Electricity Restructuring and the Environment

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95-13 December 1995

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This document appears as Discussion Paper 95-13 of the Center for Science and International Affairs and as contribution E-95-07 to the Center's Environment and Natural Resources Program. CSIA Discussion papers are works in progress. Comments are welcome and may be directed to the author in care of the Center.

This paper may be cited as: Henry Lee and Negeen Darani. "Electricity Restructuring and the Environment." CSIA Discussion Paper 95-13, Kennedy School of Government, Harvard University, December, 1995.

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December 6, 1995

The research in this report was partially sponsored by the Energy and Transportation Division, Office of Policy Development, U.S. Environmental Protection Agency.

ACKNOWLEDGMENTS

This report is the product of a group effort. I relied heavily on my research assistants, Charlie Augustine, John Farr, Janelle Schmidt and Ian Brown. Much of the original research on demand side management and the impact on demand growth was put together by Charlie Augustine. John Farr had the responsibility for collecting the information and writing the earlier drafts of the renewables sections. Negeen Darani, my co-author worked with me for fourteen months and, with the invaluable help of Ian Brown, did much of the quantitative analysis. Miriam Avins did her usual superb job of editing, and Jo-Ann Mahoney and Jesselynn Pelletier helped prepare the monograph.

I also would like to thank Alex Cristofaro, Michael Shelby, Jim Turnure and Bruce Schillo at the U.S. Environmental Protection Agency for their support of this project, and the Harvard Electricity Policy Group, not only for its financial help, but also for serving as a sounding board for the analysis and the conclusions. Carter Wall, Armond Cohen, Bill Hogan, Peter Fox-Penner and Eric Hirst offered advice and comments that were enormously helpful. Finally, I owe a special thank you to Adam Jaffe who not only commented on earlier drafts, but generously contributed to the many discussions from which this report evolved.

This report was partially supported by a grant from the U.S. Environmental Protection Agency's Office of Policy, Planning and Evaluation. The opinions and conclusions expressed in the report, however, represent those of the authors and do not necessarily reflect those of the U.S. E.P.A. or any member of the Harvard Electricity Policy Group.

Henry Lee

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Executive Summary

Regulators at both the state and federal level are considering proposals that will change how electricity is bought and sold in the United States. Vertically integrated utility companies supplying power to captive customers may soon be a relic of the past. The industry of the future is likely to emphasize competition, customer choice, unbundling of generation from the operation of the transmission system and rates driven by markets, not regulation.

Stakeholders in the electric utility policy debate are scrambling to insure that the benefits of restructuring are not outweighed by the costs. Environmental groups have been among the most vocal of these stakeholders. To accurately describe their concerns is difficult, since there are major differences within the environmental community, and their positions are in flux, as the dimensions of the proposed changes move from general principles to specific proposals.

This report addresses five questions, the answers to which will help policy makers frame the issue and target specific areas in need of further analysis.

- How will restructuring affect the incentives of industry participants to incorporate environmental consensus into their decisions?

- What do these changes signify for the future of DSM and renewable investments?

- If DSM and renewable investments are reduced, what will be the impact on air emissions -- specifically sulfur dioxide (SO_2), nitrogen dioxide (NO_x) and carbon dioxide (CO_2) emissions -- and the nation's ability to meet its reduction targets?

- If competition alters the use of existing coal and nuclear plants, what will be the effect on air emissions?

- How will these changes affect President Clinton's CO_2 reduction targets outlined in the Climate Change Action Program (CCAP)?

<u>IRP and Restructuring</u>

The allocation of risk plays an important role in shaping the behavior and decisions of industry participants. Under cost-of-service regulation, **market risk** -- the risk that the demand for the product will be less than forecasted, **fuel risk** -- the risk that fuel prices will fluctuate, and **environmental regulatory risk** -- the risk that government will impose new and costly environmental regulations in the future -- all were borne primarily by the consumer. As a result, utilities had an incentive to overbuild, give less weight to future fuel price volatility and discount the possibility of more stringent environmental standards in making their investment decisions. Integrated resource planning processes (IRP) were an attempt to counter some of the perverse incentives inherent in the allocation of these risks.

Competition reallocates these risks and with them, the corresponding incentives. Market risk, fuel risk and environmental regulatory risk will now be primarily borne by the investor, not the consumer. The incentives to overbuild or ignore emerging environmental problems will be diminished - or in some cases, eliminated.

The IRP process is not likely to survive in its present form. In a competitive industry, utility regulators will no longer have the ability to control investment decisions, beyond requiring compliance with state siting laws. There will be limited ability to enforce any type of central plan. Furthermore, generating companies will often sell to wholesalers, marketers or distribution companies and may have no direct relationship with retail customers. In a world in which no single company is situated to sell generating capacity, retail power and demand management services, "integrated supply plans" become much less realistic.

DSM and Renewables

While the present IRP process will disappear, regulation of the remaining monopoly segments of the utility system -- distribution and transmission -- will provide an opportunity for regulators to continue to require ratepayer subsidized DSM. An access charge could be collected from all distribution companies and the revenues earmarked for incremental investments in DSM or renewables. While regulators can insure that subsidies for DSM and renewable energy investments continue, they will not be able to order utilities to make specific investments. For example, they will not be able to require a utility to invest in new air conditioning systems for its industrial customers or to build a certain number of solar energy facilities, but they can insure that there are subsidies available for companies or other parties who want to make such investments. Whether government chooses to demand such social investments, or chooses to subsidize other social goals, or to provide no subsidies at all is not dependent on restructuring, but rather on where society selects to place its priorities. Restructuring simply provides the opportunity to reprioritize, if society chooses to do so.

Finally, those groups that have been able to use the IRP process to leverage their goals will lose some of their direct leverage. The new processes will emphasize incentives and subsidies, not central planning and command and control regulation.

Impact of Reduced DSM and Renewable Investments on SO_2, NO_x, and CO_2 Emissions

One of the justifications for subsidizing DSM and renewable investments was the promise that less fossil fuel would be burned and less pollution emitted. This study examines this promise and specifically looks at the potential impact of reduced DSM and renewable investments on SO_2, NO_x, and CO_2 emissions. To place these impacts in context, we compare the resulting increased emissions to the targets for SO_2, and NO_x reductions set forth in the Clean Air Act Amendments (CAAA) of 1990 and the CO_2 emissions goals announced in the President's Climate Change Action Program.

In most reduction scenarios, the increases in SO_2 and NO_x emissions from reductions in subsidized DSM and renewable investments were less than 3 percent of the CAAA goals. These increases will manifest themselves -- not necessarily as more total emissions -- but in the form of higher marginal abatement costs for NO_x and in the case of SO_2, higher prices for tradeable allowances.

While the numbers for SO_2 and NO_x emission increase from lost DSM and renewable investments are small, the increases in CO_2 emissions are larger. A forty percent reduction in the *growth* of ratepayer-subsidized DSM will result in increased CO_2 emissions equal to 5 percent of the CCAP target. A forty percent reduction in projected renewable investments will result in slightly smaller increases in CO_2 by 2000, but larger increases in the following decade.

Utilization of Coal and Nuclear Plants

The largest potential impact on air emissions will *not* be the loss of DSM or renewables, but the effect of greater use of older dirtier coal plants and/or the premature closure of existing nuclear facilities. In the early 1990s, coal generating stations were operating at capacity utilization rates in the low to mid-sixties. Even a moderate increase of 3 percentage points will have a substantial impact on NO_x emissions - 492,316 tons of additional NO_x or 24.6 percent of the CAAA targets. Such an increase will place substantial upward pressure on NO_x abatement costs, as states will have to find other emission reductions elsewhere. The figures for CO_2 are equally large - 43 million tons or 15 percent of the CCAP goal.

There may be technical constraints in the ability to increase coal utilization rates, but if such increases do occur, downwind states will be forced to pursue more costly NO_x abatement programs to meet the statutory requirements of the CAAA. Moreover, the differences in regulatory treatment of new versus old facilities may become more controversial. In economic terms, older facilities have enjoyed a subsidy in the form of avoiding the environmental costs they impose on society. This subsidy has been paid for by newer facilities. If all facilities must compete against each other, this inter-industry subsidy may reinforce the incentives to extend the use of these older plants and serve as a disincentive to invest in new, cleaner alternatives. Removal of rules and regulations setting artificial depreciation schedules may counter some of this pressure, but is unlikely to eliminate it.

The numbers for premature shutdowns of nuclear capacity are also impressive. If 6,000 MW of nuclear capacity is prematurely retired, the subsequent increase in NO_x emissions would equal 5 percent of the CAAA targets. The increase in CO_2 would be between 14 and 28 million tons or 5-10 percent of President Clinton's goal.

Early retirement of nuclear plants or increased utilization of existing nuclear facilities will have a greater effect on CO_2 emissions than the loss of ratepayer subsidized DSM investments. Twelve thousand megawatts of nuclear capacity avoids the same amount of CO_2 emissions as *all* the utility subsidized DSM investments projected for 1997.

In a competitive market, owners of nuclear facilities will find it very difficult to afford any major maintenance investments (i.e. over $100 million), since such improvements would no longer be put into a rate base and amortized over 10-20 years. As a result, owners faced with such an investment may choose to prematurely retire their facilities. Any loss of nuclear capacity will, in the short-run, translate into greater use of fossil fuel plants and more air emissions.

We are not recommending greater use of nuclear power. In fact, there may be environmental and economic reasons to accelerate the early retirement of nuclear facilities. We are simply saying that the future utilization of such facilities will have a substantial effect on air emissions, especially CO_2 and NO_x.

President Clinton's CO_2 Reduction Target

Finally, reductions in DSM and renewable investment rates and possible changes in the utilization of existing coal and nuclear facilities could result in measurable increases in CO_2 emissions. These increases were not accounted for in the CCAP calculations of CO_2 emission reductions needed to stabilize emissions at 1990 levels. Therefore, the CO_2 increases projected in this study will make it more difficult to achieve established emission reduction targets. For example, the carbon emission reductions needed to meet the CCAP stabilization goal could be approximately twenty percent higher. Some of this increase will occur regardless of any additional action to restructure the industry and is related to the move to a more competitive wholesale electricity market -- a move that started seven years ago. In addition, 11-20 percent of reductions in the President's plan may be endangered as utilities decrease their investments in DSM and energy efficiency and the IRP process becomes less binding.

SECTION 1: INTRODUCTION

On April 20, 1994, the Public Utilities Commission of the state of California proposed a far-reaching plan to restructure California's electric service industry.[1] Thirteen months later the Commission voted to support several major changes in the California electricity structure: 1) the establishment of a mandatory electric power pool to begin operation in 1997; 2) the creation of an independent transmission grid operator; and 3) the prospect of eventually allowing direct retail access to an array of power sellers. The Commission's goal is to introduce greater competition into the electric utility sector and reduce the cost of electricity to California consumers.

When the original plan was announced, shockwaves reverberated throughout the industry, as the various participants assessed the implications of the proposal. Among those most concerned were the leaders of the environmental community, who saw their gains in energy efficiency and renewables threatened. They responded aggressively. For example, in a New York Times opinion piece, Ralph Cavanagh, Energy Program Director of the Natural Resources Defense Council, stated that:

> Abandoning conservation and renewable power spells real trouble. Electricity production has a greater effect on the environment than any other economic activity. It accounts for one-third of America's total carbon dioxide emissions and two-thirds of the sulfur dioxide emissions that contribute so much to acid rain. The California Commission which often serves as a national model, has promised an open mind and a willingness to substitute alternative reforms as it conducts its hearings. We must hope it listens to a growing host of critics; the environmental stakes could hardly be greater.[2]

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[1] California Public Utility Commission, "Order Instituting Rule Making and Order Instituting Investigation: On the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation," R.94-04-031 and I. 94-04-032, filed April 20, 1994.

[2] Ralph Cavanagh, "Electricity Shopping Can Be a Bad Deal," New York Times, June 12, 1994, Section C, p. 11.

Is competition the environmental disaster some claim? Will it result in abandoning energy conservation, demand-side management, and investments in renewable power? If it does, what is the likely impact on the environment?

To answer these questions, the paper begins with a brief history of the events that led to the adoption of integrated resource planning (IRP) processes and the recent pressure to restructure the industry. We then assess the impact of greater competition on demand-side management, renewables, changes in plant utilization, and growth in electricity demand and the subsequent effect of these factors on air emissions, our surrogate measure of environmental quality.

How We Got to Where We Are

The California proposals are part of a trend toward restructuring the electric business into a more competitive industry. Experts point to the passage of the Public Utility Regulatory Policy Act (PURPA) of 1978 as the first step. This Act allowed certain electricity generators, primarily small or renewable units or cogeneration plants[3] to sell power to electric utility companies at prices no less than the cost to the utility of building or purchasing an incremental kilowatt of new generating capacity (that is the cost the utility avoided by buying the power). In some states including California, additional subsidies were provided, and as a result, a mini-construction boom emerged. Most of the new power facilities were small, renewable generators, primarily biomass and hydro systems. By the mid 1980s, this surge ended and a nascent independent power industry emerged. This industry relied more on conventional fuels and larger plants, but took advantage of the PURPA provisions stipulating that utilities must purchase power at avoided cost from any

[3] A cogenerating facility captures the heat or steam from industrial, commercial, heating or cooling activities to produce electricity. Renewable energy resources, generally considered to be inexhaustible and replenishable sources of electricity generation, include hydroelectric, biomass, solar, geothermal, wind and photovoltaics.

co-generator. By the early 1990s, approximately half of the new capacity built each year in the United States was owned by independent producers.[4]

The belief that electricity was best generated by vertically integrated monopolies -- a concept that the industry adhered to for close to 60 years -- was fast evaporating. Twenty-seven states required their utilities to establish auction systems for new capacity.[5] The response exceeded all expectations. Quite often, the quantities offered were 10-15 times the amount of capacity sought. Dramatic improvements in the efficiency of new generating equipment and the collapse of natural gas prices reduced the price of new capacity still further. In 1992, the momentum towards competition was dramatically enhanced by the passage of the Energy Policy Act, which opened the transmission grid and institutionalized the opportunity for a competitive wholesale electricity market.

By the middle of the decade, it was clear that a competitive wholesale market was not only possible, but probably inevitable. However, the adoption of a market system for *new* generating capacity was uneven across states and franchise areas. What made the California proposal revolutionary was its call for the introduction of a competitive market for *all* wholesale capacity, whether new or old, as well as the introduction of retail competition.

Opinion is split on the wisdom of introducing *retail* competition, that is, allowing generators to sell power directly to consumers rather than through franchise distribution companies. Retail price differences between neighboring utilities -- sometimes as great as 50 percent -- provide a tantalizing opportunity for enterprising industrial customers to

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[4] Independent Power Producers built 50 percent of new generating capacity in 1991, 62 percent in 1992, 46 percent in 1993 and 61 percent in 1994. See RCG/Hagler-Bailly "Profile IX, U.S. Independent Power Markets: 1994 Status and Trends," Ch. 5.

[5] National Association of Regulatory Utility Commissioners, Utility Regulation in the U.S. and Canada, Compilation, 1994-95, p. 505.

reduce their costs by buying power from another utility or independent power producer. Limited retail competition was proposed, but not enacted, in the late 1980s and early 1990s in Nevada, New Mexico, and Connecticut.[6] In early 1994, Michigan decided to conduct a limited retail competition experiment[7], but the California proposal is the most far-reaching to date.

Context

The merits of the regulatory processes and structures that have governed the electricity industry over the past 60 years are under intense scrutiny. Those who benefit from the existing processes and structure are concerned that these new proposals will erode or eliminate those benefits.

Environmental advocates are especially concerned. In their testimony before various regulatory and legislative bodies, they have expressed many concerns. Two stand out. First, they fear that competition will significantly reduce investments in demand-side management and the environmental benefits from such investments will be lost. They argue that in a competitive regime, competition will be largely based on price; social costs, such as environmental damages, will be ignored. Mandatory demand-side management programs and renewable investment quotas will not survive.

Their second concern is that the integrated resource planning (IRP) mechanism that provided environmental advocates with direct input into electric utility investment decisions will disappear, and that utilities and independent power producers will ignore future environmental risks. The IRP process has led to increased investments in energy efficiency,

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[6] Harvey Simons, "Competing for Electrons: The Public Service Company of New Mexico and the City of Albuquerque (Harvard Electricity Policy Group, October 1993) and DOE/EIA, "Performance Issues for a Changing Electric Power Industry", DOE/EIA - 0586. (January 1995) p. 19-22.

[7] Michigan Public Service Commission, "Major Elements of the Retail Wheeling Framework," Cases U - 10143 and U - 10176, April 11, 1994.

and environmentalists argue that they should not lose the opportunity to influence the future direction of energy investments in an era when environmental concerns will become more important -- not less. Environmental advocates fear that in a market-driven regime, environmental values and concerns will not be incorporated into capacity investment decisions. The IRP process provides an opportunity to introduce emerging environmental issues -- such as climate change or small particulate emissions -- into future investment strategies prior to formal legislative action. Unless generators are forced to build diversity into their future generation portfolio, many people believe investors will undervalue the risk of government imposing additional environmental regulations in the future.

Inherent in this position is a concern that the partnerships that have emerged between environmental organization and utilities will disappear. If environmentalists lose their seat at the proverbial regulatory table (or perhaps, the table itself is removed), then electric utility companies will be less willing to cooperate in addressing emerging environmental issues. In other words, a trend toward greater collaboration between the environmental community and the utilities will be replaced by a trend toward increased conflict.

An example of this collaboration is the dramatic increase in utility investment in demand-side management (DSM) from $872 million dollars in 1989 to over $2.77 billion in 1993. This commitment came about largely because of an effective lobbying effort by environmental groups who used the IRP process to articulate the economic and environmental benefits of subsidizing DSM investments. Some environmental groups fear that a move to retail competition, will result in the demise of these programs. According to Ralph Cavanagh of the Natural Resources Defense Fund, "If utilities were going to live or die solely by how low they could drive the short-term commodity price of electricity, they would have every reason to resist investment to reduce pollution or to help customers save energy." [8]

Are these fears well founded? Will two decades of government intervention to promote energy efficiency and renewables come to an end if and when regulators adopt proposals for a more competitive industry? More specifically:

- Will the IRP process disappear?
- Will investment in DSM and renewables decline in a market driven industry?
- If the answer to the first two questions is yes, how will this affect the environment?
- Will competition trigger other effects, such as changes in how coal and nuclear generating facilities are used, and how will the ensuing effects on emissions compare with the effects of reductions in DSM and renewable investments?

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8 Ralph Cavanagh, "The Great "Retail Wheeling" Illusion -- and More Productive Energy Futures," (draft), September 1993, p. 33.

SECTION 2:
WILL THE IRP PROCESS DISAPPEAR?

The Massachusetts Electric Utility Market Reform Task Force argued that there is a basic incompatibility between competition and Integrated Resource Planning.

> Utilities fear an evolving asymmetry with low cost utilities and utility operators limited to cost based-revenues and regulated profit and high cost utilities limited by competition. Most fundamentally, the IRM (Integrated Resource Management) process, or any other micro-management of utility decision making is inconsistent with the use of market forces to discipline behavior and create incentives for efficiency. To many commentators, the choice is thus between the increased use of competition as a goal to efficiency versus continued regulation of a monopoly.[9]

In theory, the incompatibility of all inclusive central planning mechanisms, such as IRP, with free markets is indisputable. At the same time, the more interesting question is not whether IRP is compatible with competition, but rather whether the *goals* of IRP are incompatible with a more competitive electric power market.

The Basic Elements of IRP

Integrated Resource Planning is a comprehensive approach to utility planning that evaluates both demand and supply side resource options. Its object is to minimize long-term societal costs. These costs include all direct costs, as well as costs associated with environmental and other externalities.[10]

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[9] Massachusetts Electric Utility Market Reform Task Force, [convened under the aegis of the Massachusetts Department of Energy Resources], July 1994.

[10] Eric Hirst, Bruce Driver, and Eric Blank, "Integrated Resource Planning: A Model Rule"; [Public Utilities Fortnightly, March 1993, p. 24]

Virtually all IRP processes contain several common elements. First, the utility must submit an "integrated resource plan" to the state public utility commission (PUC) for review. The plan usually is based on a multi-year demand forecast and a strategy for meeting that forecast in the "least cost" way. Whether "least cost" means least private cost (revenue requirements) or social cost (incorporating the cost of environmental impacts in addition to revenue requirements) depends on the policy of the particular state. The plan must discuss and compare both supply and demand side resource options, and must include an assessment of energy conservation opportunities.[11]

The plan must first assess the demand for electricity over the planning horizon and offer an investment strategy for supplying the power to meet that forecast. The utility can select between generating power with existing capacity, building new capacity, purchasing power from other generators, and reducing demand through conservation or load management programs.

The PUC reviews the utility's IRP submission, receives input from interested parties such as consumer and environmental advocacy groups, and approves or rejects the plan. Approval is tantamount to an ex-ante finding that the utility's plan is prudent; consequently, some construction and most market risk is shifted from the utility shareholders to the customers, although there is always a "regulatory risk" (albeit small) that costs may be disallowed at a later date by a new group of regulators.

