subject of other analytical efforts by ICF.

- Emission Reductions From and Trading With Other Sectors - were not assessed at EPA's direction. The costs of emission reductions from other sectors could be significant. The value of intersector trading could also be important, and is worthy of further investigation.

- Low Sulfur Oil Prices - were assumed not to increase in response to greater forecasted demand by utilities for low-sulfur residual oil. However, these prices may increase, resulting in higher costs for all users of low sulfur residual oil.

- Gas Prices - were not assumed to increase for this analysis. Gas consumption was also assumed not to increase. To the extent utilities are able to obtain additional gas supplies, the forecasted costs under some of the cases may be overstated somewhat. However, gas prices would also increase in response to increased demand for gas and for competing fuels (such as low-sulfur oils).

- Short-Run Production and Transportation Bottlenecks - were not assumed in this analysis. Rather, the analysis assumed that market prices would come into equilibrium and excluded any short-run disequilibrium effects. Short-run production or transportation constraints could influence the costs of any major emission reduction program in the near-term, although they are not likely to have any significant impact under the Proxmire and 30 Yr/1.2 as described herein, since only moderate reductions are required under both of these cases in 1995.

- Scrubber Manufacturing Constraints - were not assumed in this analysis. However, none of the cases forecasts a significant amount of retrofit scrubber activity in the near-term, and thus no constraints to building these scrubbers would be expected.

INDIRECT COSTS NOT MEASURED

Many of the indirect costs of the emission reduction and emission trading cases were not measured for this analysis, including:

- Administrative and Transaction Costs - associated with establishing regulatory mechanisms to implement a trading program could be significant.

- Lost Investments in Existing Mining Operations - will depend on the extent to which regional coal production falls below existing levels. Some losses, particularly in the Midwest and Northern Appalachia, could occur under several of the emission reduction alternatives examined because of shifts in regional coal production.

- Indirect and Regional Impacts of Lost Mining Jobs - will depend on the shifts in regional coal production and the attendant changes in coal mining employment.

- Costs of Abrogating Long-Term Contracts - Fifty percent of current medium and high sulfur long-term coal contracts still in effect in 1995 and 2000 were assumed to be abrogated as a result of "force majeure" clauses under the emission reduction cases. Costs of abrogating these long-term contracts could be significant, depending on the specific provisions of various existing coal contracts. These costs have not been addressed in this analysis. To the extent these become important, the cost impacts identified in this analysis would understate the actual impacts.

- Indirect and Regional Impacts of New Mining, Transportation, and Manufacturing Jobs - will vary with the forecasted increases and decreases in regional mining employment, shifts in coal shipments, and increases in manufacturing (e.g., retrofit scrubbers).

- Impact of Higher Electricity Rates on Electricity Demand - This analysis did not examine the effects of higher electricity rates on the demand for electricity, in that when the price of electricity increases, the demand for consumption of electricity is reduced. Not incorporating this price elasticity of demand has the effect of overstating compliance costs somewhat in that some of the required reductions would be achieved by producing less electricity. However, there would also be a loss to consumers (i.e., a loss in consumer surplus, in economists' terms) as a result of the higher rates and reduced consumption. This loss would also have to be added to the reported costs of the programs.

- Opportunity Costs of Capital - An acid rain program will likely lead to increased investments in control technologies. These funds could be put to other social uses (with possibly higher returns), and hence there could be opportunity costs. These costs were not measured for this analysis.

APPENDIX A

BASE CASE FORECASTS

This appendix presents detailed forecasts of utility sulfur dioxide emissions and regional coal production assuming no implementation of federal acid rain legislation. Also included are forecasts of emissions, changes in utility compliance costs, and coal market effects were existing-new trading (at a 1.2 to 1 trading ratio) to be instituted.

TABLE A-1

SULFUR DIOXIDE FORECASTS
EPA BASE CASES

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	EPA BASE CASE 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	EPA BASE CASE 2010	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
Utility SO2 Emissions (millions of tons)								
31-Eastern States								
Coal								
Existing	14.92	14.21	15.26	0.0	15.85	-1.96	16.76	-7.37
New	0.0	0.0	0.15	0.0	0.34	1.65	1.47	6.19
TOTAL COAL	14.92	14.21	15.41	0.0	16.20	-0.30	18.23	-1.18
OIL/GAS	1.27	0.57	1.02	0.0	1.19	-0.02	0.82	-0.06
TOTAL 31-EASTERN STATES	16.19	14.78	16.43	0.0	17.39	-0.33	19.05	-1.24
17-Western States								
Coal								
Existing	1.10	1.48	2.00	-0.03	2.05	-0.18	2.01	-0.78
New	0.0	0.0	0.05	0.02	0.09	0.15	0.55	0.71
TOTAL COAL	1.10	1.48	2.05	0.0	2.13	-0.03	2.56	-0.07
OIL/GAS	0.09	0.01	0.12	0.0	0.13	0.0	0.11	-0.07
TOTAL 17-WESTERN STATES	1.19	1.49	2.17	-0.00	2.26	-0.03	2.67	-0.14
United States								
Coal								
Existing	16.02	15.69	17.26	-0.03	17.90	-2.14	18.77	-8.14
New	0.0	0.0	0.20	0.03	0.43	1.80	2.01	6.90
TOTAL COAL	16.02	15.69	17.46	0.0	18.33	-0.33	20.79	-1.24
OIL/GAS	1.36	0.58	1.14	0.0	1.32	-0.02	0.93	-0.13
TOTAL UNITED STATES	17.38	16.27	18.60	0.0	19.65	-0.36	21.72	-1.38

Note: Totals may not add due to independent rounding.

TABLE A-2

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
EPA BASE CASE WITH
EXISTING-NEW INTERSTATE TRADING

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
Utility Annual Costs (billions of mid-1987 $/yr.)			
Capital	-0.0	-0.3	-2.5
O&M	-0.0	-0.3	-2.2
Fuel	-0.0	-0.2	-0.6
TOTAL	-0.0	-0.7	-5.3
Utility Cumulative Capital Costs (billions of mid-1987 $)			
31-Eastern States	0.0	-2.3	-21.0
17-Western States	-0.1	-0.8	-4.8
Total U.S.	-0.1	-3.1	-25.8
SO2 Retrofit Scrubber Capacity (GW)			
31-Eastern States	0.0	0.0	0.0
17-Western States	0.0	0.0	7.9
Total U.S.	0.0	0.0	7.9
New Capacity Trading with Existing Capacity (GW)			
31-Eastern States	0.0	15.5	149.4
17-Western States	0.3	6.9	47.9
Total U.S.	0.3	22.4	197.3

Note: Totals may not add due to independent rounding.

TABLE A-3

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
EPA BASE CASES

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	EPA BASE CASE 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	EPA BASE CASE 2010	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
31 EASTERN STATES								
COAL								
LOW SULFUR	0.87	1.89	2.63	-0.07	3.36	-0.25	6.81	1.31
LOW-MEDIUM SULFUR	1.61	1.56	2.08	0.09	2.65	0.41	3.82	0.48
HIGH-MEDIUM SULFUR	3.18	3.66	3.83	-0.04	3.78	-0.27	4.85	0.21
HIGH SULFUR	3.86	3.90	3.80	0.02	4.12	0.10	5.08	-2.13
TOTAL	9.53	11.01	12.34	0.00	13.90	-0.00	20.57	-0.12
OIL	1.99	0.93	1.54	0.00	1.98	-0.02	1.79	-0.09
GAS	1.01	0.92	0.79	0.0	0.71	0.0	0.44	0.0
17 WESTERN STATES								
COAL								
LOW SULFUR	1.41	1.61	2.42	0.02	2.70	0.06	5.56	0.56
LOW-MEDIUM SULFUR	0.43	0.94	0.85	0.03	0.95	0.02	1.55	-0.51
HIGH-MEDIUM SULFUR	0.74	0.96	1.11	-0.04	1.22	-0.11	1.21	-0.09
HIGH SULFUR	0.01	0.07	0.07	-0.01	0.06	0.02	0.08	0.00
TOTAL	2.59	3.58	4.44	0.00	4.93	-0.01	8.40	-0.04
OIL	0.48	0.06	0.24	0.0	0.28	0.00	0.34	-0.01
GAS	2.58	2.28	1.64	0.0	1.90	0.0	0.99	0.0
TOTAL U.S.								
COAL								
LOW SULFUR	2.28	3.50	5.06	-0.05	6.06	-0.18	12.38	1.87
LOW-MEDIUM SULFUR	2.04	2.49	2.93	0.12	3.60	0.43	5.37	-0.02
HIGH-MEDIUM SULFUR	3.92	4.62	4.94	-0.08	4.99	-0.37	6.06	0.13
HIGH SULFUR	3.87	3.97	3.87	0.01	4.18	0.12	5.16	-2.13
TOTAL	12.12	14.58	16.79	-0.01	18.84	-0.01	28.96	-0.16
OIL	2.47	0.99	1.79	0.00	2.26	-0.02	2.13	-0.11
GAS	3.59	3.20	2.43	0.0	2.61	0.0	1.44	0.0

TABLE A-4

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
EPA BASE CASES

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	EPA BASE CASE 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	EPA BASE CASE 2010	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
Coal Production								
NORTHERN APPALACHIA	185.	166.	180.	1.	188.	11.	258.	28.
CENTRAL APPALACHIA	233.	245.	282.	-1.	330.	-12.	407.	-11.
SOUTHERN APPALACHIA	26.	26.	23.	-0.	25.	-0.	36.	-2.
MIDWEST	134.	133.	125.	0.	143.	-3.	175.	-55.
WEST	251.	316.	428.	-1.	479.	4.	777.	29.
TOTAL COAL REGIONS	830.	881.	1038.	-0.	1165.	-1.	1653.	-12.
Coal Transportation								
WESTERN COAL TO EAST	N.A.	N.A.	55.	-1.	70.	1.	183.	15.

TABLE A-5

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
EPA BASE CASES

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 1995	EPA BASE CASE 2000	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 2000	EPA BASE CASE 2010	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 2010
ME	17.	10.	3.	0.	4.	0.	5.	-0.
NH	80.	74.	64.	0.	63.	0.	73.	57.
VT	0.	1.	3.	0.	3.	0.	3.	-2.
MA	258.	230.	272.	0.	299.	152.	363.	674.
RI	5.	2.	0.	0.	2.	-0.	0.	-0.
CT	29.	56.	17.	0.	36.	-1.	13.	-1.
NY	479.	420.	481.	-0.	518.	444.	543.	1017.
PA	1422.	1320.	1275.	-4.	1186.	0.	1232.	-263.
NJ	103.	97.	130.	0.	127.	-18.	191.	559.
MD	222.	217.	315.	0.	332.	37.	344.	268.
DE	51.	63.	60.	0.	60.	10.	62.	48.
DC	4.	1.	4.	0.	4.	0.	3.	0.
VA	157.	131.	240.	0.	293.	221.	341.	7.
WV	984.	969.	961.	0.	1007.	-177.	1037.	-481.
NC	445.	337.	504.	0.	520.	19.	660.	118.
SC	210.	162.	184.	0.	209.	28.	308.	84.
GA	704.	976.	874.	16.	946.	-111.	1021.	-294.
FL	692.	501.	937.	-14.	968.	325.	910.	21.
OH	2185.	2193.	2572.	-18.	2677.	-365.	2849.	-738.
MI	608.	401.	449.	0.	477.	-1.	516.	514.
IL	1110.	1073.	955.	3.	1096.	-149.	1407.	-425.
IN	1672.	1498.	1710.	4.	1782.	-186.	2007.	-908.
WI	488.	367.	273.	69.	267.	8.	327.	32.
KY	1029.	745.	893.	-13.	935.	-18.	941.	-409.
TN	910.	802.	856.	-31.	922.	-103.	1056.	-260.
AL	535.	563.	512.	-8.	565.	-66.	595.	-168.
MS	122.	113.	146.	-5.	153.	-43.	168.	-24.
MN	159.	124.	169.	-2.	218.	-14.	216.	-59.
IA	236.	219.	302.	3.	368.	-119.	438.	-203.
MO	1227.	997.	1058.	-6.	1118.	-210.	1196.	-426.
AR	27.	69.	125.	4.	151.	4.	131.	8.
LA	21.	67.	86.	3.	84.	4.	89.	16.
TOTAL 31-EASTERN STATES	16191.	14798.	16431.	-0.	17386.	-327.	19047.	-1237.

TABLE A-5

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
EPA BASE CASES

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 1995	EPA BASE CASE 2000	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 2000	EPA BASE CASE 2010	CHANGE FROM EPA BASE EX.-NEW INTER TRADING 2010
ND	79.	124.	177.	-7.	188.	-50.	244.	-71.
SD	30.	32.	50.	-19.	51.	-23.	58.	-37.
KS	102.	166.	224.	-6.	230.	-13.	232.	-66.
NE	48.	45.	116.	-0.	122.	-14.	133.	-55.
OK	45.	80.	209.	0.	225.	4.	225.	-12.
TX	295.	430.	695.	23.	710.	-8.	890.	-28.
MT	23.	22.	45.	0.	48.	20.	64.	-1.
WY	128.	135.	62.	0.	70.	26.	68.	18.
ID	0.	0.	0.	0.	0.	0.	0.	0.
CO	71.	84.	130.	1.	137.	1.	145.	-15.
NM	79.	114.	56.	0.	56.	0.	57.	-0.
UT	25.	27.	69.	-2.	70.	-24.	77.	27.
AZ	84.	104.	126.	7.	130.	21.	138.	34.
NV	38.	35.	76.	0.	79.	10.	78.	9.
WA	68.	85.	114.	0.	128.	20.	217.	-65.
OR	4.	2.	16.	1.	20.	-0.	20.	-15.
CA	70.	3.	0.	0.	0.	0.	20.	137.
AK	0.	0.	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2166.	-4.	2263.	-30.	2668.	-141.
TOTAL U.S.	17380.	16286.	18597.	-4.	19649.	-357.	21716.	-1378.

TABLE A-6

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION 1/
(Millions of Mid 1987 Dollars)
EPA BASE CASES

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
MAINE/VT/NH	0.	1.	-33.
MASS/CONN/RHODE I.	-0.	-62.	-308.
NEW YORK	2.	-146.	-337.
PENNSYLVANIA	7.	41.	-10.
NEW JERSEY	-0.	0.	-183.
MARYLAND/DELAWARE	1.	-17.	-116.
VIRGINIA	1.	-87.	-186.
WEST VIRGINIA	4.	12.	-58.
N.&S.CAROLINA	-1.	-47.	-470.
GEORGIA	-5.	-16.	-174.
FLORIDA	1.	-153.	-248.
OHIO	3.	21.	-519.
MICHIGAN	0.	8.	-183.
ILLINOIS	-1.	-23.	-389.
INDIANA	-4.	-6.	-146.
WISCONSIN	-1.	2.	-112.
KENTUCKY	-3.	-32.	-94.
TENNESSEE	-3.	-9.	-350.
ALABAMA	-1.	-10.	-12.
MISSISSIPPI	2.	1.	-67.
MINNESOTA	-1.	-3.	-23.
IOWA	-0.	0.	-68.
MISSOURI	-0.	-11.	-210.
ARKANSAS	-0.	2.	-1.
LOUISIANA	1.	0.	-5.
TOTAL 31-EASTERN STATES	1.	-537.	-4305.

1/ Includes transfer costs for emissions rights.

TABLE A-6

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION 1/
(Millions of Mid 1987 Dollars)
EPA BASE CASES

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
N. & S. DAKOTA	1.	1.	-123.
KANSAS/NEBRASKA	-2.	-10.	-147.
OKLAHOMA	-1.	-9.	-68.
TEXAS	-20.	-73.	-424.
MONTANA	-0.	-24.	-30.
WYOMING	0.	-7.	11.
IDAHO	0.	0.	0.
COLORADO	-1.	-7.	-17.
NEW MEXICO	-0.	5.	-15.
UTAH	-0.	-3.	-90.
ARIZONA	-1.	-8.	24.
NEVADA	-0.	-18.	-6.
WASHINGTON/OREGON	-1.	-46.	-103.
CALIFORNIA	0.	-0.	4.
TOTAL 17-WESTERN STATES	-26.	-200.	-985.
TOTAL U.S.	-24.	-737.	-5291.

1/ Includes transfer costs for emissions rights.

TABLE A-7

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
EPA BASE CASES

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
MAINE/VT/NH	0.0	0.1	-2.0
MASS/CONN/RHODE I.	0.0	-1.0	-3.7
NEW YORK	0.0	-1.2	-2.0
PENNSYLVANIA	0.1	0.4	-0.1
NEW JERSEY	0.0	0.0	-2.5
MARYLAND/DELAWARE	0.0	-0.4	-2.2
VIRGINIA	0.0	-2.3	-3.7
WEST VIRGINIA	0.1	0.3	-1.4
N.&S.CAROLINA	-0.0	-0.5	-4.1
GEORGIA	-0.1	-0.3	-2.4
FLORIDA	0.0	-1.5	-2.3
OHIO	0.0	0.2	-4.4
MICHIGAN	0.0	0.1	-2.0
ILLINOIS	-0.0	-0.3	-3.0
INDIANA	-0.1	-0.1	-2.3
WISCONSIN	-0.1	0.0	-2.9
KENTUCKY	-0.1	-0.8	-2.1
TENNESSEE	-0.0	-0.1	-4.2
ALABAMA	-0.0	-0.2	-0.2
MISSISSIPPI	0.2	0.1	-2.9
MINNESOTA	-0.0	-0.1	-1.2
IOWA	-0.1	0.0	-3.4
MISSOURI	0.0	-0.2	-4.1
ARKANSAS	0.0	0.1	-0.1
LOUISIANA	0.0	0.0	-0.1
TOTAL 31-EASTERN STATES	0.0	-0.4	-2.6

TABLE A-7

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
EPA BASE CASES

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
N. & S. DAKOTA	0.1	0.1	-2.9
KANSAS/NEBRASKA	-0.0	-0.5	-4.8
OKLAHOMA	-0.1	-0.4	-1.9
TEXAS	-0.1	-0.4	-1.9
MONTANA	0.0	-2.7	-3.2
WYOMING	0.0	-0.5	0.7
IDAHO	0.0	0.0	0.0
COLORADO	-0.0	-0.3	-0.6
NEW MEXICO	0.0	0.3	-0.8
UTAH	0.0	-0.3	-3.8
ARIZONA	-0.0	-0.2	0.4
NEVADA	0.0	-1.3	-0.4
WASHINGTON/OREGON	-0.0	-1.0	-1.4
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	-0.1	-0.4	-1.5
TOTAL U.S.	-0.0	-0.4	-2.3

1/ Calculated as follows (using 1995 as an example):

$$\left[\frac{\text{1995 Emission Reduction Case Annualized Cost} - \text{1995 Base Case Annualized Cost}}{\text{1995 Electricity Sales}}\right] \div \text{1982 Average Electricity Rates}$$

TABLE A-8

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
EPA BASE CASE WITH
EXISTING-NEW INTERSTATE TRADING

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
MAINE/VT/NH	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	0.0
NEW YORK	0.0	0.0	0.0
PENNSYLVANIA	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0
MARYLAND/DELAWARE	0.0	0.0	0.0
VIRGINIA	0.0	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.0
GEORGIA	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0
OHIO	0.0	0.0	0.0
MICHIGAN	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0
INDIANA	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.0
TENNESSEE	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.0	0.0	0.0

TABLE A-8

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
EPA BASE CASE WITH
EXISTING-NEW INTERSTATE TRADING

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
N. & S. DAKOTA	0.0	0.0	1.5
KANSAS/NEBRASKA	0.0	0.0	0.2
OKLAHOMA	0.0	0.0	0.0
TEXAS	0.0	0.0	3.4
MONTANA	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.0
ARIZONA	0.0	0.0	1.1
NEVADA	0.0	0.0	0.5
WASHINGTON/OREGON	0.0	0.0	1.2
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	7.9
TOTAL U.S.	0.0	0.0	7.9

TABLE A-9

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
EPA BASE CASE WITH
EXISTING-NEW INTERSTATE TRADING

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
MAINE/VT/NH	0.0	0.0	1.3
MASS/CONN/RHODE I.	0.0	1.5	11.4
NEW YORK	0.0	4.0	14.8
PENNSYLVANIA	0.0	0.0	0.5
NEW JERSEY	0.0	0.0	9.6
MARYLAND/DELAWARE	0.0	0.6	6.9
VIRGINIA	0.0	2.6	8.4
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.8	14.7
GEORGIA	0.0	0.0	5.1
FLORIDA	0.0	5.3	11.6
OHIO	0.0	0.0	12.4
MICHIGAN	0.0	0.0	11.4
ILLINOIS	0.0	0.0	10.2
INDIANA	0.0	0.0	0.0
WISCONSIN	0.0	0.0	5.1
KENTUCKY	0.0	0.6	0.6
TENNESSEE	0.0	0.1	16.3
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	3.7
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.8
MISSOURI	0.0	0.0	3.8
ARKANSAS	0.0	0.0	0.2
LOUISIANA	0.0	0.0	1.2
TOTAL 31-EASTERN STATES	0.0	15.5	149.4

TABLE A-9

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
EPA BASE CASE WITH
EXISTING-NEW INTERSTATE TRADING

	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 1995	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2000	CHANGE FROM EPA BASE EX.-NEW INTER. TRADING 2010
N. & S. DAKOTA	0.0	0.0	2.1
KANSAS/NEBRASKA	0.0	0.0	0.2
OKLAHOMA	0.0	0.3	4.6
TEXAS	0.3	0.7	22.3
MONTANA	0.0	1.0	1.0
WYOMING	0.0	1.2	1.2
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.6	1.0
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	2.1
ARIZONA	0.0	0.6	3.1
NEVADA	0.0	0.6	1.5
WASHINGTON/OREGON	0.0	2.0	2.0
CALIFORNIA	0.0	0.0	6.7
TOTAL 17-WESTERN STATES	0.3	6.9	47.9
TOTAL U.S.	0.3	22.4	197.3

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE A-10

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 1995	Chg from Base Interstate Existing-New 1995	Base 2000	Chg from Base Interstate Existing-New 2000	Base 2010	Chg from Base Interstate Existing-Ne 2010
Northern Appalachia							
Pennsylvania	22.3	18.0	+0.2	17.8	+1.2	30.1	+9.0
Ohio	9.0	6.2	-	5.3	+0.1	6.7	-1.8
Maryland	0.7	0.5	-	0.4	-	0.3	-
Northern West Virginia	12.8	13.5	-	11.7	+0.8	17.8	-1.3
TOTAL	44.7	38.2	+0.2	35.2	+2.1	54.3	+5.9
Central Appalachia							
Southern West Virginia	23.8	21.8	-	23.6	-0.9	32.5	-0.9
Virginia	13.3	12.2	-	13.2	-0.5	18.2	-0.5
Eastern Kentucky	29.8	27.3	-0.1	29.5	-1.1	40.7	-1.1
Tennessee	2.6	2.4	-	2.6	-	3.6	-
TOTAL	69.5	63.6	-0.1	68.8	-2.5	94.9	-2.5
Southern Appalachia							
Alabama	8.6	5.8	-	5.9	-0.1	9.4	-0.6
TOTAL	8.6	5.8	-	5.9	-0.1	9.4	-0.6
TOTAL APPALACHIA	122.8	107.7	+0.1	109.9	-0.5	158.6	+2.8
Midwest							
Illinois	13.9	10.1	-	12.8	-1.1	16.6	-7.1
Indiana	5.2	3.0	-	2.1	+0.3	4.2	-1.2
Western Kentucky	7.7	6.2	-	5.5	+0.1	8.2	-1.8
TOTAL	26.8	19.4	-	20.5	-0.7	29.0	-10.1
TOTAL MIDWEST	26.8	19.4		20.5	-0.7	29.0	-10.1
Central West							
Iowa	0.1	0.1	-	0.1	-	0.1	-
Missouri	1.1	0.9	-	0.6	-	0.4	-
Kansas	0.2	0.3	-	0.2	-	0.2	-
Northern Arkansas	0.0	0.1	-	0.1	-	0.1	-
Oklahoma	1.0	0.7	-	0.6	-	0.5	-
TOTAL	2.5	2.0	-	1.7	-	1.4	-
Gulf							
Texas	2.4	2.1	-	1.9	-	1.9	-
Louisiana	0.1	0.8	-	0.7	-	0.7	-
Southern Arkansas	0.0	0.0	-	0.0	-	0.0	-
TOTAL	2.4	2.9	-	2.6	-	2.6	-

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TABLE A-10

Coal Mining Employment
(Thousand Workers)
(continued)

	Actual 1985	Base 1995	Chg from Base Interstate Existing-New 1995	Base 2000	Chg from Base Interstate Existing-New 2000	Base 2010	Chg from Base Interstate Existing-New 2010
Rockies/Northern Plains							
Colorado	2.4	4.7	-	5.1	-	19.0	+4.2
Wyoming	4.5	4.1	-	3.6	+0.2	5.5	-0.2
Montana	1.2	1.4	-	1.6	-	2.4	-0.1
Utah	2.6	4.5	-	4.8	+0.3	10.4	+1.0
New Mexico	1.9	1.9	-	2.2	-	3.5	-0.1
Arizona	0.8	0.7	-	0.6	-	0.7	-
North Dakota	1.1	1.0	-	0.9	-	0.9	-
TOTAL	14.5	18.3	-	18.8	+0.5	42.4	+4.8
Northwest							
Washington	0.7	0.6	-	0.5	-	0.5	-
TOTAL	0.7	0.6	-	0.5	-	0.5	-
Alaska							
Alaska	0.1	0.1	-	0.1	-	0.3	-
TOTAL	0.1	0.1	-	0.1	-	0.3	-
TOTAL WEST	20.3	24.0	-	23.7	+0.5	47.2	+4.8
TOTAL U.S.	169.9	151.0	0.1	154.2	-0.7	234.8	-2.5

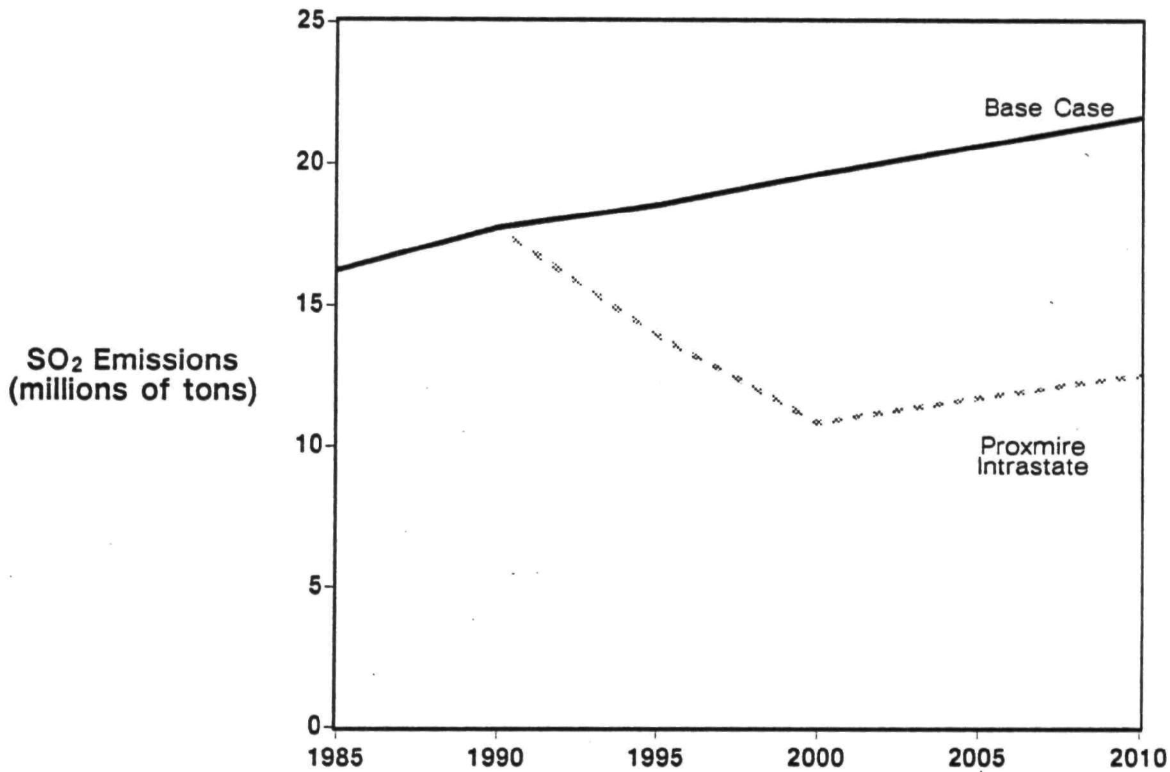
Appendix B:
Proxmire Forecasts

APPENDIX B

PROXMIRE SUMMARY AND FORECASTS

This appendix presents and discusses the results of the analyses of the Proxmire bill under various trading scenarios. This includes a discussion of the changes in utility sulfur dioxide emissions, utility costs, and coal production. Detailed forecasts from the Proxmire analyses are presented at the end of the Appendix.

