Modeling Carbon Reduction Policies in the U.S. Electric Sector

Stephen Bernow, William Dougherty, and Max Duckworth, Tellus Institute
and Michael Brower, Brower and Company

Presented by

Stephen Bernow
Tellus Institute

Environmental Protection Agency

Workshop
on
Climate Change Analysis

Alexandria, Virginia

June 6-7, 1996

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June 6-7 EPA Workshop on Analysis of Issues
Related to the Next Steps on Climate Change

Abstract

The U.S. electric sector contributes about 35 percent to the nation's total annual carbon dioxide emissions. Policies and measures that would significantly reduce the growth of carbon emissions from their expected temporal trajectory, or reduce emissions from current levels, would have to effect deep changes in this sector. Policies that accelerate adoption of more efficient electric generation and transmission technologies and systems, and the role of low carbon intensive facilities in the generation mix, would be needed in addition to those that accelerate the adoption of electricity-efficient technologies in buildings and industry.

Modeling climate change policies in the electric sector poses a number of challenges. It requires sufficient specificity in costs, operating characteristics, emissions rates and availability of the various power supply options, both existing and new, sufficient regional specificity to reflect system conditions and constraints, and adequate modeling of protocols for dispatch, retirement, repowering, IPPs, economy exchanges and new resource acquisition. In addition, in today's regulatory environment, it would require representation of compliance with Title IV, other aspects of the Clean Air Act amendments, and EPACT. Finally, emerging institutional conditions, including restructuring/deregulation and possible new and more stringent pollutant regulations, pose particular challenges owing to their still nascent status.

The National Energy Modeling System (NEMS), a computer model constructed and applied by EIA over the past few years, has an Electricity Market Module (EMM), along with companion modules representing others sectors of energy demand and supply, linked to a macro-economic model. The EMM attempts to embody many of the considerations summarized above to adequately represent technology and related decisions in that sector under different ambient and policy conditions.

We have used PCNEMS (1995 Version) and ancillary analyses to assess several policies designed to reduce carbon dioxide emissions in this sector, including extension of EPACT renewables credits, system benefits charges for sustained orderly development of renewables, carbon taxes and caps, accelerated deployment of new technologies, incentive financing, and externalities. This paper describes the sector and its representation in NEMS, the policies that we analyzed.

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Stephen Bernow, Michael Brower, William Dougherty,
and Max Duckworth[1]

Introduction

The U.S. electric sector has been an integral part of our national economy for many decades, providing cheap and reliable electricity as a spur to regional economic development and community and household amenity. However, owing to a variety of factors, the position of electric power in our national life faces new challenges. Among these factors are the local, regional and global environmental, health and safety impacts of electric power, and the physical, economic and political constraints on the availability of resources for electric generation. They reflect the availability and cost of oil and gas, the cost and risks of nuclear power, and the emissions of pollutants and greenhouse gases from coal and oil combustion.

Today, electricity satisfies almost fifteen percent of the nation's energy demand, consumes about one-third of the primary energy resources used, and represents about 1.74 percent of GDP.[2] It also contributes about 40 percent of the carbon dioxide, 70 percent of the sulfur dioxide, 30 percent of oxides of nitrogen and 40 percent of fine particulates, emitted annually in this country. It also contributes to release of myriad toxics, and to impingement on land and water resources. The U.S. electric sector alone contributes about 10 percent of the carbon emissions of the entire world. Meeting our international commitments to climate stabilization will require significant reductions in carbon emissions from this sector.

Institutional and technological changes are influencing the U.S. electric sector today. The possibility of wholesale and retail competition in a partially de-regulated industry, with an expanded role for independent power suppliers, promises opportunities but also raises concerns regarding provision of reliable, low cost, environmentally acceptable electric energy services. Additional and more stringent regulation of pollutant emissions, especially fine particulates and toxics (e.g., lead and mercury) is likely to be needed, based on new research showing that current standards do not adequately protect public health. Alongside these institutional changes are a number of technological changes that can also influence the future of the sector. Among these are the declining costs of wind and gas combined cycle plants, much lower projections of natural gas costs,

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[1] Contributions from Alan Nogee, Michael Tennis and Paul Jefferris of Union of Concerned Scientists are appreciated. Also, staff at EIA provided valuable advice and assistance on the PCNEMS model used in these analyses.