Most IRP processes include four elements that differentiate the process from past utility planning efforts. First, they almost always consider non-traditional resource choices, such as demand side management or renewables. Second, they explicitly address

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11 Charles S. Cicchetti and Ellen K. Moran, "The Evolution of the Electric Utility Sponsored Conservation Movements in North America: Remembrances of Their Past," in International Energy Conference on DSM: A Current and Future Resource (Copenhagen: October 1991), p. 43.

environmental and social goals instead of merely focusing on providing electricity.[12] Third, IRPs provide for much more public involvement than traditional planning processes, which tended to be very closed until the 1970s. Fourth, and perhaps most important, IRPs require that regulators take a prospective rather than a retrospective approach to utility management decision, making the regulator a de-facto partner in the investment decisions.

For the purpose of this study, the IRP process can be broken into three parts: integrated analysis, integrated planning and integrated procurement. *Integrated analysis* is the process of evaluating the costs and benefits of supply and demand options. Such analysis is not uncommon and is performed by many industries both regulated and unregulated. *Integrated planning* converts the analysis into a plan of action. *Integrated procurement* is the purchase of the specific demand and supply alternatives contained in the integrated plan.

Competition and IRP

To assess the implications of restructuring, it is useful to review the basic elements of the old utility regulatory system and describe what a competitive regime might look like.

Under the traditional regulatory structure, utility companies were given the exclusive right to sell electricity to consumers within their monopoly franchise area. The obligation of the company was to build or purchase the generating, transmission and distribution

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[12] Thirty-two states formally consider environmental externalities in their IRP processes. Environmental costs can be evaluated either quantitatively or qualitatively. Quantitative methods include discounts for different resource types, explicit monetization of emissions, and ranking and point systems. In 1994, 16 states required the use of quantitative methods of IRP submissions. Qualitative methods, used in 20 states, include directives for utilities to invest in a predetermined amount of DSM or renewables or higher rates of return for "desirable" resource investments than for traditional supply options. (National Association of Regulatory Commissioners, Utility Regulation Policy in the U.S. and Canada, Compilation, 1994-95, p. 504.)

capacity sufficient to meet any demand scenario. In return, the company was guaranteed the opportunity to earn a fair rate-of-return on its prudent investment. Utility revenues were a function of the prudent investment multiplied by the rate-of-return. The system provided strong incentives to avoid underinvestment by minimizing a utility's exposure to market risk. That is, if a utility overinvested and owned more capacity than needed, it would still be able to earn a rate-of-return on that capacity. Market or demand risk was transferred to the consumer. As states adopted fuel adjustment clauses to protect utilities against rapid swings in oil, gas and coal prices, consumers also bore the risk of changes in fuel prices.

Consumers had no choices. They had to buy their power from their local utility at preset rates approved by federal or state regulators. Some large industrial or commercial ratepayers had the option of moving to a new region or self-generating, but such options were not realistic for most customers.

Regulators had substantial power under this system. Through their rate-making authority and their review of utility resource plans they could directly influence the type, scope and magnitude of utility investments. Furthermore, since customers were captive, regulators could require utilities to pursue social goals, such as assistance to low-income consumers, increased environmental protection, economic development and energy conservation. Utilities were allowed to raise electricity rates to cover the cost of these social initiatives.

During the 70s and 80s, this structure began to crack. Cost overruns in the construction of many new nuclear facilities were too high to be politically acceptable and regulators did not allow all "prudent investments" into the rate base. As a result, the investment community became very sensitive to "regulatory risk". Independent Power Producers, exempted by the Public Utility Regulatory Policy Act of 1978 from most traditional utility regulation (and therefore, from many regulatory requirements), moved quickly to fill the investment vacuum left by the private utilities.

In some states, vigorous competition emerged in the market for new generating capacity. The Energy Policy Act of 1992 further opened this market by providing non-discriminatory access to the transmission system for all parties willing to pay a reasonable tariff.[13] Still in 1995, consumers could only buy their power from their local utility which still enjoyed the privileges of a vertically integrated monopoly.

What would a competitive structure look like and how would it differ from the present system? Many proposals have been floated, but for the sake of illustration, we will use a version close to that outlined by the California Public Utilities Commission in their May 24, 1995 proposal.[14]

The basic change between the old system and the new one is that consumers will be able to choose from whom they will purchase power. Investment decisions will be triggered not by regulators, but by hundreds of parties participating in a dynamic market.

The California Model

Under the California plan, a wholesale power pool would be established and utilities would transfer operating control of their transmission assets to an independent system operator (ISO). All power suppliers, including power marketers and out-of state generators, would have nondiscriminatory access to transmission services. The wholesale price of power purchased from the pool would be determined by an economically efficient auction conducted by the system operator. For example, sellers would offer to sell blocs of power in 30 or 60 minute increments over a 24 hour period. If consumers demanded 5,000 MWH at 3 p.m., then the price at that time would be the price paid by consumers and received by generators for the 5,000 MWH.

Customers could either buy from the spot market, organized through the pool, or

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[13]U.S. Public Law 102-486.

[14]California Public Utilities Commission, "order Designating Commission's Proposed Policy Decision and Requesting Comments", May 24, 1995, Decision 95-05-045.

choose to enter into financial contracts (so-called contracts for differences) with energy producers, marketers or brokers. Thus, customers would be allowed "to control their overall energy costs by constructing a portfolio of short-term energy purchases from the pool, long-term fixed price purchases through financial contracts and appropriate energy conservation and load shifting."[15] Generation and marketing would be gradually deregulated, while transmission and distribution would remain regulated monopolies.

The pool concept is controversial, and as a result, some states may decide to bypass it and allow unlimited bilateral transactions between buyers and sellers. Either way, consumers will have more choices than they do now, and the structure of the industry will be different. To fully understand the changes that might ensue if a fundamentally different industry structure is adopted challenges even the most flexible mind. There are, however, several changes that could measurably affect the environment over the long-term. In some cases the effect may be positive, while in others it is likely to be negative.

Changing the Incentives

First, the industry model of one company selling to a captive customer base will disappear. There will be many "sellers" and some will be marketers or aggregators who will not own generating plants, distribution lines or transmission wires. These new entrants will enter into financial contracts with power producers on the supply side and customers (or groups of customers) on the demand side. The supply contracts are likely to be actively traded.

Second, by unbundling the various services, generating companies will be independent of distribution companies who will not necessarily provide marketing or aggregating services. Instead, a third group of companies may be the entities from whom consumers buy their power. Thus, the idea of forcing a utility to balance supply and

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[15] California Public Utilities Commission. Press Release "California Restructuring". May 24, 1995.

demand-side investments may no longer be viable since the supplier of DSM services may not be the same company that builds or invests in new power plants.

Competition will also change the allocation of risk between investors and consumers. This reallocation may mitigate the perverse incentives that created some of the environmental problems in the first place.

Under the old cost-of-service regime, consumers had no choice, but to pay for as much capacity as the utility company thought was needed. Demand risk -- the risk that there would be no buyers for the additional capacity -- was transferred from the utility to the consumer. That world will end. In a competitive regime, demand risk will be borne by the generator who may hedge all or some of this risk by entering into financial contracts with different parties.

Investors will want to avoid excess capacity, since idle power plants will not be earning any money. In recent years, utilities have become acutely aware of the value of maintaining flexibility and building a diversified portfolio of short and long-term commitments.[16] They no longer have an interest in building ever larger power plants, since such a strategy is incompatible with the emerging competitive world. Buyers are no longer willing to pay for capacity they do not need. Over-building will result in significant financial losses and is unlikely to be the focus of environmental concerns in the 90s, as it was in the 70s and 80s.

This scenario is already apparent, as utilities faced with competition from independent power producers and a surplus of excess generating capacity have become aware of the value of maintaining their options and not building in advance of demand growth. Full wholesale competition will accelerate this trend.

Reallocation of these risks may also have an environmentally negative impact as generators become more inclined to extend the life of older more polluting facilities and

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[16] Kaslow, Thomas and Pyndyck, Robert S. "Valuing Flexibility in Utility Planning" in Electricity Journal 7 (March 1994) p. 60-65.

avoid the financial risks of misjudging consumer demand growth. The strength of this influence is unclear, since there will also be countervailing factors. For example, under the old regulatory rules, utilities had to use artificial depreciation schedules that kept facilities on-line until they were fully paid-off. These rules will be eliminated.

Further, under the old regulatory regime, utilities could largely ignore the threat of future environmental risks in selecting fuels for new generating facilities. If EPA promulgated stricter pollution standards or Congress enacted a new emissions tax, utilities could pass the costs onto the ratepayer. There was no direct incentive to factor these risks into investment decisions. The IRP process sought to correct this problem, by forcing the utilities to qualitatively, and in some states, quantitatively, weigh the risk of more stringent regulation in the future and temper their investments to reflect this impact. In a competitive world, investors in new plants will not be protected from environmental regulatory risk. They will have to incorporate those risks into their decisions. Admittedly some may attach lower probabilities or lower costs to those risks than the environmental community, but at worst, all this implies is that some investors may make bad business decisions. If investors decide to build a coal plant and Congress eventually imposes a carbon tax, these investors will not be able to pass that tax along to the consumer, unless the consumer explicitly has signed a contract agreeing ex-ante to the pass-through. That is investors will either have to internalize environmental regulatory risks or identify ways of hedging them. The one exception, -- and it may be large -- is that some companies may believe that the probability of persuading their elected officials to bail them out, is high. Therefore, these companies may substantially discount these risks.

In a competitive world, environmental groups are apt to have considerably less influence on capacity investment decisions, than in a world in which those decisions are exposed to the IRP process. Lobbying regulators to direct utilities to make environmentally sensitive investments will become a less effective strategy, since the regulators will no longer have the same authority. On the other hand, certain risks, such as fuel risk, demand risk and the risk of future environmental regulation will be borne, not by consumers, but by power producers. This reallocation of risk, in general, should have an environmentally beneficial effect.

Will Environmental Groups Lose the Ability to Affect DSM and Renewable Investments?

In a restructured industry, there will be continued regulation of the remaining monopoly segments - transmission, distribution and the operation of the grid system, but there will be limited, direct regulation of generation and marketing. To determine the future influence of environmental groups in shaping investment decisions, let us return to the three elements of the IRP process: analysis, planning and procurement.

Integrated analysis - the evaluation of costs and benefits of alternative investment portfolios - can continue. Most companies in a competitive industry have a strategic planning operation that does this type of analysis, and where there is a social imperative, government agencies conduct independent assessments of these alternatives. The only differences between the competitive model and the old IRP regime is that different people may be doing the analysis, and the incentives for stakeholders to commit resources to these exercises may be reduced.

Integrated planning -- the conversion of the analyses into a plan -- can still be required for the three remaining regulated segments of the industry, but not the deregulated segments. Again, the motivations of the stakeholders to commit substantial resources will change. However, there is no reason that a regulated distribution company cannot be required to develop an annual plan and have that plan reviewed by regulators and other participating parties.

Integrated procurement will change. Power purchasing will no longer be centralized or integrated. Regulators will not be able to direct or order specific procurement decisions. However, they will still have tools available to pursue socially desirable goals. To illustrate the difference between the old IRP process and IRP type procurements in a competitive regime, let us assume that, as a result of the integrated planning process, regulators decide that 75 MW of capacity should be procured through investments in energy conservation. Under the old regime, they could simply direct the integrated utility to forego the investment in 75 MW of new generating equipment and invest in as many DSM initiatives as necessary to reach the 75 MW figure. The cost of the DSM investment was paid for by the ratepayer in the form of higher rates.

In a competitive regime, the regulators will not be able to direct the utility to make these investments, since there will no longer be any fully integrated utilities. Instead, they can direct the distribution utility - or theoretically, either of the other two regulated segments of the industry -- to procure 75 MW of DSM, or energy efficiency. The utility could hold an auction and pay DSM suppliers to provide 75 MW of avoided capacity. The cost of this procurement would be paid for by the users of the distribution system in the form of a supplemental fee. Since most, if not all, consumers would be users of the system, the fee would be similar to a tax on all customers.

Let us assume that the integrated planning process also recommended the procurement of 50 MW of solar power. Under the old regulatory regime, the regulators would direct the relevant utility to invest in 50 MW of solar capacity. In a competitive regime, the regulators' authority is much more proscribed. None of the three regulated segments of the industry may be in the business of building or buying power. These functions may have been absorbed by unregulated generators and marketers. Instead, the regulators could direct the distribution company -- which they will still regulate -- to provide subsidies to solar generators sufficient to insure that 50 MW of solar power is price competitive and can be sold either in the spot or contract markets. To insure that the subsidization is efficient, the distribution company could hold an auction and award payments to the lowest bidders. That is the winners would be the solar generators who sought the lowest subsidies. Further, the subsidy would only be paid when the solar power is actually sold. Revenue for the subsidy would be obtained through a fee collected from all users of the distribution system.

Theoretically, similar mechanisms could be designed to pay generators not to produce power from socially harmful alternatives, but from a practical perspective, such a mechanism would be difficult to implement.

In summation, it will be possible in a competitive regime to maintain some of the principle elements of the IRP process. There will be opportunities to pursue many of the goals of the existing process, but the means will differ. Further, the price tag attached to those means will be more explicit and thus more vulnerable to political attack.

SECTION 3:

WILL INVESTMENTS IN DEMAND-SIDE MANAGEMENT SURVIVE?

"Demand-side management" is any effort to influence customers' electricity purchasing decisions. The primary objective of most utility DSM programs is to defer the need to create new capacity, including building generating facilities and purchasing power, and reducing the use of fossil fuels. There are generally two ways DSM programs influence usage:[17]

1. Energy Efficiency (conservation): These programs reduce the aggregate level of energy the customer uses.
2. Load Management: These programs shift the customer's use from peak to off-peak times.

Only conservation clearly reduces pollution. The environmental effect of load management depends on a utility's resource mix. A utility that meets its base load requirements with coal and its peak load requirements with gas or hydro may actually increase emissions by shifting load from peak to base. A utility that meets its base requirements with hydro or nuclear power will lessen emissions by making the same shift. Peak-clipping may also offer the benefit of delaying the siting and construction of new plants, since the need for peak capacity usually triggers new construction. Programs that reduce peak loads without shifting demand to off-peak times have the same environmental impact as conservation programs.

[17] EIA/DOE, Electric Power Annual, (U.S. Government Printing Office, Washington, D.C.), 1992, p. 101

TABLE 1: DSM Peak-load Reductions and Energy Savings

ITEM	1993	1992	1991	1990	1989
Peak-load Reductions (mw)	23,181	17,204	16,739	14,772	12,463
Energy Savings (Million kilowatt hours)	44,349	36,164	23,343	18,671	16,268
Cost (Thousand Dollars)	$2,768,662	$2,243,270	$1,747,933	$1,177,457	$872,935

Source: (EIA Electric Power Annual 1993 Jan. 94, p. 106)

The EIA data in Table 1 show that over the five years 1989-1993, DSM spending and savings have grown rapidly. However, while U.S. utilities spent over $2.7 billion on DSM programs in 1993, no small sum, those expenditures represented only 1.3 percent of utility revenues.[18]

Finally, DSM is often divided into market-driven DSM initiatives and ratepayer or utility-driven DSM initiatives. The former are initiatives that respond to changes in price. The latter are above and beyond market responses and are subsidized by ratepayers. While market-driven DSM may be affected by a utility restructuring, most of the debate is about the fate of ratepayer-subsidized DSM.

Environmentalists support DSM programs because such programs reduce the amount of electricity generated, thus reducing present and future pollution levels. They point out that utilities that have aggressively pursued DSM have been working their way up a steep learning curve and argue that DSM efforts should not be undercut just as society is finally reaping significant savings. They point out that DSM is part of a chain, with each link

[18]Eric Hirst, "Costs and Effects of Electric Utility DSM Programs 1989 through 1997," (Oak Ridge, TN: Oak Ridge National Laboratory, June 1994), p. 10.

supporting the next. For example, R&D in energy-efficient technologies, such as high-efficiency lighting, is stimulated by the existence of markets that have been developed by utility DSM programs. R&D brings down the costs of new conservation technologies, increasing the number of cost-effective DSM options.

Unanswered Questions

Despite the support for DSM programs in many states, questions remain about their impacts. This problem is compounded by the lack of consistent, high-quality data. For example, Eric Hirst cautions that analysts using data reported by utilities on their DSM programs should "view the numbers with some skepticism".[19] There is little information on factors such as transaction costs, free ridership, and supply elasticities. DOE's Energy Information Administration has called for an effort to improve the collection and analysis of DSM data, but improved data will not be available for several years.[20]

Are There Important Market Barriers to Conservation Investment?

Homeowners and businesses have always made investments in energy efficiency, such as insulation and more fuel-efficient vehicles. Utility DSM programs provide subsidies (paid by ratepayers) for the purchase and installation of additional energy efficient equipment; that is, they seek to induce people to make more conservation investments than they would otherwise make. One justification for such intervention is the existence of market barriers. The three most commonly cited are information failures, "irrational" customer discount rates, and inefficient prices (that is, prices do not reflect long-run

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[19] Hirst, "Costs and Effects", p. 2

[20] EIA, Electric Power Annual 1992, p. 104

marginal costs).[21] Critics of the market-barrier argument either dispute the existence or the significance of these barriers or argue that such barriers are really marketing opportunities for entrepreneurial companies to sell conservation services to electricity customers.[22]

Who Should Pay for DSM?

Utility DSM programs use three different general approaches to achieve DSM goals: information dissemination; financial incentives; and direct installation of energy-saving equipment.[23] The costs of these efforts are defrayed by all ratepayers; that is, everyone pays in, but the benefits are enjoyed disproportionately by those who participate. Some non-participants and customers who participated in the past have begun to argue for cutbacks or the elimination of DSM efforts on the grounds that they and other ratepayers, cannot afford to continue paying these subsidies, especially while there is a surplus of electricity capacity. Critics ask: since participants in DSM programs receive the benefits in the form of lower bills, why shouldn't they bear the costs? Proponents counter by arguing that removing the subsidies will drastically reduce participation rates, increase the growth in projected demand for electricity and accelerate the need for new expensive generating facilities.

Even if there were no move toward competition, there would be substantial public pressure to redesign the present array of DSM initiatives. Eric Hirst has argued that "the

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[21]See Energy Policy, October 1994 which contains several articles on this topic.

[22]Lawrence Kolbe et. al., "It's Time for a Market-based Approach to DSM," Electricity Journal, May 1993; and James Newcombe, "The Future of Energy Efficiency Services: A Competitive Environment," Electricity Journal, May 1994.

[23]Joseph Eto and Steve Nadel, "Harvesting Demand-Side Resources: The Experience of the United States Electric Utilities," International Conference on DSM: A Current and Future Resource, p. 288.

likely key to success for DSM programs in the future will be increasing the participant contribution to program costs, thereby reducing the opposition to DSM from nonparticipating customers."[24]

Does Geography Matter for DSM Benefits?

DSM efforts have been greatest in New England and the Pacific states, the regions with the greatest excess capacity and the smallest use of coal (see Table 2). There seems to have been an inverse relationship between aggressive investment in DSM and the volume of air emissions from regional generating stations. This is not surprising since DSM has been driven more by changes in the marginal retail price of power than by environmental concerns.

[24]Hirst, "Costs and Effects", p.20.

TABLE 2: Regional Distribution of Coal Use and DSM Investment
(DSM as percent of revenue; coal as percent of resource base)

FEDERAL CENSUS REGION	COAL AS % OF CAPACITY (1992)	DSM ENERGY SAVINGS AS % OF SALES: 1992
NEW ENGLAND	12%	2.8%
MIDDLE ATLANTIC	29%	1.0%
EAST NORTH CENTRAL	67%	0.4%
WEST NORTH CENTRAL	64%	0.4%
SOUTH ATLANTIC	48%	1.9%
EAST SOUTH CENTRAL	63%	1.6%
WEST SOUTH CENTRAL	30%	0.3%
MOUNTAIN	58%	0.8%
PACIFIC	2%	1.9%
U.S. AVERAGE	43%	1.2%

Sources: EIA/DOE, Electric Power Annual 1993, pp. 24-25 and Hirst, "Cost and Effects."

While the current environmental benefits of DSM may be small, EIA data shows that DSM programs have grown substantially in 1990-1994, and utilities project rapid growth in DSM energy savings for most regions through 1997.[25] Many regions with DSM rates below the national average in 1992 are planning to expand their programs faster than the national average through 1997. These include the Mid-Atlantic, East North Central, West North Central, and Mountain regions.[26]

[25] Hirst, "Cost and Effects", p. 28-24.

[26] Ibid. pp. 25-30.

THE FUTURE OF DSM WITHOUT IRP

If states eliminate all mandated and subsidized DSM -- which, as discussed earlier, is not an inevitable result of retail competition -- will utilities stampede to leave the DSM business? The answer is probably no, for three reasons. First, those utilities that retain both distribution and marketing functions may use DSM to differentiate themselves as providers of a more comprehensive package of services. They may sell the DSM services directly, or they may offer them on the condition that the customer remain on line for some specified period.[27] One utility executive referred to this use of DSM as "garlic against the werewolves of competition." Such DSM programs would seek to reduce customer's costs and steer load away from expensive peaks toward cheaper off-peak times of use. New interactive computer technologies will allow utilities and other purveyors of information to provide customers with much better data on their use patterns, as well as the ability to effectively use that information to change their consumption patterns and bills.