SO2 EMISSION REDUCTIONS UNDER THE PROXMIRE CASES



Utility
SO_2 Emissions
(million tons)

	1995			2000			2010		
	Base	Proxmire	Reductions	Base	Proxmire	Reductions	Base	Proxmire	Reductions
Existing	18.4	13.8	-4.6	19.2	10.3	-8.9	19.7	10.0	-9.7
New	0.2	0.2	+0.0	0.4	0.6	+0.1	2.0	2.7	+0.6
Total	18.6	14.0	-4.6	19.6	10.9	-8.8	21.7	12.6	-9.1

SO_2 EMISSION REDUCTIONS UNDER THE PROXMIRE CASES

- The Proxmire bill requires emission reductions in two phases:

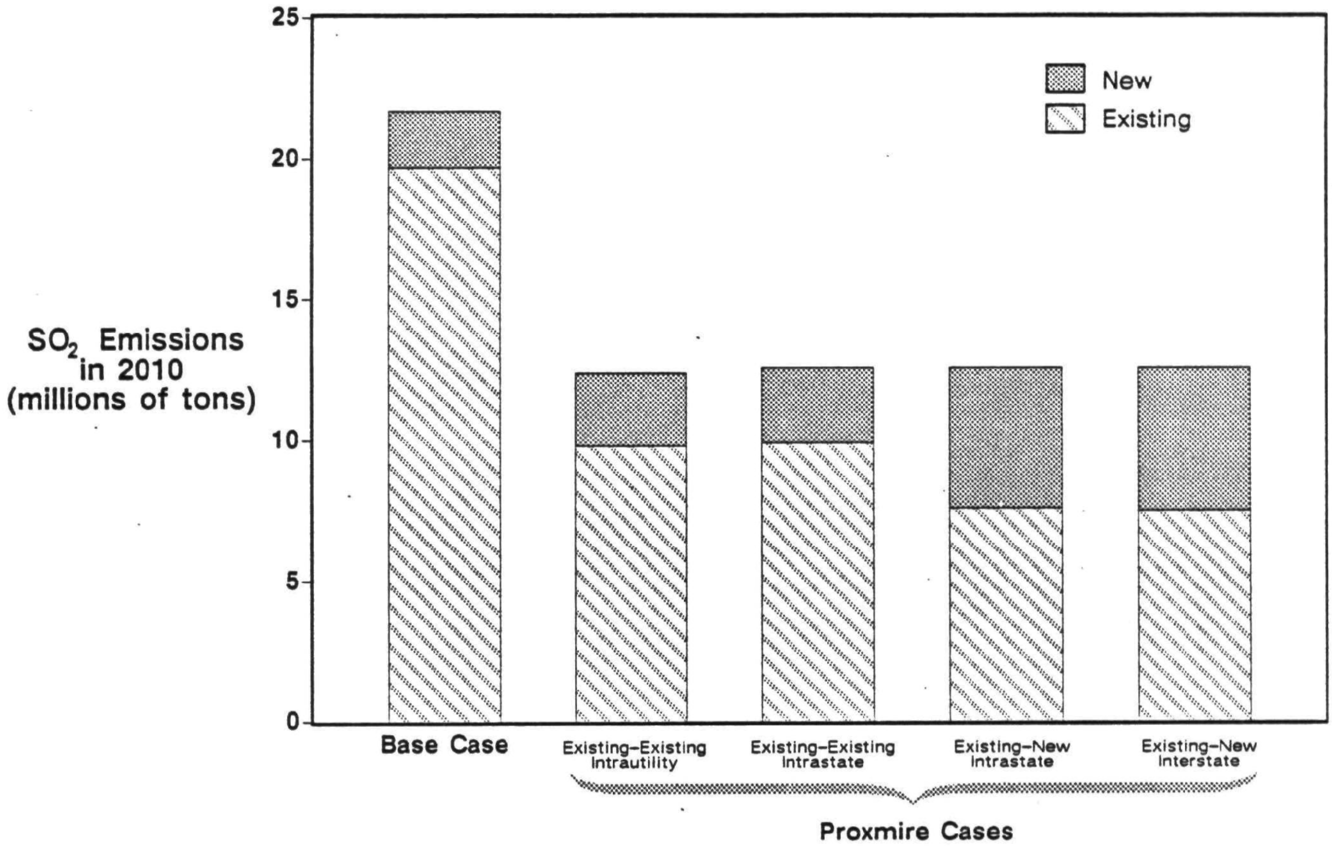
  -- In the first phase, SO_2 emissions would be reduced by approximately 4.6 million tons below Base Case levels by 1995.

  -- When Phase II is imposed, emission reductions would total about 9 million tons below 2000 Base Case levels.

- Under Phase II of Proxmire, emission reductions below Base Case levels increase slightly between 2000 and 2010 (from 8.8 to 9.1 million tons). This occurs because emission levels from existing non-NSPS sources are capped at a constant level by the Proxmire reduction requirements, while Base Case emissions from existing non-NSPS sources are forecast to increase over that period (as electricity demand growth leads to higher utilization of coal powerplants).

- Despite the slightly higher level of emission reductions in 2010 than in 2000, total emissions under the Proxmire increase between 2000 and 2010. This is because emissions from new powerplants are not limited by the bill. Thus, increases in emissions from new powerplants lead to a net increase in total emissions of 1.8 million tons over this period (as can be seen in the table on the opposite page). Note that approximately 200 gigawatts of new coal capacity is forecast to be brought into service during the 2000-2010 period.

SO2 EMISSIONS BY PLANT TYPE -- PROXMIRE CASES IN 2010

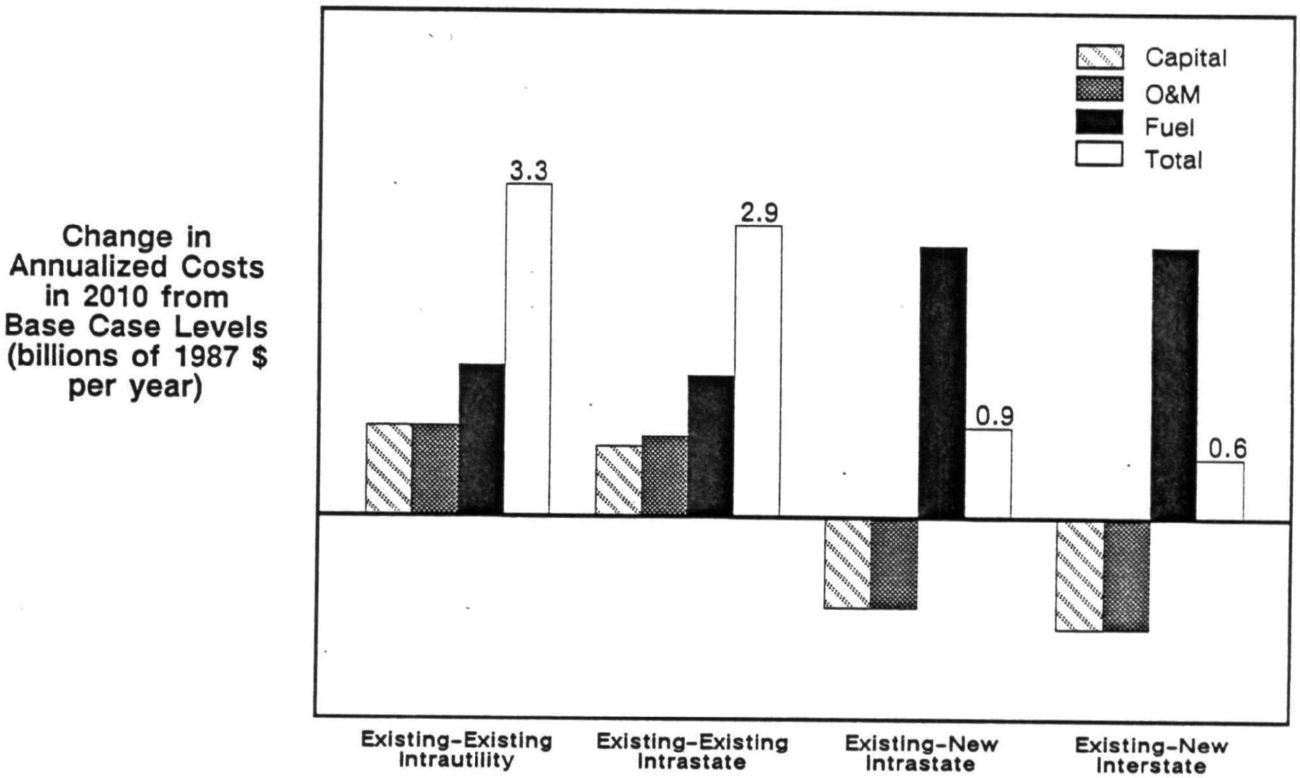


SO2 EMISSIONS BY PLANT TYPE -- PROXMIRE CASES IN 2010

- Emission reductions under the Proxmire bill by 2010 are forecast to total about 9 million tons. Reductions are slightly greater in the intrautility trading case (about 9.3 million tons versus 9.1 million tons in the other trading cases). This is because Base Case emissions for some utilities are forecast to be lower than their maximum allowable emission levels under Proxmire, and these utilities are assumed to be unable or not permitted to trade these "unused" emission reductions to another utility.

- Allowing existing-new trades results in substantial emission shifts between new and existing sources. Emissions from new sources in 2010 are 2.3 million tons higher in the existing-new intrastate trading case (than in the comparable existing-existing trading case), reflecting about 190 gigawatts of new coal capacity which is built without scrubbers. On the other hand, the existing-new intrastate trading case requires 2.3 million tons more reductions from existing powerplants to compensate for the increase in new emissions. To achieve these reductions, utilities in the existing-new intrastate trading case are forecast to build 38 gigawatts of retrofit scrubbers, or about 33 gigawatts more retrofit scrubbers than in the existing-existing intrastate trading case.

CHANGE IN ANNUALIZED COSTS IN 2010 -- PROXMIRE CASES



CHANGE IN ANNUALIZED COSTS IN 2010 -- PROXMIRE CASES

The costs of the Proxmire bill are highly dependent upon the trading scheme; as more trading flexibility is allowed, costs are reduced.

- Allowing more trading on a geographic basis enables significant cost reductions:
  - Expanding trading from the intrautility to intrastate level leads to annualized cost savings of $0.4 billion by 2010.
  - Permitting trading on the interstate level leads to estimated further savings of $0.2-0.4 billion by 2010.[1]
- Existing-new trading reduces costs substantially:
  - Comparing the two intrastate cases in 2010, existing-new trading is about $2.0 billion per year less expensive than the analogous existing-existing trading case.
- The annualized cost components are affected substantially by existing-new trading:
  - Capital and O&M costs in 2010 are actually lower in the existing-new trading cases than Base Case levels because of the significant savings on new scrubber capital and O&M expenditures as many new plants are built without scrubbers.
  - On the other hand, fuel costs are substantially higher for the existing-new cases than for the existing-existing cases. This occurs because (1) more switching to lower sulfur fuels is necessary in the existing-new cases in order to obtain more emission reductions from existing sources to offset new plant emission increases, and (2) new unscrubbed powerplants choose to burn low sulfur fuels as opposed to scrubbing high sulfur coals as some new plants do in the Base Case.

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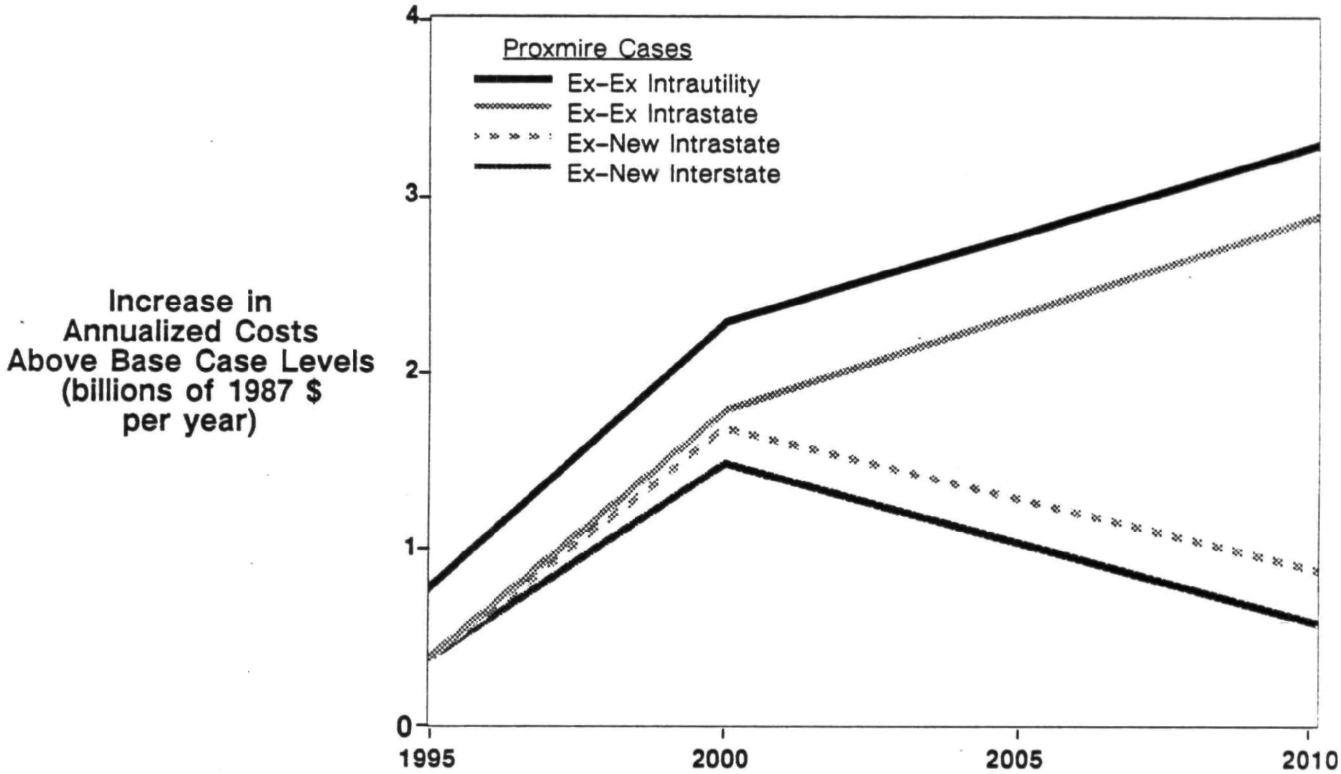
[1]A Proxmire bill interstate existing-existing trading case was not examined for this analysis. However, based on previous analyses conducted for EPA, annualized costs for this case are estimated to be about $0.2-$0.4 billion less than the intrastate trading case. As shown on the opposite page, the existing-new interstate trading is about $0.3 billion less costly than the comparable intrastate trading case.

CHANGES IN ANNUALIZED COSTS OVER TIME -- PROXMIRE CASES

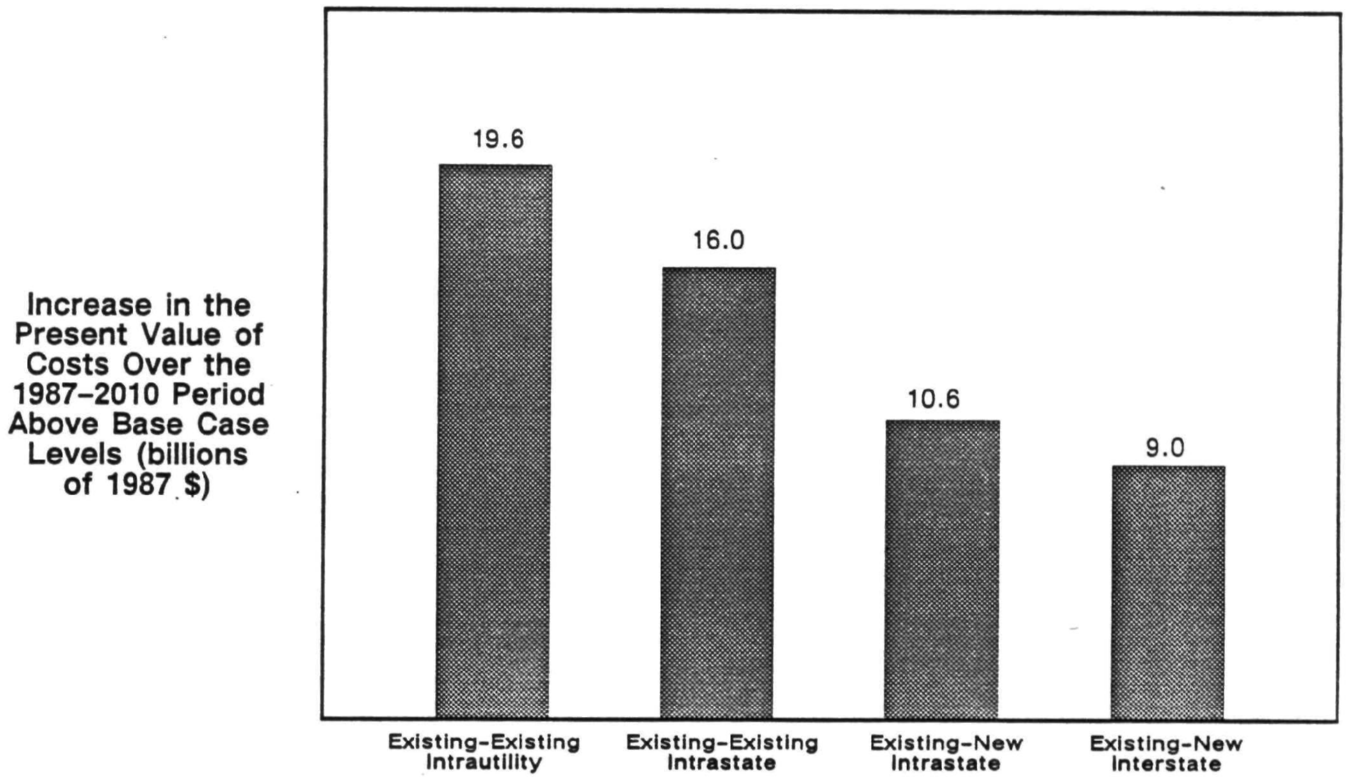


CHANGES IN ANNUALIZED COSTS OVER TIME -- PROXMIRE CASES

- Annualized costs increase over time relative to Base Case levels for the existing-existing trading cases. Between 1995 and 2000, much of the relative increase in cost is due to rising fuel costs, as more fuel switching is forecast (because of the more stringent emission requirements of Phase II). After 2000, costs continue to increase, reflecting (1) somewhat greater emission reductions being required, and (2) greater depletion of lower sulfur coal reserves, resulting in increased fuel price premiums.

- When existing-new trading is permitted under Proxmire, annualized costs are much lower than in comparable existing-existing trading cases. This is particularly true over time (e.g., by 2010) as more new capacity is built without scrubbers, thereby taking advantage of existing-new trading opportunities. Existing-new trading at the intrastate level lowers annualized costs by $2.0 billion in 2010 from levels forecast under existing-existing trading. In earlier years, the savings are substantially less (less than $0.1 billion in 1995 and only about $0.1 billion in 2000) because much less new coal capacity is expected to be built by that time.

PRESENT VALUE OF COSTS -- PROXMIRE CASES



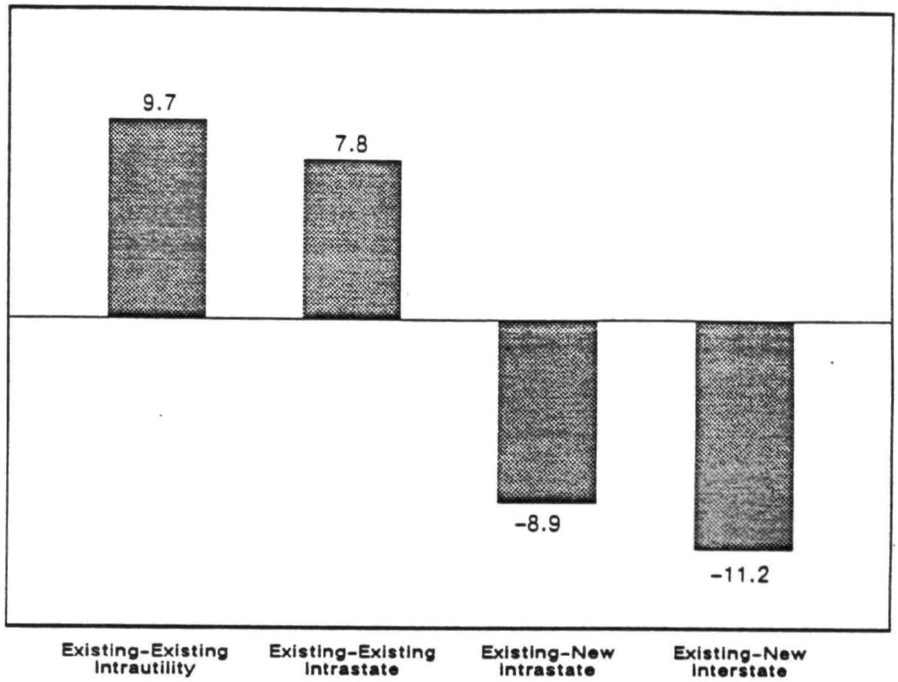
PRESENT VALUE OF COSTS -- PROXMIRE CASES

- The change in present value of costs reflects the increase in annualized costs incurred over the forecast period (i.e., through 2010) discounted back to 1987 using the utilities' real discount rate. Similar to the changes in annualized costs, as the scope and flexibility of trading permitted increases, the present value of costs are reduced. For example, expanding the scope of emissions trading from intrautility to intrastate or from intrastate to interstate reduces the increase in the present value of costs by roughly 20 percent each.

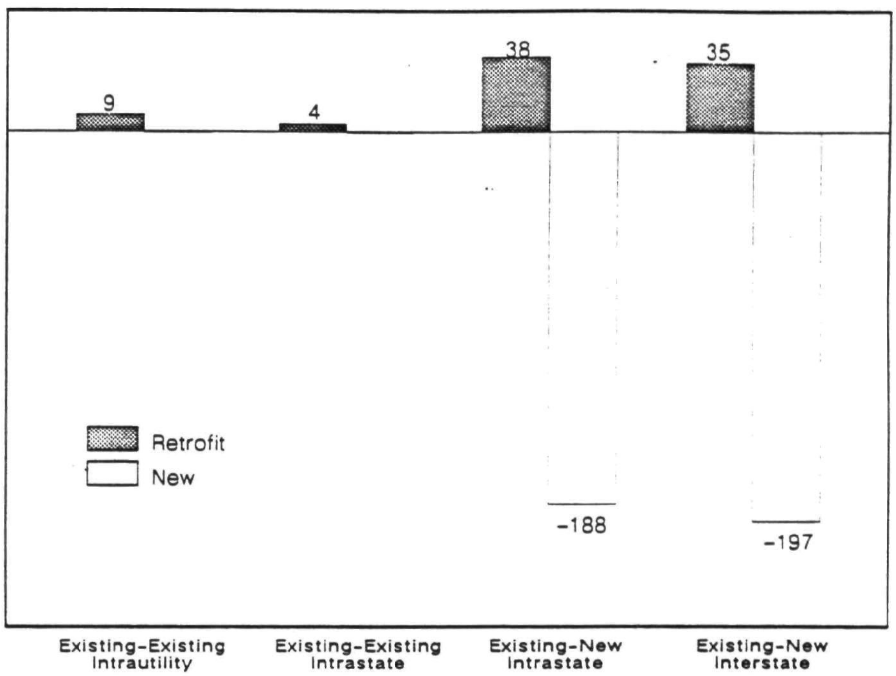
- Existing-new trading also significantly reduces the present value of costs associated with reducing emissions under Proxmire. At the intrastate level, the present value of costs with existing-new trading is about $10 billion, or about 35 percent less than the present value of costs under the equivalent existing-existing trading scheme. While this represents a substantial net cost savings, it is less significant than the annualized cost savings realized in 2010 (about 70 percent lower costs than in the existing-existing trading case). This is because costs are only somewhat lower in earlier forecast years (i.e., 10 percent lower in 2000 and effectively equal in 1995), as much less new coal capacity has been built to engage in existing-new trades by that time. As noted earlier, changes in annualized costs in the earlier years have a greater impact on the changes in the present value of costs.

CHANGES IN CUMULATIVE CAPITAL COSTS AND SCRUBBER CAPACITY
UNDER THE PROXMIRE CASES

Change in Cumulative Capital Costs from Base Case Levels by 2010 (billions of 1987 $)



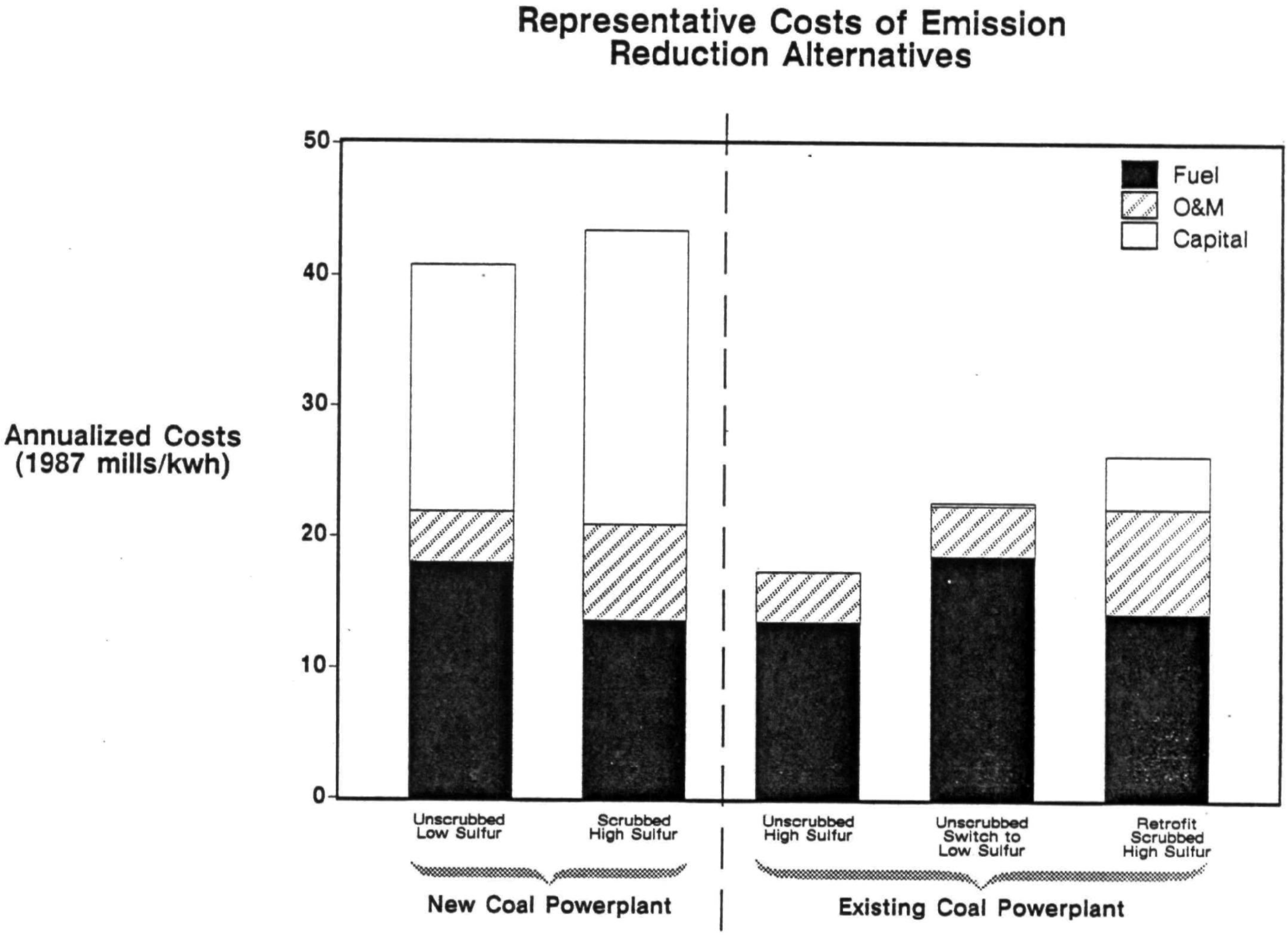
Change in Scrubber Capacity from Base Case Levels in 2010 (gigawatts)



CHANGES IN CUMULATIVE CAPITAL COSTS AND SCRUBBER CAPACITY UNDER THE PROXMIRE CASES

- Increases in cumulative capital costs under the two existing-existing trading cases range from $8 billion to $10 billion by 2010. This range in costs is due to the difference in retrofit scrubber capacity. More retrofit scrubbers are built under the intrautility trading case than in the intrastate case because there is less flexibility in meeting the emission requirements. Thus, capital costs are higher. In addition, in both cases, much of the increase in capital costs relative to the Base Case occurs because utilities choose to scrub more high sulfur coals at new powerplants. Although this strategy leads to higher capital and O&M costs, it enables utilities to take advantage of inexpensive high sulfur coals which experience greatly lowered levels of demand (and, hence, lower prices) under Proxmire, and to avoid lower sulfur coals which experience price increases.

- Existing-new trading lowers cumulative capital costs substantially. By 2010, the cumulative capital costs for the existing-new intrastate trading case are $9 billion less than Base Case levels, and $17 billion less than the existing-existing intrastate trading case. This reflects sizable capital savings on avoided new scrubber capacity. While much less new scrubbed capacity is forecast in the existing-new trading cases, somewhat more retrofit scrubber capacity is forecast. This occurs because (as discussed on the next page) the cost per ton removed of retrofit scrubbing at some existing units is lower than the incremental cost of scrubbing a new powerplant (versus using a low sulfur coal without scrubbing.)



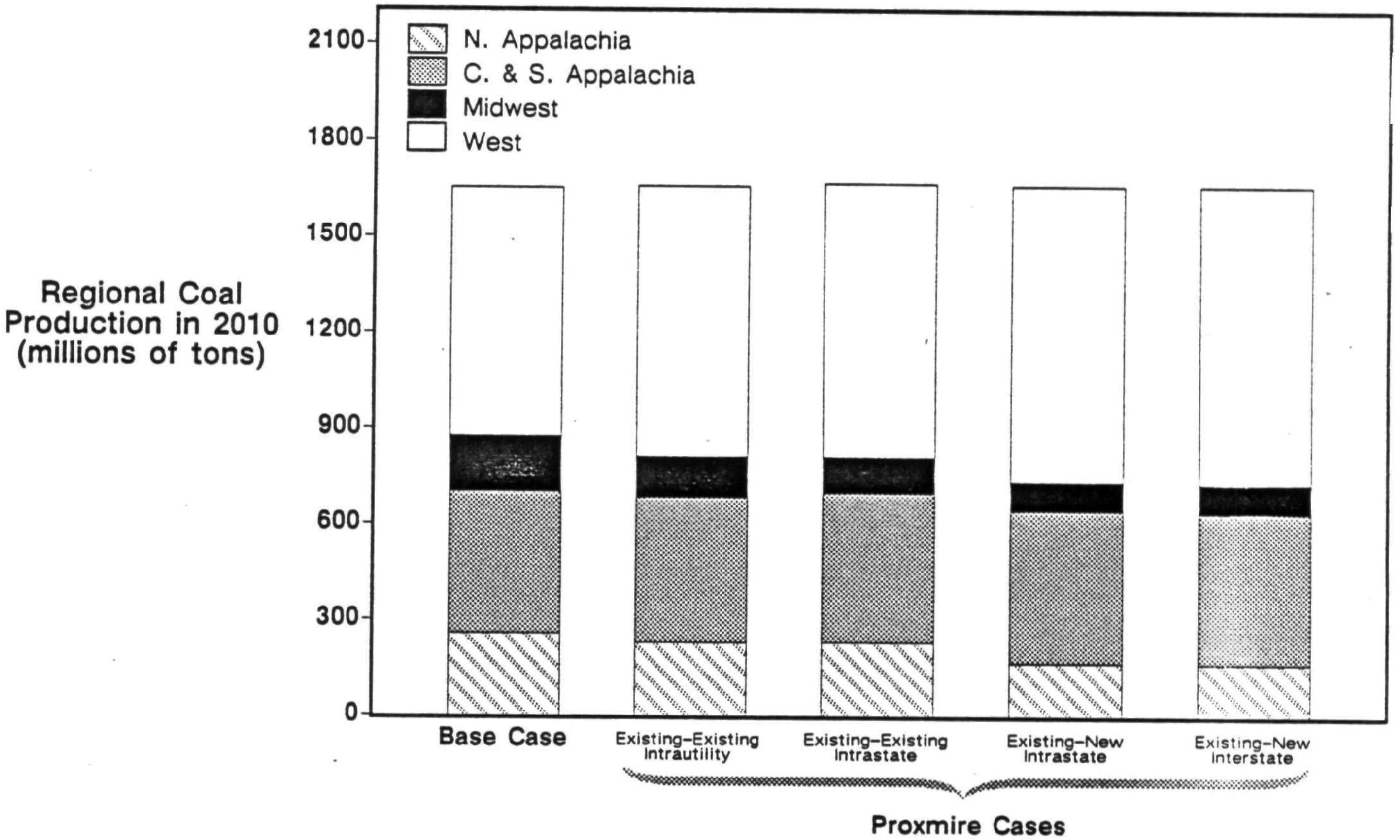
Total Annual Costs (mills/kwh)	40.6	43.4	17.3	22.7	26.3
Incremental Costs (mills/kwh)	-	2.8	-	5.4	9.0
Emission Rate (lbs. SO_2/mm Btu)	1.0	0.6	5.0	1.0	0.5
Reduction in Emission Rate (lbs. SO_2/mm Btu)	-	0.4	-	4.0	4.5
$ Per Ton SO_2 Removed	-	1400	-	270	400

VALUE OF EXISTING-NEW TRADES FOR PROXMIRE CASES

- Allowing existing-new emissions trading in meeting the Proxmire reduction requirements results in much lower costs than is forecast under a more restrictive trading scheme which limits trades among existing sources. These lower costs result from utilities building new powerplants without scrubbers and offsetting the emission increases through more cost-effective reductions at existing sources.