[2] Counting the value added in the inputs to the electric sector, including fuels and equipment manufacture, the share of GDP would approach about twice that figure.

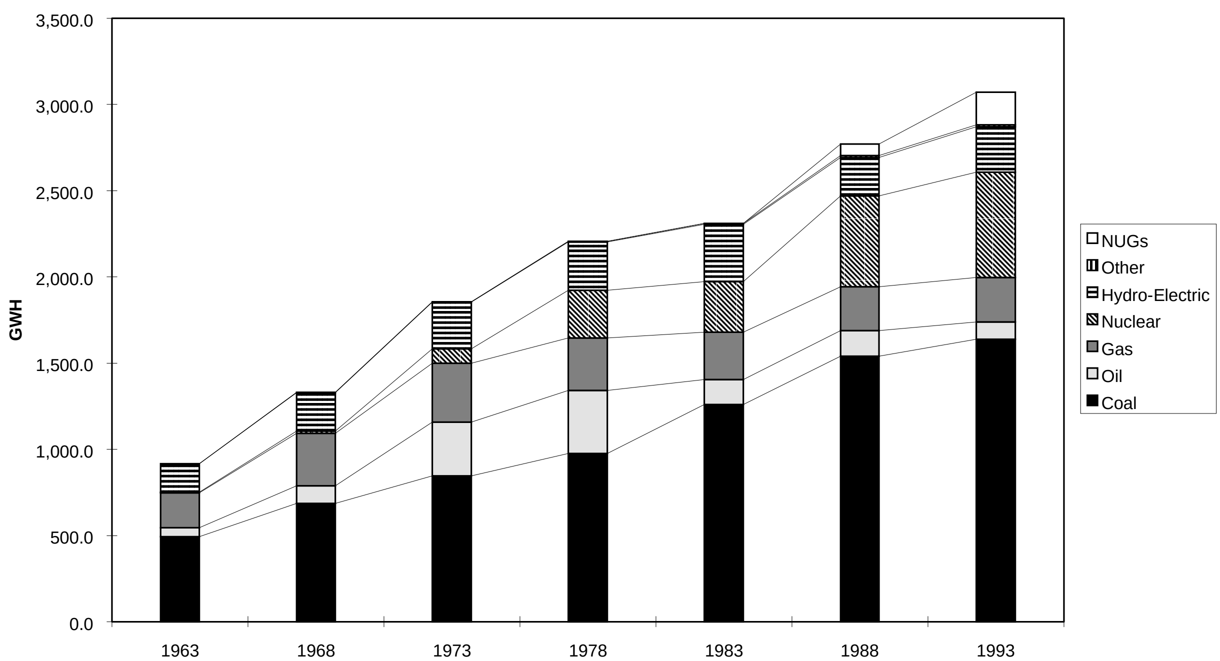
and relatively low costs of scrubbers and other means of complying with Title IV of the 1990 Clean Air Act Amendments.

These changes have created a new electric sector context, in the larger context of economic globalization and transition, for setting and meeting national climate change goals and commitments. Appropriate policies will have to be designed to be effective in this context.

Background

The current situation follows about three decades of deep changes and daunting challenges in U.S. electric utility industry, summarized in Figure 1.

Figure 1: Electric Generation by Type 1963 - 1993



Sources: Coal, Oil, Gas, Nurclear, Hydro-Electric, and Other from EEI; NUGs from NERC

Many changes occurred during this period; two oil embargoes and price hikes, the Fuel Use Act, the advent of nuclear power and the Three Mile Island Accident, the emergence of DSM and IRP, the PURPA law and growth of the independent power industry, energy efficiency standards, the Clean Air Act and its Amendments (including Title IV), and the Energy Policy Act of 1990. These events and others -- including structural shifts in the economy market induced investments in energy efficiency, etc. -- influenced the magnitude of the electric sector, its mix of resources, and its environmental impacts and have set the stage for the opportunities and policy debate on its future.