Second, if electricity becomes a pure commodity, profit margins will be under pressure. Therefore, as long as prices equal or exceed marginal operating costs, power purchaser will wish to maximize the output of their investments. This implies that they may pursue DSM programs that seek to flatten their load mix, through load building, valley filling, and load shifting.

Third, some analysts are predicting an energy marketplace where "super-ESCOs" [Energy Service Companies] compete with each other to offer energy conservation services directly to paying customers rather than through utility subsidized DSM programs.[28]

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[27]James Newcombe, "Energy Efficiency Services: What Role in a Competitive Environment?", Electricity Journal, Nov. 1994, p. 34-35.

[28]James Newcombe, "The Future of Energy Efficiency Sources in a Competitive Environment" E Source Inc., Boulder, Co. May 1994.

While there is widely diverging opinion as to how robust that market will be, there is evidence that some utilities are preparing to compete in that arena. As James Newcombe argues in the November 1994 issue of the *Electricity Journal*:

> The move toward a more competitive electric power industry holds the potential to promote the development of an energy efficiency services industry that is more creative in conceptualizing and packaging services, more robust as a long-term commercial enterprise, and delivers greater customer value at the end of the day than the existing system either allows or encourages.[29]

Yet these three points are not conclusive. For example, for Newcombe's thesis to be correct, one would have to believe that there will be more investment in DSM in a market with lower-priced electricity than in a market with higher prices. If there is so much opportunity for super ESCOs in a lower-priced competitive world, why has their presence been invisible in a subsidized high-priced regulatory world? More generally, DSM investments are a response to market opportunities and incentives; if competition changes those incentives, the level of investment will change. At present, these incentives are supplemented by subsidies paid by ratepayers. If these subsidies are eliminated or their design changed, then all other factors being equal, the scope and magnitude of these investments will be lower.

Some DSM critics believe that in a competitive electricity industry, investment in truly cost-effective DSM would not drop as much as expected, since many participants are currently getting the utility to pay them to do something they would have done anyway. As New England Electric System's CEO, John Rowe, states:

> I think that we all are going to be groping with the question, "Is everyone a

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[29]James Newcombe, "Energy Efficiency Services: What role in a competitive market?", Electricity Journal, November 1994, p. 34-35.

free rider?" with respect to the big utility DSM programs. I cannot conceive of why any industrial customer in Massachusetts or Rhode Island would spend their own money for energy efficiency when they could get a good subsidy from us if they can just get in the front of our line.[30]

While there is no definitive way to quantify how much investment in energy efficiency customers would make if utilities stopped the DSM programs, utility estimates of "free riders" show that for some industrial programs, private demand may be significant. For example, Massachusetts Electric Company (MECO) programs in 1991 saved approximately 225 million KWHs, and fully 33 percent of those savings were considered "free rider" savings -- the customers would have made the investments on their own without utility assistance.[31] Industrial lighting and insulation (building shell) programs had the highest free rider rate, while residential lighting programs generally had the lowest.

All of these arguments may be superseded by the fundamental reality that in a fairly competitive electricity industry, customers will be price sensitive. If electricity rates drop, an increasing number of DSM investments will fail the customer's cost-benefit analysis. To the extent that competition lowers the cost of electricity, consumers will be less interested in saving energy. Thus, it seems likely that deregulating parts of the utility industry during a period of capacity surplus will result in a reduction in market-driven DSM investments. However, when the market tightens and prices rise, the demand for DSM options will increase.

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[30]John Rowe, quoted in "DSM at Mid-Passage" by Kennedy Maize and John McCaughey, Quad Report, Spring 1993, p.5.

[31]Massachusetts Electric Company, "1992 DSM Performance Report," June 1993, Appendix B.

Ratepayer-Funded DSM

Given the opportunity, most customers would prefer not to subsidize someone else's service. That is, it will be very difficult to maintain cross-subsidies both between and within consumer classes. Furthermore, de-coupling mechanisms that protect utility revenue streams from losses due to energy-efficiency improvements are not easily integrated into a market driven world.[32]

Ultimately, policy makers must decide whether government should continue to use the remaining regulated monopoly segments of the industry - distribution and transmission - to pursue such societal goals. If so, then it is possible to design a system in which customers will find it very difficult to avoid whatever costs society wishes to impose. The point is that government has a choice to make. If it ignores that choice and does not explicitly act to retain some version of the existing ratepayer subsidized DSM programs, those programs are likely to disappear in a market-driven structure. The cause of their demise would not be the inevitable incompatibility of subsidized DSM with a restructured industry, but rather society's choosing different priorities.

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[32] In most states with mandated utility DSM programs, the utility is allowed to adjust their rates to compensate for the loss of revenues from energy saved as a result of DSM programs.

SECTION 4

COMPETITION AND RENEWABLES

The promise of renewable energy -- an unlimited supply and a low environmental impact -- has captivated the public's interest for almost two decades. To move from a world of nuclear and fossil fuel power to one of renewables has been a long-range goal of the environmental community. At various times, government policies ranging from tax credits to mandatory purchase requirements have been enacted to stimulated the production and use of renewables. The environmental community believes that greater competition, especially retail competition, might dampen the growth of renewable sources of energy. Is this perception justified?

Expected Growth of Renewables

In 1992, 10.7 percent of U.S. electricity production was supplied by renewables. The majority of this production came from hydropower (8.1 percent), which can be produced at highly favorable costs at appropriate sites. Table 3 shows the amount of electricity produced by renewables in 1992, and the Energy Information Administration's (EIA) projections for 2010.

Table 3: U.S. Electric Generation with Renewables
(billion kWh)

	1992	2000*	Annual Growth	2010*	Annual Growth
Conventional Hydroelectric	247.9	305.7	2.1%	306.6	1.3%
Geothermal	16.7	36.0	10.1%	57.2	7.1%
Municipal Solid Waste	17.2	20.2	2.0%	32.0	4.0%
Biomass/Other Waste	41.7	48.4	1.9%	83.6	13.8%
Solar**	1.8	2.4	3.7%	4.8	5.8%
Wind	2.9	2.9	0%	29.1	13.6%
Total Renewable	328.2	414.9	3.0%	513.3	2.5%
Non-hydro	80.3	109.9	4.0%	206.7	5.4%
Total Generation***	3050.0	3433.0	1.5%	3833.0	1.3%
% Renewable	10.7%	12.1%	—	13.4%	—
% Non-hydro	2.6%	3.2%	—	5.4%	—

Note: Annual growth was calculated using 1992 as the base case.

Source: Energy Information Administration, Annual Energy Outlook 1994, DOE/EIA 0383(94) Washington, D.C., January, 1994, pp. 65 and 73

*These projections depend on assumptions about GDP growth, electricity, demand, the present and future costs of renewable technologies, and fuel prices. In general, the Annual Energy Outlook model presumes continuance of current regulatory practices. For example, prices for electricity are assumed to be regulated at the state level. Some externality cost considerations are included as dictated by state PUCs. Compliance with the Clean Air Act

Amendments of 1990 is assumed. The model does take into account the tax credits for wind, solar, geothermal, and biomass specified in the Energy Policy Act of 1992. In the EIA model, average real electricity prices are expected to increase at approximately 0.6 percent annually from 6.8 to 7.6 cents/KWH between 1992 and 2010.
**Utility-grid-connected generation only.
***Includes utilities and non-utility generators.

Other projections by environmental groups, consultants, and trade associations predict higher levels of growth.[33] These projections usually depend on the implementation of policies to foster the development of renewables, such as intensified government sponsored R&D or large federal taxes on carbon-based fuels. However, the U.S. EIA's forecast is far from pessimistic or conservative. In the 18-year period 1992-2010, electricity generated by non-hydro renewables is forecasted to grow at a rate of 5.4 percent per year. While in its Annual Energy Outlook, 1994, EIA projects that total U.S. electric generation will grow from 2,798 billion KWH in 1992 to 3,260 billion KWH in 2010, which is only a 0.9% annual growth rate.[34]

Economic Costs

Past, present, and future costs of producing electricity using renewable technologies are estimated in Tables 4 and 5.

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[33]Keith L. Kozloff and Roger C. Dower, A New Power Base: Renewable Energy Policies for the Nineties and Beyond (World Resources Institute, 1993), pp. 15-17 and The Union of Concerned Scientists (UCS), "Climate Stabilization Case" presented in EIA's, "Renewable Resources in the US Electricity Supply" DOE/EIZ-0561(93) Washington, D.C., February 1993), (pp. 18-20.) Total renewables generation is forecasted at 695 billion KWH in this case which assumes greater steps are taken to limit CO2 emissions.

[34] DOE/EIA, Annual Energy Outlook 1994. Reference Case Projections, p. 65.

TABLE 4: Total Renewable Generation Costs
(cents/KWH, constant dollars)

	Early 1980s	1993	Projected (1995-2000)	EPRI Targets (2005-2010)
Hydroelectric (new and upgrades)	1-6	1-6	1-6	N.A.
Geothermal (High-Temp Hydro)	7	5-7	4.7-7	6
Biomass (Landfill Gas)	N.A.	5.5-7	5.5-7	N.A.
Solar Electric (Photovoltaics)	150	15-40	6-20	8
Solar Electric (Solar Thermal)	14.2-24 (including prototypes)	8-10	8	6
Wind	25	5-9	4-5	4

Sources: Jan Hamrin and Nancy Rader, *Investing in the Future: A Regulator's Guide to Renewables*, (Washington, D.C., National Association of Regulatory Utility Commissioners. 1993), p. 18. Cost figures are drawn from a variety of sources and should be viewed as rough estimates only. Calculations use traditional methods developed for fuel-based technologies combining capital and operating costs using an appropriate capacity factor.

Electric Power Research Institute, *Research, Development & Delivery Plan: 1994-1998* (January, 1994). Values are estimates for commercial costs of electricity production as established in EPRI's ongoing research and development plans. (While large hydropower facilities have historically proven economical, the costs of other form of renewables have been prohibitive for large-scale development. In recent years, however, the costs of wind and geothermal power have decreased. Nonetheless, as Table 5 shows, renewables typically cannot compete on a strict levelized cost per kilowatt hour basis.

TABLE 5: Levelized Electricity Costs
(cents/KWH, constant dollars)

	1992	2010
Combined Cycle Natural Gas	4.3	5.6
Coal (Steam Electric)	4.2	4.8
Wind, Biomass Solar	5.1	5.5

Source: EIA, Annual Energy Outlook 1994, p. 38-45.

The most significant factor affecting the expansion of the use of renewable technologies is the future costs of fossil fuels. As fossil fuel generation costs rise, renewables become a more attractive investment. Those who believe that oil will cost $40 per barrel and gas $4.00 per mcf can confidently forecast much higher penetration rates for renewables. Conversely, as fossil fuel prices drop, renewables become less attractive.

Some forms of renewables are already practical in remote areas. For example, renewable resources that do not need to be attached to a grid, such as biomass fueled gasifiers and solar technologies, can be built in modules and located in remote areas. Renewable technologies may also make measurable in-roads into the self-generation market. The modularity of renewables technologies, such as wind, can provide an advantage to customers with smaller loads seeking to self-generate. Finally, some consumers may be willing to voluntarily pay more for power generated by "green" technologies than by technologies perceived as being less environmentally friendly, although at this writing, "green-pricing" schemes have had limited success.[35]

[35] The Public Service of Colorado surveyed its customers about their willingness to pay a 2.8 percent premium on their monthly electric bills for "green" power. Eighty-two percent responded positively, but in the two years since the program went into effect only 1 percent have signed on to pay a monthly $1.78 surcharge to support power generated by more environmentally sound technologies.

Existing Investment Incentives

Over the past two decades, the federal government has periodically enacted programs and policies to encourage the development of renewables. Billions of federal R&D money has been targeted at renewables, and generous investment tax credits has been enacted. Federal support has ebbed and flowed over this 20-year period, contributing to a boom and bust cycle of investment, but some industries such as wind, photovoltaics and geothermal have certainly benefitted. The Public Utilities Regulatory Policies Act (PURPA) of 1978, the Energy Policy Act of 1992 (EPAct), and state Integrated Resource Planning mechanisms (IRP) have all attempted to spur the use of renewables. Such policies have been justified, partly by their potential to realize environmental benefits and partly by a concern that the United States should reduce its dependence on fossil fuels to improve its energy security.

- PURPA

PURPA encourages non-utility developers to invest in renewable generation options by exempting "qualifying facilities" from utility regulation, while requiring utilities to purchase their output at full avoided cost. To qualify, facilities must meet federal guidelines on size, ownership, and other factors.

The effects of PURPA have varied, depending on the specific policies adopted by individual states. In general, more investment in renewables occurred in states where regulation gave developers high avoided-cost rates and predictable revenue streams. This was particularly true in the early to mid-1980s when projections of avoided cost were quite high. For example, California leads all states in hydro, geothermal, biomass, solar and wind generating capacity. The majority of these facilities benefitted from Interim Standard Offer #4 (ISO4) Contracts, which were available from 1983 to 1985. ISO4 fixed energy and capacity payments for non fossil fuel projects at very favorable rates for the first 10 years of operation.[36] Other important factors included the adoption of standard contracts with the terms and conditions for sales to utilities clearly spelled out; payments for the value of increased system reliability through the availability of additional generating capacity even when no electricity is produced; and no limitations on non dispatchable or low-capacity facilities. The latter provision was important because solar and wind generators produce power intermittently, depending on the weather.

In the 1980s, biomass and municipal solid waste (MSW) facilities received the bulk of the electrical renewable investment. From 1980 to 1989, more than 17,000 MW of renewable capacity qualified under PURPA, including 7,618 MW of biofuels and waste; 3,578 MW of small hydro; 2,460 MW of geothermal energy; and 2,226 MW of wind power.[37] Applications for qualifying facility status peaked in 1985 and 1986 and then declined markedly due to lower calculations of avoided cost.

- **Energy Policy Act of 1992 (EPAct)**

The EPAct establishes a 10 percent investment tax credit for solar and geothermal projects and a 1.5 cent per KWH production tax credit or payment for electricity produced by wind or closed-loop biomass facilities brought on line before July 1, 1999. (A closed-loop facility is supplied by a dedicated farm or plantation that provides the facility with rapid growth feedstocks.) Facilities can earn this credit for their first 10 years of production.

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[36]In the past, fixed energy payments were as high as 12-15 cents per KWH, see Independent Power Report, July 14, 1995.

[37]Kozloff and Dower, A New Power Base, 1993, p.76. Some of this capacity was never built.

- **Integrated Resource Planning**

By explicitly requiring utilities to consider the environmental and resource diversity benefits of renewables, IRP processes foster renewables. For example, one survey showed that 24 state PUCs have adopted qualitative or quantitative rules directing that environmental externalities be considered in their IRP processes.[38] In another survey, 15 states indicated that renewables are specifically encouraged in their planning process.[39] In contrast, 18 states were described as either having IRP process that were undeveloped or as lacking such processes altogether. New York and California took this requirement still further by ordering utilities to set aside a portion of their purchased capacity for renewable resources.[40]

<u>The Effect of Deregulation on Policies Important to Renewables.</u>

To understand the effect of deregulation on the renewables industry, one must first consider the fate of existing policies that support renewables. For example, the subsidies of EPAct will certainly remain in a deregulated marketplace. There is also no reason to suppose that state policies utilizing the tax code or general funds (such as state-funded renewables subsidies) would change. For example, state tax exemptions to renewables developers may be unaffected, but a PUC regulation requiring utilities to purchase a preset quantity of renewable capacity may not.

Utilities most likely will not be required to purchase power from "Qualifying

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[38]Jan Hamrin and Nancy Rader, "Investing in the Future: A Regulators Guide to Renewables" (February 1993).

[39]Blair Swezey and Karen Sinclair, "Status Report on Renewable Energy in the States" (National Renewable Energy Laboratory, December 1992.)

[40]Blair Swezey, "The Impact of Competitive Bidding on the Market Prospect for renewables; Electric Technologies" (National Renewable Energy Lab; September 1993) p. 462.

Facilities" (as mandated by PURPA). Prices paid to renewables generators are likely to be less than those paid to qualifying facilities under PURPA and may be reduced still further if competition drives down wholesale prices.

Renewables R&D

Proponents of renewables have expressed the fear that research and development on renewable energy systems will be drastically reduced if the utility industry becomes more competitive. Market-driven R&D decisions will undervalue the benefits of renewables, since the social benefits -- the "spill-over" of new technology to the electric industry and its customers -- outweigh the benefits to any individual company. Without some government intervention, these societal benefits might be ignored.

This issue touches on the essential conundrum facing those who seek to stimulate greater investments in renewables: how to maintain support for government intervention in an economic and political context characterized by functioning markets for energy, minimal public concerns for energy security, and relatively low energy prices.

While the implementation mechanics might be different, regulators can use the same mechanisms for renewables as for demand-side management. Access fees on the remaining regulated monopoly transmission and distribution system could be used to collect revenue. A portion of that revenue could be used to subsidize research and demonstrate new and improved technologies. If the public is unconvinced that the benefits from such subsidies are worth the cost, then such mechanisms will either not be established or the revenue collected will be allocated for other purposes. Obviously the public's reaction is dynamic; as energy security or the need for stricter environmental standards become more politically prominent, the public's support for intervention will increase. If the reverse occurs, public support will decline further.

But if regulators choose not to subsidize renewables, will this reduce the rate at which renewables develop? Certainly the loss of $200-350 million per year in government subsidies would reduce investments in renewables R&D. But as mentioned earlier, investors will no longer be protected from environmental regulatory risks. Therefore, some investors will find renewables a useful hedge against future upward pressure on fossil fuel.

The most significant factor, however, is that investors in renewables have grown very skeptical about the consistency of government support. Today's incentives may be removed tomorrow, and bankers are usually unsympathetic to the excuse that "government reneged on the subsidy." As a result, investors insist that renewables be cost competitive. Wind energy, for example, is competitive in some areas and may do quite well in a competitive market. Some renewable technologies may eventually become price-competitive and be successful in the marketplace. For other technologies, government subsidies are unlikely to be sufficient to create a robust market for either customers or investors.

There has been much less commercialization of renewables than one would have been led to expect by the number of government programs and policies enacted since the 1973 oil embargo. Ignoring large-scale hydro, grid-connected renewable electric capacity is less than 3 percent of total U.S. electric generating capacity.[41] A competitive electric utility industry is likely to hold renewable electric generating alternatives to the same test that the old integrated regulatory regime demanded of them – that they be cost-competitive. The debate over restructuring has often confused the possible impact of reduced public interest in government intervention on behalf of renewables and the possible impact of a more competitive industry on the rate of commercialization of renewables options. The former could have serious implications, especially in the area of R&D, but the latter by itself is not likely to dramatically change the economic thresholds that renewable technologies must meet to be accepted in the marketplace.

[41] Murray Silverman and Susan Worthman: "The Future of Renewable Energy Industries," Electricity Journal, March 1995, p.12.

SECTION 5:

ENVIRONMENTAL IMPACTS OF REDUCED DSM AND RENEWABLE INVESTMENTS

Environmental organizations have fought to increase utility investments in DSM and renewables in the belief that such investments improve the environment. After all, generating plants that are never built do not pollute, and fossil fuels not burned are no danger to public health.

Electric utility plants are major consumers of fossil fuels and contribute 72 percent of the nation's SO_2 emissions, 36 percent of the CO_2 emissions, and 33 percent of the NOx emissions; utilities have a greater impact on air emissions than almost any other industrial source.[42] Large generating facilities can use several million gallons of water a day for cooling and steam, and leave a footprint of 10-100 acres. It should be no surprise, therefore, that environmental proponents have focused considerable attention on this industry and the regulatory processes that govern it.

This section assesses the effectiveness of existing and proposed DSM and renewable investments in reducing SO_2, NO_x, CO_2 and the impacts on future reductions, if restructuring causes drastic reductions in DSM and renewable investments. That is, if regulators are unable or unwilling to continue ratepayer subsidies for DSM and renewables and investors take their money elsewhere, what is the potential impact on air emissions?

It is important to remember that DSM programs produce social benefits beyond avoiding environmental damages. For example, by reducing the need to invest in new capacity or purchase additional fuel, DSM programs can keep consumer bills lower than

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[42]The SO_2 and NO_x percentages were obtained from: U.S. E.P.A. National Air Pollutant Emission Trends 1990-1993. (Research Triangle Park, E.P.A. 454/R94-32, October 1994) p. 2-32 and 2-30. The CO_2 percentage was calculated using numbers obtained from DOE/EIA, Emissions of Greenhouse Gases in the United States 1987-1994, (DOE/EIA - 0578, October 1995) p. 12.

they would be otherwise. The Conservation Law Foundation estimates that in New England alone, DSM has saved consumers $280 million annually.[43] DSM also provides energy security benefits, since decreases in electricity consumption contribute to lower reliance on fossil fuels and all else being equal, less demand for oil imports. This benefit is smaller today than 15 years ago, as electricity generators have substantially reduced their use of oil.[44] Renewables provide some of the same societal benefits as DSM. They reduce fossil fuel consumption, pollute less and provide energy security benefits.