- In most instances, the incremental costs of scrubbing a new coal powerplant unit (relative to burning low sulfur coal unscrubbed at a new plant) is more costly (on a cost per ton removed basis) than reducing emissions at existing units. For instance, an existing unscrubbed unit can shift to lower sulfur coals and reduce emissions at a cost of $100-400 per ton removed or can add a scrubber at a cost of $300-600 per ton removed. By comparison, reductions obtained by scrubbing a new powerplant unit (versus burning low sulfur coal unscrubbed at the new plant) can cost over $1000 per ton. Reductions at new scrubbed powerplants are more expensive because scrubbed new powerplants generally have slightly lower emissions than new unscrubbed low sulfur plants, but have significantly higher costs. In contrast, many more reductions are achieved at a comparable or lower cost when an existing high sulfur plant switches to low sulfur coal or retrofits a scrubber. As a result of these underlying economics, nearly 200 gigawatts of new coal capacity is forecast to be built <u>without scrubbers</u> by 2010 in the existing-new Proxmire cases.

REGIONAL COAL PRODUCTION IN 2010 FOR PROXMIRE CASES

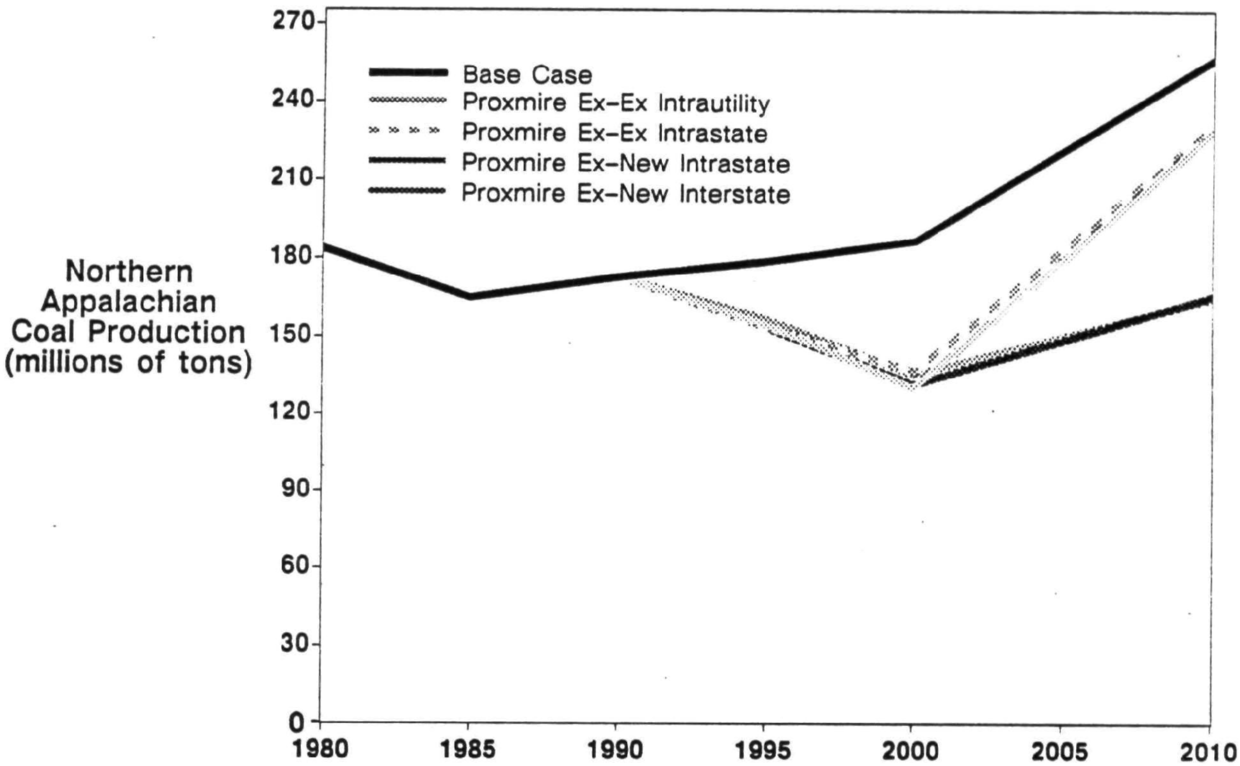


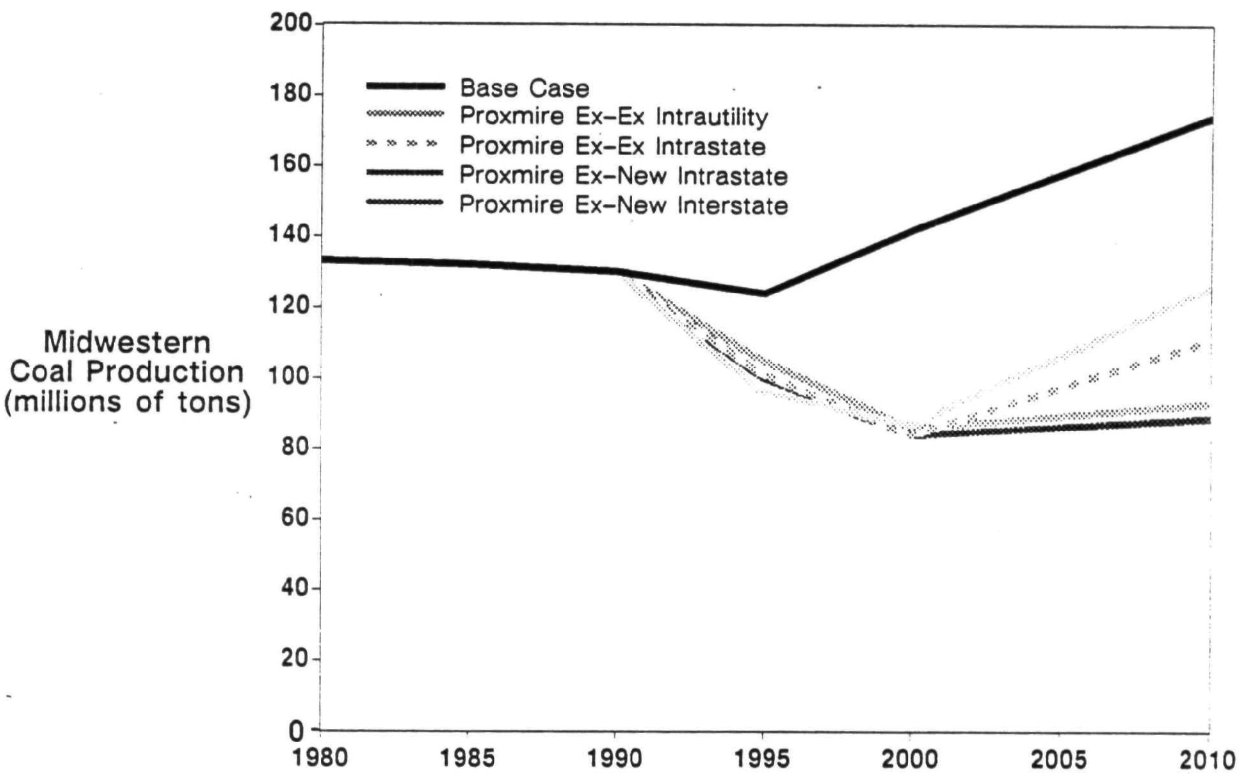
REGIONAL COAL PRODUCTION IN 2010 FOR PROXMIRE CASES

- Most of the required reductions in the Proxmire cases are achieved through switching to lower sulfur coals. This is because coal switching in many instances is more cost-effective (in terms of incremental cost per ton of emissions removed) in meeting the emission requirements. As a result, production from low sulfur coal regions increases from Base Case levels in all trading variants of the Proxmire bill. However, high sulfur coal producing regions lose production to the low sulfur coal producing regions.

- The existing-new trading cases lead to even more shifts in production from high sulfur regions to low sulfur regions. While production from high sulfur coal regions (the Midwest and Northern Appalachia) is forecast to fall by about 80-90 million tons (from Base Case levels) in 2010 for the existing-existing trading cases, production from these regions is estimated to decline by almost 180 million tons -- or twice as large a drop -- in the existing-new cases. This occurs because (1) even more fuel shifting occurs in the existing-new trading cases, since more emissions must be reduced from existing sources in order to offset emissions increases at new unscrubbed powerplants, and (2) new unscrubbed powerplants burn low sulfur coals (as opposed to new scrubbed plants burning high sulfur coals in the Base Case and the existing-existing trading cases). In earlier forecast years, there are much smaller regional coal production shifts because there are fewer existing-new trades.

COAL PRODUCTION OVER TIME -- PROXMIRE CASES





COAL PRODUCTION OVER TIME -- PROXMIRE CASES

- Coal production in the high sulfur coal producing regions (the Midwest and Northern Appalachia) is forecast to experience substantial declines from Base Case levels under the Proxmire bill. By 1995, production in these two regions is forecast to be about 50 million tons less than levels suggested by the Base Case, and about 110 million tons less than Base Case levels by 2000, with the declines from Base Case levels split roughly equally between these two regions. By 2010, the Midwest is forecast to experience more significant declines than Northern Appalachia under the Proxmire bill. This occurs because there is still a sizable market for medium sulfur coals (which can be mined in Northern Appalachia), while demand for high sulfur coals (which are predominant in the Midwest) decreases significantly.

- The Proxmire existing-new trading cases result in even further reductions in high sulfur coal production from the Midwest and Northern Appalachia by 2010. This effect is more pronounced in Northern Appalachia because (1) utilities in the East build unscrubbed new powerplants under existing-new trading (instead of scrubbed higher sulfur coal plants) and use low sulfur coals at these new unscrubbed plants in order to minimize the number of existing-new emission trades, and (2) existing powerplants shift more from high and medium sulfur coals to low sulfur coals in order to offset emission increases from unscrubbed new powerplants.

TABLE B-1A

SULFUR DIOXIDE FORECASTS
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1995
<u>Utility SO2 Emissions</u>							
(millions of tons)							
31-Eastern States							
Coal							
EXISTING	14.92	14.21	15.26	-4.66	-4.53	-4.53	-4.55
NEW	0.00	0.00	0.15	0.01	0.01	0.01	0.01
TOTAL COAL	14.92	14.21	15.41	-4.65	-4.52	-4.52	-4.54
OIL/GAS	1.27	0.57	1.02	-0.34	-0.02	-0.03	-0.00
TOTAL 31-EASTERN STATES	16.19	14.78	16.43	-4.99	-4.55	-4.55	-4.54
17-Western States							
Coal							
EXISTING	1.10	1.48	2.00	-0.01	-0.01	-0.04	-0.03
NEW	0.00	0.00	0.05	0.00	0.00	0.02	0.02
TOTAL COAL	1.10	1.48	2.05	-0.01	-0.01	-0.01	-0.01
OIL/GAS	0.09	0.01	0.12	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	1.19	1.49	2.17	-0.01	-0.01	-0.01	-0.01
United States							
Coal							
EXISTING	16.02	15.69	17.26	-4.66	-4.54	-4.57	-4.58
NEW	0.00	0.00	0.20	0.01	0.01	0.03	0.03
TOTAL COAL	16.02	15.69	17.46	-4.66	-4.53	-4.53	-4.55
OIL/GAS	1.36	0.58	1.14	-0.34	-0.02	-0.03	-0.00
TOTAL UNITED STATES	17.38	16.27	18.60	-5.00	-4.55	-4.56	-4.55

Note: Totals may not add due to independent rounding.

TABLE B-1B

SULFUR DIOXIDE FORECASTS
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2000
Utility SO2 Emissions (millions of tons)							
31-Eastern States							
Coal							
EXISTING	14.92	14.21	15.85	-8.56	-8.46	-8.74	-8.76
NEW	0.00	0.00	0.34	0.09	0.09	0.52	0.56
TOTAL COAL	14.92	14.21	16.20	-8.47	-8.37	-8.22	-8.20
OIL/GAS	1.27	0.57	1.19	-0.57	-0.43	-0.58	-0.60
TOTAL 31-EASTERN STATES	16.19	14.78	17.39	-9.04	-8.79	-8.79	-8.80
17-Western States							
Coal							
EXISTING	1.10	1.48	2.05	0.01	0.01	-0.14	-0.18
NEW	0.00	0.00	0.09	0.03	0.03	0.19	0.24
TOTAL COAL	1.10	1.48	2.13	0.04	0.04	0.05	0.06
OIL/GAS	0.09	0.01	0.13	0.0	0.0	-0.01	-0.03
TOTAL 17-WESTERN STATES	1.19	1.49	2.26	0.04	0.04	0.04	0.04
United States							
Coal							
EXISTING	16.02	15.69	17.90	-8.54	-8.45	-8.88	-8.94
NEW	0.00	0.00	0.43	0.11	0.12	0.72	0.80
TOTAL COAL	16.02	15.69	18.33	-8.43	-8.33	-8.17	-8.13
OIL/GAS	1.36	0.58	1.32	-0.57	-0.43	-0.59	-0.62
TOTAL UNITED STATES	17.38	16.27	19.65	-9.00	-8.75	-8.75	-8.76

Note: Totals may not add due to independent rounding.

TABLE B-1C

SULFUR DIOXIDE FORECASTS
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2010
Utility SO2 Emissions (millions of tons)							
31-Eastern States							
Coal							
EXISTING	14.92	14.21	16.76	-9.66	-9.63	-10.88	-10.87
NEW	0.00	0.00	1.47	0.62	0.61	2.20	2.20
TOTAL COAL	14.92	14.21	18.23	-9.04	-9.02	-8.68	-8.67
OIL/GAS	1.27	0.57	0.82	-0.29	-0.09	-0.44	-0.44
TOTAL 31-EASTERN STATES	16.19	14.78	19.05	-9.33	-9.11	-9.11	-9.11
17-Western States							
Coal							
EXISTING	1.10	1.48	2.01	0.00	0.00	-0.76	-0.79
NEW	0.00	0.00	0.55	0.00	0.03	0.81	0.89
TOTAL COAL	1.10	1.48	2.56	0.00	0.03	0.05	0.10
OIL/GAS	0.09	0.01	0.11	0.00	0.0	-0.04	-0.07
TOTAL 17-WESTERN STATES	1.19	1.49	2.67	0.00	0.03	0.01	0.03
United States							
Coal							
EXISTING	16.02	15.69	18.77	-9.66	-9.63	-11.64	-11.70
NEW	0.00	0.00	2.01	0.63	0.64	3.01	3.08
TOTAL COAL	16.02	15.69	20.79	-9.04	-8.99	-8.63	-8.57
OIL/GAS	1.36	0.58	0.93	-0.29	-0.09	-0.48	-0.52
TOTAL UNITED STATES	17.38	16.27	21.72	-9.32	-9.09	-9.10	-9.09

Note: Totals may not add due to independent rounding.

TABLE B-2-A

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROX. EX-EX IN-STATE 1995	CHANGE FROM EPA BASE PROX. EX-NEW IN-STATE 1995	CHANGE FROM EPA BASE PROX. EX-NEW INTER. 1995
Utility Annual Costs (billions of mid-1987 $/yr.)				
Capital	0.1	0.1	0.1	0.1
O&M	0.1	0.1	0.1	0.1
Fuel	0.5	0.3	0.3	0.2
Total	0.8	0.4	0.4	0.4
Utility Cumulative Capital Costs (billions of mid-1987 $)				
31-Eastern States	1.2	0.8	0.9	0.9
17-Western States	0.0	0.0	0.0	-0.1
Total U.S.	1.2	0.9	0.9	0.8
Average Cost Per Ton SO2 Removed	154	98	96	87
SO2 Retrofit Scrubber Capacity (GW)				
31-Eastern States	0.8	0.1	0.0	0.0
17-Western States	0.0	0.0	0.0	0.0
Total U.S.	0.8	0.1	0.0	0.0
New Capacity Trading with Existing Capacity (GW)				
31-Eastern States	0.0	0.0	0.0	0.0
17-Western States	0.0	0.0	0.3	0.3
Total U.S.	0.0	0.0	0.3	0.3

Note: Totals may not add due to independent rounding.

TABLE B-2-B

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROX. EX-EX IN-STATE 2000	CHANGE FROM EPA BASE PROX. EX-NEW IN-STATE 2000	CHANGE FROM EPA BASE PROX. EX-NEW INTER. 2000
Utility Annual Costs (billions of mid-1987 $/yr.)				
Capital	0.5	0.3	0.2	0.1
O&M	0.4	0.3	0.1	0.1
Fuel	1.3	1.2	1.4	1.3
Total	2.3	1.9	1.7	1.5
Utility Cumulative Capital Costs (billions of mid-1987 $)				
31-Eastern States	5.8	4.0	2.7	2.4
17-Western States	0.1	0.1	-0.5	-0.8
Total U.S.	5.9	4.1	2.3	1.6
Average Cost Per Ton SO2 Removed	253	212	195	174
SO2 Retrofit Scrubber Capacity (GW)				
31-Eastern States	7.9	4.2	7.5	6.4
17-Western States	0.0	0.0	0.8	0.0
Total U.S.	7.9	4.2	8.3	6.4
New Capacity Trading with Existing Capacity (GW)				
31-Eastern States	0.0	0.0	15.5	15.5
17-Western States	0.0	0.0	6.0	6.9
Total U.S.	0.0	0.0	21.5	22.4

Note: Totals may not add due to independent rounding.

TABLE B-2-C

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROX. EX-EX IN-STATE 2010	CHANGE FROM EPA BASE PROX. EX-NEW IN-STATE 2010	CHANGE FROM EPA BASE PROX. EX-NEW INTER. 2010
Utility Annual Costs (billions of mid-1987 $/yr.)				
Capital	0.9	0.7	-0.9	-1.1
O&M	0.9	0.8	-0.9	-1.1
Fuel	1.5	1.4	2.7	2.8
Total	3.3	2.9	0.9	0.6
Utility Cumulative Capital Costs (billions of mid-1987 $)				
31-Eastern States	9.6	7.6	-5.2	-5.8
17-Western States	0.1	0.2	-3.8	-5.3
Total U.S.	9.7	7.8	-8.9	-11.1
Average Cost Per Ton SO2 Removed	349	319	99	66
SO2 Retrofit Scrubber Capacity (GW)				
31-Eastern States	8.8	4.5	28.8	27.9
17-Western States	0.0	0.0	9.3	7.6
Total U.S.	8.8	4.5	38.1	35.5
New Capacity Trading with Existing Capacity (GW)				
31-Eastern States	0.0	0.0	135.5	141.5
17-Western States	0.0	0.0	52.4	55.1
Total U.S.	0.0	0.0	187.9	196.6

Note: Totals may not add due to independent rounding.

TABLE B-3A

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1995
31 EASTERN STATES							
COAL							
LOW SULFUR	0.87	1.89	2.63	1.26	1.21	1.22	1.17
LOW-MEDIUM SULFUR	1.61	1.56	2.08	0.68	0.62	0.60	0.76
HIGH-MEDIUM SULFUR	3.18	3.66	3.83	-0.55	-0.58	-0.54	-0.77
HIGH SULFUR	3.86	3.90	3.80	-1.37	-1.25	-1.28	-1.15
TOTAL	9.53	11.01	12.34	0.02	0.01	0.00	0.00
OIL	1.99	0.93	1.54	0.00	0.00	0.00	0.0
GAS	1.01	0.92	0.79	0.0	0.0	0.0	0.0
17 WESTERN STATES							
COAL							
LOW SULFUR	1.41	1.61	2.42	-0.04	-0.07	-0.08	-0.10
LOW-MEDIUM SULFUR	0.43	0.94	0.85	0.03	0.06	0.08	0.10
HIGH-MEDIUM SULFUR	0.74	0.96	1.11	0.00	0.00	-0.01	-0.02
HIGH SULFUR	0.01	0.07	0.07	0.01	0.01	0.01	0.01
TOTAL	2.59	3.58	4.44	0.00	0.00	-0.00	-0.00
OIL	0.48	0.06	0.24	0.0	0.0	0.00	0.0
GAS	2.58	2.28	1.64	0.0	0.0	0.0	0.0
TOTAL U.S.							
COAL							
LOW SULFUR	2.28	3.50	5.06	1.21	1.13	1.14	1.07
LOW-MEDIUM SULFUR	2.04	2.49	2.93	0.70	0.68	0.67	0.86
HIGH-MEDIUM SULFUR	3.92	4.62	4.94	-0.54	-0.57	-0.54	-0.79
HIGH SULFUR	3.87	3.97	3.87	-1.35	-1.23	-1.26	-1.13
TOTAL	12.12	14.58	16.79	0.02	0.01	-0.00	0.00
OIL	2.47	0.99	1.79	0.00	0.00	0.00	0.0
GAS	3.59	3.20	2.43	0.0	0.0	0.0	0.0

TABLE B-3B

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2000
31 EASTERN STATES							
COAL							
LOW SULFUR	0.87	1.89	3.36	3.62	4.02	4.31	4.31
LOW-MEDIUM SULFUR	1.61	1.56	2.65	0.37	0.11	0.03	-0.06
HIGH-MEDIUM SULFUR	3.18	3.66	3.78	-1.89	-1.92	-2.04	-1.93
HIGH SULFUR	3.86	3.90	4.12	-2.08	-2.18	-2.28	-2.29
TOTAL	9.53	11.01	13.90	0.02	0.03	0.03	0.03
OIL	1.99	0.93	1.98	0.03	0.01	-0.01	-0.01
GAS	1.01	0.92	0.71	0.0	0.0	0.0	0.0
17 WESTERN STATES							
COAL							
LOW SULFUR	1.41	1.61	2.70	-0.34	-0.38	-0.19	-0.37
LOW-MEDIUM SULFUR	0.43	0.94	0.95	0.37	0.43	0.26	0.49
HIGH-MEDIUM SULFUR	0.74	0.96	1.22	-0.05	-0.06	-0.09	-0.15
HIGH SULFUR	0.01	0.07	0.06	0.02	0.02	0.02	0.02
TOTAL	2.59	3.58	4.93	0.00	0.00	-0.01	-0.01
OIL	0.48	0.06	0.28	0.00	0.00	-0.00	-0.00
GAS	2.58	2.28	1.90	0.0	0.0	0.0	0.0
TOTAL U.S.							
COAL							
LOW SULFUR	2.28	3.50	6.06	3.28	3.63	4.12	3.94
LOW-MEDIUM SULFUR	2.04	2.49	3.60	0.74	0.54	0.29	0.43
HIGH-MEDIUM SULFUR	3.92	4.62	4.99	-1.94	-1.98	-2.12	-2.08
HIGH SULFUR	3.87	3.97	4.18	-2.06	-2.16	-2.26	-2.27
TOTAL	12.12	14.58	18.84	0.02	0.03	0.02	0.02
OIL	2.47	0.99	2.26	0.03	0.01	-0.01	-0.01
GAS	3.59	3.20	2.61	0.0	0.0	0.0	0.0

TABLE B-3C

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2010
31 EASTERN STATES							
COAL							
LOW SULFUR	0.87	1.89	6.81	0.79	1.33	6.00	6.48
LOW-MEDIUM SULFUR	1.61	1.56	3.82	2.07	1.78	-0.51	-0.91
HIGH-MEDIUM SULFUR	3.18	3.66	4.85	-1.23	-1.26	-2.42	-2.63
HIGH SULFUR	3.86	3.90	5.08	-1.60	-1.80	-3.06	-2.94
TOTAL	9.53	11.01	20.57	0.04	0.04	0.01	0.00
OIL	1.99	0.93	1.79	0.03	0.01	-0.05	-0.06
GAS	1.01	0.92	0.44	0.0	0.0	0.0	0.0
17 WESTERN STATES							
COAL							
LOW SULFUR	1.41	1.61	5.56	-0.17	-0.32	0.22	0.24
LOW-MEDIUM SULFUR	0.43	0.94	1.55	0.09	0.24	-0.15	-0.24
HIGH-MEDIUM SULFUR	0.74	0.96	1.21	0.08	0.08	-0.10	-0.04
HIGH SULFUR	0.01	0.07	0.08	0.0	0.0	0.00	-0.00
TOTAL	2.59	3.58	8.40	0.00	0.00	-0.03	-0.04
OIL	0.48	0.06	0.34	0.00	0.00	-0.01	-0.01
GAS	2.58	2.28	0.99	0.0	0.0	0.0	0.0
TOTAL U.S.							
COAL							
LOW SULFUR	2.28	3.50	12.38	0.62	1.02	6.21	6.71
LOW-MEDIUM SULFUR	2.04	2.49	5.37	2.17	2.01	-0.66	-1.14
HIGH-MEDIUM SULFUR	3.92	4.62	6.06	-1.15	-1.18	-2.52	-2.67
HIGH SULFUR	3.87	3.97	5.16	-1.60	-1.80	-3.06	-2.94
TOTAL	12.12	14.58	28.96	0.04	0.05	-0.02	-0.04
OIL	2.47	0.99	2.13	0.03	0.01	-0.07	-0.07
GAS	3.59	3.20	1.44	0.0	0.0	0.0	0.0

TABLE B-4A

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1995
Coal Production							
NORTHERN APPALACHIA	185.	166.	180.	-24.	-25.	-25.	-22.
CENTRAL APPALACHIA	233.	245.	282.	40.	39.	39.	26.
SOUTHERN APPALACHIA	26.	26.	23.	1.	1.	1.	1.
MIDWEST	134.	133.	125.	-28.	-23.	-24.	-19.
WEST	251.	316.	428.	7.	5.	5.	11.
TOTAL COAL REGIONS	830.	881.	1038.	-4.	-3.	-4.	-3.
Coal Transportation							
WESTERN COAL TO EAST	N.A.	N.A.	55.	-1.	-2.	-2.	5.

TABLE B-4B

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2000
Coal Production							
NORTHERN APPALACHIA	185.	166.	188.	-56.	-50.	-55.	-51.
CENTRAL APPALACHIA	233.	245.	330.	58.	52.	54.	50.
SOUTHERN APPALACHIA	26.	26.	25.	2.	2.	2.	2.
MIDWEST	134.	133.	143.	-55.	-58.	-58.	-56.
WEST	251.	316.	479.	45.	51.	54.	51.
TOTAL COAL REGIONS	830.	881.	1165.	-4.	-4.	-4.	-4.
Coal Transportation							
WESTERN COAL TO EAST	N.A.	N.A.	70.	29.	34.	38.	36.

TABLE B-4C

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2010
Coal Production							
NORTHERN APPALACHIA	185.	166.	258.	-28.	-26.	-91.	-92.
CENTRAL APPALACHIA	233.	245.	407.	17.	21.	43.	38.
SOUTHERN APPALACHIA	26.	26.	36.	-5.	-6.	-7.	-10.
MIDWEST	134.	133.	175.	-48.	-63.	-85.	-81.
WEST	251.	316.	777.	72.	80.	152.	156.
TOTAL COAL REGIONS	830.	881.	1653.	7.	7.	11.	11.
Coal Transportation							
WESTERN COAL TO EAST	N.A.	N.A.	183.	49.	59.	128.	132.

TABLE B-5A

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1995
ME	17.	10.	3.	0.	0.	-0.	0.
NH	80.	74.	64.	-8.	-9.	-9.	-20.
VT	0.	1.	3.	-3.	-2.	-2.	0.
MA	258.	230.	272.	-31.	-14.	-14.	0.
RI	5.	2.	0.	0.	0.	0.	0.
CT	29.	56.	17.	-2.	4.	4.	0.
NY	479.	420.	481.	-125.	0.	0.	-13.
PA	1422.	1320.	1275.	-196.	-170.	-170.	-74.
NJ	103.	97.	130.	-29.	-27.	-27.	-17.
MD	222.	217.	315.	-98.	-96.	-96.	-23.
DE	51.	63.	60.	-1.	1.	1.	0.
DC	4.	1.	4.	0.	0.	0.	0.
VA	157.	131.	240.	-93.	-98.	-98.	-100.
WV	984.	969.	961.	-212.	-201.	-201.	-333.
NC	445.	337.	504.	-28.	-30.	-30.	-29.
SC	210.	162.	184.	21.	25.	25.	-48.
GA	704.	976.	874.	-275.	-274.	-274.	-228.
FL	692.	501.	937.	-266.	-150.	-150.	-211.
OH	2185.	2193.	2572.	-1445.	-1447.	-1447.	-1233.
MI	608.	401.	449.	-13.	-0.	-0.	-16.
IL	1110.	1073.	955.	-141.	-135.	-135.	-205.
IN	1672.	1498.	1710.	-795.	-797.	-797.	-638.
WI	488.	367.	273.	58.	69.	69.	-43.
KY	1029.	745.	893.	-339.	-283.	-283.	-242.
TN	910.	802.	856.	-349.	-350.	-350.	-439.
AL	535.	563.	512.	-1.	6.	6.	-124.
MS	122.	113.	146.	-34.	-5.	-5.	-82.
MN	159.	124.	169.	-1.	2.	2.	-18.
IA	236.	219.	302.	-57.	-56.	-56.	-171.
MO	1227.	997.	1058.	-518.	-498.	-498.	-245.
AR	27.	69.	125.	-10.	-11.	-11.	3.
LA	21.	67.	86.	0.	0.	-0.	3.
TOTAL 31-EASTERN STATES	16191.	14798.	16431.	-4992.	-4545.	-4547.	-4545.