Growth of the sector prior to 1973 was at or greater than 7 percent annually, more than doubling every ten years, declining to over 3 percent in the mid-1970s, and further to about 1 percent between 1978 and 1983 owing to high fuel costs, cost of capital and electricity prices, before resuming at about 3 percent through 1988 and about 2 percent since. There has been a long term trend towards a decline of oil and gas-fired generation, while nuclear generation has increased to its current steady state level. In recent years independent power and renewables have begun to make significant contributions, well after PURPA and the initial forays of state IRP rules.

Over the period from 1988 to 1993 integrated resource planning (IRP), including renewables, independent power and DSM, was making its greatest headway in various jurisdictions around the U.S., and in some notable cases (including New York, Massachusetts, California, Nevada) the IRP protocols required inclusion off externalities.

While demand-side activity by some energy utilities traces back into the 1970s, electric utility DSM became significant nationally in the late 1980s in the context of IRP. Cumulative aggregate national electric energy savings from utility DSM grew from 16,300 GWh/year in 1989 (Hirst 1994) to 45,300 GWh/year in 1994 (EIA 1995). Peak demand savings roughly doubled between 1989 and 1993, reaching 23,000 MW in that year. While savings were projected to continue to grow throughout the 1990s due to the cumulative effect of DSM, actual spending by utilities peaked at $2.7 billion in 1993-4 and was projected to decline thereafter (EIA 1995).Non-utility (NUG) generation and non-hydro renewable resources also began to play a significant role during this period, increasing from almost 2.5 percent in 1988 to almost seven percent in 1993.

The electric DSM decline that began in the mid 1990s was not proximately caused by declining electric avoided costs, since the latter had generally been declining since the mid 1980s, while DSM was growing steadily. Ultimately, however, the gap between declining avoided costs and stable or growing retail rates, especially in high-cost service areas, fueled the shift from the regulatory policy driving DSM --the integrated resource planning (IRP) paradigm[3]-- to a market-competition policy during 1994-5.

By 1996, with both the Federal Energy Regulatory Commission and regulators in most states where IRP had been strong supporting the policy of deregulation and competition in power supply, most utilities began to cut back DSM substantially, and some entirely. While there were counter-trends -- the first DSM in some states started in 1995-6, for example -- our best estimate is that utility DSM spending will fall to half its peak levels, or further, before stabilizing, in a "business-as-usual" scenario. Stabilization is possible, however, since many states' policy frameworks allow for DSM funding through the electric distribution companies, which will remain regulated utilities after restructuring. Nevertheless, based on what has been learned from DSM experience to date and refinements leading to more effective programs, future DSM expenditures would likely produce greater energy and capacity savings per dollar invested than did the average of past programs.

Coal-fired generation has continued to maintain a share of approximately 50 percent of total generation, while growing steadily in absolute terms. Title IV of the 1990 Clean Air Act Amendments is expected to reduce SO_2 emissions by about 50 percent at surprisingly low costs, rendering coal generation -- with its CO_2, NO_x, particulates and mercury emissions -- an

[3] Originally developed as a framework to counter a tendency for vertically integrated utilities to invest in excess and/or uneconomic capacity under rate-of-return regulation, IRP had evolved during the 1980s to include the concept of utility investment in those DSM resources less costly than long-term supply from a total resource and/or societal perspective. The competitive model proposed deregulation and industry restructuring, not IRP, as the solution to excess generation investment by utilities, and refocussed solely on the supply component of energy costs.

economically attractive option in the competitive environment that appears to be emerging in the industry. Thus, while renewable electric resources and cleaner, more efficient fossil technologies (such as NGCCs) have markedly improved costs and performance, the existing coal fleet will largely prevail in the absence of complementary policies to further protect the environment and public health.

If the only goal for this important sector of our economy and national life were cheap and reliable electricity, this future prospect would not be problematic. However, a broader and deeper vision for this sector (in concert with others) is to ensure public health, and local, regional and global environmental integrity, while maintaining a vital economy and meaningful employment opportunities for the nation's citizens.

Base Case Projections

The evolution of electric sector over the next 15 years will be dominated by the economic, technological and institutional factors described above. As restructuring of the electric utility industry is still a nascent process, it is not readily amenable to modeling in general and by NEMS in particular. Nonetheless, we reflect this process of change in our Base Case by assuming no further utility sponsored Demand-side Management (DSM), leaving it to our policy scenarios to reflect interventions to preserve and expand this policy option.[4]

In Table 1, above, we present the Base Case projections of electric generation in the U.S. assuming 1996 AEO fuel prices.[5] We take all 1995 AEO planned additions through the year 1998, but have eliminated those assumed for the subsequent years. The table provides results that reflect the feedbacks from the fuel supply and macro-economic modules of NEMS.