In sum, both DSM and renewables are a means to achieve certain societal goals -- a cleaner environment, greater energy security, and lower prices by avoidance of fuel and capacity costs. It is important to focus on these ends and not be diverted by the means.

This paper discusses environmental benefits only. Further, air pollution is our sole measure of environmental benefits - both because it is easiest to measure and because there is a general consensus that it has the greatest environmental impact. Specifically, the paper focuses on two conventional pollutants -- SO_2 and NO_x -- and one unconventional CO_2. As the principal contributor to atmospheric greenhouse gas concentrations, CO_2 reductions have been the primary means of responding to the threat of global climate change.

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[43] Personal communication with Armond Cohen, Senior Attorney, Conservation Law Foundation; January 23, 1995.

[44] According to the EIA Electric Power Annual 1993, p. 41, oil fired generation has decreased, 39 percent from 1989 to 1993. Oil generation is projected to drop another 37% by the year 2010, falling from a 4% share to a 2% share of total electricity generation during the projected period (EIA Annual Energy Outlook 1994, p. 25).

Sulfur Dioxide (SO_2)

SO_2 is a byproduct of the combustion of fossil fuels. It is a known health hazard, and the major contributor to acid deposition. In 1990, Congress passed the Clear Air Act Amendments which called for a 10 million ton annual reduction in SO_2 emissions by 2000. It imposed an emission cap of 8.9 million tons, but allowed emitters to trade allowances which are equivalent to permits to pollute. This latter provision gave polluters the opportunity to buy allowances, if the cost of further abatement exceeds the cost of the allowances. Under no circumstances can the total number of allowances in existence at any time exceed the cap.

The economics of emission trading is such that there exists little incentive to reduce emission levels below the cap. Therefore, any SO_2 reductions lost because of reductions in DSM and renewable investments must be made up elsewhere by the year 2000. Theoretically, it is possible that the total elimination of renewables and DSM investments would have no impact on SO_2 emissions in 2000. However, a decrease in DSM and renewable investments might force emitters to either invest in more costly abatement options or purchase allowances - thus increasing the demand for such allowances and consequently their price.

In 1997, the U.S. EPA is scheduled to promulgate new standards for small airborne particles. It is likely that the agency will focus on sulfates - small particles derived from SO_2 emissions. If the agency's new standards are stricter, reductions beyond 8.9 million tons might be necessary which will mean fewer allowances and still higher abatement costs. SO_2 is included in this section to place into perspective the effectiveness of DSM and renewables in reducing SO_2 emissions.

Nitrous Oxide (NO_x)

NO_x is a principal contributor to the atmospheric ozone problem that plagues some of our cities in the summer (and Los Angeles, year round) and is a contributor to acid rain.

The Clean Air Act established emission standards for NO_x which vary depending on the type of fuel burned, the combustion equipment used, and the date at which the plant was permitted. The 1990 Clean Air Amendments require additional annual reductions of 2 million tons by 2000. In 1993 and 1994, states filed implementation plans to meet this new target. Some of these plans allowed for emissions trading within a specific region, such as the Ozone Transport Commission, which is comprised of the Northeast and Mid-Atlantic states.

There is a concern that deregulation of generation might spur utilities in the midwest to increase their use of dirtier coal plants and thus increase NO_x emissions. Since the prevailing winds are west to east, these emissions might increase the smog and acid rain problems in the Northeast.

Carbon Dioxide (CO_2)

CO_2 is likely to be the most controversial of the three pollutants analyzed in this report. There are no Congressionally mandated emission reduction targets. President Clinton's Global Climate Change Action Plan (CCAP) sets voluntary goals;[45] any attempts to make them mandatory would trigger substantial political controversy. There is no consensus on the appropriate magnitude and timing of CO_2 reductions.

To provide a context to compare the impact of DSM and renewables on SO_2, NO_x, and CO_2 emissions, we measure their abatement potential against existing U.S. emission reduction goals; the Clean Air Act Amendments of 1990 are used as the benchmark for SO_2 and NO_x emission reductions. CO_2 reductions are measured against the goals set by the CCAP.

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[45] The Climate Change Action Plan consists of a series of government supply-side and demand-side initiatives that coordinate industry and government efforts to stabilize greenhouse gas emissions at 1990 levels by the year 2000.

IMPACT OF A REDUCTION IN DSM

To calculate the effects of reductions in DSM investments, we must make three assumptions. First, we must estimate a base case from which the reductions will be subtracted. In its Electric Power Annual 1993, the Energy Information Administration projected that utilities will save 90.075 billion kWh by 1997.[46] While these projections may prove to be overly optimistic, they are the most up-to-date official government numbers.

Second, we must make assumptions about which fossil fuels are displaced by the DSM investment. In 1995, most of the nation enjoyed a surplus of generating capacity, therefore, electricity savings resulted in less use of existing capacity, as opposed to avoiding the construction of new facilities. Since existing facilities are dispatched on a least-cost basis, the power displaced is likely to be produced from non-baseload units. In later years, this situation could change, and the system could be capacity short. In such a case, DSM investment would displace investment in new capacity, but much of this new capacity would consist of cleaner and more efficient dispatchable facilities.

Therefore, for our base case we assume that the generation displaced by DSM would be 33 percent coal and 67 percent natural gas and oil. In 1993, DSM reduced electricity demand by 1.4 percent or 44,349 million KWH. Table 6 shows the resulting reductions in SO_2, NO_x, and CO_2.

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[46]. DOE/EIA, Electric Power Annual 1993, (U.S. Government Printing Office, Washington, D.C.), p.113.

TABLE 6: 1993 Avoided Emissions from DSM

	Savings (tons)	Percent of CAAA/CCAP reduction goal
SO_2	172,100	1.7
NO_x	93,625	4.7
CO_2	34,407,274	12.3

If you measured against national emission reduction targets, the SO_2 and NO_x reductions are 1.7 percent and 4.7 percent of those targets respectively and the CO_2 reductions are 12.3 percent of the stabilization goal.

To measure the possible effect of reduced DSM investment resulting from greater competition within the industry, two hypothetical "reduction scenarios": a 40 percent reduction and a 70 percent reduction. The latter is based on the assumption that the free rider estimates contained in evaluations of existing utility DSM programs are a good proxy of the floor below which DSM investments are unlikely to fall.[47] The 40 percent figure was chosen arbitrarily but represents a level of reduction that is both substantial and possible.

[47] For example, Massachusetts Electric Co. calculated that 33 percent of the participants in its DSM programs would have made the same investments without a subsidy (Massachusetts Electric Co., 1992 DSM Performance Report, Westboro, MA, June 1993), Appendix B.

TABLE 7: Impact of Decreases in Projected DSM Growth

	Current Projections for 1997	Projection with 40 Percent Reduction	Projection with 70 Percent Reduction
Electricity Savings (million kWh)	90,075	71,785	58,067
SO_2 avoided (tons)	349,547	278,569	225,334
NO_x avoided (tons)	190,158	151,545	122,585
CO_2 avoided (tons)	69,883,105	55,693,030	45,050,152

These cases assume a 1993 base line of 44,349 million kWhs. Predicted growth in DSM savings is reduced by 40 percent and 70 percent.

Table 7 shows that if DSM growth is reduced by 70 percent, SO_2, NO_x, and CO_2 emission reductions from DSM investments would be 35 percent less than current projections. Under the 40 percent reduction scenario, the reductions would be 20 percent lower.

Table 8 shows the effect of these "lost DSM savings", on the present national emissions targets -- 10 million tons for SO_2, 2 million tons for NO_x and CO_2 emissions stabilized in the year 2000 at 1990 levels -- a reduction of 278.92 million tons from projected emissions.[48]

[48] The Clean Air Act Amendments set a ceiling level for SO_2 emissions in the year 2000. Therefore, the 70,978 tons figure would have to be offset with an equal reduction somewhere else. Since utilities are the major source of SO_2, it is reasonable to predict that the offset would come in the form of other types of pollution abatement investments -- some of which may be less cost-effective.

TABLE 8: Emissions Savings Lost as Result of 40 percent Reduction in DSM Investment in 1997

	40% reduction in growth	% of environmental goal lost
Lost energy savings (GWh)	18,290	
Unachieved SO_2 savings (tons)	70,978	0.7% of CAAA reductions
Unachieved NO_x savings	38,613	1.9% of CAAA reductions
Unachieved CO_2 savings	14,190,075	5.1% of CCAP goal

Table 8 suggests that the fate of DSM programs will not have a substantial effect on the nation's ability to meet its SO_2 and NO_x reduction targets. The effect on CO_2 emissions is greater. A 40 percent reduction in DSM savings results in increased CO_2 emissions equal to 5 percent of the Climate Change goals. This figure is not trivial.

These results are further supported by comparing the effect of DSM investments to the effect of a similar level of investment in repowering old coal burning facilities with natural gas.

In 1993, utilities invested $2.77 billion in DSM programs and reported savings of 44.3 GWHs. What if this money had been invested in repowering older coal facilities with natural gas? Based on recent capital cost figures for coal to gas repowering projects, $2.77 billion buys 4,396 MW of repowered capacity. The avoided emissions from closing the coal facilities plus the emissions from new gas units can be compared with emissions reductions realized by DSM programs. We assume DSM backs out 33 percent coal generation and 67 percent oil and gas generation. (See Appendix A and B for details of the methodology and the assumptions.)

TABLE 9: Comparison of Emission Savings: DSM vs. Repowering
(tons)

	DSM	Repowering
Avoided SO_2	210,971	409,930
Avoided NO_x	95,650	156,281
Avoided CO_2	32,492,068	15,175,773

The results in Table 9 show that similar, if not greater, environmental benefits can be reaped from repowering. The one exception would be CO_2 emission, where DSM has a much greater impact. Additionally, the economic benefits of repowering may look more attractive to investors than DSM.

Conclusion

While DSM has probably contributed to emission reductions, the reductions have been small, especially in terms of their impact in meeting national emission reduction goals. In many cases, programs such as emission caps or investments such as repowering, will reduce NO_x emissions and SO_2 emissions more effectively than DSM. CO_2 emission reductions are an exception, where DSM investments remain one of the more effective options available.

IMPACT OF CHANGES IN RENEWABLES

To determine the impact of a reduction in the growth of renewable investments, a baseline must be assumed, and growth predictions calculated from that baseline. The focus of this analysis is *additional renewable generation that displaces conventional electricity production*. The emission benefits derived from these sources are applied toward the CAAA and CCAP emissions reductions goals. Although each additional unit of renewable generation creates benefits in terms of avoided emissions, renewable generation that satisfies growth in electricity demand simply holds emission levels constant -- it does not actually reduce-pollution.

The baseline for the growth cases is derived from EIA's 1992 reference case for nonhydro renewables -- 80,300 million kWh.[49] Renewable generation from conventional hydropower was not considered in this analysis because most of the emphasis in the future will be on alternatives other than large and moderate scale hydro dams. The baseline case assumed EIA's prediction of 5.4 percent annual growth in nonhydro renewables. (In Appendix C, we analyze a second higher renewable growth scenario for sensitivity purposes.) The Department of Energy projects that nonhydro renewables will generate an additional 126,400 million kWh in the year 2010.

Resulting pollution benefits depend on assumptions about what this additional "emission-free" generation displaces.[50] This analysis assumes 50 percent of nonhydro renewable growth meets *new* demands, thereby avoiding the construction of new generation using conventional fuels. For modeling purposes, we assumed that 50 percent of the construction avoided would be from clean coal plants and 50 percent from combined cycle gas facilities. The remaining 50 percent of renewable growth supplants existing coal generation. Results are summarized in Table 10. (For calculations and emissions factors, see Appendix C.)

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[49]EIA/DOE, Annual Energy Outlook 1994, p. 73.

[50]To facilitate this analysis, emissions from renewable electric generation are assumed to be zero.

Table 10: Total Emissions Saved from Nonhydro Renewable Growth

	Year 2000		Year 2010	
	Volume (tons)	% of U.S. Reduction Targets	Volume (tons)	% of U.S. Reduction Targets
SO2	165,908	1.7%	708,472	7.1%
NOx	68,450	3.4%	292,300	14.6%
CO2	25,858,116	9.3%	110,421,144	39.6%

These numbers are relatively small. Renewable investments will play an insignificant role in meeting SO_2 and NO_x standards in the year 2000. The CO_2 numbers are higher, but most of the emission reductions foregone occur after the year 2000.

The second part of this analysis projects the effects of gains and losses in projected nonhydro renewable growth. Because the future of renewables investments in a competitive electricity is uncertain, three possible scenarios were considered to bound the analysis: a 10 percent gain, a 20 percent loss, and a 40 percent loss. These scenarios represent *changes in nonhydro renewable growth*. The 10 percent gain represents the possibility that nonhydro renewables will become more cost-competitive, while the 40 percent decrease predicts that higher costs of nonhydro renewables (compared to conventional generation sources) will deter some, but not all, nonhydro renewable growth. Growth assumptions are taken from the baseline above (5.4 percent annual growth), from which the three scenarios are then calculated. The results are summarized in Table 11. (Again, for calculations, see Appendix C.)

TABLE 11: Changes in Emissions Due to Increased/Decreased Growth of Nonhydro Renewables in Competition
(tons)

2000

Change in Emissions	10% gain	20% loss	40% loss
SO2	-16,591	+33,182	+66,363
NOx	-3,845	+13,690	+27,380
CO2	-2,585,812	+5,171,623	+10,343,246

2010

Change in Emissions	10% gain	20% loss	40% loss
SO2	-70,847	+141,694	+283,389
NOx	-29,230	+58,460	+116,920
CO2	-11,042,114	+22,084,229	+44,168,458

The SO_2 emissions lost by the year 2000 would be infinitesimal and only 2.9 percent of the CAAA goal in the year 2010. The NO_x numbers are slightly higher, but still low, 1.4 percent by the year 2000 and 5.8 percent by the year 2010. CO_2 emission reductions are lower by 3.7 percent in 2000 and 15.8 percent in 2010.

Conclusion

Emission reductions from renewable investments are small and are much lower than those from changing the utilization of existing coal and nuclear facilities. Further, most of the emission reductions occur after the year 2000. In the assumed scenarios, changing renewable investment patterns will not have a significant impact on efforts to meet CAAA and CCAP year 2000 targets, but will have a non-trivial effect in the first decade of the next century.

SECTION 6

ENVIRONMENTAL IMPACTS OF CHANGES IN FACILITY UTILIZATION AND DEMAND GROWTH PATTERNS

The early debate over the environmental effects of restructuring has focused on DSM and renewables, but other changes may have as substantial an impact or greater. For example, competition may affect the choice of fuels used in power generation, how much individual plants are used, the timing of plant retirements and the rate of growth in the demand for additional electricity.

If older and more polluting coal plants have lower operating costs than cleaner natural gas-fueled plants, competitive pressures will push utilities to run their dirtier plants more and their less polluting, but more expensive plants less. This would increase CO_2 and SO_2 emissions.[51] The most dramatic and significant impact, however, would be a substantial increase in NO_x emissions that would impact downwind states.

The retirement of nuclear facilities, which emit almost no air pollution, may be accelerated, necessitating greater use of existing fossil fueled plants. This scenario would substantially increase NO_x and CO_2 emissions.

If competition pushes electricity prices down, demand for energy will rise more rapidly. With all other factors unchanged, increases in electricity demand will result in the burning of more fossil fuels and consequently more pollution. This effect does not seem to be as large as others examined in this paper, but is worthy of attention.

Finally, competition could push generators to improve the efficiency of their equipment. A measure of efficiency for electricity generators is the heat rate; the lower the rate, the more electricity a plant can produce for a given amount of fuel. The less fuel burned, the lower the emissions. In this instance, competition could benefit the

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[51] SO_2 increases would be short-lived because of the emissions cap that will go into effect in the year 2000.

environment by stimulating the construction of efficient facilities.

Retail competition and further restructuring will not trigger these changes. They are already emerging in those regions that have established a competitive market for new capacity. To the extent that restructuring expands the dimensions and scope of wholesale competition, these changes will become larger and more visible.

Predicting the Future: Six factors that matter

Changes in fuel utilization will have at least as large an effect on air emissions as any other factor discussed in this report. This is especially true of CO_2 and NO_x emissions; any substitution of coal for gas will increase emissions. On the other hand, efficiency improvement could measurably *reduce* emissions. Unfortunately, it is not clear how competition is likely to affect fuel utilization and the emergence of more efficient generating technologies. To varying degrees, six factors will influence the rate at which fuel use changes and efficiency improvements occur in a restructured electric utility industry. While some factors, such as fuel price expectations, are exogenous to the rapid changes taking place in the industry, other factors, such as the timing of deregulation are tied directly to the specifics of regulatory reforms.

1. Timing

If the transition to a more competitive structure is rapid, the restructured industry will need to contend with the existing surplus of generating capacity. To the extent that a significant portion of this surplus consisted of older, dirtier facilities, competition could increase emissions, especially through the year 2000.

2. Future Fuel Price Expectations: Impact on Operation of Existing Plants

Fuel prices account for a substantial portion of a generating plant's operation and maintenance costs. Furthermore, most utility grids operate on a least-cost dispatching schedule; that is, the grid operator dispatches plants in a sequence, beginning with the facility with the lowest operating cost first, and moving up the cost curve until all of the demand is met. As relative fuel prices change, the dispatching sequence will also change, and with it the level of emissions. Historically, predicting future prices for coal, gas and oil has proven difficult; one can only conclude that if the move to competition continues to coincide with decreases in natural gas prices relative to coal prices, air emissions will decrease accordingly.

3. Fuel Price Expectations: Impact on Investment in New Plants

Investors in new generating facilities are influenced by their perception of fuel price trends, especially their forecast of future fuel price volatility. Despite the fact that natural gas was trumpeted by the Bush Administration and the environmental community as the fuel of choice, new coal generating capacity grew more in 1988-1991 than new natural gas capacity. Coal's success stemmed from its low cost in many areas of the United States and its comparatively low price volatility. This trend was reversed in the period 1992-1994 as gas generating technologies improved and gas prices, while still volatile, dropped.[52] How perceptions about price reliability evolve in a more competitive market could have a significant impact on the choices of fuels used, the types of investments made, and consequently, on the level of air emissions.

4. Technology Advances

In the short run, technological developments will not measurably affect air emissions; the present capacity surplus will be used to meet any growth in demand. However, at some

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[52]From 1988-1991, net added coal capacity was 6,332 MW net gas additions totaled 2,412 MW. From 1992-1994, however, net coal additions dropped to 784 MW, while gas increased to 3,489 MW. (numbers were calculated using EIA/DOE's Electric Power Annual from 1988-1994)

point new capacity will be needed. Will the technology of the first decade of the next century be a series of 250 MW facilities feeding into a large pool, or will it consist of much smaller generating plants, either connected to a particular manufacturing facility or to a group of consumers, serving as a mini-load center? Will technological advances in the next 10 years favor coal, gas, or renewables? The only point of consensus is that should the trend in generation efficiency improvements continue, newer generations of plants will prove to be substantially less polluting than their predecessors, not only for SO_2 and NO_x, but also for CO_2.

5. The Clean Air Act Amendments of 1990

The Clean Air Act Amendments of 1990 represents the most far-reaching pollution abatement program in U.S. history, and will substantially affect the electric utility industry and its use of fossil fuels. While the carbon reduction goals in President Clinton's Climate Change Action Plan will contribute substantially to reductions in CO_2 emissions, utilities will also be thinking about greenhouse gas reduction goals as they develop their strategies for meeting their SO_2 and NO_x reduction targets. To date, some of these solutions have been both complex and creative. For example, Niagara Mohawk, a utility in upstate New York, agreed to reduce its CO_2 emissions by 1.75 million tons and transfer credit for this reduction to Arizona Public Service Company, which has agreed to transfer 25,000 tons of SO_2 allowances to Niagara Mohawk.[53] Regardless of ongoing changes in the structure of the industry, the Clean Air Act Amendments will continue to have a significant influence on utilities' fuel choices and generation decisions.

A6. The Scope of Deregulation

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[53]For more details, see Peter Passell, "For Utilities, New Clean-Air Plan," The New York Times, (November 18, 1994), D1.

Some states have indicated that they intend to move as quickly as possible to a system of retail competition. Others have introduced proceedings to assess whether to follow suit, while still others have expressed little or no interest in changing the regulatory status-quo. There are many points between the present cost-of-service regime, and open retail competition; where each state will end up is unclear.

The range of uncertainty around each of these six factors is large. One person's assumptions will differ substantially from that of another. Many models will be built to address these factors, but the answers these models provide will be driven by the assumptions about these factors.

Rather than attempt to forecast the use of fossil fuels and future dispatching sequences, in this section of the paper we will explore four possible effects of deregulation: changes in the operation of existing facilities; the accelerated retirement of nuclear capacity; potential increases in the rate of demand growth; and efficiency improvements in new generating plants.