TABLE B-5A

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1995
ND	79.	124.	177.	0.	0.	-0.	-9.
SD	30.	32.	50.	0.	0.	0.	-20.
KS	102.	166.	224.	-1.	0.	-0.	4.
NE	48.	45.	116.	-2.	-2.	-2.	-3.
OK	45.	80.	209.	0.	0.	0.	0.
TX	295.	430.	695.	-4.	-4.	-4.	23.
MT	23.	22.	45.	0.	0.	-0.	0.
WY	128.	135.	62.	0.	0.	-0.	0.
ID	0.	0.	0.	0.	0.	0.	0.
CO	71.	84.	130.	-1.	-2.	-2.	1.
NM	79.	114.	56.	0.	0.	-0.	0.
UT	25.	27.	69.	0.	0.	-0.	-13.
AZ	84.	104.	126.	0.	0.	0.	7.
NV	38.	35.	76.	0.	0.	0.	0.
WA	68.	85.	114.	0.	0.	-5.	-2.
OR	4.	2.	16.	0.	0.	0.	4.
CA	70.	3.	0.	0.	0.	0.	0.
AK	0.	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2166.	-8.	-7.	-14.	-7.
TOTAL U.S.	17380.	16286.	18597.	-5000.	-4552.	-4561.	-4552.

TABLE B-5B

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2000
ME	17.	10.	4.	-2.	-2.	-2.	-3.
NH	80.	74.	63.	-30.	-30.	-30.	-27.
VT	0.	1.	3.	-3.	-2.	-2.	-1.
MA	258.	230.	299.	-124.	-97.	-97.	-38.
RI	5.	2.	2.	0.	0.	-0.	2.
CT	29.	56.	36.	-7.	-7.	-7.	37.
NY	479.	420.	518.	-109.	-39.	-39.	4.
PA	1422.	1320.	1186.	-556.	-536.	-536.	-523.
NJ	103.	97.	127.	-26.	-24.	-24.	-51.
MD	222.	217.	332.	-162.	-165.	-165.	-147.
DE	51.	63.	60.	-6.	-4.	-4.	-22.
DC	4.	1.	4.	0.	1.	1.	0.
VA	157.	131.	293.	-123.	-124.	-124.	-99.
WV	984.	969.	1007.	-532.	-523.	-523.	-494.
NC	445.	337.	520.	-97.	-98.	-98.	-86.
SC	210.	162.	209.	-64.	-62.	-62.	-15.
GA	704.	976.	946.	-546.	-546.	-546.	-567.
FL	692.	501.	968.	-382.	-291.	-291.	-371.
OH	2185.	2193.	2677.	-1993.	-1993.	-1993.	-1963.
MI	608.	401.	477.	-68.	-67.	-67.	-63.
IL	1110.	1073.	1096.	-562.	-567.	-567.	-706.
IN	1672.	1498.	1782.	-1166.	-1161.	-1161.	-1079.
WI	488.	367.	267.	-35.	-36.	-36.	-68.
KY	1029.	745.	935.	-519.	-523.	-523.	-497.
TN	910.	802.	922.	-616.	-617.	-617.	-580.
AL	535.	563.	565.	-209.	-209.	-209.	-228.
MS	122.	113.	153.	-40.	-9.	-9.	-88.
MN	159.	124.	218.	-61.	-61.	-61.	-76.
IA	236.	219.	368.	-202.	-202.	-202.	-234.
MO	1227.	997.	1118.	-765.	-765.	-765.	-787.
AR	27.	69.	151.	-36.	-36.	-36.	-20.
LA	21.	67.	84.	0.	0.	-0.	-5.
TOTAL 31-EASTERN STATES	16191.	14798.	17386.	-9039.	-8792.	-8792.	-8796.

TABLE B-5B

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2000
ND	79.	124.	188.	0.	0.	-0.	-50.
SD	30.	32.	51.	0.	0.	0.	-22.
KS	102.	166.	230.	5.	4.	4.	-7.
NE	48.	45.	122.	1.	-5.	-5.	-13.
OK	45.	80.	225.	1.	5.	5.	-10.
TX	295.	430.	710.	6.	6.	6.	27.
MT	23.	22.	48.	13.	13.	13.	35.
WY	128.	135.	70.	0.	0.	0.	30.
ID	0.	0.	0.	0.	0.	0.	0.
CO	71.	84.	137.	0.	0.	0.	3.
NM	79.	114.	56.	0.	0.	0.	0.
UT	25.	27.	70.	0.	0.	-0.	-24.
AZ	84.	104.	130.	0.	0.	0.	21.
NV	38.	35.	79.	0.	0.	0.	0.
WA	68.	85.	128.	16.	16.	16.	46.
OR	4.	2.	20.	0.	0.	-0.	-0.
CA	70.	3.	0.	0.	0.	0.	0.
AK	0.	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2263.	41.	38.	38.	38.
TOTAL U.S.	17380.	16286.	19649.	-8998.	-8754.	-8754.	-8759.

TABLE B-5C

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2010
ME	17.	10.	5.	0.	0.	0.	-3.
NH	80.	74.	73.	-24.	-24.	-24.	-21.
VT	0.	1.	3.	-2.	-2.	-2.	-2.
MA	258.	230.	363.	-78.	-30.	-30.	-23.
RI	5.	2.	0.	1.	0.	0.	1.
CT	29.	56.	13.	10.	2.	2.	20.
NY	479.	420.	543.	-23.	43.	43.	-20.
PA	1422.	1320.	1232.	-627.	-605.	-605.	-762.
NJ	103.	97.	191.	15.	16.	16.	70.
MD	222.	217.	344.	-106.	-107.	-107.	-114.
DE	51.	63.	62.	-0.	1.	1.	-21.
DC	4.	1.	3.	0.	0.	-0.	0.
VA	157.	131.	341.	-115.	-116.	-116.	-18.
WV	984.	969.	1037.	-569.	-569.	-569.	-551.
NC	445.	337.	660.	-171.	-165.	-165.	-80.
SC	210.	162.	308.	-108.	-120.	-120.	-85.
GA	704.	976.	1021.	-526.	-536.	-536.	-615.
FL	692.	501.	910.	-267.	-207.	-207.	-196.
OH	2185.	2193.	2849.	-1996.	-1996.	-1996.	-1963.
MI	608.	401.	516.	-46.	-43.	-43.	33.
IL	1110.	1073.	1407.	-772.	-769.	-769.	-820.
IN	1672.	1498.	2007.	-1363.	-1356.	-1356.	-1423.
WI	488.	367.	327.	-56.	-56.	-56.	-28.
KY	1029.	745.	941.	-524.	-526.	-526.	-520.
TN	910.	802.	1056.	-586.	-583.	-583.	-459.
AL	535.	563.	595.	-235.	-235.	-235.	-301.
MS	122.	113.	168.	-26.	1.	1.	-45.
MN	159.	124.	216.	-74.	-75.	-75.	-93.
IA	236.	219.	438.	-258.	-258.	-258.	-261.
MO	1227.	997.	1196.	-788.	-788.	-788.	-818.
AR	27.	69.	131.	-13.	-13.	-13.	-4.
LA	21.	67.	89.	0.	0.	-0.	10.
TOTAL 31-EASTERN STATES	16191.	14798.	19047.	-9329.	-9114.	-9114.	-9114.

TABLE B-5C

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
PROXMIRE CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2010
ND	79.	124.	244.	-1.	1.	1.	9.
SD	30.	32.	58.	-0.	0.	0.	-24.
KS	102.	166.	232.	1.	1.	1.	-61.
NE	48.	45.	133.	1.	1.	-15.	-55.
OK	45.	80.	225.	2.	6.	6.	-7.
TX	295.	430.	890.	-3.	14.	14.	-30.
MT	23.	22.	64.	0.	0.	0.	2.
WY	128.	135.	68.	0.	0.	-0.	19.
ID	0.	0.	0.	0.	0.	0.	0.
CO	71.	84.	145.	0.	0.	0.	-0.
NM	79.	114.	57.	0.	0.	-0.	-0.
UT	25.	27.	77.	0.	0.	-0.	19.
AZ	84.	104.	138.	0.	0.	-0.	65.
NV	38.	35.	78.	0.	0.	0.	24.
WA	68.	85.	217.	6.	6.	6.	-68.
OR	4.	2.	20.	0.	0.	-0.	-15.
CA	70.	3.	20.	0.	0.	-0.	152.
AK	0.	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2668.	4.	28.	10.	28.
TOTAL U.S.	17380.	16286.	21716.	-9324.	-9086.	-9104.	-9087.

TABLE B-6A

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION (Millions of Mid 1987 Dollars) PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 1995
MAINE/VT/NH	4.	2.	3.	3.
MASS/CONN/RHODE I.	22.	7.	7.	6.
NEW YORK	72.	-5.	-4.	2.
PENNSYLVANIA	-0.	-22.	-18.	-13.
NEW JERSEY	10.	5.	5.	4.
MARYLAND/DELAWARE	45.	37.	37.	33.
VIRGINIA	34.	32.	32.	27.
WEST VIRGINIA	32.	22.	23.	14.
N.&S.CAROLINA	46.	42.	43.	10.
GEORGIA	46.	42.	42.	27.
FLORIDA	81.	8.	6.	14.
OHIO	222.	203.	201.	215.
MICHIGAN	50.	45.	44.	38.
ILLINOIS	-31.	-44.	-44.	-68.
INDIANA	53.	34.	38.	48.
WISCONSIN	-11.	-15.	-16.	-30.
KENTUCKY	15.	-4.	-8.	-8.
TENNESSEE	21.	22.	21.	29.
ALABAMA	1.	1.	-0.	-20.
MISSISSIPPI	5.	0.	-0.	-7.
MINNESOTA	-1.	-1.	-2.	-6.
IOWA	-3.	-9.	-11.	-12.
MISSOURI	44.	22.	25.	36.
ARKANSAS	6.	6.	9.	5.
LOUISIANA	1.	2.	3.	2.
TOTAL 31-EASTERN STATES	763.	432.	436.	350.

TABLE B-6A

CHANGE IN ANNUALIZED UTILITY SULFUR
DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 1995
N. & S. DAKOTA	0.	0.	0.	5.
KANSAS/NEBRASKA	-10.	-9.	-12.	-7.
OKLAHOMA	1.	2.	-2.	-2.
TEXAS	-5.	-3.	-20.	15.
MONTANA	-2.	1.	-1.	-1.
WYOMING	3.	3.	3.	16.
IDAHO	0.	0.	0.	0.
COLORADO	3.	5.	6.	5.
NEW MEXICO	-0.	0.	1.	-0.
UTAH	2.	2.	2.	2.
ARIZONA	11.	11.	21.	12.
NEVADA	2.	2.	2.	2.
WASHINGTON/OREGON	3.	3.	3.	0.
CALIFORNIA	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	8.	17.	4.	48.
TOTAL U.S.	772.	449.	440.	397.

1/ Includes transfer costs for emission trades.

TABLE B-6B

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION (Millions of Mid 1987 Dollars) PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 2000
MAINE/VT/NH	16.	12.	12.	12.
MASS/CONN/RHODE I.	79.	47.	44.	34.
NEW YORK	58.	11.	-51.	-47.
PENNSYLVANIA	173.	142.	144.	141.
NEW JERSEY	8.	0.	-1.	-2.
MARYLAND/DELAWARE	83.	83.	74.	71.
VIRGINIA	65.	63.	47.	26.
WEST VIRGINIA	141.	134.	135.	139.
N.&S.CAROLINA	74.	63.	47.	37.
GEORGIA	122.	113.	121.	125.
FLORIDA	100.	38.	-66.	-58.
OHIO	507.	506.	514.	517.
MICHIGAN	49.	40.	47.	49.
ILLINOIS	28.	21.	27.	15.
INDIANA	259.	203.	229.	224.
WISCONSIN	19.	6.	17.	12.
KENTUCKY	156.	61.	57.	58.
TENNESSEE	134.	139.	148.	147.
ALABAMA	51.	36.	40.	44.
MISSISSIPPI	-2.	-5.	-4.	-42.
MINNESOTA	-6.	-13.	0.	1.
IOWA	21.	18.	27.	18.
MISSOURI	178.	172.	184.	182.
ARKANSAS	56.	56.	50.	28.
LOUISIANA	-5.	-6.	10.	5.
TOTAL 31-EASTERN STATES	2361.	1940.	1852.	1740.

TABLE B-6B

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 2000
N. & S. DAKOTA	-0.	0.	6.	-17.
KANSAS/NEBRASKA	-36.	-41.	-33.	-36.
OKLAHOMA	-11.	-12.	-11.	-12.
TEXAS	-21.	-24.	-11.	-15.
MONTANA	-26.	-29.	-39.	-42.
WYOMING	-3.	1.	10.	-11.
IDAHO	0.	0.	0.	0.
COLORADO	7.	10.	4.	4.
NEW MEXICO	-6.	-6.	-4.	-4.
UTAH	1.	2.	2.	-10.
ARIZONA	27.	32.	26.	16.
NEVADA	1.	1.	-17.	-18.
WASHINGTON/OREGON	-22.	-25.	-73.	-67.
CALIFORNIA	-0.	0.	-0.	-0.
TOTAL 17-WESTERN STATES	-90.	-91.	-138.	-214.
TOTAL U.S.	2270.	1849.	1714.	1526.

1/ Includes transfer costs for emission trades.

TABLE B-6C

CHANGE IN ANNUALIZED UTILITY SULFUR
DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 2010
MAINE/VT/NH	9.	7.	-3.	-5.
MASS/CONN/RHODE I.	38.	10.	-84.	-91.
NEW YORK	39.	-8.	-159.	-171.
PENNSYLVANIA	285.	282.	235.	195.
NEW JERSEY	31.	27.	-45.	-55.
MARYLAND/DELAWARE	75.	70.	22.	14.
VIRGINIA	70.	72.	57.	36.
WEST VIRGINIA	214.	215.	230.	237.
N.&S.CAROLINA	54.	42.	-98.	-100.
GEORGIA	155.	151.	128.	130.
FLORIDA	112.	69.	-101.	-94.
OHIO	552.	553.	460.	458.
MICHIGAN	51.	49.	-52.	-61.
ILLINOIS	162.	156.	1.	22.
INDIANA	428.	374.	390.	388.
WISCONSIN	44.	28.	-19.	-25.
KENTUCKY	252.	143.	137.	137.
TENNESSEE	161.	163.	91.	86.
ALABAMA	103.	89.	95.	78.
MISSISSIPPI	13.	11.	-72.	-78.
MINNESOTA	19.	16.	-12.	-12.
IOWA	62.	57.	55.	56.
MISSOURI	231.	221.	164.	159.
ARKANSAS	15.	15.	40.	24.
LOUISIANA	3.	3.	8.	9.
TOTAL 31-EASTERN STATES	3177.	2815.	1467.	1334.

TABLE B-6C

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 1/ 2010
N. & S. DAKOTA	5.	5.	-76.	-95.
KANSAS/NEBRASKA	-5.	-5.	-39.	-137.
OKLAHOMA	9.	10.	-87.	-82.
TEXAS	51.	57.	-172.	-183.
MONTANA	1.	1.	-38.	-39.
WYOMING	10.	10.	-5.	-3.
IDAHO	0.	0.	0.	0.
COLORADO	8.	9.	-6.	4.
NEW MEXICO	1.	2.	-17.	-21.
UTAH	-12.	-11.	-91.	-91.
ARIZONA	1.	1.	41.	50.
NEVADA	1.	2.	-11.	-13.
WASHINGTON/OREGON	4.	4.	-67.	-92.
CALIFORNIA	1.	2.	3.	-33.
TOTAL 17-WESTERN STATES	75.	87.	-565.	-735.
TOTAL U.S.	3252.	2902.	902.	598.

1/ Includes transfer costs for emission trades.

TABLE B-7A

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 1995
MAINE/VT/NH	0.2	0.1	0.1	0.1
MASS/CONN/RHODE I.	0.4	0.1	0.1	0.1
NEW YORK	0.6	-0.0	-0.0	0.0
PENNSYLVANIA	0.0	-0.2	-0.2	-0.1
NEW JERSEY	0.3	0.1	0.1	0.1
MARYLAND/DELAWARE	1.4	1.2	1.2	1.2
VIRGINIA	1.2	1.1	1.1	1.0
WEST VIRGINIA	0.9	0.6	0.6	0.4
N.&S.CAROLINA	0.6	0.5	0.5	0.1
GEORGIA	0.9	0.8	0.8	0.4
FLORIDA	1.0	0.1	0.1	0.2
OHIO	2.7	2.5	2.5	2.7
MICHIGAN	0.8	0.7	0.7	0.6
ILLINOIS	-0.3	-0.5	-0.5	-0.7
INDIANA	0.9	0.6	0.7	0.8
WISCONSIN	-0.4	-0.5	-0.5	-1.0
KENTUCKY	0.4	-0.1	-0.2	-0.2
TENNESSEE	0.5	0.5	0.5	0.7
ALABAMA	0.0	0.0	-0.0	-0.4
MISSISSIPPI	0.4	0.0	-0.0	-0.6
MINNESOTA	0.0	0.0	-0.1	-0.3
IOWA	-0.2	-0.6	-0.7	-0.7
MISSOURI	1.2	0.6	0.6	0.9
ARKANSAS	0.3	0.3	0.4	0.2
LOUISIANA	0.0	0.1	0.1	0.1
TOTAL 31-EASTERN STATES	0.6	0.3	0.3	0.3

TABLE B-7A

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 1995
N. & S. DAKOTA	0.0	0.0	0.0	0.3
KANSAS/NEBRASKA	-0.3	-0.3	-0.3	-0.2
OKLAHOMA	0.1	0.1	-0.1	-0.1
TEXAS	-0.0	-0.0	-0.1	0.1
MONTANA	-0.2	0.1	0.0	-0.1
WYOMING	0.2	0.2	0.3	1.2
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.2	0.3	0.3	0.3
NEW MEXICO	-0.0	0.0	0.1	0.0
UTAH	0.1	0.1	0.1	0.1
ARIZONA	0.2	0.2	0.5	0.2
NEVADA	0.2	0.1	0.1	0.2
WASHINGTON/OREGON	0.1	0.1	0.1	0.0
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.0	0.1
TOTAL U.S.	0.5	0.3	0.3	0.2

1/ Calculated as follows:

$$\left[\frac{\text{1995 Emission Reduction Case Annualized Cost} - \text{1995 Base Case Annualized Cost}}{\text{1995 Electricity Sales}}\right] \div \text{1982 Average Electricity Rates}$$

2/ Includes transfer costs for emission trades.

TABLE B-7B

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (I.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 2000
MAINE/VT/NH	0.9	0.6	0.7	0.7
MASS/CONN/RHODE I.	1.3	0.8	0.8	0.5
NEW YORK	0.5	0.1	-0.4	-0.4
PENNSYLVANIA	1.6	1.3	1.3	1.3
NEW JERSEY	0.2	0.0	-0.0	-0.0
MARYLAND/DELAWARE	2.3	2.3	2.0	2.0
VIRGINIA	1.7	1.6	1.2	0.7
WEST VIRGINIA	3.5	3.4	3.4	3.4
N.&S.CAROLINA	0.8	0.7	0.5	0.4
GEORGIA	2.2	2.1	2.2	2.2
FLORIDA	1.0	0.4	-0.7	-0.6
OHIO	5.8	5.8	5.9	6.0
MICHIGAN	0.7	0.6	0.7	0.7
ILLINOIS	0.3	0.2	0.3	0.1
INDIANA	4.3	3.4	3.8	3.7
WISCONSIN	0.6	0.2	0.5	0.4
KENTUCKY	3.7	1.5	1.4	1.4
TENNESSEE	3.0	3.1	3.3	3.3
ALABAMA	0.9	0.7	0.7	0.8
MISSISSIPPI	-0.1	-0.3	-0.3	-4.2
MINNESOTA	-0.2	-0.5	0.0	0.0
IOWA	1.1	1.0	1.4	1.0
MISSOURI	4.4	4.2	4.5	4.5
ARKANSAS	2.4	2.4	2.2	1.2
LOUISIANA	-0.2	-0.2	0.3	0.2
TOTAL 31-EASTERN STATES	1.7	1.4	1.3	1.3

TABLE B-7B

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 2000
N. & S. DAKOTA	0.0	0.0	0.3	0.9
KANSAS/NEBRASKA	-1.1	-1.2	-1.0	-1.1
OKLAHOMA	-0.4	-0.5	-0.4	-0.5
TEXAS	-0.1	-0.1	-0.1	-0.1
MONTANA	-2.9	-3.2	-4.4	-4.7
WYOMING	-0.2	0.1	0.7	0.7
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.3	0.5	0.2	0.2
NEW MEXICO	-0.3	-0.3	-0.2	-0.2
UTAH	0.1	0.2	0.1	-0.5
ARIZONA	0.5	0.6	0.5	0.3
NEVADA	0.1	0.1	-1.3	-1.3
WASHINGTON/OREGON	-0.5	-0.5	-1.6	-1.5
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	-0.2	-0.2	-0.3	-0.4
TOTAL U.S.	1.2	1.0	0.9	0.8

1/ Calculated as follows:

$$\left[\frac{\frac{\text{2000 Emission Reduction Case Annualized Cost} - \text{2000 Base Case Annualized Cost}}{\text{2000 Electricity Sales}}}{} \right] \div \text{1982 Average Electricity Rates}$$

2/ Includes transfer costs for emission trades.

TABLE B-7C

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 2010
MAINE/VT/NH	0.6	0.4	-0.1	-0.3
MASS/CONN/RHODE I.	0.5	0.1	-1.0	-1.1
NEW YORK	0.2	0.0	-1.0	-1.0
PENNSYLVANIA	3.0	2.9	2.4	2.0
NEW JERSEY	0.4	0.4	-0.6	-0.8
MARYLAND/DELAWARE	1.4	1.3	0.4	0.3
VIRGINIA	1.4	1.4	1.1	0.7
WEST VIRGINIA	5.2	5.2	5.6	5.7
N.&S.CAROLINA	0.5	0.4	-0.8	-0.9
GEORGIA	2.2	2.1	1.8	1.8
FLORIDA	1.0	0.6	-0.9	-0.9
OHIO	4.6	4.6	3.8	3.8
MICHIGAN	0.6	0.5	-0.6	-0.7
ILLINOIS	1.3	1.2	0.0	0.2
INDIANA	6.7	5.8	6.1	6.0
WISCONSIN	1.1	0.7	-0.5	-0.6
KENTUCKY	5.9	3.3	3.2	3.2
TENNESSEE	1.9	1.9	1.1	1.0
ALABAMA	1.9	1.6	1.7	1.4
MISSISSIPPI	0.5	0.4	-3.1	-3.2
MINNESOTA	1.1	0.9	-0.7	-0.7
IOWA	2.6	2.4	2.3	2.4
MISSOURI	4.4	4.2	3.2	3.1
ARKANSAS	0.8	0.8	2.1	1.2
LOUISIANA	0.1	0.1	0.2	0.3
TOTAL 31-EASTERN STATES	1.9	1.7	0.9	0.8

TABLE B-7C

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
PROXMIRE CASES VS. EPA BASE

	CHANGE FROM EPA BASE PROXMIRE INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROXMIRE IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROXMIRE INTER. EX-NEW 2/ 2010
N. & S. DAKOTA	0.1	0.1	-1.8	-2.2
KANSAS/NEBRASKA	-0.2	-0.2	-1.3	-4.5
OKLAHOMA	0.3	0.3	-2.5	-2.3
TEXAS	0.2	0.3	-0.8	-0.8
MONTANA	0.1	0.1	-4.0	-4.1
WYOMING	0.6	0.6	-0.3	-0.2
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.3	0.3	-0.2	0.2
NEW MEXICO	0.1	0.1	-1.0	-1.1
UTAH	-0.5	-0.5	-3.9	-3.9
ARIZONA	0.0	0.0	0.7	0.8
NEVADA	0.1	0.1	-0.7	-0.8
WASHINGTON/OREGON	0.0	0.1	-1.1	-1.4
CALIFORNIA	0.0	0.0	0.0	-0.3
TOTAL 17-WESTERN STATES	0.1	0.1	-0.8	-1.1
TOTAL U.S.	1.4	1.2	0.4	0.3

1/ Calculated as follows:

$$\left[\frac{\text{2010 Emission Reduction Case Annualized Cost} - \text{2010 Base Case Annualized Cost}}{\text{2010 Electricity Sales}}\right] \div \text{1982 Average Electricity Rates}$$

2/ Includes transfer costs for emission trades.

TABLE B-8-A

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 1995
MAINE/VT/NH	0.0	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	0.0	0.0
NEW YORK	0.0	0.0	0.0	0.0
PENNSYLVANIA	0.0	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0	0.0
MARYLAND/DELAWARE	0.1	0.0	0.0	0.0
VIRGINIA	0.0	0.0	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.0	0.0
GEORGIA	0.0	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0	0.0
OHIO	0.1	0.1	0.0	0.0
MICHIGAN	0.0	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0	0.0
INDIANA	0.4	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.0	0.0
TENNESSEE	0.0	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0	0.0
IOWA	0.0	0.0	0.0	0.0
MISSOURI	0.2	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.8	0.1	0.0	0.0

TABLE B-8-A

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 1995
N. & S. DAKOTA	0.0	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0	0.0
TEXAS	0.0	0.0	0.0	0.0
MONTANA	0.0	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0	0.0
NEVADA	0.0	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.0	0.0
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.0	0.0
TOTAL U.S.	0.8	0.1	0.0	0.0

TABLE B-8-B

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2000
MAINE/VT/NH	0.0	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.4	0.3	0.3	0.0
NEW YORK	0.0	0.0	0.1	0.1
PENNSYLVANIA	0.1	0.1	0.6	0.4
NEW JERSEY	0.0	0.0	0.0	0.0
MARYLAND/DELAWARE	0.2	0.0	0.1	0.0
VIRGINIA	0.0	0.0	0.1	0.0
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.6	0.3	0.5	0.0
GEORGIA	0.1	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0	0.0
OHIO	1.1	1.0	1.4	1.0
MICHIGAN	0.0	0.0	0.2	0.2
ILLINOIS	0.2	0.5	0.8	1.8
INDIANA	1.8	0.3	0.8	0.4
WISCONSIN	0.3	0.0	0.0	0.1
KENTUCKY	1.4	0.4	0.4	0.4
TENNESSEE	0.1	0.0	0.1	0.1
ALABAMA	0.1	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0	0.0
IOWA	0.0	0.0	0.0	0.1
MISSOURI	1.4	1.3	1.6	1.8
ARKANSAS	0.0	0.0	0.7	0.0
LOUISIANA	0.0	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	7.9	4.2	7.5	6.4

TABLE B-8-B

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2000
N. & S. DAKOTA	0.0	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0	0.0
TEXAS	0.0	0.0	0.0	0.0
MONTANA	0.0	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.7	0.0
NEVADA	0.0	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.0	0.0
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.8	0.0
TOTAL U.S.	7.9	4.2	8.3	6.4

TABLE B-8-C

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2010
MAINE/VT/NH	0.0	0.0	0.1	0.0
MASS/CONN/RHODE I.	0.4	0.3	0.9	0.1
NEW YORK	0.0	0.0	0.1	0.1
PENNSYLVANIA	0.1	0.1	2.0	3.8
NEW JERSEY	0.0	0.0	1.4	0.6
MARYLAND/DELAWARE	0.2	0.0	1.1	1.7
VIRGINIA	0.0	0.0	2.3	0.7
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.6	0.4	3.7	2.9
GEORGIA	0.1	0.0	0.6	2.2
FLORIDA	0.0	0.0	0.6	0.1
OHIO	1.1	1.0	4.0	4.0
MICHIGAN	0.0	0.0	1.3	0.8
ILLINOIS	0.5	0.5	2.7	3.6
INDIANA	2.0	0.3	0.8	1.7
WISCONSIN	0.3	0.0	0.6	0.3
KENTUCKY	1.5	0.4	0.9	1.0
TENNESSEE	0.0	0.0	2.4	1.0
ALABAMA	0.1	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0	0.0
MINNESOTA	0.1	0.0	0.0	0.1
IOWA	0.3	0.3	0.4	0.4
MISSOURI	1.5	1.3	2.2	2.8
ARKANSAS	0.0	0.0	0.7	0.0
LOUISIANA	0.0	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	8.8	4.5	28.8	27.9

TABLE B-8-C

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2010
N. & S. DAKOTA	0.0	0.0	0.9	1.3
KANSAS/NEBRASKA	0.0	0.0	0.0	0.2
OKLAHOMA	0.0	0.0	0.0	0.0
TEXAS	0.0	0.0	3.2	3.7
MONTANA	0.0	0.0	0.1	0.0
WYOMING	0.0	0.0	0.1	0.0
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.5	0.6
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	0.4	0.0
ARIZONA	0.0	0.0	2.3	0.0
NEVADA	0.0	0.0	0.6	0.0
WASHINGTON/OREGON	0.0	0.0	1.2	1.8
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	9.3	7.6
TOTAL U.S.	8.8	4.5	38.1	35.5

TABLE B-9-A

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 1995
MAINE/VT/NH	0.0	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	0.0	0.0
NEW YORK	0.0	0.0	0.0	0.0
PENNSYLVANIA	0.0	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0	0.0
MARYLAND/DELAWARE	0.0	0.0	0.0	0.0
VIRGINIA	0.0	0.0	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.0	0.0
GEORGIA	0.0	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0	0.0
OHIO	0.0	0.0	0.0	0.0
MICHIGAN	0.0	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0	0.0
INDIANA	0.0	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.0	0.0
TENNESSEE	0.0	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0	0.0
IOWA	0.0	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.0	0.0	0.0	0.0

TABLE B-9-A

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 1995	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 1995	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 1995
N. & S. DAKOTA	0.0	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0	0.0
TEXAS	0.0	0.0	0.3	0.3
MONTANA	0.0	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0	0.0
NEVADA	0.0	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.0	0.0
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.3	0.3
TOTAL U.S.	0.0	0.0	0.3	0.3

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE B-9-B

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE	CHANGE FROM EPA BASE	CHANGE FROM EPA BASE	CHANGE FROM EPA BASE
	PROX. INTRA-UTILITY 2000	PROX. IN-STATE EX-EX 2000	PROX. IN-STATE EX-NEW 2000	PROX. INTER. EX-NEW 2000
MAINE/VT/NH	0.0	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	1.5	1.5
NEW YORK	0.0	0.0	4.0	4.0
PENNSYLVANIA	0.0	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0	0.0
MARYLAND/DELAWARE	0.0	0.0	0.6	0.6
VIRGINIA	0.0	0.0	2.6	2.6
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.8	0.8
GEORGIA	0.0	0.0	0.0	0.0
FLORIDA	0.0	0.0	5.3	5.3
OHIO	0.0	0.0	0.0	0.0
MICHIGAN	0.0	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0	0.0
INDIANA	0.0	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.6	0.6
TENNESSEE	0.0	0.0	0.1	0.1
ALABAMA	0.0	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0	0.0
IOWA	0.0	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.0	0.0	15.5	15.5

TABLE B-9-B

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2000	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2000	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2000
N. & S. DAKOTA	0.0	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.3	0.3
TEXAS	0.0	0.0	0.7	0.7
MONTANA	0.0	0.0	1.0	1.0
WYOMING	0.0	0.0	0.3	1.2
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.6	0.6
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.6	0.6
NEVADA	0.0	0.0	0.6	0.6
WASHINGTON/OREGON	0.0	0.0	2.0	0.0
CALIFORNIA	0.0	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	6.0	6.9
TOTAL U.S.	0.0	0.0	21.5	22.4