Plant Utilization Changes and Air Emissions

The environmental community has become increasingly concerned about the potential for utilities to increase the use of older, dirtier, coal facilities. Many of these plants have average operating costs of 2.3 cents per KWH or better.[54] In a competitive world, the owners of less expensive plants will have an incentive to extend the life of those facilities and avoid building newer, cleaner facilities. As a result, utilization rates will increase and with them air emissions. Further, older coal plants have not been required to meet the stringent emission standards required of new facilities. The new SO_2 emissions cap will force many of these facilities to drastically reduce their SO_2 emissions by 2000, but for most regions of the country, there are not analogous caps for NO_x. Finally, there is no

[54] EIA: Electric Power Annual 1993, P. 65.

legally enforceable program to reduce CO_2, and coal facilities are major emitters of this gas.

The Effect on NO_x and CO_2 Emissions of Increased Utilization

What if many coal-burning facilities were able to increase their capacity factor from an average of 64 percent in 1992 to an average of 67 percent by the year 2000 -- a relatively modest increase?[55] Let us assume that this increase in capacity use backs out existing oil and gas facilities (33 percent) and newer cleaner coal facilities (33 percent). The remaining capacity increase is targeted towards meeting the demand from new markets and new customers. (See Appendix D for assumptions and calculations.)

TABLE 12: Effect of a Three Percent Increase in the Use of Coal Generating Facilities (tons)

Capacity Factor Change	SO_2 Emissions Increase	NO_x Emissions Increase	CO_2 Emissions Increase
64-67 percent	1,112,722	492,316	42,928,562
Percent of U.S. Emission Reduction Goal	11.1	24.6	15.4

The results shown in Table 12 show a dramatic increase in NO_x emissions. The NO_x numbers are ten times larger than the year 2000 emission increases in our DSM and renewables scenarios in Section 5. If we assume an increase to 70 percent in average utilization rates, NO_x emission increases would double again.

Obviously these are very crude numbers. To obtain a more accurate measure of the problem, analysts will need to undertake a region by region assessment of coal capacity

[55]Net capacity factors for coal generating stations for the period 1990-1994 was lower, averaging 60.27 percent for the five year period. (See North American Electric Reliability Council, Generating Unit Statistics, 1990-1994, Princeton, N.J., June 1995.)

utilization rates, technical production constraints, plant by plant emission factors, transmission capacity, and regional price forecasts.

Assuming that EPA will enforce the two million ton reduction for NO_x called for in the Clean Air Act Amendments, the implications of such increases would be the need to pursue greater and more costly emission reductions in downwind states. That is, NO_x increases in an upwind region may require greater and more expensive controls in downwind regions to meet tropospheric ozone (smog) standards.

The CO_2 numbers in Table 12 are approximately equal to a 60 percent reduction in the projected growth in DSM investments. Such an increase will have a dramatic impact on the U.S.'s ability to meet its Climate Change Action Plan goals. In fact, adding this 43 million tons of additional CO_2 emission increases to our previous estimates of CO_2 increases from losses from reduced DSM and renewable investments would bring the potential increases resulting from restructuring to over 30 percent of the U.S.'s CO_2 reduction target.

The Likelihood Coal Plant Utilization Rate Will Increase

The emission increases resulting from even small changes in utilization rates are large. What is the probability that these rates will increase? The answer will probably depend heavily on the time frame. In the medium term, 2 - 12 years, the probability is large. In the short term, technical and transmission constraints may limit increases in plant use. In the long term, the answer may be more environmentally encouraging as newer, cleaner generating equipment replaces the existing stock.

Medium Term

Any comparison between the marginal cost of increasing the operation of an older depreciated facility and the cost of building a new one will, in most cases, favor the former. The fewer new facilities that are built, the more demand growth will be met by increasing the output from existing facilities, hence greater use of those facilities. Since 56 percent of the existing electricity capacity in the United States burns coal, it is reasonable to expect that the life of many of the older, dirtier plants will be extended for as long as possible.[56]

Short Term

Several utility companies and several environmental groups have argued that restructuring will not only increase the incentive to extend the life of existing coal plants, but will also create an incentive to flood high-cost markets with cheap coal-generated electricity. This scenario suggests that coal plants in the Midwest will increase production and sell excess power to markets in the Mid-Atlantic and Northeast where industrial rates are much higher.

Is this scenario likely to happen? The precise answer to this question demands a region-specific modeling effort that is beyond the scope of this study. Proponents of this scenario, however, must be able to show why incremental sales of cheap midwest power will suddenly become viable in a more competitive regime.

If the coal plants are inexpensive to operate, and the generating company is selling electricity into least-cost dispatching grids, these plants should already be fully utilized. There may be reasons that many of these facilities are operating at lower capacity factors, such as maintenance problems or technological constraints. Perhaps the transmission lines are too congested to allow the transportation of additional power from one region to another. Restructuring is unlikely to change these factors, at least not in the short term.

Therefore, for coal plants to suddenly be able to capture existing markets, one of the following has to be true: 1) The existing least-cost dispatching program is either not working or is constrained and restructuring will change this situation and remove these constraints; 2) several dispatchable non-coal burning plants will cease operations and the

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[56]Estimate of coal capacity as percentage of total electrical generating capacity for 1994; source: EIA Monthly Energy Review, August 1995, p. 95.

power lost will be replaced by greater sales from Midwest coal plants; or 3) state regulators will deliberately design restructuring proposals to discriminate against the use of in-state generators.

It is important to remember that we are analyzing plant utilization patterns and those patterns are controlled by variable costs, not total costs. Most restructuring proposals will not change the emphasis on least-variable cost dispatching methodologies, thus the fact that old coal plants are already depreciated should not have a bearing on how much they are used. Furthermore, if the availability of cheap surplus power is a key factor, why should we assume that buyers will flock to purchase power from Midwest coal generators rather than equally cheap, clean Canadian hydro-electric generators?

Nuclear Power and Competition

Competition in wholesale generation markets could affect the financial future of some nuclear power plants and the utilities that own them. Both the revenue from the sale of their power and the future economic viability of certain plants are likely to be affected.

In the 1980s, a number of new nuclear plants came on-line, with capital costs three to five the times original estimates. State utility commissions dealt with these plants in different ways. Some allowed the costs to be placed in the rate base as part of the utility's cost-of-service. Others allowed the utility to bill ratepayers for the interest payments, but would not permit the utility to include all, or even a portion, of the capital costs of the plant (at least until the power was needed) into the rate base. Still others negotiated settlements that pegged the plant's allowed revenue to its ability to meet performance targets. Such arrangements are not likely to be sustainable in a competitive marketplace. The significance and magnitude of this problem for many utilities cannot be underestimated -- especially since it is compounded by the prospect of large decommissioning costs.

How regulators handle this issue will affect the timing and substance of utility deregulation. However, since capital costs are sunk and the decommissioning liability is not changed by the continued operation of the plant; variable, or operating costs become the key determinant of a plant's competitiveness. Figure 1 provides a summary of nuclear generation production costs for 1993.

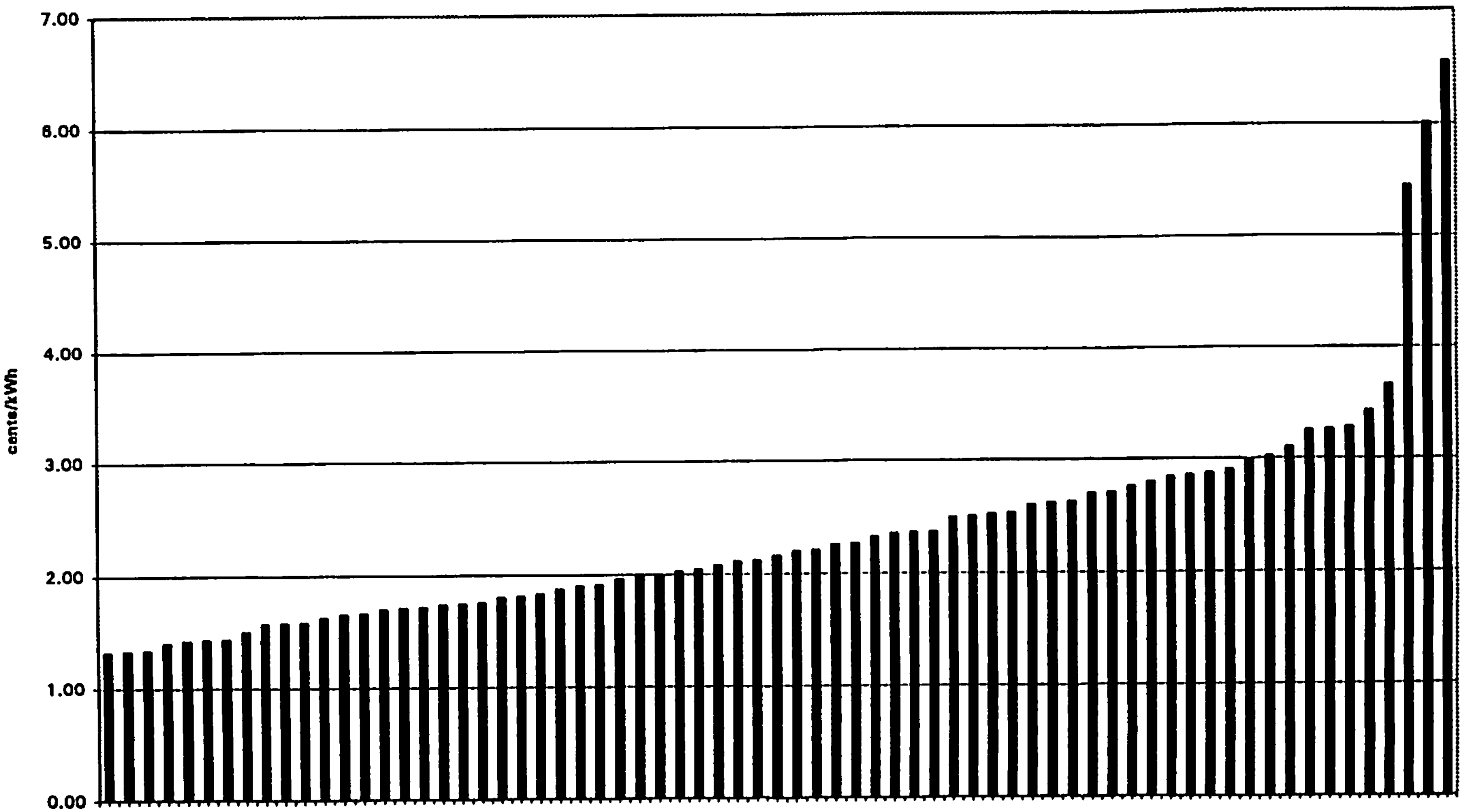
If the marginal cost of power in a competitive world was 4 cents per KWH in 1993, only three nuclear plants would have had uncompetitive operating costs. The vast majority of nuclear facilities had operating costs below 3.5 cents per KWH. Yet these figures may be misleading: first, they do not incorporate the amortization of capital costs for replacing old or worn equipment or major retrofitting projects to meet new safety requirements. If generation becomes truly competitive, utilities will not be able to put these costs into their ratebase and instead will be forced to expense them; for some plants, these costs will drive their operating expenses far above projected marginal costs. Secondly, in a competitive market, the ability to dispatch electricity quickly will be a highly valued attribute, and nuclear plants are not dispatchable. While 3.5 cents per kWh power from a nuclear plant might be profitable on a weekday afternoon, at midnight the market clearing price might be 2.0 cents. At that hour the nuclear facility would lose 1.5 cents for every kilowatt it produces. This lack of operating flexibility will be a major handicap for nuclear power plants in a competitive world.

Effect of Nuclear Retirements on Emissions

If production costs cannot be lowered, competition may force some high-cost nuclear facilities into early retirement. The level of emission increases due to such retirements will depend both on the anticipated average wholesale price and the technology and fuel used to replace the lost generation. Table 13 estimates increases of SO_2, NO_x, and CO_2 emissions for different wholesale prices and replacement technologies; it hypothesizes that 3,000 MW of nuclear capacity is no longer cost competitive at 4.5 cents/KWH, and that 6,000 MW is no longer viable at 3.5 per KWH. These are conservative figures, amounting

FIGURE 1

1993 U.S. Nuclear Plant Production Costs
(Excludes Plants with Capacity Factors < 15%)



INDIVIDUAL NUCLEAR FACILITIES
Median = 2.16 cents/Kwh
Average = 2.36 cents/Kwh

SOURCE: Nuclear Energy Institute

to approximately twice the capacity shown at risk in Figure 1.

Case I assumes that all retired nuclear production is replaced by existing coal facilities -- the scenario with the greatest polluting potential. In Case II, nuclear generation is replaced by production from facilities consisting mostly of baseload coal (60 percent), but also gas (25 percent) and renewables (15 percent); this is the lowest-polluting mix of technologies that is realistic in the next 5 to 7 years since the replacement power is most likely to be existing baseload units. Thus, Case I and Case II set bounds on the amount of increased pollution that should result from replacing nuclear generation.

TABLE 13: Expected Emissions Increases Due to Anticipated Nuclear Retirements
(Millions of tons/year, after retirement)

Case	#1		#2	
Wholesale Price (cents/KWH)	3.5	4.5	3.5	4.5
SO_2	310,892	155,446	176,436	88,218
NO_x	118,838	59,419	79,508	79,508
CO_2	38,419,678	19,209,839	27,497,991	13,798,996

As Table 13 shows, rises in SO_2 would not be significant, especially since any increase in SO_2 must be offset by a decrease elsewhere to meet the SO_2 emissions cap in 2000. The increases in NO_x emissions are not trivial, but are substantially less than those in our coal utilization scenarios. The changes in CO_2 emissions could reduce still further the United States' ability to meet its 1990 stabilization goal. A shut down of approximately 6 percent of the nation's nuclear capacity would increase CO_2 emissions by 27.5 million tons (scenario 2) or approximately 10% of the President's climate change goals.

Another way of analyzing the impacts of changes in the use of nuclear capacity is to look at the environmentally beneficial impact of the recent improvements in nuclear capacity factors. These factors improved from a 66 percent capacity utilization rate in 1990 to 73.8 percent in 1994.[57] This change backed out over 50 million tons of CO_2 and 147,000 tons of NO_x. (See Table 14). The CO_2 figure is equal to 18 percent of the reductions needed to meet the CCAP goal. The NO_x figure translates into 7 percent of the CAAA target. (See Appendix E)

These results indicate that the fate of the nation's nuclear generating capacity in a restructured utility industry will have a measurable effect on the country's ability to meet its NO_x and CO_2 goals.

TABLE 14: Effect of Changes in Nuclear Capacity Utilization on Air Emissions: 1990-1994
(66 percent in 1990 to 73.8 percent in 1994)

	Capacity Factor	SO_2 Savings (tons)	NO_x	CO_2	Percent of CCAP Goal SO_2	Percent of NO_x CCAP Goal	Percent of CCAP Goal
1994	73.8	322,198	146,207	49,591,450	3.2	7.3	17.8

[57] EIA/DOE, Monthly Energy Review, August 1995, p. 105.

Demand Changes and Their Impact on Emissions

Environmental advocates fear that a move to competition at the retail level will create a marketplace in which suppliers will have strong incentives to sell more electricity and weak incentives to promote conservation. They argue that this could lead to a significant growth in the quantity of electricity sold, thereby increasing the consumption of fossil fuels and the degradation of air quality.

The reason that a move to retail or even wholesale competition would reduce the prices of electricity is that electricity would become a commodity good, much like chemicals or steel. Most commodity markets are highly sensitive to shifts in demand and supply. If there is a surplus in generating capacity, prices will fall to match generators' short-run marginal costs, as suppliers underbid each other to maintain market share. The winners would be those who can cut costs and sell the most. Conversely, when supplies are tight and demand high, suppliers can raise their prices.

Since many utilities find themselves with a surplus of generating capacity that could last through the first half of the next decade, moving immediately to a commodity market would cause prices to plummet, stranding billions of dollars in existing assets. Therefore, the near term impact of retail or wholesale competition on the price of electricity, and its consumption, depends on how regulators treat stranded assets. If they decide to ensure that utilities are compensated for all of their prudently incurred stranded investments, electricity prices will not noticeably decrease and the growth in demand will remain relatively unchanged. If regulators decide to allow compensation for only a percentage of utilities' stranded costs, prices will drop, demand will rise, and, at least in the short term, more fossil fuels will be burned and more air pollutants emitted. To predict which outcome is most likely would require a crystal ball, not an economic model -- since regulators' decisions on this issue may follow the rules of politics more than those of economics.

However, to develop a sense of the range of possible outcomes, we examine electricity price trends in three consuming sectors -- industrial, residential and commercial --- and speculate how retail competition might affect consumption.

The Market-Clearing Price of Power

In the fall of 1994, the short-run marginal cost of power was below 3 cents per KWH in many regions of the nation. As the surplus of capacity dissipates, this cost will rise to the long-run marginal cost, which is determined by the cost of building new generators. This number constantly shifts as technology and social constraints, such as pollution abatement standards, change.

Given the present state of generation technology, cost estimates for electricity delivered from a new generating project range from of 2.8 to 4.25 cents per KWH; the most probable estimates, are at the high end of the range. (See Table 15)

TABLE 15: Greenfield Gas-Fired Generation Costs

COMPONENT	CENTS PER KILOWATT-HOUR
Fuel	1.0 - 2.0
Operating and Maintenance	0.5
Capital Costs*	1.0 - 1.25
Total Production Cost	2.5 - 3.75
Transmission Costs	0.3 - 0.5
Total Cost	2.8 - 4.25

Source: "Electricity Funding Comparison Position -- A Distinguishing Factor," Merrill Lynch, September 1993. p. 15.

*Assumes investment of $600 to $800 per kilowatt, a 10 percent to 20 percent equity component, and an expected return of about 15 percent.

To be conservative, we use 4.5 cents per kilowatt-hour as a proxy for the likely cost to generate and deliver a kilowatt-hour to end-users. This estimate is low; it assumes that any additional charge (taxes, DSM surcharges, customer service, or stranded asset recovery charges) will be very small, and it may underestimate the cost of moving to a new industry structure.

Price and Demand Effects by Sector

Because deregulation is likely to affect diverse groups of customers differently, any analysis of the impact of deregulation on price and demand must consider each rate class separately.

For decades, state economic regulators ensured that industrial and commercial customers subsidized the artificially low rates paid by residential customers. A trend away from this inter-class subsidization began in the 1970s, and residential rates have grown substantially compared to industrial rates. For example, Table 16 shows that industrial prices have been relatively steady from 1988 to 1992, while other customer classes have seen their rates increase.

TABLE 16: Changes in Electricity Rates by Customer Class: 1988 to 1993
(cents per KWH)

	1988	1993	% CHANGE
RESIDENTIAL	7.6	8.32	9.5
COMMERCIAL	7.2	7.74	7.5
INDUSTRIAL	4.7	4.85	3.2
OTHER	6.2	6.88	11.0

Sources: EIA, Electric Power Annual 1989, p. 17.; and EIA, Electric Power Annual 1993, p. 17.

- **Price and Demand Effects for Large Industrial Customers**

Industrial users, which account for about one quarter of the electrical load (25.3 percent in 1992) benefit from lower electricity prices than those paid by residential and commercial customers. This is because utilities and commissions have responded to industry threats to generate their own electricity or to relocate. In fact, according to EIA data, those census regions in which large industry consumes the most electricity have a higher differential between industrial and residential rates than other regions. Barring regulatory intervention, this differential is expected to grow.[58] EIA data show that in 1992, the average industrial rate was 4.8 cents, barely above our projected delivery cost of

[58] Eleven states Michigan, North Carolina, Kentucky, Washington, Indiana, Illinois, Tennessee, Pennsylvania, California, Ohio and Texas consume about 50 percent of the electricity consumed by industry. Source: EIA, Electric Power Annual, 1993. (U.S. Government Printing Office, Washington, D.C.) p. 52.

4.5 cents.

If the average price to large industrial customers falls from 4.8 to 4.5 cents per kilowatt-hour,[59] and the price-elasticity of demand for electricity is 1, then industrial demand between 1992 and 2002 will grow by about an additional 61 billion kilowatt-hours. Since meeting demand is largely driven by installing energy-consuming capital machinery, and this capital turns over slowly, it will take almost 10 years before the full impact of this incremental growth will be visible.

- **Price and Demand Effects for Residential Customers**

Under the pressure of competition, utilities may try to make "captive" residential customers pay a higher percentage of fixed costs. PUCs will need to decide if it is appropriate that customers with more inelastic demand (that is, residential and small commercial customers) pay a higher share of fixed costs. (This is called "Ramsey pricing" and has been politically unpopular.) If they decide that Ramsey pricing is unacceptable, PUCs will attempt to protect core customers against this cost shifting; however, it is unclear whether PUCs will be able to block industrial customers from abandoning utility service. If industrial customers do leave the system, captive customers may wind up paying a higher share of fixed costs anyway.

In Norway and the United Kingdom residential prices rose after deregulation.[60]

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[59]The experience in the United Kingdom contradicts the assumption that industrial users will be able to pay vastly lower rates. In the United Kingdom, some large industrial customers that enjoyed very low rates before deregulation actually saw their rates go up as a result of deregulation. What would happen in the United States remains uncertain. See Tim Woolf, "Retail Competition in the Electricity Industry: Lessons from the United Kingdom," Electricity Journal, June 1994, p. 58; and Larry Ruff, "Competitive Electric Markets: The Theory and Its Application" (Putnam, Hayes and Bartlett, December 1992), p. 18.

[60]Woolf, "Retail Competition in the Electricity Industry," pp. 58, 99; and Dan W. York, "Competitive Electricity Markets in Practice: Experience from Norway," Electricity Journal,

If the experience in these countries is replicated in the United States, residential prices are unlikely to fall substantially; thus, residential demand is not likely to increase significantly over the levels presently forecasted.

- **Price and Demand Effects for Commercial and Small Industrial Customers**

As Table 17 shows, commercial customers currently pay more than large industrial customers.[61] It is more costly to serve most commercial and small industrial customers, and they are unlikely to leave the system, so the utility has less incentive to cut them a deal. They have also been less successful than their larger brethren in marshalling their resources to argue successfully before the PUCs.[62]

The average commercial rate, 7.7 cents per KWH, is 41 percent higher than the 4.5 cent projected wholesale delivery cost. Some commercial customers may be able to band together and bargain for lower rates. For example, if all the McDonald's restaurants in a region bought their power as a single purchasing unit they might be able to buy it at lower prices. Of the three classes, commercial and small industrial customers stand the best chance of reaping the benefits of greater competition, since they have slightly more bargaining power than residential customers, and are presently paying prices far in excess of those paid to large industrial customers.

June 1994, p.51. (Neither the United Kingdom or Norway enjoyed as large a surplus of power at the time of deregulation as do most regions of the United States. This factor could result in more downward pressure on price.)

[61]In many states, small industriales are either put in the same rate class as commercial customers or in a rate class separate from larger customers. Further, apartment buildings are often classified as commercial operations and pay commercial rather than residential rates.

[62]Cheryl Harrington, Regulatory Assistance Project, private conversation.

The Environmental Impacts of Increased Demand

If demand for electricity does increase as a result of competition, there will be incremental impacts beyond those already discussed. Much of the increase in demand will take the form of customers' substituting electricity for other sources of energy. For example, as electricity prices drop, the manufacturing plant that had planned to buy a gas-fueled dryer will buy an electrical dryer. The consumer who was undecided between an electric and a gasoline-powered vehicle might buy the former. Therefore, the pollution avoided by not using the natural gas dryer or the gasoline powered car must be subtracted from the pollution from the additional electricity use -- and often the pollution avoided is different from the pollution emitted. For example, a gasoline-powered car's pollution includes volatile organics and carbon monoxide, neither of which are emitted in large amounts by electric generators.

In addition, there are two smaller substitution effects to consider. First, as the price of electricity falls, there will be an incentive to use more electricity and less capital and labor. That is, the manufacturing plant that intended to buy super-efficient machines will buy less efficient models. This effect would increase CO_2 and NO_x emissions; how much will depend on the fuels used to meet this incremental demand. This effect is small and materializes slowly. Secondly, as electricity prices decline, it becomes cheaper to operate electrical equipment. Consumers will leave the lights on longer and run the air conditioner more.

In summary, the rate of demand growth may increase if the utility industry becomes more competitive, but the increases will most likely be less than some analysts predict. To the extent that demand does rise, the net effect on CO_2 and NO_x emissions will be small and will be dominated by the other factors discussed in this paper. Further, each region's prices for competing energy sources and its energy mix will be important determinants of the impact on emissions of any change in the demand for electricity. This type of calculation must be done for each region to have credence.

Efficiency Improvements in Generation

Theoretically, competition should stimulate generators to improve their thermal efficiency (the ratio of the electricity generated to the energy content of the fuel). The more efficient a plant, the less fuel is needed to produce an incremental unit of electricity. Since fuel accounts for a substantial portion of a plant's operating expenses, improvements in efficiency can cut costs and improve a facility's competitive position.[63] Furthermore, the connection between the amount of fuel burned and level of air pollution suggests an added environmental value to efficiency improvements.

Recent experience with competition between independent power producers has coincided with significant increases in the efficiency of gas turbine equipment. From about 1960-1982, most generating plants were able to convert between 30-35 percent of the available energy to electricity. New gas-fired plants that came on-line in the late 1980s increased this conversion factor to the low and mid 40s, a dramatic increase. In the five years to follow, the efficiency of new combined-cycle gas turbines reached the low 50's. There are currently facilities on the drawing board that will be able to approach 65 percent efficiency.[64]

Although it is difficult to say whether innovation in gas turbine efficiency will continue to progress at its current rate or whether it will level off in the mid 60's, there is much room for improvement in other types of generating equipment such as coal boilers. Advances in microprocessor-based automation will also provide operators with a better ability to precisely control the combustion process and thus, emissions.

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[63] According to a Financial Times briefing on gas turbines, GE estimates that a single percentage point improvement in thermal efficiency for combined cycle gas turbines can reduce operating costs by $15-20 million over the life of a 400 MW unit, while reducing the pay-back period by 20 percent.

[64] Bayless, Charles E. "Why Gas Turbines will Transform Electric Utilities?" in Public Utilities Fortnightly, December 1, 1994.

Environmental Benefits

The level of emissions for SO_2 and CO_2 and the heat rate are generally considered to have a linear relationship.[65] Since efficiency (percentage of energy converted) is inversely related to the heat rate, the change in emissions can be calculated by using the equation:

$$\text{Change in emissions} = 1 - \frac{\text{Efficiency in period 1}}{\text{Efficiency in period 2}}$$

Thus a 10 percent change in efficiency is equal to a 0.9 percent change in SO_2 and CO_2 emissions.

This relationship suggests significant gains in emissions reductions as newer combined cycle technologies are incorporated into the existing system, either in the repowering of older coal and gas facilities or in the expansion of existing capacity. The "race for 60 percent efficiency" by such major manufacturers of gas turbines as Westinghouse, GE, ABB and Siemans suggests that expected efficiency gains of approximately 10 percent would not be far-fetched.

For NO_x, the link between heat rates and emissions is not so straight-forward. While a reduction in fuel used will lower "fuel NO_x" emissions, thermal efficiencies are generally increased by higher temperatures, a process which increases "thermal NO_x" emissions. Current R&D in gas turbines has been focusing upon achieving higher efficiencies while, at the same time, installing burners with lower NO_x output.

How rapidly will heat rates improve in a competitive market?

The answer to this question depends upon the rate at which newer, more efficient

[65]The level of emissions is based on the content (by weight) of carbon and sulfur in the fuel. Linearity does not necessarily hold for NO_x emissions since they are a combination of fuel NO_x and thermal NO_x, with the latter depending on boiler temperature and the level of N_2 and O_2 in the air.

generators enter into the restructured electrical system. While marginal heat rate improvements have been driven by technological advance at the drawing board stage, emissions savings can only be realized as the turbines are bought and utilized in the actual generation of electricity. Generation investment decisions are likely to be driven by such factors as the state of existing capital, near-term and long-term expected load growth and utilities' incentives to cut operating costs as the industry itself becomes more competitive.

In a competitive world, generators will be under pressure to utilize their existing stock of plants as efficiently as possible. Reserve margins will drop and utilities will try to use price to induce consumers to shift their load from peak periods to periods of less demand; thereby improving the efficiency of their systems.

McGraw Hill predicts that electricity capacity expansion will slow to 1.2 percent per annum or about one-half the levels of the past 25 years.[66] There will be some plant retirements, either for age or environmental reasons, but current projections show that less than 2.3 percent of the nation's generating capacity is expected to be retired between 1993-2000. Even if this figure is doubled the impact on total emissions will be small. Building new facilities in advance of demand will likely be an economically risky strategy.

In sum, there is potential to decrease emissions through investment in new, more efficient facilities and the repowering of old plants, but without some exogenous push, such as government incentives, the rate of new investment is likely to slow between 1995-2005, gradually accelerating thereafter. Thus the subsequent benefits will accrue slowly.

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[66] Electricity World, "The US Electricity Outlook," January 1995.

SECTION 7: EFFECT OF RESTRUCTURING ON THE UNITED STATES' CLIMATE CHANGE ACTION PLAN

In this section, we assess the possible effect of electricity restructuring on the basic components of the President's Climate Change Action Plan. Will the move to greater competition push the greenhouse gas (GHG) stabilization target further out? Will it also undercut some of the specific programs on which the administration is relying to meet its climate change goals? Since this program, which relies on voluntary reductions, is vulnerable to changes in the structure of the industry, it is useful to briefly examine the possible impacts.

Restructuring is likely to affect the Climate Change Action Plan (CCAP) in two ways:

1. In previous sections, we have shown how changes in investment patterns for DSM and renewables and changes in the utilization of coal and nuclear plants might result in substantial increases in CO_2 emissions. These additional emission increases require an upward revision of the Baseline 2000 greenhouse gas estimates from which reductions were originally calculated. It is important to note that much of this upward pressure occurs not only from restructuring that is about to happen, but also from restructuring that has already happened in many states -- specifically the emergence of a partially competitive wholesale market for electricity.

2. To the extent that individual actions of the plan rely on utility involvement, reduction estimates for those relevant provisions may need to be revised. Should the pressures of competition induce utilities to reduce their involvement in the CCAP's voluntary programs (e.g., as a means of reducing costs or as a result of the private market undervaluing the risk of future environmental regulations,) the Plan may overestimate the ability of a provision

to achieve expected results required to achieve the overall target of stabilizing at 1990 levels.

Before elaborating upon these two points, a brief description of the Plan itself is in order. As a response to the International Framework Convention on Climate Change (1992), the CCAP aims to stabilize GHG emissions at 1990 levels by the year 2000 through a set of "economically minded" supply-side and demand-side actions that coordinate the activities of industry and government. Table 17 shows the volumes that will have to be reduced to meet this stabilization goal.

TABLE 17: Annual U.S. Greenhouse Gas Emissions, 1990 & 2000
(million metric tons of carbon equivalent)

gases	1990	2000 (baseline)	2000 (Action Plan)
total greenhouse*	1462	1568	1459
net carbon**	1237	1337	1261

*net carbon emissions = gross carbon emissions minus the estimation of carbon sinks
**Total greenhouse gases consist of net carbon, methane, nitrous oxide, and hydro- and chlorofluorocarbons.

Source: The Climate Change Action Plan: Technical Supplement, (U.S. Department of Energy, March 1994) p.7.

• **Upward Revision of the 2000 Baseline**

In 1990, the US emitted 1237 million metric tons (MMT) of carbon and without any government action was projected to emit 1337 million metric tons in 2000. The CCAP estimates that a 76 MMT reduction in net carbon will be needed to stabilize total GHG at 1990 levels by 2000. This translates into a 5.7 percent reduction.[67] The additional

[67]The conversion factor (from net carbon to CO_2) emissions is 3.67. Accordingly, a 76 MMT net carbon reduction translates into a 278.92 MMT CO_2 reduction.

CO_2 emission increase estimates calculated in previous sections of this report, or any additional emission increases resulting from restructuring, were not accounted for in the Department of Energy's calculations of CO_2 emissions projections (1990-2000). Instead of having to reduce carbon emissions by 5.7 percent (and total GHG emissions by 6.9 percent) to reach the stabilization goal, it is likely that the required reduction may actually be closer to 6.7-7.0 percent for net carbon (and 8.9 percent for total GHG).

With the revised 6.7 percent estimate, the revised 2000 for net carbon will be 1351.6 MMT. Accordingly, accounting for these additional CO_2 emissions increases net carbon baseline estimates by 14.6 MMT.[68]

- **Potential Downward Revision of Relevant Action Emission Reduction Estimates**

The CCAP consists of 44 actions each of which contributes an estimated reduction in GHG, the sum total of which equals 108.6 MMT of GHG reductions. The main strategy for achieving the overall net carbon reductions of 76 MMT (or 108.6 MMT for GHG) relies upon a supply-side approach that seeks to reduce the use of coal and increase the use of natural gas and renewables and demand-side strategies that encourage increased energy efficiency and electricity conservation.

The Plan projects that 20 percent of the reductions in emissions will come from supply-side actions and 80 percent from demand-side initiatives.[69] In the short term, disproportional reliance on demand-side initiatives and reductions in the use of coal may run counter to market-driven incentives to sell more electricity using cheaper resources. Thus, competition may prove a significant disincentive to participate in the CCAP

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[68]The figures for greenhouse gases are a 33.5 MMT increase for a new 2000 projection of 1601.5 MMT.

[69]Combined GHG reductions may not equal the sum of individual actions due to synergistic effects. (Taken from the CCAP Technical Supplement, U.S. DOE, March 1994, p.84.)

programs.

To assess the validity of this hypothesis, one must first determine the degree to which the projected reductions of 108.6 MMT of GHG rely upon utility-invested DSM programs. Interestingly, the estimated 108.6 MMT reductions do **not** include the utility-specific Climate Challenge Program, which engages utilities in voluntary partnerships to reduce GHG emissions. DOE's 44 actions prescribed in the Plan account for emission reductions from end-use sectors rather than the electric utilities themselves. The conservation efforts are expected to be made by the consumers, although the suppliers will actually play a major role. According to the Plan's technical supplement:

> "Although not specifically represented in the modeling projections, the Utility Climate Challenge Program to voluntarily reduce emissions increases the likelihood that the projected electricity improvements envisioned by the Plan will occur."[70]

By February 1995, electric utilities had committed to reduce CO_2 emissions by 40 MMT. A significant portion of these commitments consists of actions that had already been planned. At the same time, even if only one-third of these commitments is new, such reductions are not trivial.

To assess the impact of restructuring, the percentage of GHG reductions in CCAP actions that involve utility cooperation is identified, and a "worst-case scenario" is calculated in which none of these provisions are pursued. (see Table 18)

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[70]U.S. DOE, <u>CCAP Technical Supplement</u>. (March 1994), p. 72.

TABLE 18: CCAP Electric Utility Programs

Provision #	Action Description	ghg reductions in 2000*
(1)	Coordinated by DOE: Rebuild America and EPA Energy Star Buildings Programs	3.1 MMTce
(2)	Expand EPA's Green Lights Program	2.5 MMTce
(6)	Form Golden Carrot Market-Pull Partnerships	11.8 MMTce
(13)	Establish Industrial Golden Carrot Program for air compressors, etc.	2.9 MMTce[71]
(15)	Expand and enhance energy analysis and diagnostic centers	0.5 MMTce
(27)	Promote integrated resource planning	1.4 MMTce
Total		22.2 MMTce

*To keep the terms of measurement consistent, remember that this table measures greenhouse gas reductions of which carbon reductions are a subset. The GHG goal is 108.6.

In the worst case, roughly 20 percent of the Plan's total greenhouse gas reductions would not be achieved, but this figure overestimates the lost reductions for three reasons. First, some actions complement each other, so not all of the savings are lost if one action is eliminated. Second, direct involvement in the Climate Challenge program by utilities is not factored into the total 108.6 MMT reduction. Third, if only the Golden Carrot Market-Pull Partnerships program continues, the percentage of greenhouse gas reductions not achieved as a result of a competitive regime will be reduced to 9.6 MMT. The Golden Carrot program relies upon utilities to pay incentives to manufacturers to make new

[71]This reduction figure includes some of the GHG reductions for provision 14 which is not listed in this table.

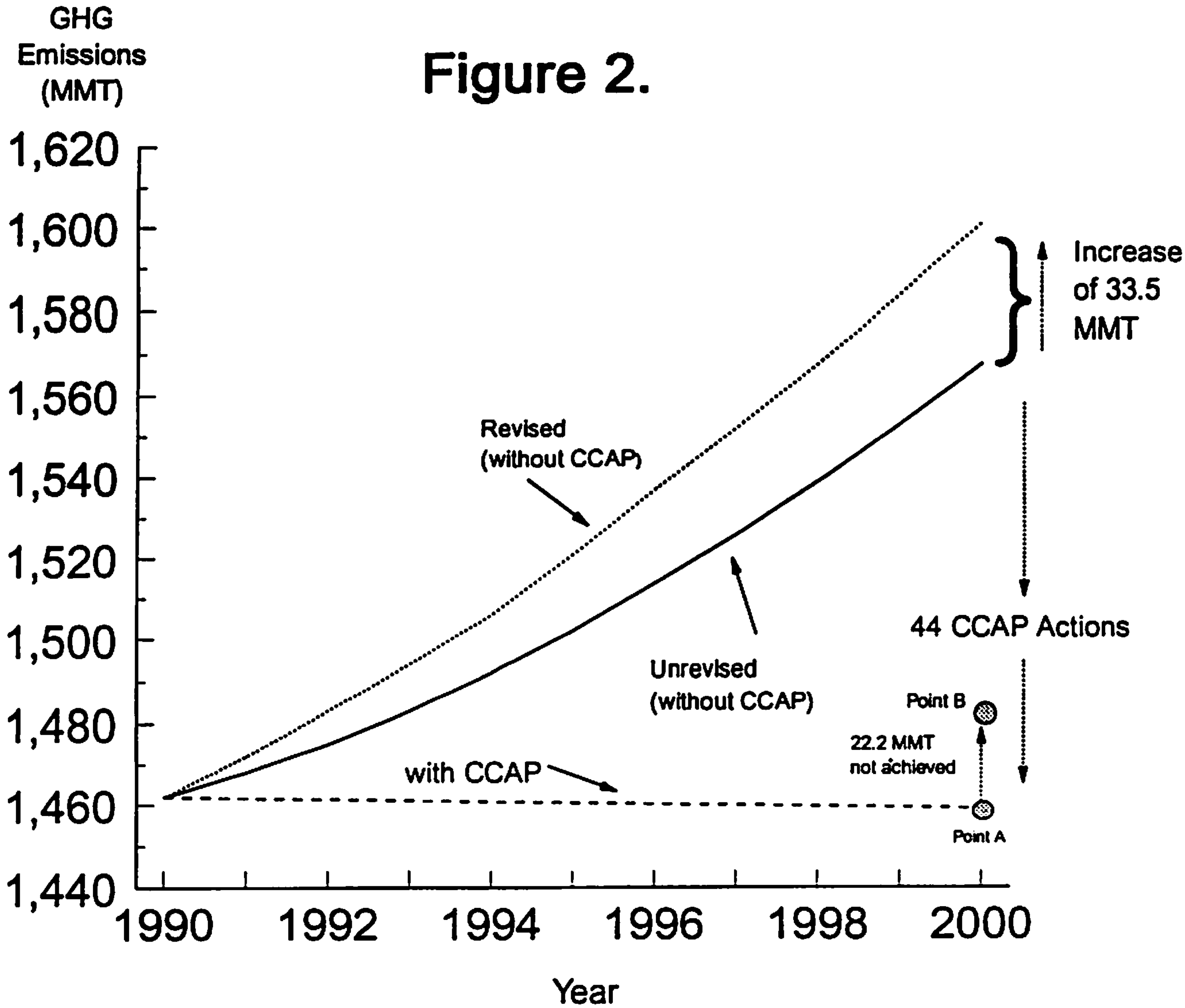
appliances and equipment more energy efficient. The incentive for utilities to participate in such programs might decrease in a competitive electricity market; if this occurs, it is not inconceivable that the DOE would find other sources of funding for the program. Interestingly the largest CO_2 reductions are not achieved by conventional DSM retrofit programs, but by programs that spur the development and commercialization of new energy-efficient technologies.

While 9 to 20 percent of the greenhouse gas (GHG) reductions outlined in the President's plan might be endangered, there are several offsetting factors. First, the plan emphasizes actions by consumers and provides incentives to stimulate such actions; DOE and state regulators can adjust the plan so that some of these incentives are maintained. Second, utilities and other generators still face the prospect that the federal government might introduce mandatory requirements in the future. For utilities to reverse all their existing commitments under the Climate Challenge program is politically risky. In 1995, this risk may look small, but it is not zero. Third, competition will remove the protection against the risk of future environmental regulation -- a safety net that has encouraged investors to discount the threat of future government interventions. As mentioned earlier, utilities can now incorporate investments to meet new environmental requirements into their cost-of-service calculations; in a competitive market they cannot. Thus, utilities will have a greater incentive to weigh the possibility of carbon taxes or mandatory reductions in CO_2 in designing their investment strategies.

To determine whether such factors will truly offset the "endangered" 9-20 percent of total greenhouse gas reductions, further analyses must assess the extent to which restructuring will erode the ability to achieve the CCAP targets, as well as the extent to which the targets themselves are likely to be pushed further out than anticipated.

The two factors impacting the CCAP goal of 1990 stabilization by 2000 (2000 baseline revision and individual action GHG reduction estimate revisions) are illustrated in Figure 2.

Figure 2.



*Note: Actual emissions growth over time does not necessarily follow these curves.
The graph was depicted as such for purposes of simplification

Increased emissions push away from the established target (point A) by 33.5 MMT while a loss of 22.2MMT (the difference between Point A and Point B) makes it more difficult to move in the direction of the target.[72] Determining the point at which the U.S. will ultimately be, given on-going changes in the electricity industry, is a difficult guessing game

[72]The 22.2 MMT figure is on the high end of the range of lost reductions. The actual figure is likely to be higher than 12.6 MMT but lower than 22.2 MMT.

of estimating magnitude of emissions increases, lost utility participation in CCAP programs, and the ability of Climate Challenge to compensate for the gap created by the first two factors.