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE B-9-C

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2010
MAINE/VT/NH	0.0	0.0	0.7	0.7
MASS/CONN/RHODE I.	0.0	0.0	7.7	6.4
NEW YORK	0.0	0.0	14.8	13.0
PENNSYLVANIA	0.0	0.0	0.5	0.5
NEW JERSEY	0.0	0.0	9.5	9.6
MARYLAND/DELAWARE	0.0	0.0	6.9	6.9
VIRGINIA	0.0	0.0	4.1	8.4
WEST VIRGINIA	0.0	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	13.0	14.7
GEORGIA	0.0	0.0	5.1	5.1
FLORIDA	0.0	0.0	11.6	11.6
OHIO	0.0	0.0	11.9	11.9
MICHIGAN	0.0	0.0	11.1	11.4
ILLINOIS	0.0	0.0	10.2	10.2
INDIANA	0.0	0.0	0.0	0.0
WISCONSIN	0.0	0.0	5.1	5.1
KENTUCKY	0.0	0.0	0.6	0.6
TENNESSEE	0.0	0.0	13.5	16.3
ALABAMA	0.0	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	3.7	3.7
MINNESOTA	0.0	0.0	0.0	0.0
IOWA	0.0	0.0	0.8	0.8
MISSOURI	0.0	0.0	3.8	3.8
ARKANSAS	0.0	0.0	0.2	0.2
LOUISIANA	0.0	0.0	0.6	0.6
TOTAL 31-EASTERN STATES	0.0	0.0	135.5	141.5

TABLE B-9-C

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
PROXMIRE CASES

	CHANGE FROM EPA BASE PROX. INTRA-UTILITY 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-EX 2010	CHANGE FROM EPA BASE PROX. IN-STATE EX-NEW 2010	CHANGE FROM EPA BASE PROX. INTER. EX-NEW 2010
N. & S. DAKOTA	0.0	0.0	7.6	7.8
KANSAS/NEBRASKA	0.0	0.0	0.2	0.2
OKLAHOMA	0.0	0.0	4.6	4.6
TEXAS	0.0	0.0	24.2	22.1
MONTANA	0.0	0.0	1.0	1.0
WYOMING	0.0	0.0	0.3	1.3
IDAHO	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	2.3	2.3
NEW MEXICO	0.0	0.0	0.0	0.0
UTAH	0.0	0.0	1.8	2.1
ARIZONA	0.0	0.0	2.5	3.1
NEVADA	0.0	0.0	1.5	1.5
WASHINGTON/OREGON	0.0	0.0	6.4	2.4
CALIFORNIA	0.0	0.0	0.0	6.8
TOTAL 17-WESTERN STATES	0.0	0.0	52.4	55.1
TOTAL U.S.	0.0	0.0	187.9	196.6

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE B-10-A

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 1995	Proxmire Cases Change From Base 1995: Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmi Inter. Ex-Ne
Northern Appalachia						
Pennsylvania	22.3	18.0	-0.3	-0.5	-0.5	-0.3
Ohio	9.0	6.2	-2.6	-2.6	-2.7	-2.1
Maryland	0.7	0.5	-	-	-	-
Northern West Virginia	12.8	13.5	-1.1	-1.3	-1.3	-1.4
TOTAL	44.7	38.2	-4.1	-4.4	-4.5	-3.8
Central Appalachia						
Southern West Virginia	23.8	21.8	+3.2	+3.1	+3.1	+2.1
Virginia	13.3	12.2	+1.8	+1.7	+1.7	+1.1
Eastern Kentucky	29.8	27.3	+4.6	+4.2	+4.3	+2.9
Tennessee	2.6	2.4	-	-	-	-
TOTAL	69.5	63.6	+9.6	+9.0	+9.1	+6.1
Southern Appalachia						
Alabama	8.6	5.8	+0.5	+0.5	+0.3	+0.4
TOTAL	8.6	5.8	+0.5	+0.5	+0.3	+0.4
TOTAL APPALACHIA	122.8	107.7	+5.9	+5.1	+4.9	+2.7
Midwest						
Illinois	13.9	10.1	-1.9	-1.8	-1.8	-1.6
Indiana	5.2	3.0	-0.5	-0.1	-0.1	-
Western Kentucky	7.7	6.2	-1.3	-1.3	-1.3	-0.9
TOTAL	26.8	19.4	-3.8	-3.2	-3.2	-2.5
TOTAL MIDWEST	26.8	19.4	-3.8	-3.2	-3.2	-2.5
Central West						
Iowa	0.1	0.1	-	-	-	-
Missouri	1.1	0.9	-0.2	-0.2	-0.2	-0.2
Kansas	0.2	0.3	-	-	-	-
Northern Arkansas	0.0	0.1	-	-	-	-
Oklahoma	1.0	0.7	-	-	-	-
TOTAL	2.5	2.0	-0.2	-0.2	-0.2	-0.2
Gulf						
Texas	2.4	2.1	-	-	-	-
Louisiana	0.1	0.8	-	-	-	-
Southern Arkansas	0.0	0.0	-	-	-	-
TOTAL	2.4	2.9	-	-	-	-

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TABLE B-10-A

Coal Mining Employment
(Thousand Workers)
(continued)

			Proxmire Cases Change From Base 1995			
	Actual 1985	Base 1995	Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmire Inter. Ex-New
Rockies/Northern Plains						
Colorado	2.4	4.7	+0.4	+0.3	+0.3	+0.7
Wyoming	4.5	4.1	-	-	-	+0.1
Montana	1.2	1.4	-0.1	-	-	-
Utah	2.6	4.5	+0.3	+0.3	+0.2	+0.4
New Mexico	1.9	1.9	+0.4	+0.3	+0.4	+0.3
Arizona	0.8	0.7	-	-	-	-
North Dakota	1.1	1.0	-	-	-	-
TOTAL	14.5	18.3	+1.0	+0.9	+0.9	+1.5
Northwest						
Washington	0.7	0.6	-	-	-	-
TOTAL	0.7	0.6	-	-	-	-
Alaska						
Alaska	0.1	0.1	-	-	-	-
TOTAL	0.1	0.1	-	-	-	-
TOTAL WEST	20.3	24.0	+0.9	+0.6	+0.7	+1.3
TOTAL U.S.	169.9	151.0	+3.1	+2.6	+2.4	+1.5

TABLE B-10-B

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 2000	Proxmire Cases Change From Base 2000: Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmire Inter. Ex-New
Northern Appalachia						
Pennsylvania	22.3	17.8	-5.0	-4.6	-5.3	-4.6
Ohio	9.0	5.3	-2.3	-2.3	-2.3	-2.4
Maryland	0.7	0.4	-	-	-	-
Northern West Virginia	12.8	11.7	-2.0	-1.2	-1.4	-1.2
TOTAL	44.7	35.2	-9.4	-8.3	-9.0	-8.2
Central Appalachia						
Southern West Virginia	23.8	23.6	+4.7	+4.1	+4.2	+3.9
Virginia	13.3	13.2	+2.5	+2.2	+2.3	+2.1
Eastern Kentucky	29.8	29.5	+5.8	+5.4	+5.6	+5.1
Tennessee	2.6	2.6	-	-	-	-
TOTAL	69.5	68.8	+13.0	+11.7	+12.1	+11.1
Southern Appalachia						
Alabama	8.6	5.9	+0.6	+0.4	+0.4	+0.6
TOTAL	8.6	5.9	+0.6	+0.4	+0.4	+0.6
TOTAL APPALACHIA	122.8	109.9	+4.2	+3.9	+3.5	+3.5
Midwest						
Illinois	13.9	12.8	-6.7	-6.9	-7.0	-6.7
Indiana	5.2	2.1	-	-0.1	-	-
Western Kentucky	7.7	5.5	-1.5	-1.4	-1.4	-1.4
TOTAL	26.8	20.5	-8.3	-8.5	-8.4	-8.1
TOTAL MIDWEST	26.8	20.5	-8.3	-8.5	-8.4	-8.1
Central West						
Iowa	0.1	0.1	-	-	-	-
Missouri	1.1	0.6	-0.1	-0.1	-0.2	-0.2
Kansas	0.2	0.2	-	-	-0.1	-0.1
Northern Arkansas	0.0	0.1	-	-	-	-
Oklahoma	1.0	0.6	-	-	-0.1	-0.1
TOTAL	2.5	1.7	-0.3	-0.3	-0.4	-0.4
Gulf						
Texas	2.4	1.9	-	-	-	-
Louisiana	0.1	0.7	-	-	-	-
Southern Arkansas	0.0	0.0	-	-	-	-
TOTAL	2.4	2.6	-	-	-	-

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TABLE B-10-B

Coal Mining Employment
(Thousand Workers)
(continued)

	Actual 1985	Base 2000	Proxmire Cases Change From Base 2000: Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmire Inter. Ex-New
Rockies/Northern Plains						
Colorado	2.4	5.1	+4.7	+5.2	+5.1	+5.1
Wyoming	4.5	3.6	+0.2	+0.3	+0.7	+0.1
Montana	1.2	1.6	+0.1	+0.1	+0.1	+0.4
Utah	2.6	4.8	+0.1	+0.1	+0.3	+0.1
New Mexico	1.9	2.2	+0.4	+0.5	+0.6	+0.7
Arizona	0.8	0.6	-	-	-	-
North Dakota	1.1	0.9	-	-	-	-
TOTAL	14.5	18.8	+5.5	+6.2	+6.8	+6.4
Northwest						
Washington	0.7	0.5	-	-	-	-
TOTAL	0.7	0.5	-	-	-	-
Alaska						
Alaska	0.1	0.1	-	-	-	-
TOTAL	0.1	0.1	-	-	-	-
TOTAL WEST	20.3	23.7	+5.2	+5.8	+6.4	+6.0
TOTAL U.S.	169.9	154.2	+0.9	+1.2	+1.5	+1.4

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TABLE B-10-C

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 2010	Proxmire Cases Change From Base 2010: Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmi: Inter. Ex-New
Northern Appalachia						
Pennsylvania	22.3	30.1	-2.8	-2.5	-12.1	-12.1
Ohio	9.0	6.7	-2.0	-2.1	-3.3	-3.3
Maryland	0.7	0.3	-	-	-	-
Northern West Virginia	12.8	17.8	-2.2	-2.2	-5.0	-5.2
TOTAL	44.7	54.3	-7.0	-6.8	-20.4	-20.6
Central Appalachia						
Southern West Virginia	23.8	32.5	+2.1	+2.6	+4.4	+4.1
Virginia	13.3	18.2	+1.2	+1.5	+2.5	+2.2
Eastern Kentucky	29.8	40.7	+2.8	+3.6	+5.8	+5.4
Tennessee	2.6	3.6	-	-	-	-
TOTAL	69.5	94.9	+6.1	+7.7	+12.7	+11.7
Southern Appalachia						
Alabama	8.6	9.4	-0.9	-1.2	-1.9	-2.5
TOTAL	8.6	9.4	-0.9	-1.2	-1.9	-2.5
TOTAL APPALACHIA	122.8	158.6	-1.8	-0.3	-9.6	-11.4
Midwest						
Illinois	13.9	16.6	-6.3	-7.6	-9.8	-9.4
Indiana	5.2	4.2	-1.5	-2.2	-2.4	-2.4
Western Kentucky	7.7	8.2	-0.8	-1.8	-3.6	-3.3
TOTAL	26.8	29.0	-8.6	-11.6	-15.8	-15.1
TOTAL MIDWEST	26.8	29.0	-8.6	-11.6	-15.8	-15.1
Central West						
Iowa	0.1	0.1	-	-	-	-
Missouri	1.1	0.4	-	-	-	-
Kansas	0.2	0.2	-	-	-	-
Northern Arkansas	0.0	0.1	-	-	-	-
Oklahoma	1.0	0.5	-	-	-	-
TOTAL	2.5	1.4	-	-	-	-
Gulf						
Texas	2.4	1.9	-	-	-	-
Louisiana	0.1	0.7	-	-	-	-
Southern Arkansas	0.0	-	-	-	-	-
TOTAL	2.4	2.6	-	-	-	-

20C0282

TABLE B-10-C

Coal Mining Employment
(Thousand Workers)
(continued)

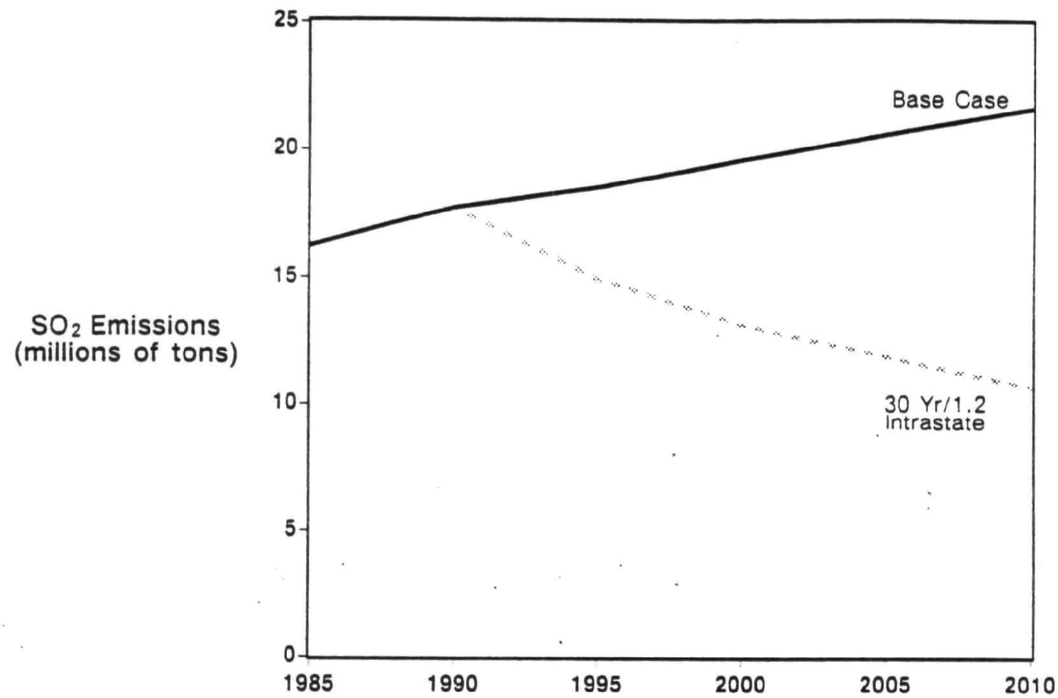
	Actual 1985	Base 2010	Proxmire Cases Change From Base 2010: Proxmire Intrautility	Proxmire In-State Ex-Ex	Proxmire In-State Ex-New	Proxmire Inter. Ex-New
Rockies/Northern Plains						
Colorado	2.4	19.0	+4.4	+4.9	+8.6	+8.5
Wyoming	4.5	5.5	+1.1	+1.4	+0.9	+0.5
Montana	1.2	2.4	-	-	+0.6	+0.6
Utah	2.6	10.4	+1.2	+1.3	+3.9	+4.2
New Mexico	1.9	3.5	-	-	+0.2	+0.2
Arizona	0.8	0.7	-	-	-	-
North Dakota	1.1	0.9	-	-	-	-
TOTAL	14.5	42.4	+6.7	+7.6	+14.2	+14.0
Northwest						
Washington	0.7	0.5	-	-	-	-
TOTAL	0.7	0.5	-	-	-	-
Alaska						
Alaska	0.1	0.3	-	-	-	-
TOTAL	0.1	0.3	-	-	-	-
TOTAL WEST	20.3	47.2	+6.7	+7.6	+14.2	+14.0
TOTAL U.S.	169.9	234.8	-3.7	-4.3	-11.2	-12.5

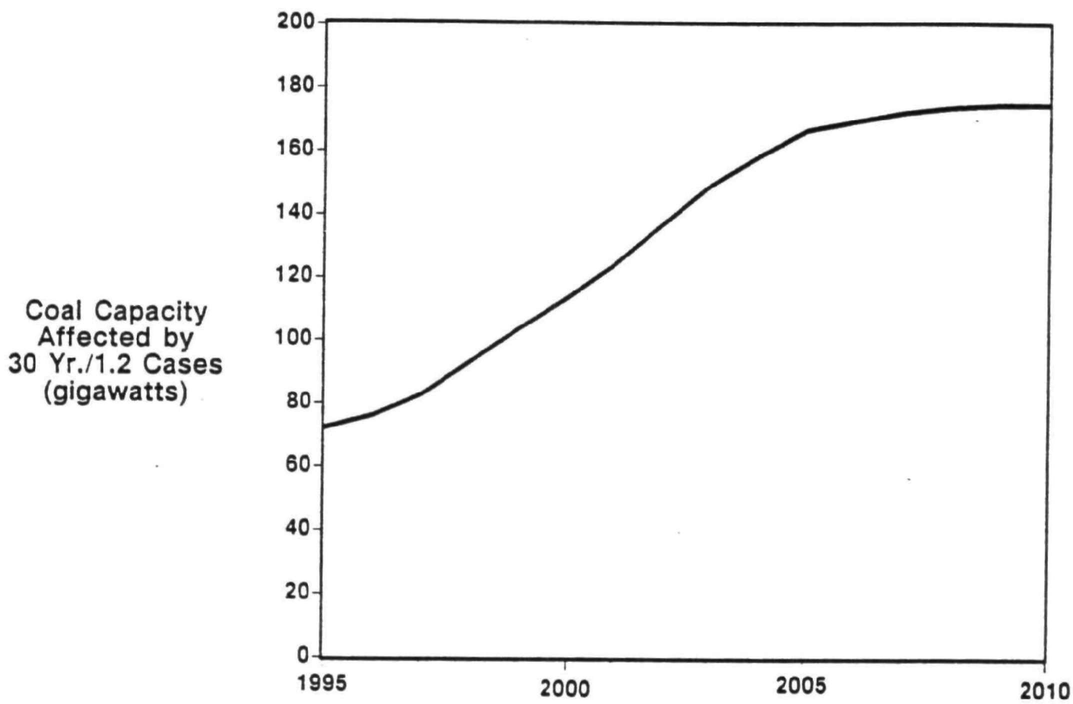
APPENDIX C

30 YEAR/1.2 LB. SUMMARY AND FORECASTS

This appendix presents and discusses the findings of the 30 Yr/1.2 analyses under various trading scenarios. The text highlights the key effects on utility sulfur dioxide emissions, utility costs, and coal production when alternative levels of emissions trading under the 30 Yr/1.2 proposal are considered. Detailed forecasts from the 30 Yr/1.2 cases are presented at the end of the appendix.

SO2 EMISSION REDUCTIONS AND COAL CAPACITY AFFECTED UNDER THE 30 YEAR/1.2 LB. PROPOSAL





SO_2 EMISSION REDUCTIONS AND COAL CAPACITY AFFECTED UNDER THE 30 YEAR/1.2 LB. PROPOSAL

- The 30 Yr/1.2 cases result in steadily increasing amounts of emission reductions (from Base Case levels) over time. Emission reductions are forecast to equal:

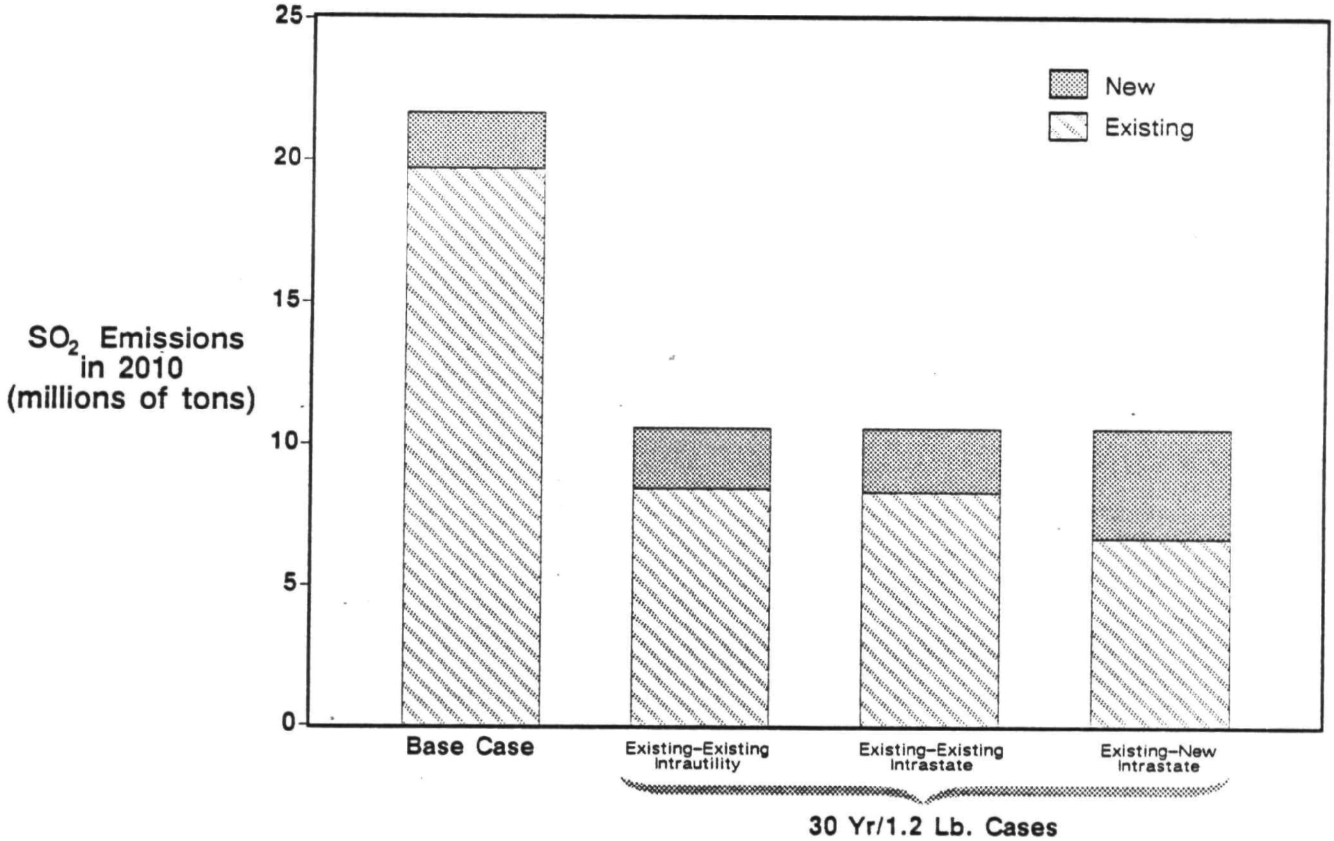
  -- 3.6 million tons by 1995
  -- 6.4 million tons by 2000
  -- 11.1 million tons by 2010.

- The amount of reductions are forecast to increase over time because the amount of capacity affected by the regulations and thus required to meet a 1.2 lb. emission rate increases over time. As shown in the figure on the opposite page, there is a steady increase in the amount of coal capacity (which is not currently meeting a 1.2 lb. limit) which reaches 30 years of age:

  -- 73 gigawatts by 1995
  -- 114 gigawatts by 2000
  -- 175 gigawatts by 2010.

- After 2010, emission reductions from Base Case levels (although not forecasted) would be expected to decline. This is because (1) no non-NSPS capacity was brought into service after 1980, so no additional capacity would reach 30 years of age after 2010 and be affected by the 1.2 lb. emission limit, and (2) some units meeting the 1.2 lb. limit begin to retire. (Based on a 60 year lifetime assumption, units built in the early 1950's would begin to retire after 2010.)

SO2 EMISSIONS BY PLANT TYPE -- 30 YEAR/1.2 LB. CASES IN 2010

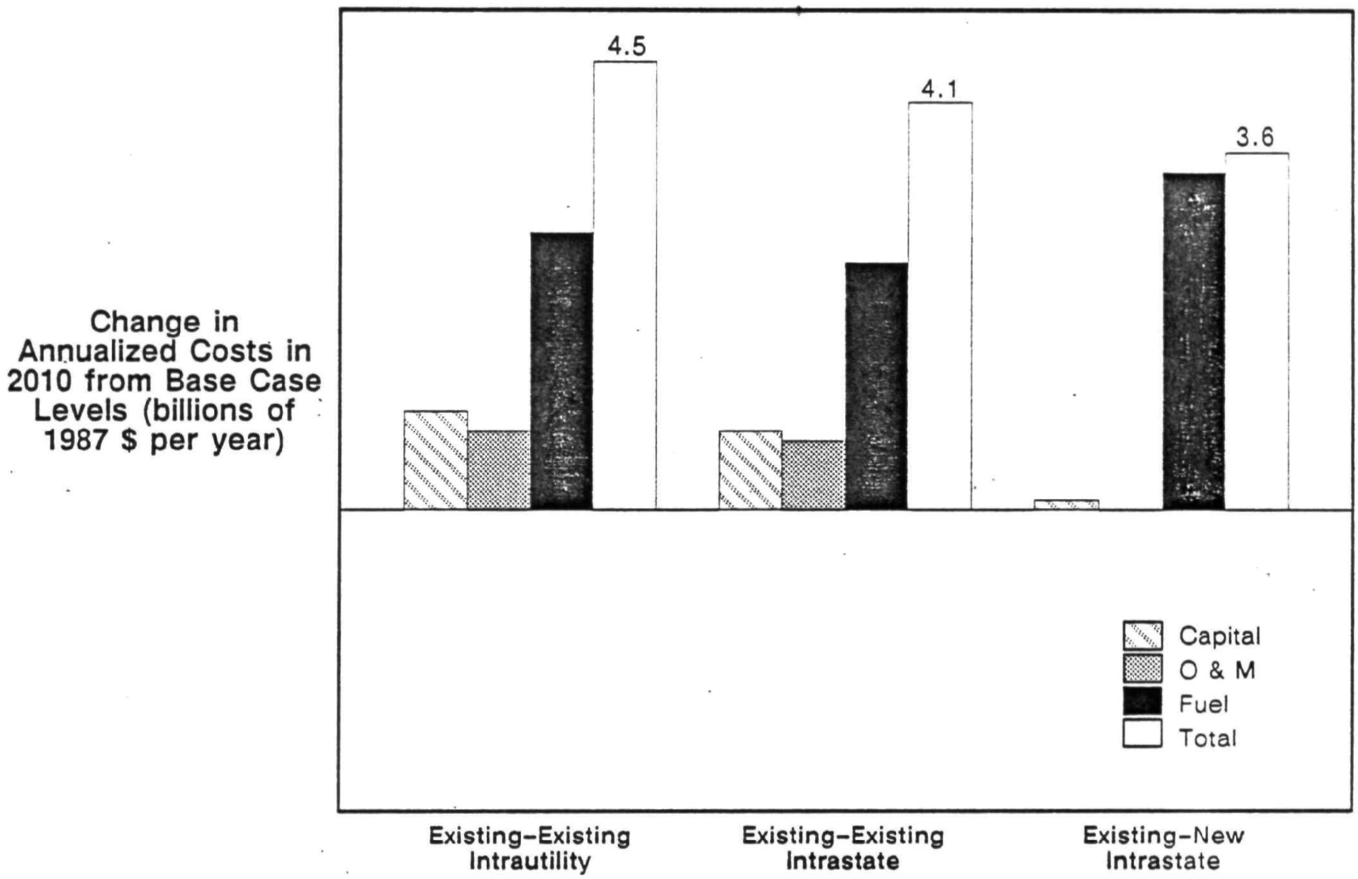


SO2 EMISSIONS BY PLANT TYPE -- 30 YEAR/1.2 LB. CASES IN 2010

- As noted previously, the 30 Yr/1.2 cases result in peak emission reductions in 2010 of approximately 11 million tons. Under the existing-existing trading cases (e.g., 30 Yr/1.2 intrastate), virtually all emissions reductions come from existing plants. There is little change in emissions from new plants.

- Under existing-new emissions trading on the intrastate level, there is a substantial shift in emissions at existing and new sources. Emissions from new sources increase by 1.9 million tons over Base Case levels as 131 gigawatts of new plants are built without scrubbers (as permitted under existing-new trading). As a result, emissions from existing powerplants are reduced by a total of 13 million tons, or 1.9 million tons <u>more</u> than in the existing-existing intrastate case. These substantial reductions from existing sources are achieved through shifts to very low sulfur coals and through the addition of 47 gigawatts of retrofit scrubbers at existing plants.

CHANGE IN ANNUALIZED COSTS IN 2010 -- 30 YEAR/1.2 LB. CASES



CHANGE IN ANNUALIZED COSTS IN 2010 -- 30 YEAR/1.2 LB. CASES

While the national level of emissions is largely unaffected by emissions trading, the costs associated with the 30 Yr/1.2 cases are significantly affected by the extent of trading permitted.

- To the extent a greater geographic scope for emissions trading is permitted, costs are significantly reduced:

  -- Under existing-existing trading on an intrautility basis (but not across state lines), the change in annual costs in 2010 totals $4.5 billion, or roughly 20 to 30 percent lower costs than assuming no trading.[2]

  -- Under existing-existing trading on an intrastate (interutility) basis, the increase in annual costs of $4.1 billion in 2010 are approximately 10 percent lower than costs assuming intrautility trading only.

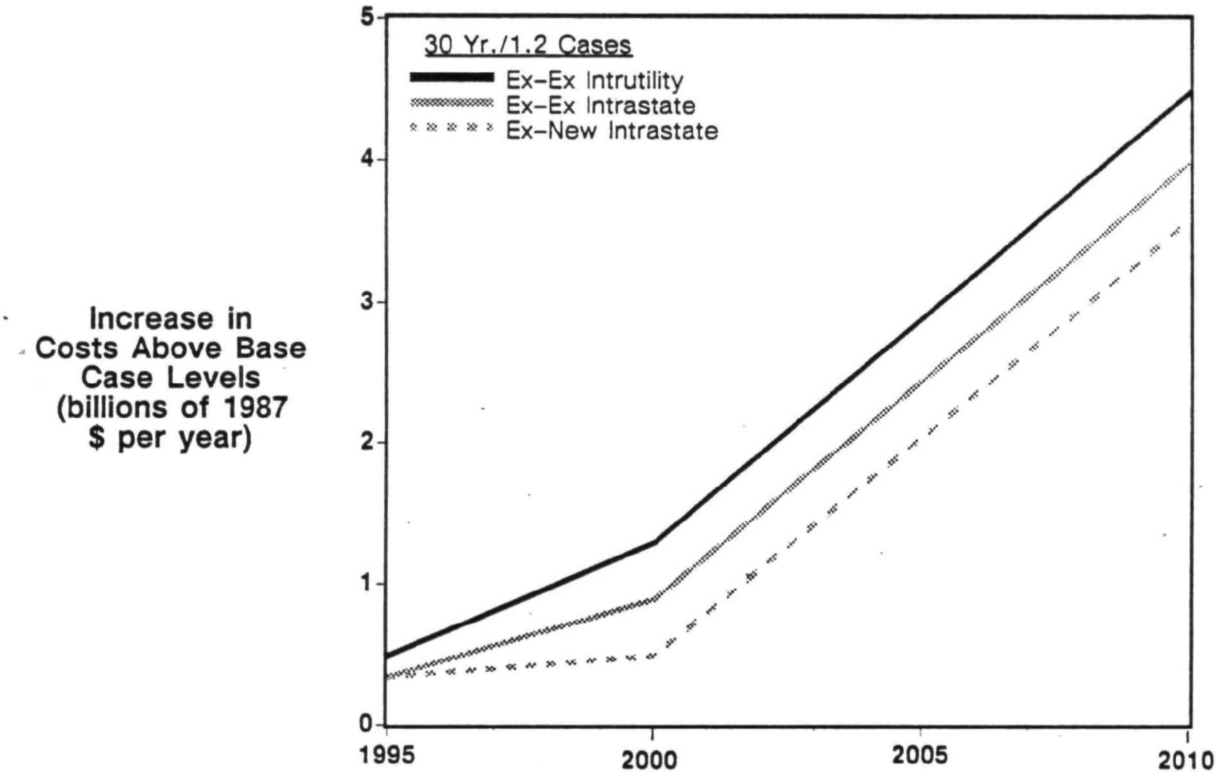
  The costs are reduced because more cost-effective emission reductions occur as the scope of trading increases. More trading possibilities increases the likelihood that a powerplant unit with high cost emission reductions can obtain reductions from a powerplant unit with lower cost emission reductions. Permitting any trading (i.e., intrautility trading versus no trading) results in the most substantial savings.