SECTION 8:
CONCLUSION

In the previous seven sections, we have covered several topics. Obviously more research needs to be done to further characterize some of these issues. The Environmental Impact Statement being prepared for the FERC Mega-NOPR will advance our understanding; as will the proceedings on utility restructuring now underway in several states.[73]

We have attempted to identify the effects of competition in the electric utility industry on air emissions, and more specifically the nation's ability to meet its air pollution reduction goals. There are other environmental issues beyond reduced air emission, such as thermal discharge, water use, noise pollution and land use considerations. Further, investments in DSM and renewables may provide other benefits such as improved energy security. These factors are not assessed in this report.

In June 1994, we convened forty experts on the utility industry and environmental policy. They discussed the pros and cons of restructuring and its effect on reaching environmental goals. Twelve months later, we convened a second meeting. The terms of the debate and the perceptions of the problem had changed dramatically. Where before there was resistance and hostility to restructuring, there now was a consensus that restructuring was inevitable. There was agreement that the IRP process, in its present form, was not compatible with the restructuring of the existing electric utility industry that is likely to emerge over the next five years. Where before, there was a unified front among environmental groups to preserve existing DSM programs, there was now a division on

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[73] "Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," Draft Environmental Impact Statement, RM 95-8 and RM 94-7, November 1995.

whether the emphasis should be preserving existing initiatives or cleaning up older, dirtier generating plants.

Our conclusions agree with the belief that the existing IRP process will not survive restructuring, but we would add several embellishments.

Competition in the generation section will eliminate some of the negative environmental incentives inherent in the old cost of service regulatory regime. Market risk, fuel risk and environmental regulatory risk will shift. These risks will be borne by the investor not the consumer, and this change should have positive environmental benefits. By eliminating guaranteed rates-of-return, competition also eliminates the incentive to over build or to invest in mega-facilities in anticipation of increases in consumption. By eliminating the fuel adjustment clause, utility generators will have to be more careful with their fuel purchasing decisions, and will have to incorporate the possibility that the government may impose further environmental regulation into those decisions. The largest negative environmental effect of competition will not be reductions in DSM or renewables, but rather the incentive to avoid incremental capital investments and expand and extend the use of the existing capital stock.

While the present IRP process will not survive, states will retain the ability to subsidize DSM and renewable investments by imposing a fee on the distribution wires and then allocate the revenues towards social programs, such as enhanced environmental protection or greater energy efficiency. Regulators will be able to provide incentives to further social goals, but they will not be able to order specific companies to make specific investments.

Those interest groups that have been able to use the IRP process to leverage their goals will lose some of that leverage. The new processes will emphasize incentives and subsidies, not central planning and command and control regulation.

The debate, however, is not about process; it is about enhancing environmental goals. Investments in DSM and renewables are a means to a socially beneficial end.

Therefore, we looked carefully at the effectiveness of utility DSM and renewable programs in furthering national environmental goals. Specifically, we selected the emission reduction goals, set forth in the 1990 Clean Air Act Amendments and President Clinton's goal of stabilizing CO_2 emissions at 1990 levels by the year 2000.

As we conducted our research it became clear that there may be other responses to restructuring that will have an even greater impact on air emissions than reductions in DSM and renewables. Greater use of old dirty coal plants or the closure of existing nuclear facilities would certainly have a substantial impact on CO_2, SO_2, and NO_x emissions. We also looked at some less obvious issues, such as the effects of building more efficient facilities or the impact of increasing the demand for electricity.

There are many uncertainties surrounding the timing, scope and substance of how state regulators will restructure the industry, and therefore, we assessed a range of possible changes in how generators operate existing facilities or invest in new equipment. Our findings have evolved over the past year and differ considerably from the preconceptions voiced at our workshop in May of 1994. Further, competition for new capacity exists in many parts of the country, and this competition has already set in motion some of these changes.

The largest impact on air emissions would be an increase in utilization of older, dirtier coal facilities. In 1992, coal plants were operating at 64 percent of capacity. Even a moderate increase to 67 percent would have a substantial impact on CO_2 and NO_x emissions. We have not assessed the technical and economic feasibility of such an increase, but given the size of the potential impact, especially on NO_x and CO_2 emissions, federal and state policy makers should target this issue for additional scrutiny. If such increases occur, downwind states will be forced to pursue much more costly NO_x reductions in order to meet the requirements of the Clean Air Act Amendments.

Further, older facilities have enjoyed far more lenient treatment by environmental regulators than newer facilities. In economic terms, these older facilities have enjoyed a subsidy in the form of avoiding the environmental costs they impose on society. This subsidy has been paid for by newer facilities. In a competitive regime, this unequal treatment of old versus new facilities will further reinforce the incentive to extend the life of older, dirtier coal facilities and increase their use to meet demand growth.

We reached several other conclusions.

- In every scenario except greater utilization of coal plants, the impact on CO_2 emissions dwarfed SO_2 and NO_x emission impacts. For example, changes in investment patterns for DSM and renewables would have a two to three times greater impact on the CO_2 reduction target than the SO_2 and NO_x goals. Early retirement of nuclear capacity, and increased utilization of coal facilities will measurably detract from the nation's ability to realize the targets laid out in the President's Climate Change Action Plan.
- Early retirement of nuclear plants will have a much greater impact on CO_2 emissions than the loss of ratepayer subsidized DSM investments. To put this impact into perspective, 12,000 MW of nuclear capacity avoids approximately the same amount of CO_2 emissions as all the utility DSM investments projected for 1997.

We are not recommending greater use of nuclear power. In fact, there may be reasons to accelerate the early retirement of nuclear facilities. We are simply saying that the future utilization of nuclear facilities will have a substantial effect on CO_2 and NO_x emissions.

Next Steps

Restructuring of the electric utility industry into a competitive industry where buyers and sellers have choices could create three environmental problems.

- The nation's ability to stabilize CO_2 emissions at 1990 levels by the year 2000 will be further impaired.
- Greater use of older dirty coal facilities and reduced amounts of available nuclear capacity will result in increased CO_2 emissions and higher costs to realize national

targets for NO_x reductions.

- Incentives to invest in research and development of new cleaner technologies for the generation and utilization of electricity may be reduced.

There are significant differences in perceptions of the significance of these problems. For example, Congress has no statutory CO_2 targets, and there are many interest groups who argue that there is inadequate scientific evidence to justify establishing such targets. There are others who believe that the evidence is more than sufficient to warrant not only the existing targets, but much stricter ones.

It is the task of the political process, to decide on whether a problem or concern merits government intervention. Our task is to characterize the problems and to lay out a menu of possible solutions. It is the task of the political process to choose from that menu.

In the past twelve months, various parties have suggested a number of options to address these problems. These include the collection of stranded "benefits" changes on the distribution wires to subsidize DSM initiatives, emission caps for NO_x, various forms of incorporating environmental concerns into power dispatching procedures, and mandatory quotas for purchasing renewable electric generating options.

The effectiveness of different policy options in addressing these problem areas should be the focus of further research.

APPENDIX A: DSM Environmental Analysis Calculations

This appendix quantifies the environmental benefits (avoided sulfur dioxide, nitrous oxide, and carbon dioxide emissions) provided by DSM programs in the United States. The source for data was EIA's Electric Power Annual 1993.

The basic methodology requires the calculation of average emissions factors for SO_2, NO_x and CO_2 in tons of total annual emissions per million kilowatt-hour. The emissions factors are then multiplied by total DSM savings (in kilowatt-hours) for 1993 to arrive at "tons of avoided emissions" achieved through DSM. The results are then compared against the environmental benchmarks of Title IV of the Clean Air Act Amendments of 1990 (for SO_2 and NOx) and President Clinton's Climate Change Action Plan (for CO_2)[74]

Environmental Benchmarks for Electricity Generators

SO_2 - reduce by 10 million tons (Title IV of CAAA '90)
NOx - reduce by 2 million tons (Title IV of CAAA '90)
CO_2 - reduce by 278,920,000 tons (estimated from CCAP)

Because statistics regarding the type of generation DSM actually displaces were not available, we considered four separate scenarios. The "simple" case assumes that DSM programs conserve all fuels proportional to their share of the load. The "peak" case assumes displacement of oil and gas generation. The "best" case assumes that DSM exclusively displaces coal generation. These three cases are designed to calculate emission factors used both in the analysis of DSM investments, and also subsequent analysis of other factors such as renewables and changes in facility utilization patterns. To an extent, these cases serve to bound the range of possible emission impacts. In section 5 of the paper, a forth scenario was used on a 67/33 case that assumed the generation displaced by DSM is 67 percent gas and oil and 33 percent coal. The reasoning behind the decision to use this case is that new generation avoided by DSM investments is likely to be gas fired, while existing generation avoided is likely to be a mixture. Finally, the "67/33" case assumes the generation displaced by DSM is 67% oil and gas and 33% coal.

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[74]While the CCAP does not specify a binding reduction target for carbon dioxide emissions, it is a useful benchmark against which to gauge CO_2 emission reductions. The CCAP attempts to stabilize greenhouse gas emissions at 1261 million metric tons (1990 level), requiring a 76 million ton reduction in net carbon from 1990 to 2000. Converting from carbon to carbon dioxide (3.67), the CCAP goal for CO_2 reductions is estimated to be 278,920,000 tons.

Utility net generation and total emissions by fuel type (1993)

	Coal	Oil	Gas	Total*
Net generation (million kWh)	1,639,151	99,539	258,915	2,882,525
SO_2 (1,000 tons)	13,844	583	1	14,432
NOx (1,000 tons)	5,288	136	424	5,852
CO_2 (1,000 tons)	1,711,673	84,129	146,584	1,946,266

*includes nuclear, hydroelectric, and other renewables

Environmental Benefits of DSM:

Electric utility investment in DSM programs: $2.77 billion
Energy savings from electric utility DSM: 44,349 million kWh

DSM savings as % of total energy demand

total demand = DSM + electric power industry net generation
= 44,349,000,000 + 3,196,924,000,000
= 3,241,300 million kWh

44,349 million kWh/3,241,300 million kWh = 1.4%

In 1993 DSM programs reduced electricity usage by approximately 1.4%.

I. Calculations for the Simple Case:

The simple case assumes that savings were achieved proportionally from all generation sources. In other words, DSM displaces generation sources by a weighted average.

Electric power industry net generation: 3,196,924 million kWh
Electric power industry emissions:

SO_2	15,208,000 tons
NOx	6,895,000 tons
CO_2	2,342,210,000 tons

Emission factors per million kWh of electricity generated:

SO_2: tons per million kWh = total tons of SO_2/total generation
= 15,208,000/3,196,924
= 4.76 tons/million kWh

NOx: tons per million kWh = total tons of NOx/total generation
= 6,895,000/3,196,924
= 2.16 tons/million kWh

CO_2: tons per million kWh = total tons of CO_2/total generation
= 2,342,210,000/3,196,924
= 732.64 tons/million kWh

Avoided emissions from DSM

SO_2: 44,349 million kWh * 4.76 tons/million kWh = 210,971 tons SO_2
NOx: 44,349 million kWh * 2.16 tons/million kWh = 95,650 tons NOx
CO_2: 44,349 million kWh * 732.64 tons/million kWh = 32,492,067 tons CO_2

% of goals achieved

210,971/10,000,000 = 2.1% of the CAAA goal for SO_2 reductions
95,650/2,000,000 = 4.8% of the CAAA goal for NOx reductions
32,492,067/278,920,000 = 11.6% of the CCAP goal for CO_2 reductions

Calculations of emissions factors for "Peak" and "Best" Cases

For the "peak" and "best" cases, the same methodology was applied to achieve different emission factors. Because much of the emphasis of DSM has been placed on programs that avoid the need to build new capacity, the peak case makes the more realistic assumption that DSM will likely displace peak generation (oil and gas), rather than base load generation, such as coal, nuclear, and hydroelectric. The emissions factor calculations for the peak and best cases do not include the effect of non-utility generators, as data on NUG emissions by fuel type was not available.

II. Peak Case: Displacement by Oil and Gas

Emissions factors per million kWh of electricity generated

SO_2: tons per million kWh = tons of SO_2 generated by oil and gas/ total oil and gas generation
= 584,000/358,454
= 1.63 tons/million kWh

NOx: tons per million kWh = tons of NOx generated by oil and gas/ total oil and gas generation
= 560,000/358,454
= 1.56 tons/million kWh

CO_2: tons per million kWh = tons of CO_2 generated by oil and gas/ total oil and gas generation
= 230,713,000/358,454
= 643.63 tons/million kWh

Avoided emissions from DSM

SO_2: 44,349 million kWh * 1.63 tons/million kWh = 72,254 tons SO_2
NOx: 44,349 million kWh * 1.56 tons/million kWh = 69,285 tons NOx
CO_2: 44,349 million kWh * 643.63 tons/million kWh = 28,544,502 tons CO_2

% of goals achieved

72,254/10,000,000 = 0.7% of the CAAA goal for SO_2 reductions
69,285/2,000,000 = 3.5% of the CAAA goal for NOx reductions
28,544,502/278,920,000 = 10.2% of the CCAP goal for CO_2 reductions

III. Best Case: Displacement by Coal

Emissions factors per million kWh of electricity generated

SO_2: tons per million kWh = tons of SO_2 generated by coal/ total coal generation
= 13,844,000/1,639,151
= 8.45 tons/million kWh

NOx: tons per million kWh = tons of NOx generated by coal/
total coal generation
= 5,288,000/1,639,151
= 3.23 tons/million kWh

CO_2: tons per million kWh = tons of CO_2 generated by coal/
total coal generation
= 1,171,673,000/1,639,151
= 1044.24 tons/million kWh

Avoided emissions from DSM

SO_2: 44,349 million kWh * 8.45 tons/million kWh = 374,564 tons
NOx: 44,349 million kWh * 3.23 tons/million kWh = 143,073 tons
CO_2: 44,349 million kWh * 1,044.24 tons/million kWh = 46,311,161 tons

% of goals achieved

374,564/10,000,000 = 3.7% of the CAAA goal for SO_2 reductions
143,073/2,000,000 = 7.2% of the CAAA goal for NOx reductions
46,311,151/278,920,000 = 16.6% of the CCAP goal for CO_2 reductions

IV. 67/33 Case: Displacement by Coal and Oil/Gas

Using emissions factors from "peak" and "best" cases above, different DSM displacement percentages can be tested. This case assumes that generation displaced by DSM is 67% oil/natural gas and 33% coal.

DSM energy savings:	44,349 million kWh
67% displaces oil/gas:	29,714 million kWh
33% displaces coal:	14,635 million kWh

Emissions factors (taken from previous calculations)

SO_2 oil/gas: 1.63 tons/million kWh
coal: 8.45 tons/million kWh

NOx oil/gas: 1.56 tons/million kWh
coal: 3.23 tons/million kWh

CO_2 oil/gas: 643.63 tons/million kWh
coal: 1044.24 tons/million kWh

Avoided emissions from DSM (tons)

SO_2	oil/gas:	48,434
	coal:	123,666
	Total:	172,100
NOx	oil/gas:	46,354
	coal:	47,271
	Total:	93,625
CO_2	oil/gas:	19,124,822
	coal:	15,282,452
	Total:	34,407,274

% of goals achieved

172,100/10,000,000 = 1.7% of the CAAA goal for SO_2 reductions
93,625/2,000,000 = 4.7% of the CAAA goal for NOx reductions
34,407,274/278,920,000 = 12.3% of the CCAP goal for CO_2 reductions

The amount of DSM investment in a competitive electricity market may not follow predicted growth. Thus, two growth reduction scenarios were considered to demonstrate the environmental consequences. The assumptions and emission factors from the 67/33 case were utilized to enable comparisons.

1993 base DSM electricity savings: 44,349 million kWh
1977 projected DSM electricity savings: 90,075 million kWh
Projected growth: 45,726 million kWh

40% Reduction in Growth

45,726 * 0.6 = 27,436 + 44,349 = 71,785 million kWh

67% displaces oil/gas: 48,096 million kWh
33% displaces coal: 23,689 million kWh

Avoided Emissions

SO_2 48,096 * 1.63 + 23,689 * 8.45 = 278,569 tons
NO_x 48,096 * 1.56 + 23,689 * 3.23 = 151,545 tons
CO_2 48,096 * 643.63 + 23,689 * 1044.24 = 55,693,030 tons

Lost Energy Savings: 90,075 - 71,785 = 18,290 million kWh

Unachieved Emissions

SO_2 349,547 - 278,569 = 70,978 tons/10,000,000 = 0.7% of CAAA reductions
NO_x 190,158 - 151,545 = 38,613 tons/2,000,000 = 1.9% of CAA reductions
CO_2 69,883,105 - 55,693,030 = 14,190,075 tons/278,920,000 = 5.1 % of CCAP goal

70% Reduction in Growth

45,726 * 0.3 = 13,718 + 44,349 = 58,067 million kWh

67% displaces oil/gas: 38,905 million kWh
33% displaces coal: 19,162 million kWh

Avoided Emissions

SO_2 38,905 * 1.63 + 19,162 * 8.45 = 225,334 tons
NO_x 38,905 * 1.56 + 19,162 * 3.23 = 122,585 tons
CO_2 38,905 * 643.63 + 19,162 * 1044.24 = 45,050,152 tons

Lost Energy Savings: 90,075 - 58,067 = 32,008 million kWh

Unachieved Emissions

SO_2 349,547 - 225,334 = 124,213 tons/10,000,000 = 1.2% of CAAA reductions
NO_x 190,158 - 122,585 = 67,573 tons/2,000,000 = 3.4% of CAAA reductions
CO_2 69,883,105 - 45,050,152 = 24,832,953 tons/279,920,000 = 8.9% of CCAP goal

Appendix B: Repowering Analysis

We have indicated that the environmental benefits of DSM must be considered within the context of the overall resource portfolio, and that DSM may impose and "opportunity cost" on environmental benefits by delaying the construction of cleaner new plants. To illustrate the possible environmental impact of this effect, we address the following question:

What would happen if the $2.77 billion invested in DSM in 1993 was instead applied to repowering dirty coal generation with cleaner, combined-cycle natural gas generation?

The term repowering will refer to the replacement of an existing generation technology by a more modern technology using the same power plant site. In many cases, the refurbishment of a plant by substituting new combustion technology for old will result in better performance and lower emissions.

Our methodology was more a "back-of-the-envelope" calculation than a robust model for analysis. Having made a few conservative assumptions about the characteristics of a typical coal plant and a typical combined-cycle gas plant, average emissions factors were estimated for each combustion technology. The difference between the two sets of emissions factors represented tons of emissions avoided per million kilowatt-hour by generating with gas instead of coal. The difference was then multiplied by total generation to arrive at tons of emissions saved through repowering.

The DSM analysis in Appendix A (utilized here to compare DSM emissions savings against repowering savings) uses a different set of emissions factors. The reason for this is that we cannot pinpoint exactly what type of generation DSM replaced, but we assume that repowering targets specific, older dirty plants. Take, for example, a comparison of the DSM "best" case (displacement of coal only) and the repowering case. While DSM is displacing all coal (dirty and clean), repowering is hopefully displacing only the dirtier coal. As a result, two sets of emissions factors are used to reflect the differences.

Finally, this analysis does not account for fuel costs. According to EIA's Electric Power Annual 1993, average fuel costs for fossil steam are 17.65 mills/kWh, and average gas turbine fuel costs are 26.39 mills/kWh. The fuel cost differential translates into 8.74 mills/kWh in moving from coal to gas. Thus, in one year, the fuel cost for the repowered facility will be an estimated $215,440,000, which is 7.8% of the initial investment of $2.77 billion for 1993. By including fuel costs, the repowering case loses 1,916.8 million kWh of generation. On the other hand, a more rigorous model would also incorporate the different life-cycles for DSM (about 14 years) and a repowered project (about 40 years). While the exclusion of fuel costs biases the analysis in favor of repowering the exclusion of the time element biases the analysis in favor of DSM.

Assumptions:

Assuming a capital cost of approximately $630/kWh for new capacity, $2.77 billion can repower 4.3968 million kW (4,396.8 MW) of coal capacity with combined cycle natural gas units. The avoided emissions are calculated by multiplying the emissions per kWh difference between coal and gas by the number of kWh for each type of plant. Rather than single out any of the 261 "Phase 1" generators identified by EPA as highly polluting, we consider a "typical" dirty old coal generator with a typical heat rate of 10,500 BTU and a load factor of 64 percent (NERC, pp.8-9). The repowered unit runs at a heat rate of 8,100 BTU, and we assume the same load factor. This last assumption is unlikely where there is a capacity surplus and older, less efficient plants may be operating at less than full capacity. However, from a broad national perspective, this assumption is reasonable.

Emissions factors for repowering analysis
(Factors derived from EIA, Electric Power Annual 1993, pp. 167-171)

Typical coal plant (i.e. prime candidate for repowering), cyclone firing configuration, burning bituminous coal with 2% sulfur content. Assumes heat rate of 10,500 BTU/kWh and fuel heating value of 12,000 BTU/lb.

SO_2: 16.63 tons/million kWh
NOx: 7.40 tons/million kWh
CO_2: 1078.51 tons/million kWh

Combined-cycle gas plants with scrubber. Assumes heat rate of 8,100 BTU/kWh and fuel heating value of 1,050 BTU/cu ft.