- The annualized costs are reduced even further when existing-new trades are permitted. Of the 30 Yr/1.2 trading schemes analyzed, the existing-new intrastate trading case is the least costly, costing about $3.6 billion per year by 2010 or about $0.5 billion less than if only existing-existing trading is permitted. These savings occur because the costs of meeting the current NSPS (e.g., scrubbing a new plant) are more expensive than the costs of emission reductions at existing units.

- Capital and O&M costs are substantially lower in the existing-new trading case than in the other cases. This reflects much less scrubber capacity, as new capacity is built without scrubbers and the increases in new powerplant emissions are largely offset by emissions reductions through fuel switching at existing powerplants. Fuel costs for the existing-new trading case are higher, because more switching to lower sulfur fuels occurs at existing units in order to achieve these additional emission reductions, and new units choose to burn lower sulfur coals unscrubbed.

[2] A 30 Yr/1.2 case with no trading (unit-by-unit limits) was not analyzed for this study. However, previous analysis of similar cases conducted by ICF for EPA suggests costs of about $5.5-6.5 billion in 2010.

CHANGES IN ANNUALIZED COSTS OVER TIME -- 30 YEAR/1.2 LB. CASES



CHANGES IN ANNUALIZED COSTS OVER TIME -- 30 YEAR/1.2 LB. CASES

- Annualized costs increase significantly over time relative to Base Case levels for the 30 Yr/1.2 cases because the amount of reductions increases, and because the marginal and average costs per ton of emission reductions increase as greater reductions are required.

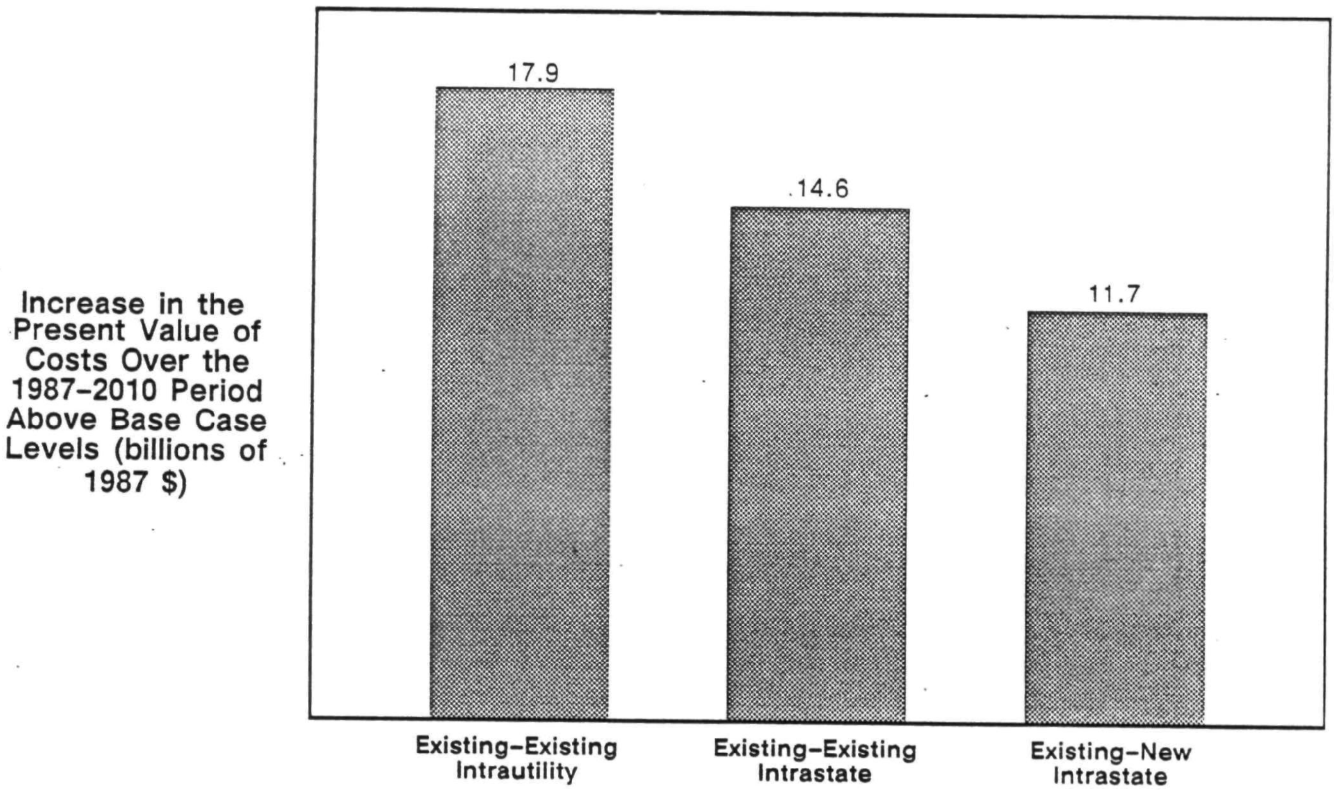
- The annualized cost savings associated with existing-new trading at the intrastate level, as compared to existing-existing trading at the intrastate level, increase significantly between 1995 and 2000.

    -- In 1995, savings are limited because there is very little new capacity built which can trade with existing sources and take advantage of the exemption from building scrubbers.

    -- By 2000, the existing-new intrastate case is about $0.5 billion per year less costly than its existing-existing trading counterpart, as more new plants are built without scrubbers.

- Although there are more existing-new trading opportunities by 2010, the cost savings relative to the existing-existing trading case remain roughly the same as in 2000, reflecting a lower incremental value associated with existing-new trades. This occurs because of the substantial emission reductions required by 2010, resulting in few additional opportunities for further cost-effective reductions at existing sources.

PRESENT VALUE OF COSTS -- 30 YEAR/1.2 LB. CASES

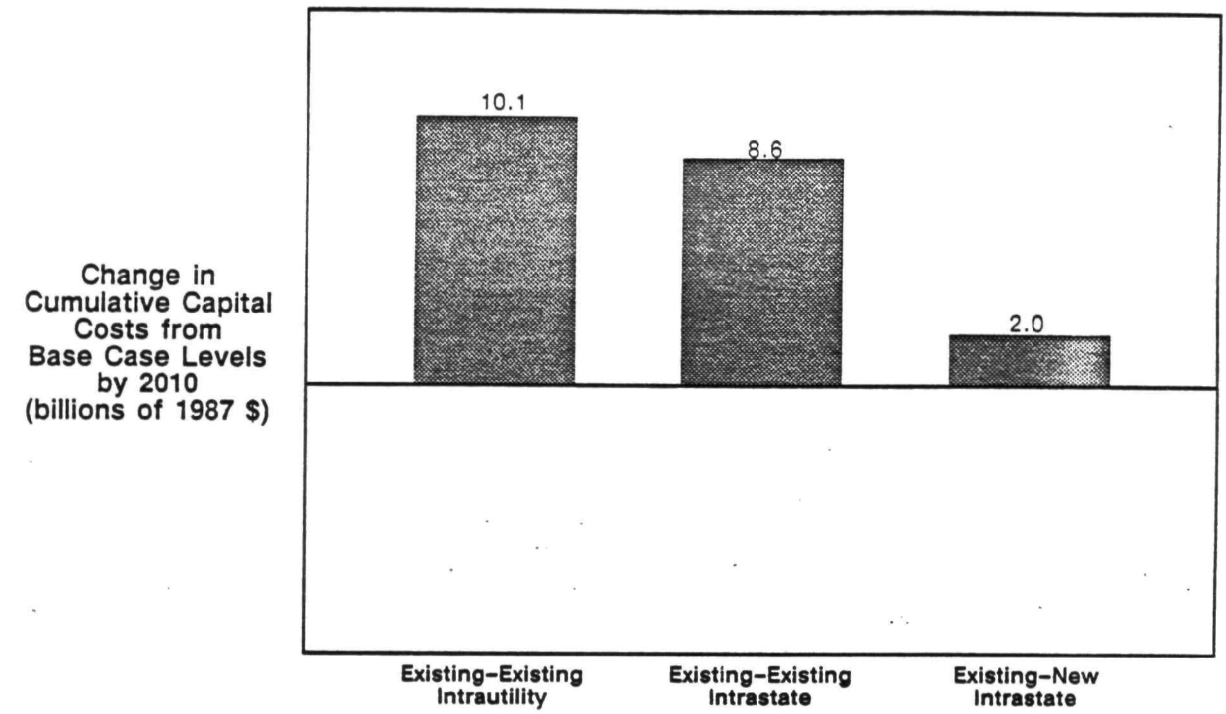


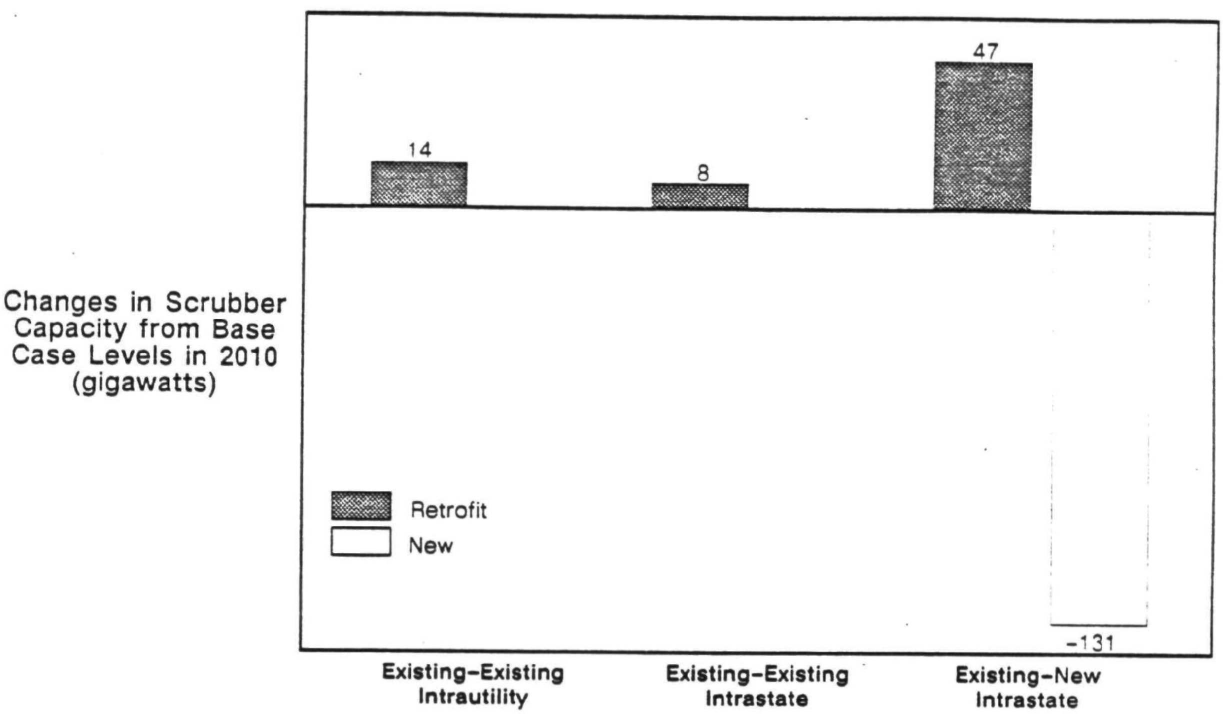
PRESENT VALUE OF COSTS -- 30 YEAR/1.2 LB. CASES

- The change in present value of costs reflects the increase in annualized costs incurred over the forecast period (i.e., through 2010) discounted back to 1987 using the utilities' real discount rate. Similar to the changes in annualized costs, the changes in present value of costs increase as emissions trading becomes more restricted, because cost-effective reductions become more difficult to obtain and hence the average reduction becomes more expensive. For example, the existing-existing intrautility trading case has a present value of costs which is $3.3 billion (or 20 percent) higher than the existing-existing intrastate trading case.

- In present value terms, existing-new trading costs $2.9 billion (or about 20 percent) less than existing-existing trading under the intrastate 30 Yr/1.2 cases. Note that the percentage cost savings are more substantial than the annualized cost savings in 2010 (about 10 percent lower costs as noted before). This is because the annualized cost savings are greater in earlier forecast years (about 50 percent in 2000), and these costs savings are more significant in present value terms than those cost savings that accrue in later forecast years.

CHANGES IN CUMULATIVE CAPITAL COSTS AND SCRUBBER CAPACITY
UNDER 30 YEAR/1.2 LB. CASES -- 2010





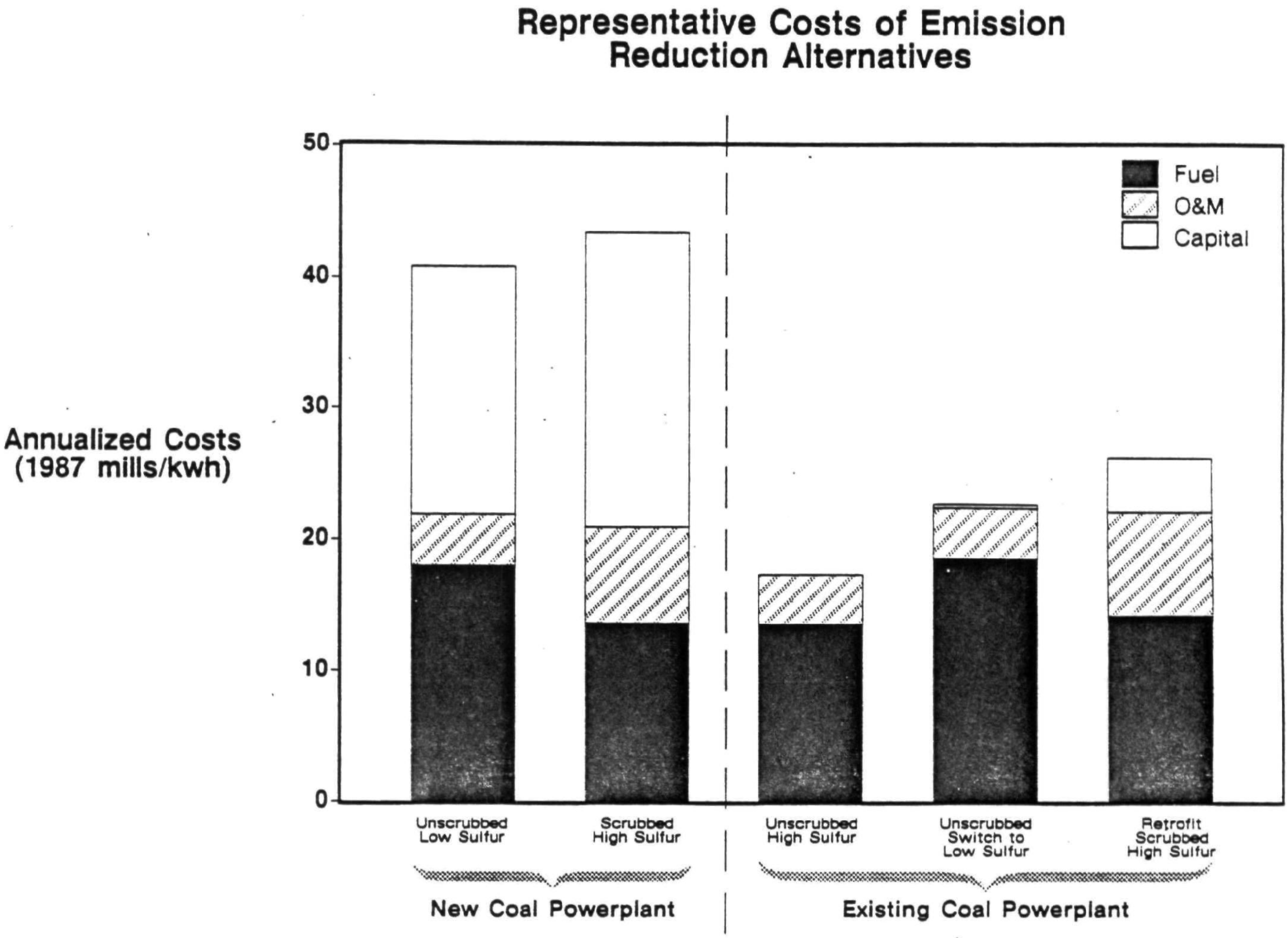
CHANGES IN CUMULATIVE CAPITAL COSTS AND SCRUBBER CAPACITY UNDER 30 YEAR/1.2 LB. CASES -- 2010

- Cumulative capital costs (from Base Case levels) by 2010 increase by about $10 billion for the 30 Yr/1.2 case with the least flexible emissions trading scheme -- existing-existing intrautility trading. This increase reflects about 14 gigawatts of existing capacity being retrofitted with scrubbers in order to achieve the emission reductions required from existing powerplants. Expanding the scope of trading to the existing-existing intrastate level reduces cumulative capital costs (to a $9 billion increase over the Base Case), as fewer scrubbers are retrofitted and more cost-effective fuel switching is used to achieve the required emission reductions.

- Cumulative capital costs are substantially affected by existing-new trading. Existing-new trading enables utilities to build many new units without scrubbers, thereby substantially lowering capital costs. The change in cumulative capital costs in 2010 for the existing-new intrastate trading case is only about $2 billion higher than Base Case levels (and is actually lower than Base Case levels in 2000) because less new scrubber capacity is built.

- New scrubber capacity decreases by over 131 gigawatts from Base Case levels by 2010, due to the ability to offset these new emissions increases with further reductions from existing sources. Some of these reductions are forecast to come from installing retrofit scrubbers at about 47 gigawatts of existing plants, which is a more cost-effective strategy (on a cost per ton removed basis) than scrubbing new plants to meet NSPS. Thus, the net decrease in scrubber capacity is 84 gigawatts.

VALUE OF EXISTING-NEW TRADES FOR 30 YEAR/1.2 LB. CASES



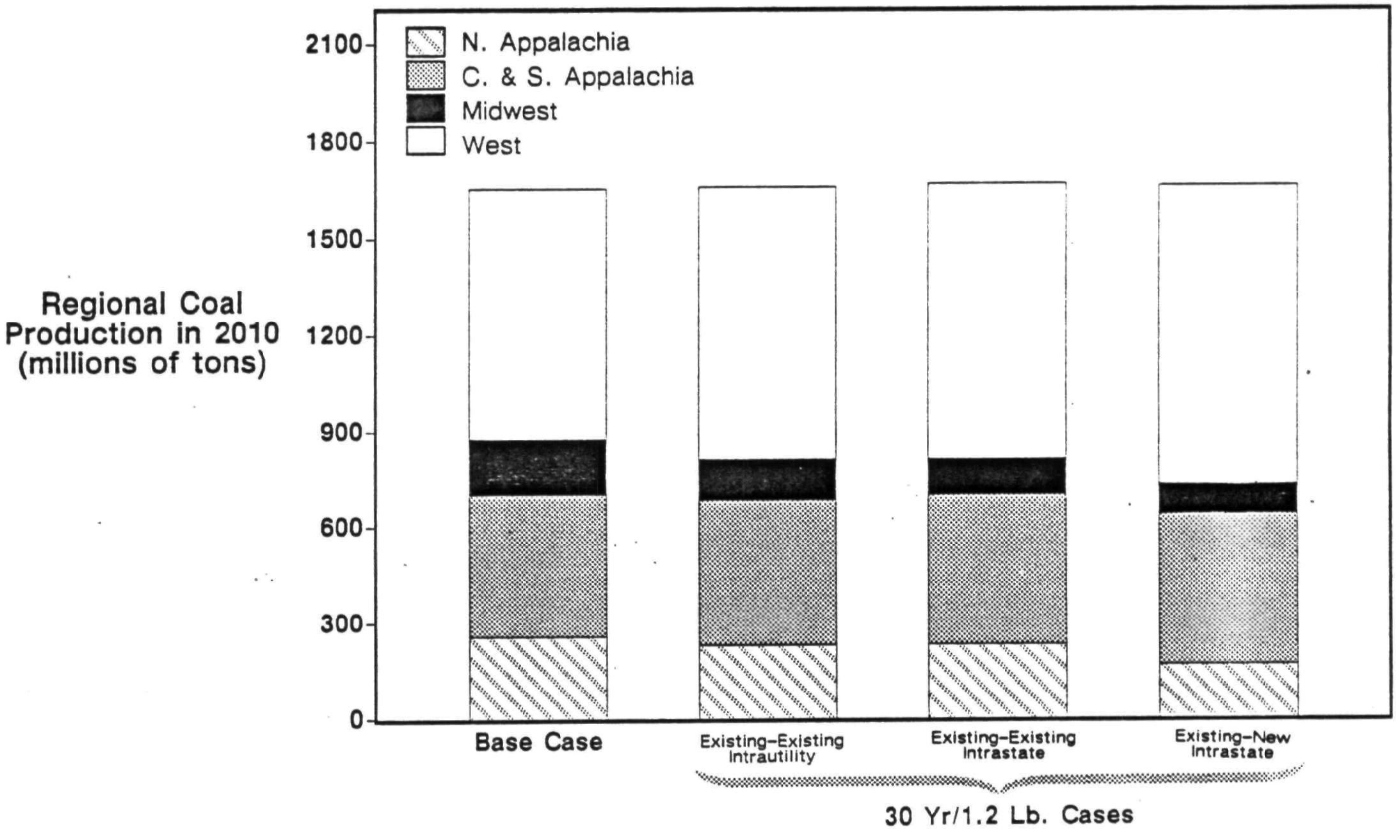
Total Annual Costs (mills/kwh)	40.6	43.4	17.3	22.7	26.3
Incremental Costs (mills/kwh)	-	2.8	-	5.4	9.0
Emission Rate (lbs. SO_2/mm Btu)	1.0	0.6	5.0	1.0	0.5
Reduction in Emission Rate (lbs. SO_2/mm Btu)	-	0.4	-	4.0	4.5
$ Per Ton SO_2 Removed	-	1400	-	270	400

VALUE OF EXISTING-NEW TRADES FOR 30 YEAR/1.2 LB. CASES

- As noted previously, existing-new trading on the intrastate level under 30 Yr/1.2 leads to substantial annualized and cumulative capital cost savings over the existing-existing intrastate counterpart. Much of these savings result from allowing utilities to build new coal powerplants without scrubbers, provided that the resulting increases in emissions from these unscrubbed new powerplants are compensated by commensurate decreases in emissions from existing sources.

- The table on the opposite page reveals the favorable economics associated with building new unscrubbed powerplants and obtaining offsetting emission reductions from existing plants. Although the economics presented are only representative, they indicate that coal switching or retrofit scrubbing at an existing coal unit generally leads to much more cost-effective emission reductions (in terms of dollars per ton removed) than the incremental costs of scrubbing high sulfur coal (versus burning low sulfur coal without scrubbing) at a new plant.

REGIONAL COAL PRODUCTION IN 2010 FOR 30 YEAR/1.2 LB. CASES



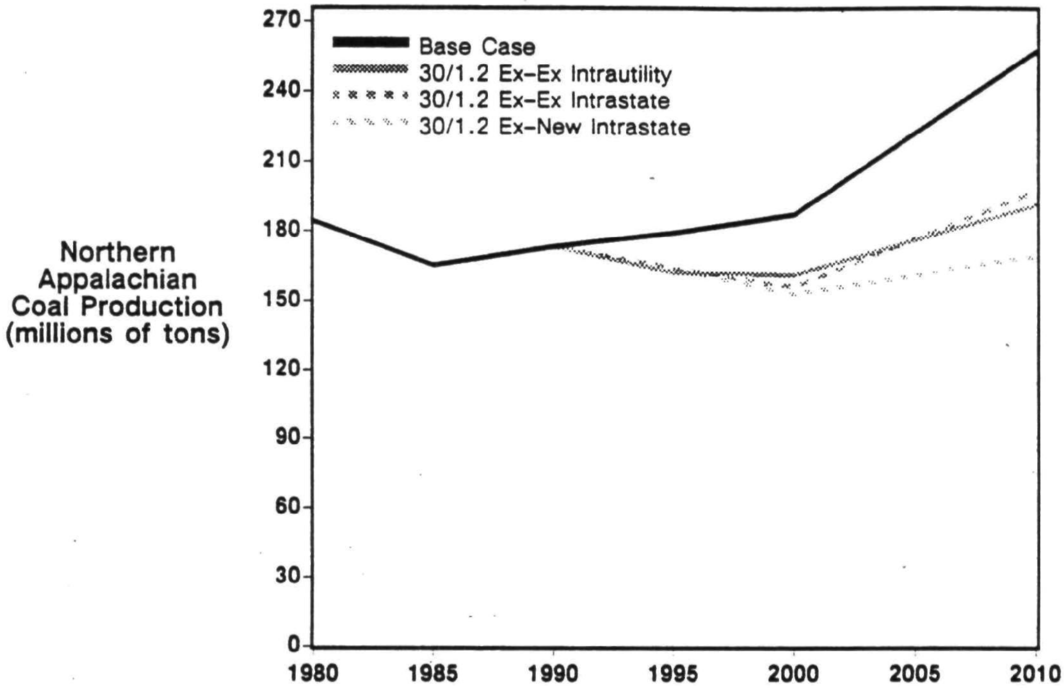
REGIONAL COAL PRODUCTION IN 2010 FOR 30 YEAR/1.2 LB. CASES

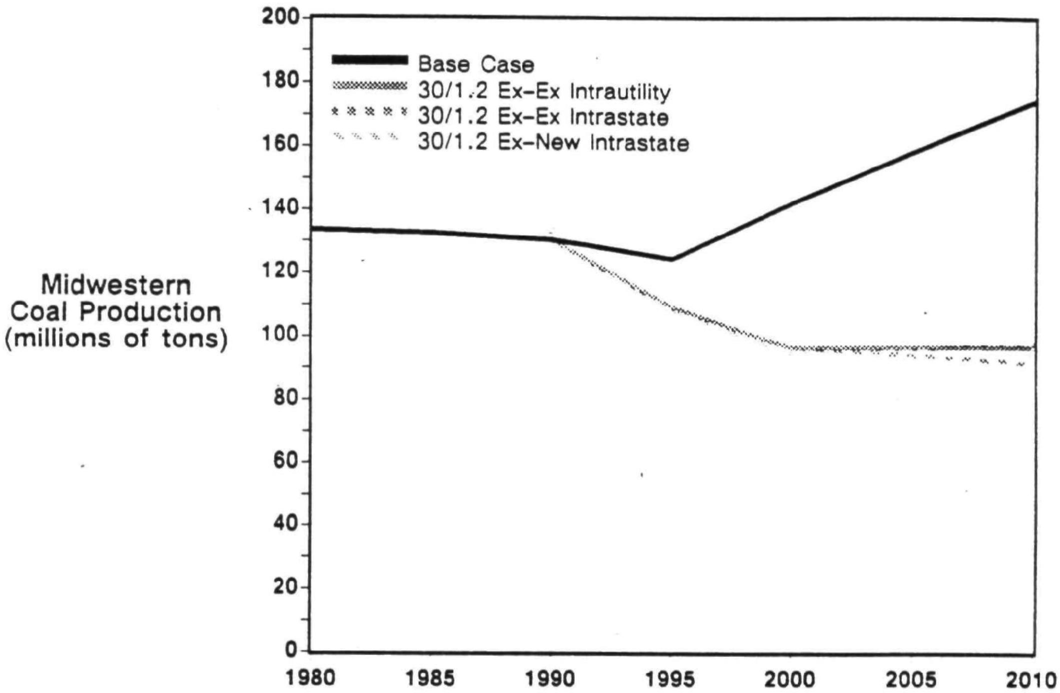
- Total national coal production levels are forecast to shift relatively little as a result of the emission reductions required by the 30 Yr/1.2 proposal.

- However, regional coal production is affected considerably by requiring emission reductions and by allowing emissions trading. High sulfur coal producing regions (such as Northern Appalachia and the Midwest) would register significant declines in production as a result of the 30 Yr/1.2 proposal. Conversely, low sulfur coal producing regions in Central Appalachia and in the West would experience large production gains. These swings in coal production occur as existing coal powerplants shift towards low sulfur coals and away from high sulfur coals in order to reduce emissions. Typically, these fuel shifts are the first type of strategy pursued in reducing emissions since they lead to more cost-effective reductions than does retrofit scrubbing.

- Existing-new trading schemes lead to further production declines from high sulfur coal regions (and further increases in production from low sulfur coal regions) by stimulating more fuel shifting activity from higher to lower sulfur coals at existing powerplants. This fuel shifting serves to further reduce emissions at existing powerplants so as to offset increased emissions from new (unscrubbed) sources. Moreover, some new scrubbed powerplants use high sulfur coals when there is no existing-new trading. Many of these powerplants shift to low sulfur coals without scrubbing when existing-new trading is permitted.

COAL PRODUCTION OVER TIME -- 30 YEAR/1.2 LB. CASES





COAL PRODUCTION OVER TIME -- 30 YEAR/1.2 LB. CASES

- High sulfur coal producing regions are adversely affected by proposed sulfur dioxide emission reduction requirements. Production from both the Midwest and from Northern Appalachia falls significantly as a result of the 30 Yr/1.2 proposal. The Midwest would experience a much larger decline (well below current levels), while Northern Appalachia's decline would not result in production being significantly below 1985 levels. This is because demand for medium sulfur coals (which can be found in Northern Appalachia, but not in the Midwest) does not fall as much as demand for high sulfur coals under the 30 Yr/1.2 proposal. More significant coal production losses below Base Case levels occur over time because emission reduction requirements become more stringent, resulting in lower demand for higher (and eventually medium) sulfur coals.