SO_2: 0 tons/million kWh
NOx: 1.06 ton/million kWh
CO_2: 462.86 tons/million kWh

Emissions differentials between coal and gas:

SO_2: 16.63 tons/million kWh
NOx: 6.34 tons/million kWh
CO_2: 615.65 tons/million kWh

This means that for every million kWh generated by a clean new gas plant instead of a dirty old coal plant will save 16.63 tons of SO_2, 6.34 tons of NOx, and 615.65 tons and CO_2.

Emissions savings from repowering

Net generation = 4,396,800 kW * (365*24*.64) = 24,650 million kWh

SO_2: 24,650 million kWh * 16.63 tons/million kWh = 409,930 tons
NOx: 24,650 million kWh * 6.34 tons/million kWh = 156,281 tons
CO_2: 24,650 million kWh * 615.65 tons/million kWh = 15,175,773 tons

Results of DSM/Repowering Comparison

	"Simple" DSM case	Repowering coal with gas
Avoided SO_2	210,971 tons	409,930 tons
Avoided NOx	95,650 tons	156,281 tons
Avoided CO_2	32,492,068 tons	15,175,773 tons

Appendix C: Renewables Analysis

This appendix explains assumptions and calculations used to determine the impact of changes in the growth of nonhydro renewable investments. As the electricity industry moves closer to competition, nonhydro renewable investments may not grow at currently projected rates. Note: this in NOT an analysis of real decreases in nonhydro renewable investments, but rather decreases in projected *growth*. The results of these calculations are summarized in Tables 9 and 10.

Figures for the baseline growth assumptions were taken calculated from Table A16, p. 73 of EIA, Annual Energy Outlook 1994.

General formula for annual growth: $G_t = G_0(1+r)^n$

Where n = number of years
r = annual growth
G_t = projected generation in year t
G_0 = generation in year 0 (1992)

1992 Nonhydro renewable generation: 80,300 million kWh
2000 Projected nonhydro renewable generation: 109,900 million kWh
2010 Projected nonhydro renewable generation: 206,700 million kWh

Growth rate from 1992 to 2000 = 4.0%
Growth rate from 1992 to 2010 = 5.4%

EIA's figures predict that nonhydro renewable growth substantially increases after the year 2000. This is likely reflective of the progress of nonhydro renewable technology. Thus, for this analysis, annual growth rates between both 1992-2000 (n=8) and 1992-2010 (n=18) were renewable technology.

Three possibilities result from nonhydro renewable growth: (a) increased renewable generation meets increased electricity demand and displaces planned conventional generation; (b) increased renewable generation replaces current conventional generation; or (c) a combination of (a) and (b).

For purposes of this analysis it was assumed that 50% of the additional nonhydro renewable generation meets increased demand, 1/2 displacing cleaner coal and 1/2 supplanting combined-cycle natural gas. The remaining 50% replaces current coal generation.

Emissions factors (tons/million kWh)

	Cleaner coal*	Combined-cycle natural gas (Appendix B)	Average existing coal (Appendix A)
SO2	5.52	0	8.45
NOx	1.73	1.06	3.23
CO2	943.0	462.86	1044.24

*Emissions factors derived from EIA, Electric Power Annual 1993, pp. 167-172.

For purposes of this analysis, it was assumed that nonhydro renewable generation produces zero emissions.

Calculations

General formula for emissions production:

Emissions = the sum of additional generation * emission factor * replacement factor

Year 2000: 4.0% annual growth

Additional nonhydro renewable generation =
109,900 million kWh - 80,300 million kWh =
29,600 million kWh

SO2: (29,600 * 5.52 * 0.25) + (29,600 * 0 * 0.25) +
(29,600 * 8.45 * 0.5) = 165,908 tons

NOx: (29,600 * 1.73 * 0.25) + (29,600 * 1.06 * 0.25) +
(29,600 * 3.23 * 0.5) = 68,450 tons

CO2: (29,600 * 943.0 * 0.25) + (29,600 * 462.86 * 0.25) +
(29,600 * 1044.24 * 0.5) = 25,858,116 tons

Year 2010: 5.4% annual growth

Additional nonhydro renewable generation =

206,700 million kWh - 80,300 million kWh =
126,400 million kWh

SO_2: (126,400 * 5.52 * 0.25) + (126,400 * 0 * 0.25) +
(126,400 * 8.45 * 0.5) = 708,472 tons

NO_x: (126,400 * 1.73 * 0.25) + (126,400 * 1.06 * 0.25) +
(126,400 * 3.23 * 0.5) = 292,300 tons

CO_2: (126,400 * 943.0 * 0.25) + (126,400 * 462.86 * 0.25) +
(126,400 * 1044.24 * 0.5) = 110,421,144 tons

The calculated emissions savings can then be compared to CAAA and CCAP benchmarks.

Year 2000
SO_2: 165,908/10,000,000 = 1.7%

NO_x: 68,450/2,000,000 = 3.4%

CO_2: 25,858,116/278,920,000 = 9.3%

Year 2010
SO_2: 708,472/10,000,000 = 7.1%

NO_x: 292,300/2,000,000 = 14.6%

CO_2: 110,421,144/278,920,000 = 39.6%

Randge of Impacts

The second set of calculations produce a sensitivity analysis of changes in nonhydro renewable generation forecasts. Given the base cases of 4.0% and 5.4% annual growth, in 2000 nonhydro renewables will produce 29,600 million kWh more than 1992 levels. By the year 2010 production will total an additional 126,400 million kWh. What is the effect if the actual number is 10% higher than projected? 20% lower? 40% lower?

Year 2000

Additional generation: 29,600 million kWh
Projection: 10% higher = 32,560 million kWh
20% lower = 23,680 million kWh
40% lower = 17,760 million kWh

Emissions (tons)

10% more than forecast:

SO2: (32,560 * 5.52 * 0.25) + (32,560 * 0 * 0.25) + (32,560 * 8.45 * 0.5) = 182,499 tons

NOx: (32,560 * 1.73 * 0.25) + (32,560 * 1.06 * 0.25)+ (32,560 * 3.23 * 0.5) = 72,295 tons

CO2: (32,560 * 943.0 * 0.25) + (32,560 * 462.86 * 0.25) + (32,560 * 1044.24 * 0.5) = 28,443,928 tons

20% less than forecast:

SO2: (23,680 * 5.52 * 0.25) + (23,680 * 0 * 0.25) + (23,680 * 8.45 * 0.5) = 132,726 tons

NOx: (23,680 * 1.73 * 0.25) + (23,680 * 1.06 * 0.25)+ (23,680 * 3.23 * 0.5) = 54,760 tons

CO2: (23,680 * 943.0 * 0.25) + (23,680 * 462.86 * 0.25) + (23,680 * 1044.24 * 0.5) = 20,686,493 tons

40% less than forecast:

SO2: (17,760 * 5.52 * 0.25) + (17,760 * 0 * 0.25) + (17,760 * 8.45 * 0.5) = 99,545 tons

NOx: (17,760 * 1.73 * 0.25) + (17,760 * 1.06 * 0.25)+ (17,760 * 3.23 * 0.5) = 41,070 tons

CO2: (17,760 * 943.0 * 0.25) + (17,760 * 462.86 * 0.25) + (17,760 * 1044.24 * 0.5) = 15,514,870 tons

Year 2010

Additional generation: 126,400 million kWh

Projection: 10% higher = 139,040 million kWh

20% lower = 101,120 million kWh

40% lower = 75,840 million kWh

Emissions (tons)

10% more than forecast:

SO2: (139,040 * 5.52 * 0.25) + (139,040 * 0 * 0.25) + (139,040 * 8.45 * 0.5) = 779,319 tons

NOx: (139,040 * 1.73 * 0.25) + (139,040 * 1.06 * 0.25)+ (139,040 * 3.23 * 0.5) = 321,530 tons

CO2: (139,040 * 943.0 * 0.25) + (139,040 * 462.86 * 0.25) + (139,040 * 1044.24 * 0.5) = 121,463,258 tons

20% less than forecast:

SO2: (101,120 * 5.52 * 0.25) + (101,120 * 0 * 0.25) + (101,120 * 8.45 * 0.5) = 566,778 tons

NOx: (101,120 * 1.73 * 0.25) + (101,120 * 1.06 * 0.25)+ (101,120 * 3.23 * 0.5) = 233,840 tons

CO2: (101,120 * 943.0 * 0.25) + (101,120 * 462.86 * 0.25) + (101,120 * 1044.24 * 0.5) = 88,336,915 tons

40% less than forecast:

SO2: (75,840 * 5.52 * 0.25) + (75,840 * 0 * 0.25) + (75,840 * 8.45 * 0.5) = 425,083 tons

NOx: (75,840 * 1.73 * 0.25) + (75,840 * 1.06 * 0.25)+ (75,840 * 3.23 * 0.5) = 175,380 tons

CO2: (75,840 * 943.0 * 0.25) + (75,840 * 462.86 * 0.25) + (75,840 * 1044.24 * 0.5) = 66,252,686 tons

Changes in Emissions

Year 2000

10% more than forecast:

SO2: 165,908 - 182,499 = -16,591/10,000,000 = 0.2% gain in CAAA emission reduction goal

NOx: 68,450 - 72,295 = -3,845/2,000,000 = 0.2% gain in CAAA emission reduction goal

CO2: 25,858,116 - 28,443,928 = -2,585,812/278,920,000 = 0.1% gain in CCAP emission reduction goal

20% less than forecast:

SO2: 165,908 - 132,726 = 33,182/10,000,000 = 0.03% loss in CAAA emission reduction goal

NOx: 68,450 - 54,760 = 13,690/2,000,000 = 0.07% loss in CAAA emission reduction goal

CO2: 25,858,116 - 20,686,493 = 5,171,623/278,920,000 = 1.9% loss in CCAP emission reduction goal

40% less than forecast:

SO2: 165,908 - 99,545 = 66,363/10,000,000 = 0.07% loss in CAAA emission reduction goal

NOx: 68,450 - 41,070 = 27,380/2,000,000 = 1.4% loss in CAAA emission reduction goal

CO2: 25,858,116 - 15,514,870 = 10,343,246/278,920,000 = 3.7% loss in CCAP emission reduction goal

Year 2010

10% more than forecast:

SO2: 708,472 - 779,319 = -70,847/10,000,000 = 0.7% gain in CAAA emission reduction goal

NOx: 292,300 - 321,530 = 29,230/2,000,000 = 1.5% gain in CAAA emission reduction goal

CO2: 110,421,144 - 121,463,258 = -11,042,114/278,920,000= 4.0% gain in CCAP emission reduction goal

20% less than forecast:

SO_2: 708,472 - 566,778 = 141,694/10,000,000 = 1.4% loss in CAAA emission reduction goal

NO_x: 292,300 - 233,840 = 58,460/2,000,000 = 2.9% loss in CAAA emission reduction goal

CO_2: 110,421,144 - 88,336,915 = 22,084,229/278,920,000 = 7.9% loss in CCAP emission reduction goal

40% less than forecast:

SO_2: 708,472 - 425,083 = 283,389/10,000,000 = 2.8% loss in CAAA emission reduction goal

NO_x: 292,300 - 175,380 = 116,920/2,000,000 = 5.8% loss in CAAA emission reduction goal

CO_2: 110,421,144 - 66,252,686 = 44,168,458/278,920,000 = 15.8% loss in CCAP emission reduction goal

The growth assumptions projected by EIA may seem overly pessimistic to some environmental advocates. To demonstrate what might happen under a more optimistic scenario, second cases were calculated with an annual growth rate 1.5 times current projections (i.e. 6.0% and 8.1% respectively):

2000 Projected nonhydro renewable generation: 127,986 million kWh
2010 Projected nonhydro renewable generation: 326,300 million kWh

Note: These figures appear only in this appendix and were not used in analysis.

Year 2000: 6.0% annual growth

Additional nonhydro renewable generation =
127,986 million kWh - 80,300 million kWh =
47,686 million kWh

SO_2: (47,686 * 5.52 * 0.25) + (47,686 * 0 * 0.25) +
(47,686 * 8.45 * 0.5) = 267,280 tons

NO_x: (47,686 * 1.73 * 0.25) + (47,686 * 1.06 * 0.25) +

$(47,686 * 3.23 * 0.5) = 110,274$ tons

CO_2: $(47,686 * 943.0 * 0.25) + (47,686 * 462.86 * 0.25) +$
$(47,686 * 1044.24 * 0.5) = 41,657,774$ tons

Year 2010: 8.1% annual growth

Additional nonhydro renewable generation =
326,300 million kWh - 80,300 million kWh =
246,000 million kWh

SO_2: $(246,000 * 5.52 * 0.25) + (246,000 * 0 * 0.25) +$
$(246,000 * 8.45 * 0.5) = 1,378,830$ tons

NOx: $(246,000 * 1.73 * 0.25) + (246,000 * 1.06 * 0.25) +$
$(246,000 * 3.23 * 0.5) = 568,875$ tons

CO_2: $(246,000 * 943.0 * 0.25) + (246,000 * 462.86 * 0.25) +$
$(246,000 * 1044.24 * 0.5) = 214,901,910$ tons

CAAA and CCAP Percentages:

Year 2000

SO_2: 267,280/10,000,000 = 2.7% of CAAA Goal

NOx: 110,274/2,000,000 = 5.5% of CAAA Goal

CO_2: 41,657,774/278,920,000 = 14.9% of CCAP Goal

Year 2010

SO_2: 1,378,830/10,000,000 = 13.8% of CAAA Goal

NOx: 568,875/2,000,000 = 28.4% of CAAA Goal

CO_2: 214,901,910/278,920,000 = 77.0% of CCAP Goal

Appendix D: Coal Utilization Analysis

This appendix quantifies the potential emissions consequences from a boost in the capacity factor of older, coal-burning electricity generators. Results are summarized in Table 11.

The base of the calculation is EIA's Net Summer Coal Steam Capability projections for the year 2000 (Annual Energy Outlook 1994, Table 9, p. 66). This figure must be multiplied by 365 days, 24 hours, and the assumed capacity factor to obtain net generation.

(a) 297.2 million kw * 365 * 24 * 0.64 = 1,666,222 million kWh

This figure would be the net coal generation in the year 2000 if the capacity factor remained 64. This procedure must be repeated for the hypothetical condition that the capacity factor will have increased to 67 by 2000.

(b) 297.2 million kw * 365 * 24 * 0.67 = 1,744,326 million kWh

Subtracting (a) from (b) produces additional net generation due to the increase in the capacity factor.

1,744,326 - 1,666,222 = 78,104 million kWh

That is, if coal generators operate consistently over the next few years at 64% of capacity, then annual net generation will be 1,666,222 million kWh. But if a competitive market causes utility operators to increase efficiency to 67%, this will produce an additional 78,104 million kWh.

For this analysis, it was assumed that additional net generation will be supplied by dirtier, older coal facilities. Further, it was assumed that 1/3 of this generation will displace existing peak generation, 1/3 will displace current cleaner coal generation, and 1/3 will meet new electricity demand. The following table summarizes assumed emission factors:

	Dirty Coal*	Peak**	Cleaner Coal***
SO_2	16.63	1.63	5.52
NO_x	7.40	1.56	1.73
CO_2	1078.51	643.63	943.0

*Taken from Appendix B
**Taken from Appendix A oil/natural gas
***Taken from Appendix C

Cleaner coal facilities are more recently built generators that are tangential-fired with recirculation, a heat rate of 9,200 BTU/kWh, and a fuel heating value of 12,000 BTU/lb. Older dirtier coal facilities employ cyclone firing configuration, burning bituminous coal with 2% sulfur content (assumes heat rate of 10,5000 BTU/kWh, and fuel heating value of 12,000 BTU/lb.).

SO2: 78,104/3 * [16.63 + (16.63-1.63) + (16.63-5.52)] = 1,112,722 tons

NOx: 78,104/3 * [7.40 + (7.40-1.56) + (7.40-1.73)] = 492,316 tons

CO2: 78,104/3 * [1078.51 + (1078.51-643.63) + (1078.51-943.0) = 42,928,562 tons

Emissions Goals

SO2: 1,112,722/10,000,000 = 11.13%

NOx: 492,316/2,000,000 = 24.62%

CO2: 42,928,562/278,920,000 = 15.39%

Appendix E: Nuclear Analysis

Part I of this appendix considers the potential environmental impact of nuclear retirements on air emission levels. Part II calculates the emissions savings of increased capacity factors in nuclear utilization over the past few years.

Part I.

In a more competitive electricity industry, higher cost nuclear facilities may not be able to rival prices available from other generation sources, thus they would likely shut down earlier than planned. This analysis focuses on two retirement scenarios:

a) 6,000,000 kW of nuclear generation are shut down at 3.5 cents/kWh

b) 3,000,000 kW of nuclear generation are shut down at 4.5 cents/kWh

Assumptions:

The excess demand handled by nuclear retirements would have to be met by other generation sources. In order to set bounds on the amount of increased pollution that should result, two extreme cases are applied to the above scenarios:

1) 100% of retired nuclear generation is replaced by existing coal facilities (Appendix A coal emission factors)

2) Nuclear generation replaced by 50% baseload coal, 35% peakload oil/natural gas, and 15% renewables. Coal and oil/natural gas emission factors were taken from Appendix A, while it is assumed that renewable generation produces zero emissions.[75]

The calculations also assume a 70% capacity factor for nuclear generation.

The results are summarized in Table 14.

CALCULATIONS

Capacity

<u>3.5 cent scenario</u>:

6 million kW * (365*24) * .70 = 36,792 million kWh

[75]This assumption is not necessarily true from biomass and municipal solid waste.

4.5 cent scenario:
3 million kW * (365*24) * .70 = 18,396 million kWh

Case I: Expected emissions increases - nuclear generation replaced by existing coal

Emissions factors
(tons/million kWh)

SO_2	8.45
NO_x	3.23
CO_2	1044.24

	3.5 cents	4.5 cents
SO_2 (tons)	310,892	155,446
NO_x (tons)	118,838	59,419
CO_2 (tons)	38,419,678	19,209,839

Case II: Expected emissions increases - nuclear generation replace by 50% baseload coal, 35% oil/natural gas, and 15% renewables

Emissions factors
(tons/million kWh)

	Coal	Oil/Natural Gas	Renewables
SO_2	8.45	1.63	0
NO_x	3.23	1.56	0
CO_2	1044.24	643.63	0

3.5 cents
SO_2: (36792*.5*8.45) + (36792*.35*1.63) + (36792*.15*0) = 176,436
NO_x: (36792*.5*3.23) + (36792*.35*1.56) + (36792*.15*0) = 79,508
CO_2: (36792*.5*1044.24) + (36792*.35*643.63) + (36792*.15*0) =
27,497,991

4.5 cents
SO_2: (18396*.5*8.45) + (18396*.35*1.63) + (18396*.15*0) = 88,218
NO_x: (18396*.5*3.23) + (18396*.35*1.56) + (18396*.15*0) = 79,508
CO_2: (18396*.5*1044.24) + (18396*.35*643.63) + (18396*.15*0) =
13,748,996

Part II.

Increasing nuclear capacity factors produce environmental benefits in terms of avoided air emissions. This analysis calculated the additional emissions saved by increasing nuclear efficiency between 1990 and 1994. Nuclear capacity figures were taken from EIA, Monthly Energy Review, September 1995, p. 105.

For simplification, it is assumed that nuclear generation replaces other generation sources, not demand growth. Because of uncertainty as to which sources nuclear generation backed out, it was assumed that it displaced all sources proportionally (Appendix A, "Simple" case emissions factors: SO_2 - 4.76 tons/million kWh; NO_x - 2.16 tons/million kWh; CO_2 - 732.64 tons/million kWh).

A. Total emissions savings from annual U.S. nuclear generation

Year	Capacity Factor	Net Generation (million kWh)	Maximum Possible Generation (million kWh)
1990	66.0	576,862	874,033
1994	73.8	640,440	867,805

Year	Annual SO2 Savings (tons)	Annual NOx Savings (tons)	Annual CO2 Savings (tons)
1990	2,745,863	1,246,022	422,632,176
1994	3,048,494	1,383,350	469,211,962

Maximum Generation = net generation/capacity factor/100
Annual savings = net generation * emissions factor

B. Hypothetical emissions with constant 1990 capacity factor

Year	SO2 Savings, 1990 Capacity Factor	NOx Savings, 1990 Capacity Factor	CO2 Savings, 1990 Capacity Factor
1994	2,726,296	1,237,143	419,620,512

Emissions savings = 1994 max generation * 1990 capacity factor/100 * emissions factor

C. Benefits from actual increased nuclear capacity factor

Year	Extra SO2 Savings	Extra NOx Savings	Extra CO2 Savings
1994	322,198	146,207	49,591,450

Percentage of CAAA SO2 Goals	Percentage of CAAA NOx Goals	Percentage of CCAP CO2 Goals
3.22%	7.31%	17.98%

Extra emissions savings = 1994 actual emissions savings - 1994 hypothetical emissions savings

CAAA SO2 reduction goals: 10,000,000 tons/year
CAAA NOX reduction goals: 2,000,000 tons/year
CCAP CO2 reduction goals: 278,920,000 tons/year

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