- Similar to the Proxmire case, existing-new trading under the 30 Yr/1.2 results in even greater production losses from high sulfur coal regions (particularly from Northern Appalachia), as new powerplants are built without scrubbers and use lower sulfur coals. However, the incremental impact of existing-new trading on high sulfur coal production is much less under the 30 Yr/1.2 than under the Proxmire case (as discussed on page B-19) because there are fewer existing-new trades.

TABLE C-1A

SULFUR DIOXIDE FORECASTS
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
Utility SO2 Emissions (millions of tons)						
31-Eastern States						
Coal						
EXISTING	14.92	14.21	15.26	-3.45	-3.50	-3.50
NEW	0.00	0.00	0.15	0.00	0.01	0.01
TOTAL COAL	14.92	14.21	15.41	-3.45	-3.49	-3.49
OIL/GAS	1.27	0.57	1.02	-0.12	-0.08	-0.08
TOTAL 31-EASTERN STATES	16.19	14.78	16.43	-3.57	-3.57	-3.57
17-Western States						
Coal						
EXISTING	1.10	1.48	2.00	-0.05	-0.06	-0.08
NEW	0.00	0.00	0.05	0.00	0.00	0.02
TOTAL COAL	1.10	1.48	2.05	-0.05	-0.06	-0.06
OIL/GAS	0.09	0.01	0.12	-0.02	-0.01	-0.01
TOTAL 17-WESTERN STATES	1.19	1.49	2.17	-0.07	-0.07	-0.07
United States						
Coal						
EXISTING	16.02	15.69	17.26	-3.51	-3.56	-3.59
NEW	0.00	0.00	0.20	0.00	0.01	0.04
TOTAL COAL	16.02	15.69	17.46	-3.50	-3.55	-3.55
OIL/GAS	1.36	0.58	1.14	-0.14	-0.08	-0.08
TOTAL UNITED STATES	17.38	16.27	18.60	-3.64	-3.64	-3.64

Note: Totals may not add due to independent rounding.

TABLE C-1B

SULFUR DIOXIDE FORECASTS
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE 30YR/1.2 .NTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
Utility SO2 Emissions (millions of tons)						
31-Eastern States						
Coal						
EXISTING	14.92	14.21	15.85	-6.13	-6.14	-6.26
NEW	0.00	0.00	0.34	0.02	0.04	0.49
TOTAL COAL	14.92	14.21	16.20	-6.11	-6.10	-5.77
OIL/GAS	1.27	0.57	1.19	-0.23	-0.22	-0.56
TOTAL 31-EASTERN STATES	16.19	14.78	17.39	-6.34	-6.33	-6.33
17-Western States						
Coal						
EXISTING	1.10	1.48	2.05	-0.10	-0.10	-0.26
NEW	0.00	0.00	0.09	0.01	0.01	0.15
TOTAL COAL	1.10	1.48	2.13	-0.09	-0.09	-0.10
OIL/GAS	0.09	0.01	0.13	-0.02	-0.02	-0.02
TOTAL 17-WESTERN STATES	1.19	1.49	2.26	-0.11	-0.11	-0.11
United States						
Coal						
EXISTING	16.02	15.69	17.90	-6.23	-6.25	-6.52
NEW	0.00	0.00	0.43	0.04	0.05	0.64
TOTAL COAL	16.02	15.69	18.33	-6.20	-6.20	-5.87
OIL/GAS	1.36	0.58	1.32	-0.25	-0.24	-0.58
TOTAL UNITED STATES	17.38	16.27	19.65	-6.45	-6.44	-6.44

Note: Totals may not add due to independent rounding.

TABLE C-1C

SULFUR DIOXIDE FORECASTS
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
Utility SO2 Emissions						
(millions of tons)						
31-Eastern States						
Coal						
EXISTING	14.92	14.21	16.76	-10.53	-10.54	-11.57
NEW	0.00	0.00	1.47	0.22	0.33	1.38
TOTAL COAL	14.92	14.21	18.23	-10.31	-10.22	-10.18
OIL/GAS	1.27	0.57	0.82	-0.33	-0.41	-0.45
TOTAL 31-EASTERN STATES	16.19	14.78	19.05	-10.63	-10.63	-10.63
17-Western States						
Coal						
EXISTING	1.10	1.48	2.01	-0.41	-0.34	-0.88
NEW	0.00	0.00	0.55	0.00	0.02	0.53
TOTAL COAL	1.10	1.48	2.56	-0.41	-0.36	-0.35
OIL/GAS	0.09	0.01	0.11	-0.02	-0.06	-0.07
TOTAL 17-WESTERN STATES	1.19	1.49	2.67	-0.42	-0.43	-0.43
United States						
Coal						
EXISTING	16.02	15.69	18.77	-10.94	-10.89	-12.45
NEW	0.00	0.00	2.01	0.22	0.31	1.91
TOTAL COAL	16.02	15.69	20.79	-10.71	-10.58	-10.54
OIL/GAS	1.36	0.58	0.93	-0.35	-0.48	-0.52
TOTAL UNITED STATES	17.38	16.27	21.72	-11.06	-11.06	-11.06

Note: Totals may not add due to independent rounding.

TABLE C-2-A

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 1995	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 1995
Utility Annual Costs (billions of mid-1987 $/yr.)			
Capital	0.2	0.1	0.1
O&M	0.2	0.1	0.1
Fuel	0.2	0.2	0.2
Total	0.5	0.4	0.4
Utility Cumulative Capital Costs (billions of mid-1987 $)			
31-Eastern States	1.8	0.7	0.7
17-Western States	0.2	0.1	0.0
Total U.S.	1.9	0.8	0.8
Average Cost Per Ton SO2 Removed	138	98	97
SO2 Retrofit Scrubber Capacity (GW)			
31-Eastern States	2.5	0.0	0.0
17-Western States	0.0	0.0	0.0
Total U.S.	2.5	0.0	0.0
New Capacity Trading with Existing Capacity (GW)			
31-Eastern States	0.0	0.0	0.0
17-Western States	0.0	0.0	0.3
Total U.S.	0.0	0.0	0.3

Note: Totals may not add due to independent rounding.

TABLE C-2-B

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2000	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2000
Utility Annual Costs (billions of mid-1987 $/yr.)			
Capital	0.4	0.2	-0.0
O&M	0.3	0.2	-0.1
Fuel	0.7	0.5	0.6
Total	1.3	0.9	0.5
Utility Cumulative Capital Costs (billions of mid-1987 $)			
31-Eastern States	3.6	1.9	-0.1
17-Western States	0.4	0.1	-0.3
Total U.S.	4.1	2.0	-0.4
Average Cost Per Ton SO2 Removed	203	137	74
SO2 Retrofit Scrubber Capacity (GW)			
31-Eastern States	4.9	0.9	1.0
17-Western States	0.2	0.0	1.0
Total U.S.	5.1	0.9	2.1
New Capacity Trading with Existing Capacity (GW)			
31-Eastern States	0.0	0.0	15.5
17-Western States	0.0	0.0	5.2
Total U.S.	0.0	0.0	20.7

Note: Totals may not add due to independent rounding.

TABLE C-2-C

UTILITY SULFUR DIOXIDE CONTROL COST FORECASTS
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2010	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2010
Utility Annual Costs (billions of mid-1987 $/yr.)			
Capital	1.0	0.8	0.1
O&M	0.8	0.7	0.0
Fuel	2.8	2.6	3.4
Total	4.5	4.1	3.6
Utility Cumulative Capital Costs (billions of mid-1987 $)			
31-Eastern States	9.0	8.2	2.4
17-Western States	1.1	0.4	-0.4
Total U.S.	10.1	8.6	2.0
Average Cost Per Ton SO2 Removed	407	372	323
SO2 Retrofit Scrubber Capacity (GW)			
31-Eastern States	11.3	7.2	33.5
17-Western States	2.7	0.5	13.6
Total U.S.	13.9	7.8	47.0
New Capacity Trading with Existing Capacity (GW)			
31-Eastern States	0.0	0.0	96.2
17-Western States	0.0	0.0	34.6
Total U.S.	0.0	0.0	130.8

Note: Totals may not add due to independent rounding.

TABLE C-3A

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
31 EASTERN STATES						
COAL						
LOW SULFUR	0.87	1.89	2.63	1.05	0.83	0.86
LOW-MEDIUM SULFUR	1.61	1.56	2.08	0.49	0.64	0.59
HIGH-MEDIUM SULFUR	3.18	3.66	3.83	-0.77	-0.61	-0.60
HIGH SULFUR	3.86	3.90	3.80	-0.76	-0.86	-0.86
TOTAL	9.53	11.01	12.34	0.01	-0.00	-0.00
OIL	1.99	0.93	1.54	0.01	0.00	0.00
GAS	1.01	0.92	0.79	0.0	0.0	0.0
17 WESTERN STATES						
COAL						
LOW SULFUR	1.41	1.61	2.42	-0.06	-0.03	-0.05
LOW-MEDIUM SULFUR	0.43	0.94	0.85	0.07	0.04	0.05
HIGH-MEDIUM SULFUR	0.74	0.96	1.11	-0.02	-0.03	-0.02
HIGH SULFUR	0.01	0.07	0.07	0.00	0.01	0.01
TOTAL	2.59	3.58	4.44	-0.00	0.00	-0.00
OIL	0.48	0.06	0.24	0.00	0.00	0.00
GAS	2.58	2.28	1.64	0.0	0.0	0.0
TOTAL U.S.						
COAL						
LOW SULFUR	2.28	3.50	5.06	0.99	0.80	0.82
LOW-MEDIUM SULFUR	2.04	2.49	2.93	0.56	0.68	0.64
HIGH-MEDIUM SULFUR	3.92	4.62	4.94	-0.79	-0.64	-0.62
HIGH SULFUR	3.87	3.97	3.87	-0.76	-0.84	-0.85
TOTAL	12.12	14.58	16.79	0.01	-0.00	-0.00
OIL	2.47	0.99	1.79	0.01	0.00	0.00
GAS	3.59	3.20	2.43	0.0	0.0	0.0

TABLE C-3B

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
31 EASTERN STATES						
COAL						
LOW SULFUR	0.87	1.89	3.36	2.09	2.19	2.13
LOW-MEDIUM SULFUR	1.61	1.56	2.65	0.50	0.59	0.80
HIGH-MEDIUM SULFUR	3.18	3.66	3.78	-0.87	-0.97	-1.03
HIGH SULFUR	3.86	3.90	4.12	-1.69	-1.81	-1.88
TOTAL	9.53	11.01	13.90	0.02	0.01	0.02
OIL	1.99	0.93	1.98	0.01	0.00	-0.02
GAS	1.01	0.92	0.71	0.0	0.0	0.0
17 WESTERN STATES						
COAL						
LOW SULFUR	1.41	1.61	2.70	-0.13	-0.12	0.02
LOW-MEDIUM SULFUR	0.43	0.94	0.95	0.23	0.23	0.11
HIGH-MEDIUM SULFUR	0.74	0.96	1.22	-0.12	-0.13	-0.15
HIGH SULFUR	0.01	0.07	0.06	0.02	0.02	0.02
TOTAL	2.59	3.58	4.93	-0.00	-0.00	-0.00
OIL	0.48	0.06	0.28	0.00	-0.00	-0.00
GAS	2.58	2.28	1.90	0.0	0.0	0.0
TOTAL U.S.						
COAL						
LOW SULFUR	2.28	3.50	6.06	1.96	2.08	2.15
LOW-MEDIUM SULFUR	2.04	2.49	3.60	0.73	0.82	0.91
HIGH-MEDIUM SULFUR	3.92	4.62	4.99	-1.00	-1.10	-1.17
HIGH SULFUR	3.87	3.97	4.18	-1.68	-1.79	-1.87
TOTAL	12.12	14.58	18.84	0.02	0.01	0.01
OIL	2.47	0.99	2.26	0.02	0.00	-0.02
GAS	3.59	3.20	2.61	0.0	0.0	0.0

TABLE C-3C

UTILITY FUEL CONSUMPTION FORECASTS
(IN QUADS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
31 EASTERN STATES						
COAL						
LOW SULFUR	0.87	1.89	6.81	4.45	4.33	7.05
LOW-MEDIUM SULFUR	1.61	1.56	3.82	0.14	0.12	-1.84
HIGH-MEDIUM SULFUR	3.18	3.66	4.85	-1.88	-1.65	-2.28
HIGH SULFUR	3.86	3.90	5.08	-2.70	-2.77	-2.91
TOTAL	9.53	11.01	20.57	0.01	0.03	0.03
OIL	1.99	0.93	1.79	0.03	0.02	-0.02
GAS	1.01	0.92	0.44	0.0	0.0	0.0
17 WESTERN STATES						
COAL						
LOW SULFUR	1.41	1.61	5.56	-0.09	0.10	0.09
LOW-MEDIUM SULFUR	0.43	0.94	1.55	0.17	-0.01	-0.05
HIGH-MEDIUM SULFUR	0.74	0.96	1.21	-0.09	-0.09	-0.04
HIGH SULFUR	0.01	0.07	0.08	-0.01	0.0	-0.00
TOTAL	2.59	3.58	8.40	-0.01	-0.00	0.00
OIL	0.48	0.06	0.34	0.01	-0.00	-0.00
GAS	2.58	2.28	0.99	0.0	0.0	0.0
TOTAL U.S.						
COAL						
LOW SULFUR	2.28	3.50	12.38	4.37	4.43	7.13
LOW-MEDIUM SULFUR	2.04	2.49	5.37	0.31	0.11	-1.88
HIGH-MEDIUM SULFUR	3.92	4.62	6.06	-1.97	-1.74	-2.32
HIGH SULFUR	3.87	3.97	5.16	-2.71	-2.77	-2.91
TOTAL	12.12	14.58	28.96	0.00	0.03	0.03
OIL	2.47	0.99	2.13	0.05	0.02	-0.02
GAS	3.59	3.20	1.44	0.0	0.0	0.0

TABLE C-4A

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
Coal Production						
NORTHERN APPALACHIA	185.	166.	180.	-17.	-15.	-15.
CENTRAL APPALACHIA	233.	245.	282.	22.	22.	22.
SOUTHERN APPALACHIA	26.	26.	23.	0.	1.	1.
MIDWEST	134.	133.	125.	-15.	-15.	-16.
WEST	251.	316.	428.	7.	6.	5.
TOTAL COAL REGIONS	830.	881.	1038.	-2.	-2.	-3.
Coal Transportation						
WESTERN COAL TO EAST	N.A.	N.A.	55.	6.	6.	6.

TABLE C-4B

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
Coal Production						
NORTHERN APPALACHIA	185.	166.	188.	-26.	-31.	-33.
CENTRAL APPALACHIA	233.	245.	330.	41.	46.	50.
SOUTHERN APPALACHIA	26.	26.	25.	3.	3.	3.
MIDWEST	134.	133.	143.	-46.	-46.	-48.
WEST	251.	316.	479.	23.	22.	24.
TOTAL COAL REGIONS	830.	881.	1165.	-6.	-5.	-5.
Coal Transportation						
WESTERN COAL TO EAST	N.A.	N.A.	70.	12.	11.	13.

TABLE C-4C

COAL PRODUCTION AND SHIPMENT FORECASTS
(IN MILLIONS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
Coal Production						
NORTHERN APPALACHIA	185.	166.	258.	-66.	-60.	-88.
CENTRAL APPALACHIA	233.	245.	407.	42.	37.	17.
SOUTHERN APPALACHIA	26.	26.	36.	-6.	-7.	-7.
MIDWEST	134.	133.	175.	-78.	-83.	-77.
WEST	251.	316.	777.	115.	122.	176.
TOTAL COAL REGIONS	830.	881.	1653.	7.	10.	20.
Coal Transportation						
WESTERN COAL TO EAST	N.A.	N.A.	183.	93.	99.	147.

TABLE C-5A

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
ME	17.	10.	3.	-1.	-1.	-1.
NH	80.	74.	64.	-15.	-15.	-15.
VT	0.	1.	3.	-2.	-2.	-2.
MA	258.	230.	272.	-38.	-37.	-37.
RI	5.	2.	0.	0.	0.	0.
CT	29.	56.	17.	0.	0.	0.
NY	479.	420.	481.	-158.	-158.	-158.
PA	1422.	1320.	1275.	-232.	-232.	-232.
NJ	103.	97.	130.	-51.	-49.	-49.
MD	222.	217.	315.	-88.	-88.	-88.
DE	51.	63.	60.	-11.	-11.	-11.
DC	4.	1.	4.	0.	-0.	-0.
VA	157.	131.	240.	-74.	-74.	-74.
WV	984.	969.	961.	-230.	-230.	-230.
NC	445.	337.	504.	-61.	-60.	-60.
SC	210.	162.	184.	-31.	-31.	-31.
GA	704.	976.	874.	-107.	-107.	-107.
FL	692.	501.	937.	-144.	-144.	-144.
OH	2185.	2193.	2572.	-689.	-689.	-689.
MI	608.	401.	449.	-51.	-51.	-51.
IL	1110.	1073.	955.	-230.	-230.	-230.
IN	1672.	1498.	1710.	-563.	-563.	-563.
WI	488.	367.	273.	-38.	-38.	-38.
KY	1029.	745.	893.	-98.	-98.	-98.
TN	910.	802.	856.	-316.	-316.	-316.
AL	535.	563.	512.	-147.	-147.	-147.
MS	122.	113.	146.	-5.	-5.	-5.
MN	159.	124.	169.	-30.	-30.	-30.
IA	236.	219.	302.	-65.	-65.	-65.
MO	1227.	997.	1058.	-96.	-96.	-96.
AR	27.	69.	125.	-2.	-2.	-2.
LA	21.	67.	86.	0.	-0.	-0.
TOTAL 31-EASTERN STATES	16191.	14798.	16431.	-3572.	-3568.	-3568.

TABLE C-5A

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 1995	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
ND	79.	124.	177.	-9.	-8.	-8.
SD	30.	32.	50.	-3.	-3.	-3.
KS	102.	166.	224.	-23.	-23.	-23.
NE	48.	45.	116.	-14.	-14.	-14.
OK	45.	80.	209.	-0.	0.	0.
TX	295.	430.	695.	-0.	-0.	-0.
MT	23.	22.	45.	-1.	-1.	-1.
WY	128.	135.	62.	-0.	-0.	-0.
ID	0.	0.	0.	0.	0.	0.
CO	71.	84.	130.	-1.	-1.	-1.
NM	79.	114.	56.	0.	0.	0.
UT	25.	27.	69.	-12.	-12.	-12.
AZ	84.	104.	126.	-0.	-0.	-0.
NV	38.	35.	76.	0.	0.	0.
WA	68.	85.	114.	-5.	-5.	-5.
OR	4.	2.	16.	0.	0.	0.
CA	70.	3.	0.	0.	0.	0.
AK	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2166.	-68.	-67.	-67.
TOTAL U.S.	17380.	16286.	18597.	-3639.	-3636.	-3636.

TABLE C-5B

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
ME	17.	10.	4.	-2.	-2.	-2.
NH	80.	74.	63.	-40.	-40.	-40.
VT	0.	1.	3.	-2.	-2.	-2.
MA	258.	230.	299.	-72.	-71.	-71.
RI	5.	2.	2.	-0.	-0.	-0.
CT	29.	56.	36.	-0.	-0.	-0.
NY	479.	420.	518.	-171.	-171.	-171.
PA	1422.	1320.	1186.	-522.	-522.	-522.
NJ	103.	97.	127.	-65.	-63.	-63.
MD	222.	217.	332.	-123.	-123.	-123.
DE	51.	63.	60.	-21.	-21.	-21.
DC	4.	1.	4.	-0.	-0.	-0.
VA	157.	131.	293.	-94.	-94.	-94.
WV	984.	969.	1007.	-303.	-303.	-303.
NC	445.	337.	520.	-96.	-94.	-94.
SC	210.	162.	209.	-67.	-69.	-69.
GA	704.	976.	946.	-196.	-196.	-196.
FL	692.	501.	968.	-286.	-286.	-286.
OH	2185.	2193.	2677.	-1258.	-1258.	-1258.
MI	608.	401.	477.	-73.	-73.	-73.
IL	1110.	1073.	1096.	-504.	-504.	-504.
IN	1672.	1498.	1782.	-866.	-866.	-866.
WI	488.	367.	267.	-38.	-38.	-38.
KY	1029.	745.	935.	-278.	-278.	-278.
TN	910.	802.	922.	-385.	-385.	-385.
AL	535.	563.	565.	-173.	-173.	-173.
MS	122.	113.	153.	-30.	-24.	-24.
MN	159.	124.	218.	-63.	-63.	-63.
IA	236.	219.	368.	-146.	-146.	-146.
MO	1227.	997.	1118.	-458.	-458.	-458.
AR	27.	69.	151.	-2.	-2.	-2.
LA	21.	67.	84.	-0.	-0.	-0.
TOTAL 31-EASTERN STATES	16191.	14798.	17386.	-6336.	-6326.	-6326.

TABLE C-5B

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2000	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
ND	79.	124.	188.	-40.	-41.	-41.
SD	30.	32.	51.	-4.	-3.	-3.
KS	102.	166.	230.	-35.	-35.	-35.
NE	48.	45.	122.	-18.	-18.	-18.
OK	45.	80.	225.	0.	0.	0.
TX	295.	430.	710.	-1.	-0.	-0.
MT	23.	22.	48.	-1.	-1.	-1.
WY	128.	135.	70.	-0.	-0.	-0.
ID	0.	0.	0.	0.	0.	0.
CO	71.	84.	137.	-1.	-1.	-1.
NM	79.	114.	56.	0.	0.	0.
UT	25.	27.	70.	-12.	-12.	-12.
AZ	84.	104.	130.	0.	0.	0.
NV	38.	35.	79.	-0.	-0.	-0.
WA	68.	85.	122.	1.	1.	1.
OR	4.	2.	27.	-1.	-1.	-1.
CA	70.	3.	0.	0.	0.	0.
AK	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2263.	-111.	-111.	-111.
TOTAL U.S.	17380.	16286.	19649.	-6447.	-6437.	-6437.

TABLE C-5C

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
ME	17.	10.	8.	-3.	-3.	-3.
NH	80.	74.	70.	-42.	-42.	-42.
VT	0.	1.	3.	-2.	-2.	-2.
MA	258.	230.	363.	-104.	-101.	-101.
RI	5.	2.	0.	0.	0.	0.
CT	29.	56.	13.	-0.	0.	0.
NY	479.	420.	543.	-157.	-155.	-155.
PA	1422.	1320.	1232.	-767.	-767.	-767.
NJ	103.	97.	191.	-70.	-70.	-70.
MD	222.	217.	344.	-161.	-159.	-159.
DE	51.	63.	62.	-19.	-20.	-20.
DC	4.	1.	3.	0.	-0.	-0.
VA	157.	131.	341.	-112.	-112.	-112.
WV	984.	969.	1037.	-608.	-608.	-608.
NC	445.	337.	660.	-232.	-232.	-232.
SC	210.	162.	308.	-141.	-140.	-140.
GA	704.	976.	1021.	-603.	-603.	-603.
FL	692.	501.	910.	-395.	-395.	-395.
OH	2185.	2193.	2849.	-2077.	-2077.	-2077.
MI	608.	401.	516.	-99.	-99.	-99.
IL	1110.	1073.	1407.	-872.	-872.	-872.
IN	1672.	1498.	2007.	-1420.	-1420.	-1420.
WI	488.	367.	327.	-65.	-65.	-65.
KY	1029.	745.	941.	-529.	-529.	-529.
TN	910.	802.	1056.	-631.	-631.	-631.
AL	535.	563.	595.	-273.	-273.	-273.
MS	122.	113.	168.	-66.	-66.	-66.
MN	159.	124.	216.	-86.	-86.	-86.
IA	236.	219.	438.	-257.	-257.	-257.
MO	1227.	997.	1196.	-842.	-842.	-842.
AR	27.	69.	131.	-4.	-4.	-4.
LA	21.	67.	89.	0.	-0.	-0.
TOTAL 31-EASTERN STATES	16191.	14798.	19047.	-10635.	-10629.	-10629.

TABLE C-5C

TOTAL SULFUR DIOXIDE EMISSIONS BY STATE
(IN THOUSANDS OF TONS)
30 YR/1.2 CASES VS. EPA BASE

	1980	1985	EPA BASE CASE 2010	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
ND	79.	124.	244.	-64.	-63.	-63.
SD	30.	32.	58.	-29.	-30.	-30.
KS	102.	166.	232.	-77.	-77.	-78.
NE	48.	45.	133.	-32.	-32.	-32.
OK	45.	80.	225.	-18.	-18.	-18.
TX	295.	430.	890.	-114.	-116.	-116.
MT	23.	22.	64.	-5.	-5.	-5.
WY	128.	135.	68.	-0.	0.	0.
ID	0.	0.	0.	0.	-0.	-0.
CO	71.	84.	145.	-1.	-1.	-1.
NM	79.	114.	57.	-0.	-0.	-0.
UT	25.	27.	77.	-20.	-20.	-20.
AZ	84.	104.	138.	0.	0.	0.
NV	38.	35.	78.	-0.	-0.	-0.
WA	68.	85.	164.	-67.	-67.	-67.
OR	4.	2.	73.	3.	3.	3.
CA	70.	3.	20.	0.	0.	0.
AK	0.	0.	0.	0.	0.	0.
TOTAL 17-WESTERN STATES	1189.	1488.	2668.	-425.	-426.	-425.
TOTAL U.S.	17380.	16286.	21716.	-11059.	-11055.	-11055.

TABLE C-6A

CHANGE IN ANNUALIZED UTILITY SULFUR
DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
MAINE/VT/NH	5.	5.	5.
MASS/CONN/RHODE I.	21.	20.	20.
NEW YORK	74.	66.	66.
PENNSYLVANIA	17.	15.	13.
NEW JERSEY	16.	15.	15.
MARYLAND/DELAWARE	43.	37.	37.
VIRGINIA	23.	21.	22.
WEST VIRGINIA	27.	35.	35.
N.&S.CAROLINA	41.	46.	46.
GEORGIA	4.	2.	2.
FLORIDA	30.	4.	4.
OHIO	59.	17.	17.
MICHIGAN	50.	54.	54.
ILLINOIS	5.	-5.	-3.
INDIANA	55.	-3.	-2.
WISCONSIN	4.	5.	5.
KENTUCKY	-35.	-43.	-42.
TENNESSEE	8.	11.	11.
ALABAMA	22.	23.	23.
MISSISSIPPI	-0.	-1.	-0.
MINNESOTA	6.	5.	6.
IOWA	-3.	-1.	-1.
MISSOURI	-50.	-52.	-51.
ARKANSAS	9.	7.	10.
LOUISIANA	2.	3.	3.
TOTAL 31-EASTERN STATES	432.	286.	296.

TABLE C-6A

CHANGE IN ANNUALIZED UTILITY SULFUR
DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
N. & S. DAKOTA	0.	0.	0.
KANSAS/NEBRASKA	7.	5.	8.
OKLAHOMA	3.	5.	6.
TEXAS	36.	20.	2.
MONTANA	-3.	-3.	-3.
WYOMING	5.	6.	8.
IDAHO	0.	0.	0.
COLORADO	8.	9.	9.
NEW MEXICO	-0.	-0.	-0.
UTAH	2.	2.	2.
ARIZONA	26.	22.	22.
NEVADA	2.	2.	2.
WASHINGTON/OREGON	1.	1.	1.
CALIFORNIA	14.	0.	0.
TOTAL 17-WESTERN STATES	100.	69.	56.
TOTAL U.S.	533.	355.	352.

TABLE C-6B

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
MAINE/VT/NH	25.	25.	25.
MASS/CONN/RHODE I.	45.	36.	12.
NEW YORK	109.	107.	39.
PENNSYLVANIA	173.	137.	144.
NEW JERSEY	35.	32.	30.
MARYLAND/DELAWARE	76.	65.	50.
VIRGINIA	50.	47.	-5.
WEST VIRGINIA	41.	30.	31.
N.&S.CAROLINA	87.	89.	71.
GEORGIA	-5.	-7.	-6.
FLORIDA	67.	51.	-37.
OHIO	165.	96.	96.
MICHIGAN	50.	53.	52.
ILLINOIS	1.	-18.	-18.
INDIANA	157.	76.	77.
WISCONSIN	14.	7.	8.
KENTUCKY	13.	-33.	-52.
TENNESSEE	39.	38.	34.
ALABAMA	25.	23.	23.
MISSISSIPPI	-0.	-1.	-2.
MINNESOTA	2.	2.	1.
IOWA	7.	4.	4.
MISSOURI	46.	6.	3.
ARKANSAS	4.	2.	3.
LOUISIANA	20.	20.	6.
TOTAL 31-EASTERN STATES	1246.	887.	587.

TABLE C-6B

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
N. & S. DAKOTA	21.	11.	11.
KANSAS/NEBRASKA	-7.	-9.	-10.
OKLAHOMA	-8.	-7.	-15.
TEXAS	-16.	-19.	-98.
MONTANA	-17.	-17.	-19.
WYOMING	1.	4.	0.
IDAHO	0.	0.	0.
COLORADO	8.	10.	-3.
NEW MEXICO	-4.	-2.	-4.
UTAH	3.	3.	1.
ARIZONA	33.	29.	24.
NEVADA	3.	2.	-17.
WASHINGTON/OREGON	-11.	-9.	-59.
CALIFORNIA	55.	-0.	-0.
TOTAL 17-WESTERN STATES	61.	-4.	-189.
TOTAL U.S.	1307.	883.	398.

TABLE C-6C

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
MAINE/VT/NH	35.	35.	36.
MASS/CONN/RHODE I.	27.	36.	2.
NEW YORK	193.	108.	119.
PENNSYLVANIA	416.	392.	393.
NEW JERSEY	171.	107.	110.
MARYLAND/DELAWARE	114.	136.	117.
VIRGINIA	82.	79.	54.
WEST VIRGINIA	269.	267.	278.
N.&S.CAROLINA	106.	101.	42.
GEORGIA	205.	200.	202.
FLORIDA	224.	212.	204.
OHIO	602.	627.	563.
MICHIGAN	86.	83.	49.
ILLINOIS	234.	218.	157.
INDIANA	458.	440.	463.
WISCONSIN	34.	29.	2.
KENTUCKY	164.	143.	143.
TENNESSEE	206.	206.	168.
ALABAMA	121.	119.	127.
MISSISSIPPI	25.	21.	18.
MINNESOTA	21.	18.	12.
IOWA	62.	59.	54.
MISSOURI	264.	261.	220.
ARKANSAS	16.	11.	14.
LOUISIANA	13.	12.	14.
TOTAL 31-EASTERN STATES	4146.	3917.	3561.

TABLE C-6C

CHANGE IN ANNUALIZED UTILITY SULFUR DIOXIDE CONTROL COSTS BY REGION
(Millions of Mid 1987 Dollars)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
N. & S. DAKOTA	55.	52.	49.
KANSAS/NEBRASKA	100.	54.	56.
OKLAHOMA	38.	27.	-37.
TEXAS	84.	35.	-50.
MONTANA	-9.	-11.	-24.
WYOMING	5.	1.	-3.
IDAHO	0.	-6.	-6.
COLORADO	20.	17.	5.
NEW MEXICO	-6.	-7.	-17.
UTAH	-0.	-8.	-39.
ARIZONA	14.	14.	47.
NEVADA	5.	4.	-8.
WASHINGTON/OREGON	16.	14.	32.
CALIFORNIA	34.	6.	14.
TOTAL 17-WESTERN STATES	356.	193.	20.
TOTAL U.S.	4501.	4110.	3581.

TABLE C-7A

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
MAINE/VT/NH	0.2	0.3	0.3
MASS/CONN/RHODE I.	0.4	0.3	0.3
NEW YORK	0.6	0.6	0.6
PENNSYLVANIA	0.1	0.1	0.1
NEW JERSEY	0.4	0.4	0.4
MARYLAND/DELAWARE	1.3	1.2	1.2
VIRGINIA	0.8	0.8	0.8
WEST VIRGINIA	0.7	0.9	0.9
N.&S.CAROLINA	0.5	0.6	0.6
GEORGIA	0.1	0.0	0.0
FLORIDA	0.4	0.0	0.0
OHIO	0.7	0.2	0.2
MICHIGAN	0.8	0.9	0.9
ILLINOIS	0.1	-0.1	0.0
INDIANA	0.9	-0.1	0.0
WISCONSIN	0.2	0.2	0.2
KENTUCKY	-1.0	-1.2	-1.2
TENNESSEE	0.2	0.3	0.3
ALABAMA	0.4	0.5	0.5
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.3	0.3	0.3
IOWA	-0.2	-0.1	-0.1
MISSOURI	-1.3	-1.4	-1.3
ARKANSAS	0.4	0.3	0.5
LOUISIANA	0.1	0.1	0.1
TOTAL 31-EASTERN STATES	0.3	0.2	0.2

TABLE C-7A

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 1995	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 1995
N. & S. DAKOTA	0.0	0.0	0.0
KANSAS/NEBRASKA	0.2	0.2	0.2
OKLAHOMA	0.1	0.2	0.2
TEXAS	0.2	0.1	0.0
MONTANA	-0.4	-0.4	-0.4
WYOMING	0.4	0.4	0.6
IDAHO	0.0	0.0	0.0
COLORADO	0.4	0.5	0.5
NEW MEXICO	0.0	0.0	0.0
UTAH	0.1	0.1	0.1
ARIZONA	0.6	0.5	0.5
NEVADA	0.1	0.1	0.1
WASHINGTON/OREGON	0.0	0.0	0.0
CALIFORNIA	0.1	0.0	0.0
TOTAL 17-WESTERN STATES	0.2	0.1	0.1
TOTAL U.S.	0.2	0.1	0.1

1/ Calculated as follows:

$$\left[\frac{\text{1995 Emission Reduction Case Annualized Cost} - \text{1995 Base Case Annualized Cost}}{\text{1995 Electricity Sales}}\right] \div \text{1982 Average Electricity Rates}$$

TABLE C-7B

PERCENT CHANGE IN ELECTRICITY RATES BASED ON
ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
MAINE/VT/NH	1.4	1.4	1.4
MASS/CONN/RHODE I.	0.8	0.6	0.2
NEW YORK	0.9	0.8	0.3
PENNSYLVANIA	1.6	1.3	1.3
NEW JERSEY	0.7	0.6	0.6
MARYLAND/DELAWARE	2.1	1.8	1.4
VIRGINIA	1.3	1.2	-0.1
WEST VIRGINIA	1.0	0.8	0.8
N.&S.CAROLINA	0.9	1.0	0.8
GEORGIA	-0.1	-0.1	-0.1
FLORIDA	0.7	0.5	-0.4
OHIO	1.9	1.1	1.1
MICHIGAN	0.7	0.8	0.8
ILLINOIS	0.0	-0.2	-0.2
INDIANA	2.6	1.3	1.3
WISCONSIN	0.4	0.2	0.2
KENTUCKY	0.3	-0.8	-1.2
TENNESSEE	0.9	0.8	0.8
ALABAMA	0.5	0.4	0.4
MISSISSIPPI	0.0	-0.1	-0.2
MINNESOTA	0.1	0.1	0.0
IOWA	0.4	0.3	0.2
MISSOURI	1.1	0.2	0.1
ARKANSAS	0.2	0.1	0.1
LOUISIANA	0.5	0.5	0.1
TOTAL 31-EASTERN STATES	0.9	0.6	0.4

TABLE C-7B

PERCENT CHANGE IN ELECTRICITY RATES BASED ON
ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2000	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2000
N. & S. DAKOTA	1.1	0.5	0.5
KANSAS/NEBRASKA	-0.2	-0.3	-0.3
OKLAHOMA	-0.3	-0.3	-0.6
TEXAS	-0.1	-0.1	-0.1
MONTANA	-1.9	-1.8	-2.1
WYOMING	0.1	0.3	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.4	0.5	-0.1
NEW MEXICO	-0.2	-0.1	-0.2
UTAH	0.2	0.2	0.1
ARIZONA	0.7	0.6	0.5
NEVADA	0.2	0.2	-1.3
WASHINGTON/OREGON	-0.2	-0.2	-1.3
CALIFORNIA	0.6	0.0	0.0
TOTAL 17-WESTERN STATES	0.1	0.0	-0.2
TOTAL U.S.	0.7	0.5	0.2

1/ Calculated as follows:

$$\left[\frac{\text{2000 Emission Reduction Case Annualized Cost} - \text{2000 Base Case Annualized Cost}}{\text{2000 Electricity Sales}}\right] \div \text{1982 Average Electricity Rates}$$

TABLE C-7C

PERCENT CHANGE IN ELECTRICITY RATES BASED ON ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
MAINE/VT/NH	2.2	2.2	2.2
MASS/CONN/RHODE I.	0.3	0.4	0.0
NEW YORK	1.2	0.7	0.7
PENNSYLVANIA	4.3	4.1	4.1
NEW JERSEY	2.3	1.4	1.5
MARYLAND/DELAWARE	2.1	2.6	2.2
VIRGINIA	1.6	1.6	1.1
WEST VIRGINIA	6.5	6.5	6.7
N.&S.CAROLINA	0.9	0.9	0.4
GEORGIA	2.9	2.8	2.9
FLORIDA	2.0	1.9	1.9
OHIO	5.0	5.2	4.7
MICHIGAN	1.0	0.9	0.5
ILLINOIS	1.8	1.7	1.2
INDIANA	7.2	6.9	7.2
WISCONSIN	0.9	0.7	0.0
KENTUCKY	3.8	3.3	3.3
TENNESSEE	2.5	2.4	2.0
ALABAMA	2.2	2.1	2.3
MISSISSIPPI	1.0	0.9	0.7
MINNESOTA	1.2	1.0	0.6
IOWA	2.6	2.5	2.3
MISSOURI	5.1	5.0	4.2
ARKANSAS	0.8	0.6	0.7
LOUISIANA	0.4	0.3	0.4
TOTAL 31-EASTERN STATES	2.5	2.3	2.1

TABLE C-7C

PERCENT CHANGE IN ELECTRICITY RATES BASED ON
ANNUALIZED COSTS (i.e., LEVELIZED BASIS) 1/
(PERCENT)
30 YR/1.2 CASES VS. EPA BASE

	CHANGE FROM EPA BASE 30YR/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-EX 2010	CHANGE FROM EPA BASE 30YR/1.2 IN-STATE EX-NEW 2010
N. & S. DAKOTA	1.2	1.2	1.1
KANSAS/NEBRASKA	3.2	1.8	1.8
OKLAHOMA	1.1	0.8	-1.1
TEXAS	0.4	0.2	-0.2
MONTANA	-1.0	-1.1	-2.5
WYOMING	0.3	0.1	-0.2
IDAHO	0.0	-1.9	-1.9
COLORADO	0.7	0.6	0.2
NEW MEXICO	-0.3	-0.4	-0.9
UTAH	0.0	-0.3	-1.7
ARIZONA	0.2	0.2	0.8
NEVADA	0.3	0.3	-0.5
WASHINGTON/OREGON	0.3	0.2	0.5
CALIFORNIA	0.3	0.1	0.1
TOTAL 17-WESTERN STATES	0.4	0.2	0.0
TOTAL U.S.	1.9	1.7	1.5

1/ Calculated as follows:

$$\left[\frac{\text{2010 Emission Reduction Case Annualized Cost} - \text{2010 Base Case Annualized Cost}}{\text{2010 Electricity Sales}} \right] \div \text{1982 Average Electricity Rates}$$

TABLE C-8-A

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 1995	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 1995
MAINE/VT/NH	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	0.0
NEW YORK	0.2	0.0	0.0
PENNSYLVANIA	0.2	0.0	0.0
NEW JERSEY	0.0	0.0	0.0
MARYLAND/DELAWARE	0.2	0.0	0.0
VIRGINIA	0.0	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.0
GEORGIA	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0
OHIO	0.7	0.0	0.0
MICHIGAN	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0
INDIANA	1.2	0.0	0.0
WISCONSIN	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.0
TENNESSEE	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	2.5	0.0	0.0

TABLE C-8-A

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 1995	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 1995
N. & S. DAKOTA	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0
TEXAS	0.0	0.0	0.0
MONTANA	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0
NEVADA	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.0
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.0
TOTAL U.S.	2.5	0.0	0.0

TABLE C-8-B

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2000	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2000
MAINE/VT/NH	0.2	0.2	0.2
MASS/CONN/RHODE I.	0.0	0.0	0.0
NEW YORK	0.2	0.0	0.0
PENNSYLVANIA	0.2	0.0	0.0
NEW JERSEY	0.3	0.2	0.2
MARYLAND/DELAWARE	0.3	0.0	0.0
VIRGINIA	0.1	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.5	0.5	0.6
GEORGIA	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0
OHIO	0.7	0.0	0.0
MICHIGAN	0.0	0.0	0.0
ILLINOIS	0.1	0.0	0.0
INDIANA	1.3	0.0	0.0
WISCONSIN	0.1	0.0	0.0
KENTUCKY	0.4	0.0	0.0
TENNESSEE	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.0
MISSOURI	0.5	0.0	0.0
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	4.9	0.9	1.0

TABLE C-8-B

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2000	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2000
N. & S. DAKOTA	0.1	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0
TEXAS	0.0	0.0	0.0
MONTANA	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.7
NEVADA	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.3
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.2	0.0	1.0
TOTAL U.S.	5.1	0.9	2.1

TABLE C-8-C

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2010	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2010
MAINE/VT/NH	0.2	0.2	0.2
MASS/CONN/RHODE I.	0.0	0.0	0.9
NEW YORK	0.2	0.0	0.5
PENNSYLVANIA	0.8	0.5	1.8
NEW JERSEY	0.3	0.2	1.6
MARYLAND/DELAWARE	0.6	0.1	2.6
VIRGINIA	0.1	0.0	1.2
WEST VIRGINIA	0.1	0.0	0.2
N.&S.CAROLINA	0.8	0.5	2.8
GEORGIA	0.2	0.0	0.5
FLORIDA	0.8	0.3	3.2
OHIO	1.1	0.5	4.1
MICHIGAN	0.0	0.0	1.6
ILLINOIS	1.2	1.4	3.4
INDIANA	1.8	0.7	1.5
WISCONSIN	0.2	0.0	0.8
KENTUCKY	0.6	0.7	1.1
TENNESSEE	0.0	0.1	1.2
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.6
MINNESOTA	0.0	0.0	0.0
IOWA	0.3	0.1	0.4
MISSOURI	2.0	1.7	3.1
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	11.3	7.2	33.5

TABLE C-8-C

RETROFIT SCRUBBER CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2010	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2010
N. & S. DAKOTA	0.3	0.2	1.2
KANSAS/NEBRASKA	0.7	0.3	0.4
OKLAHOMA	0.3	0.0	0.4
TEXAS	1.3	0.0	5.3
MONTANA	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.6
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.9
ARIZONA	0.0	0.0	2.3
NEVADA	0.0	0.0	0.7
WASHINGTON/OREGON	0.0	0.0	1.8
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	2.7	0.5	13.6
TOTAL U.S.	13.9	7.8	47.0

TABLE C-9-A

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 1995	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 1995
MAINE/VT/NH	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	0.0
NEW YORK	0.0	0.0	0.0
PENNSYLVANIA	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0
MARYLAND/DELAWARE	0.0	0.0	0.0
VIRGINIA	0.0	0.0	0.0
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.0
GEORGIA	0.0	0.0	0.0
FLORIDA	0.0	0.0	0.0
OHIO	0.0	0.0	0.0
MICHIGAN	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0
INDIANA	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.0
TENNESSEE	0.0	0.0	0.0
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.0	0.0	0.0

TABLE C-9-A

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 1995	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 1995	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 1995
N. & S. DAKOTA	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.0
TEXAS	0.0	0.0	0.3
MONTANA	0.0	0.0	0.0
WYOMING	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0
NEVADA	0.0	0.0	0.0
WASHINGTON/OREGON	0.0	0.0	0.0
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	0.3
TOTAL U.S.	0.0	0.0	0.3

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE C-9-B

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2000	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2000
MAINE/VT/NH	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	1.5
NEW YORK	0.0	0.0	4.0
PENNSYLVANIA	0.0	0.0	0.0
NEW JERSEY	0.0	0.0	0.0
MARYLAND/DELAWARE	0.0	0.0	0.6
VIRGINIA	0.0	0.0	2.6
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	0.8
GEORGIA	0.0	0.0	0.0
FLORIDA	0.0	0.0	5.3
OHIO	0.0	0.0	0.0
MICHIGAN	0.0	0.0	0.0
ILLINOIS	0.0	0.0	0.0
INDIANA	0.0	0.0	0.0
WISCONSIN	0.0	0.0	0.0
KENTUCKY	0.0	0.0	0.6
TENNESSEE	0.0	0.0	0.1
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	0.0
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.0
MISSOURI	0.0	0.0	0.0
ARKANSAS	0.0	0.0	0.0
LOUISIANA	0.0	0.0	0.0
TOTAL 31-EASTERN STATES	0.0	0.0	15.5

TABLE C-9-B

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2000	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2000	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2000
N. & S. DAKOTA	0.0	0.0	0.0
KANSAS/NEBRASKA	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	0.3
TEXAS	0.0	0.0	0.7
MONTANA	0.0	0.0	0.2
WYOMING	0.0	0.0	0.3
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	0.6
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.6
NEVADA	0.0	0.0	0.6
WASHINGTON/OREGON	0.0	0.0	2.0
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	5.2
TOTAL U.S.	0.0	0.0	20.7

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE C-9-C

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2010	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2010
MAINE/VT/NH	0.0	0.0	0.0
MASS/CONN/RHODE I.	0.0	0.0	4.1
NEW YORK	0.0	0.0	5.7
PENNSYLVANIA	0.0	0.0	0.5
NEW JERSEY	0.0	0.0	2.7
MARYLAND/DELAWARE	0.0	0.0	5.1
VIRGINIA	0.0	0.0	2.7
WEST VIRGINIA	0.0	0.0	0.0
N.&S.CAROLINA	0.0	0.0	8.7
GEORGIA	0.0	0.0	3.7
FLORIDA	0.0	0.0	11.6
OHIO	0.0	0.0	11.8
MICHIGAN	0.0	0.0	8.8
ILLINOIS	0.0	0.0	9.0
INDIANA	0.0	0.0	0.0
WISCONSIN	0.0	0.0	4.6
KENTUCKY	0.0	0.0	0.6
TENNESSEE	0.0	0.0	7.6
ALABAMA	0.0	0.0	0.0
MISSISSIPPI	0.0	0.0	3.7
MINNESOTA	0.0	0.0	0.0
IOWA	0.0	0.0	0.8
MISSOURI	0.0	0.0	3.8
ARKANSAS	0.0	0.0	0.2
LOUISIANA	0.0	0.0	0.5
TOTAL 31-EASTERN STATES	0.0	0.0	96.2

TABLE C-9-C

NEW CAPACITY TRADING WITH EXISTING CAPACITY
(GIGAWATTS)
30 YEAR/1.2 LB. CASES

	CHANGE FROM EPA BASE 30/1.2 INTRA-UTILITY 2010	CHANGE FROM EPA BASE 30/1.2 EX-EX IN-STATE 2010	CHANGE FROM EPA BASE 30/1.2 EX-NEW IN-STATE 2010
N. & S. DAKOTA	0.0	0.0	1.7
KANSAS/NEBRASKA	0.0	0.0	0.0
OKLAHOMA	0.0	0.0	4.6
TEXAS	0.0	0.0	17.9
MONTANA	0.0	0.0	0.2
WYOMING	0.0	0.0	0.3
IDAHO	0.0	0.0	0.0
COLORADO	0.0	0.0	2.2
NEW MEXICO	0.0	0.0	0.0
UTAH	0.0	0.0	1.3
ARIZONA	0.0	0.0	2.6
NEVADA	0.0	0.0	1.5
WASHINGTON/OREGON	0.0	0.0	2.4
CALIFORNIA	0.0	0.0	0.0
TOTAL 17-WESTERN STATES	0.0	0.0	34.6
TOTAL U.S.	0.0	0.0	130.8

Reflects new coal powerplants built without control technologies to meet NSPS-Da requirements.

TABLE C-10-A

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 1995	30 Yr/1.2 lb. Cases Change From Base 1995: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Northern Appalachia					
Pennsylvania	22.3	18.0	-0.8	-0.3	-0.3
Ohio	9.0	6.2	-0.8	-1.3	-1.3
Maryland	0.7	0.5	-	-	-
Northern West Virginia	12.8	13.5	-1.1	-0.9	-0.9
TOTAL	44.7	38.2	-2.7	-2.5	-2.5
Central Appalachia					
Southern West Virginia	23.8	21.8	+2.1	+2.1	+2.1
Virginia	13.3	12.2	+1.1	+1.1	+1.1
Eastern Kentucky	29.8	27.3	+2.9	+2.9	+2.9
Tennessee	2.6	2.4	-	-	-
TOTAL	69.5	63.6	+6.1	+6.1	+6.1
Southern Appalachia					
Alabama	8.6	5.8	+0.1	+0.2	+0.2
TOTAL	8.6	5.8	+0.1	+0.2	+0.2
TOTAL APPALACHIA	122.8	107.7	+3.5	+3.8	+3.8
Midwest					
Illinois	13.9	10.1	-1.1	-1.5	-1.5
Indiana	5.2	3.0	-	-	-
Western Kentucky	7.7	6.2	-0.8	-0.6	-0.6
TOTAL	26.8	19.4	-1.9	-2.1	-2.1
TOTAL MIDWEST	26.8	19.4	-1.9	-2.1	-2.1
Central West					
Iowa	0.1	0.1	-	-	-
Missouri	1.1	0.9	-0.2	-0.2	-
Kansas	0.2	0.3	-	-	-
Northern Arkansas	0.0	0.1	-	-	-
Oklahoma	1.0	0.7	-	-	-
TOTAL	2.5	2.0	-0.2	-0.2	-
Gulf					
Texas	2.4	2.1	-	-	-
Louisiana	0.1	0.8	-	-	-
Southern Arkansas	0.0	0.0	-	-	-
TOTAL	2.4	2.9	-	-	-

20C0282

TABLE C-10-A

Coal Mining Employment
(Thousand Workers)
(continued)

	Actual 1985	Base 1995	30 Yr/1.2 lb. Cases Change From Base 1995: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Rockies/Northern Plains					
Colorado	2.4	4.7	+0.5	+0.4	+0.4
Wyoming	4.5	4.1	+0.1	+0.1	+0.1
Montana	1.2	1.4	-0.2	-0.1	-0.1
Utah	2.6	4.5	+0.3	+0.3	+0.2
New Mexico	1.9	1.9	+0.3	+0.3	+0.3
Arizona	0.8	0.7	-	-	-
North Dakota	1.1	1.0	-	-	-
TOTAL	14.5	18.3	+1.0	+1.0	+0.9
Northwest					
Washington	0.7	0.6	-	-	-
TOTAL	0.7	0.6	-	-	-
Alaska					
Alaska	0.1	0.1	-	-	-
TOTAL	0.1	0.1	-	-	-
TOTAL WEST	20.3	24.0	+0.8	+0.8	+0.9
TOTAL U.S.	169.9	151.0	+2.4	+2.5	+2.6

20C0282

TABLE C-10-B

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 2000	30 Yr/1.2 lb. Cases Change From Base 2000: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Northern Appalachia					
Pennsylvania	22.3	17.8	-2.5	-2.6	-3.2
Ohio	9.0	5.3	-1.5	-2.0	-2.0
Maryland	0.7	0.4	-	-	-
Northern West Virginia	12.8	11.7	-0.4	-0.5	-0.4
TOTAL	44.7	35.2	-4.4	-5.1	-5.6
Central Appalachia					
Southern West Virginia	23.8	23.6	+3.3	+3.7	+3.9
Virginia	13.3	13.2	+1.8	+2.0	+2.2
Eastern Kentucky	29.8	29.5	+4.1	+4.5	+4.9
Tennessee	2.6	2.6	-	-	-
TOTAL	69.5	68.8	+9.2	+10.2	+11.1
Southern Appalachia					
Alabama	8.6	5.9	+0.6	+0.7	+0.7
TOTAL	8.6	5.9	+0.6	+0.7	+0.7
TOTAL APPALACHIA	122.8	109.9	+5.4	+5.8	+6.2
Midwest					
Illinois	13.9	12.8	-6.0	-6.0	-6.5
Indiana	5.2	2.1	-	-	-
Western Kentucky	7.7	5.5	-0.9	-0.9	-0.8
TOTAL	26.8	20.5	-6.9	-6.9	-7.3
TOTAL MIDWEST	26.8	20.5	-6.9	-6.9	-7.3
Central West					
Iowa	0.1	0.1	-	-	-
Missouri	1.1	0.6	-0.2	-0.2	-0.2
Kansas	0.2	0.2	-0.1	-0.1	-0.1
Northern Arkansas	0.0	0.1	-	-	-
Oklahoma	1.0	0.6	-0.1	-0.1	-0.1
TOTAL	2.5	1.7	-0.4	-0.4	-0.4
Gulf					
Texas	2.4	1.9	-	-	-
Louisiana	0.1	0.7	-	-	-
Southern Arkansas	0.0	0.0	-	-	-
TOTAL	2.4	2.6	-	-	-

20C0282

TABLE C-10-B

Coal Mining Employment
(Thousand Workers)
(continued)

	Actual 1985	Base 2000	30 Yr/1.2 lb. Cases Change From Base 2000: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Rockies/Northern Plains					
Colorado	2.4	5.1	+2.5	+2.2	+2.0
Wyoming	4.5	3.6	-	+0.2	+0.2
Montana	1.2	1.6	-	-	+0.1
Utah	2.6	4.8	+0.3	+0.2	+0.2
New Mexico	1.9	2.2	+0.3	+0.3	+0.3
Arizona	0.8	0.6	-	-	-
North Dakota	1.1	0.9	-	-	-
TOTAL	14.5	18.8	+3.1	+2.9	+2.8
Northwest					
Washington	0.7	0.5	-	-	-
TOTAL	0.7	0.5	-	-	-
Alaska					
Alaska	0.1	0.1	-	-	-
TOTAL	0.1	0.1	-	-	-
TOTAL WEST	20.3	23.7	+2.7	+2.5	+2.4
TOTAL U.S.	169.9	154.2	+1.2	+1.4	+1.3

TABLE C-10-C

Coal Mining Employment
(Thousand Workers)

	Actual 1985	Base 2010	30 Yr/1.2 lb. Cases Change From Base 2010: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Northern Appalachia					
Pennsylvania	22.3	30.1	-8.2	-7.0	-11.7
Ohio	9.0	6.7	-2.9	-2.8	-3.3
Maryland	0.7	0.3	-	-	-
Northern West Virginia	12.8	17.8	-4.1	-4.0	-5.0
TOTAL	44.7	54.3	-15.2	-13.8	-20.0
Central Appalachia					
Southern West Virginia	23.8	32.5	+4.4	+3.9	+2.3
Virginia	13.3	18.2	+2.4	+2.1	+1.2
Eastern Kentucky	29.8	40.7	+5.9	+5.3	+3.1
Tennessee	2.6	3.6	-	-	-
TOTAL	69.5	94.9	+12.7	+11.3	+6.6
Southern Appalachia					
Alabama	8.6	9.4	-1.6	-1.8	-1.9
TOTAL	8.6	9.4	-1.6	-1.8	-1.9
TOTAL APPALACHIA	122.8	158.6	-4.1	-4.3	-15.3
Midwest					
Illinois	13.9	16.6	-9.5	-9.9	-8.8
Indiana	5.2	4.2	-2.2	-1.9	-2.4
Western Kentucky	7.7	8.2	-2.9	-3.7	-3.4
TOTAL	26.8	29.0	-14.6	-15.5	-14.6
TOTAL MIDWEST	26.8	29.0	-14.6	-15.5	-14.6
Central West					
Iowa	0.1	0.1	-	-	-
Missouri	1.1	0.4	-	-	-
Kansas	0.2	0.2	-	-	-
Northern Arkansas	0.0	0.1	-	-	-
Oklahoma	1.0	0.5	-	-	-
TOTAL	2.5	1.4	-	-	-
Gulf					
Texas	2.4	1.9	-	-	-
Louisiana	0.1	0.7	-	-	-
Southern Arkansas	0.0	-	-	-	-
TOTAL	2.4	2.6	-	-	-

20C0282

TABLE C-10-C

Coal Mining Employment
(Thousand Workers)
(continued)

	Actual 1985	Base 2010	30 Yr/1.2 lb. Cases Change From Base 2010: 30 Yr/1.2 lb Intrautility	30 Yr/1.2 lb Intra. Ex-Ex	30 Yr/1.2 lb Intra. Ex-New
Rockies/Northern Plains					
Colorado	2.4	19.0	+6.9	+7.7	+9.7
Wyoming	4.5	5.5	+0.9	+0.8	+1.2
Montana	1.2	2.4	+0.3	+0.4	+0.6
Utah	2.6	10.4	+2.6	+2.2	+3.9
New Mexico	1.9	3.5	-	-	+0.2
Arizona	0.8	0.7	-	-	-
North Dakota	1.1	0.9	-	-	-
TOTAL	14.5	42.4	+10.7	+11.1	+15.6
Northwest					
Washington	0.7	0.5	-	-	-
TOTAL	0.7	0.5	-	-	-
Alaska					
Alaska	0.1	0.3	-	-	-
TOTAL	0.1	0.3	-	-	-
TOTAL WEST	20.3	47.2	+10.7	+11.1	+15.6
TOTAL U.S.	169.9	234.8	-8.0	-8.7	-14.3

20C0282

Appendix D:
Base Assumptions

APPENDIX D

BASE CASE ASSUMPTIONS

This appendix presents a detailed list of 1987 Interim EPA Base Case assumptions and specifications.

INTERIM 1987 EPA BASE CASE ASSUMPTIONS

Critical Parameter	Interim 1987 EPA Base
ELECTRIC UTILITY ENERGY DEMAND	
U.S. Imported Crude Oil Prices (Early-1986 $/barrel)	1990 = 17.80 1995 = 23.60 2000 = 27.40 2010 = 36.80
Electricity Growth Rate (% Per Year)	1987 = 2.7 1988 = 2.5 1990 = 2.0 1995 = 2.0 2000 = 2.0 2010 = 2.0 1987-1990 = 2.2 1991-2010 = 2.1
Total U.S. Nuclear Capacity	1990 = 103 1995 = 106 2000 = 106 2010 = 79
Nuclear Capacity Factors (%)	1990 = 67 1995 = 67 2000 = 67 2010 = 67
Utility Capital Costs (Early-1986 $/Kw)	Coal = 900 - 1,010 Nuclear = 1,725 - 1,960 Turbine = 275 - 315 Scrubbers, Dry = 99 - 112 Scrubbers, Wet = 204 - 245
Power Plant Lifetime (Years)	Coal Steam 60 years Oil/Gas Steam 60 years Nuclear 35 years Oil/Gas Turbine 20 years
Repowering/Refurbishment Assumptions	All coal capacity refurbishes

INTERIM 1987 EPA BASE CASE ASSUMPTIONS
(continued)

Critical Parameter	Interim 1987 EPA Base
Coal Powerplant Heat Rates Over Time	0.25% per year increase over current levels. After refurbishment heat rates are improved (decreased) by five percent from previous forecast levels.
Minimum Turndown Rates	Coal 35% Oil/Gas Steam 20%
Canadian Power Imports (billions of kwhrs)	1990 = 68 1995 = 64 2000 = 76 2010 = 75
Cogeneration (billions of Kwhrs)	1990 = 85 1995 = 117 2000 = 154 2010 = 194
FINANCIAL PARAMETERS	
Tax Depreciation Life (years)	15
Retrofit Pollution Control	15
Others	
Real Discount Rates (% Per Year)	Coal Mine = 6.00% Utility = 4.27%
Real Capital Charge Rates	
Coal/Nuclear/Combined Cycle	9.4%
New Scrubbers/Particulate Equip	9.4%
Combustion Turbines	11.3%
Retrofit Scrubbers	9.0%
Book Life (years)	
Coal/Nuclear/Combined Cycle	30
Combustion Turbine	20
Pollution Control-Retrofit	30
Pollution Control-New	30
Input Year Dollars	Early 1986
Output Year Dollars	Mid 1987
Escalation Input to Output Dollars	1.045

INTERIM 1987 EPA BASE CASE ASSUMPTIONS
(continued)

Critical Parameter	Interim 1987 EPA Base
NON-UTILITY COAL DEMAND	
Industrial/Retail Coal Use (millions of tons)	1990 = 87 1995 = 91 2000 = 98 2010 = 137
Coal Exports (millions of tons)	
-- Steam Coal	1990 = 24 1995 = 46 2000 = 67 2010 = 67
-- Metallurgical Coal Exports	1990 = 49 1995 = 53 2000 = 61 2010 = 65
Domestic Metallurgical Coal Use (millions of tons)	1990 = 37 1995 = 35 2000 = 32 2010 = 29
Synthetics (Coal Input in millions of tons)	1990 = 6 1995 = 6 2000 = 6 2010 = 6
COAL SUPPLY PARAMETERS	
Coal Transportation Rates	
-- Rail	Long-run marginal costs based on engineering analysis.
-- Truck; Barge	Long-run marginal costs based on engineering analysis.
Mining Costs (% Annual Real Escalation)	Capital = 0.0% Labor = 2% Materials = 0.0% Deep Productivity = 3% Surface Productivity = 2%

INTERIM 1987 EPA BASE CASE ASSUMPTIONS
(continued)

Critical Parameter	Interim 1987 EPA Base
OTHER GOVERNMENTAL REGULATIONS	
Federal Leasing Policy	Enough
Air Pollution Regulations	Most recent federal and state rules, including proposed changes in SIPs, state acid rain programs. No changes in limits associated with proposed federal tall stacks regulations. Large industrial boilers must scrub by 1995.