The overall growth in demand is projected at 1.4 percent/year from 1992 through 2010, somewhat slower than the recent past, while prices remain stable in real terms. The share of coal generation declines from 53 to 47 percent, while that of gas increases from 9 to 19 percent and the contribution of non-utility generation (NUGs or IPPs) increases from about 2 percent to almost 10 percent. Utility and IPP renewables remain steady at about 10 percent. Cogeneration and IPP power is a mix of natural gas, renewables, and coal. Carbon dioxide increases at about 1 percent per year, a bit slower than growth in electric generation at 1.1 percent/yr, while SO_2 declines owing to the Title IV cap and trade system.

[4] Increased competition could also entail a different capital structure and costs of capital (i.e., higher) for electric power plant investments to reflect the different levels of perceived business risk in such an environment. On the other hand, it has been argued that this could be offset by competitive pressures on the capital costs of new facilities; while this may be a real phenomenon, we already may have seen much of the benefit in recent years.

[5] We have used PCNEMS (1995 version). As we have made some changes to the underlying assumptions in the demand modules, modified the 1995 AEO planned electric generation additions, and based our plant costs and characteristics on AEO 1996 assumptions, the Base Case results here differ somewhat from the AEO 1995 and 1996 projections.

Table 1
Base Case Electric Sector Projections
- 1996 Fuel Prices -

	1992	1995	2000	2005	2010
Generation (Million Mwh)					
Utility and IPPs					
Coal Steam	1578	1665	1687	1724	1782
Petroleum	90	77	80	96	87
Natural Gas	280	316	410	530	703
Nuclear	619	621	651	652	595
Pumped Storage	(3)	(2)	(2)	(2)	(2)
Renewable	293	330	365	384	404
Cogen Purchases	107	130	138	148	159
Net Imports	28	42	38	48	51
Total	**2992**	**3179**	**3367**	**3580**	**3779**
Sales (Million MWh)	2763	2992	3168	3370	3559
Price (1993 c/kWh)	7.1	6.7	6.6	6.6	6.8
Carbon (Million Tonnes)	475.5	498.4	516.0	545.0	573.3
SO2 (Million Tonnes)	13.6	11.1	9.4	8.4	8.3
NOx (Million Tonnes)	7.1	6.8	5.4	5.7	6.0

Issues

There are a number of recent and emerging institutional and technological developments -- industry restructuring, clean air compliance markets and technologies, costs and performance of alternative electric generation options, market barriers -- that will help to shape the future of the electric sector and the policies that will be needed to achieve efficiency, environmental protection and carbon reductions. These developments and their likely impacts are summarized in the following sections.

Institutional

The electric utility industry in the U.S. is currently in transition. While its historic structure is changing, it is not yet apparent what new structures will emerge. The strong push toward deregulation and competition may find limited expression in increased competition within wholesale power markets, but could also extend to include direct access to generation for retail customers. Here, we will use the term ”restructuring” for these changes, ignoring many important details.

The FERC is taking a leading role at the national level in promoting electric industry restructuring. Its *Notice of Proposed Rulemaking* on open access and stranded costs was a major step toward increased competition in wholesale electricity markets. Related activities in the states are moving at very different paces. Some states are moving to provide direct retail access as early as January 1, 1998, while other states are taking no apparent action on restructuring.

The potential environmental impacts of electricity restructuring are enormous. While there are some potential environmental benefits from restructuring, in the absence of complementary policies the threats seem to loom larger. On the benefits side would be incentives to build new, more efficient and cleaner generating facilities while shutting down existing units with much higher rates of air pollutant emissions. Some have argued that subjecting the existing units to market pressures will cause this retirement and replacement to take place. It appears, however, that the vast majority of existing power plants, including the existing fleets of coal and oil fired plants, are competitive compared to new plants for which new construction investment would be required. This is true, even at today's low natural gas prices, and notwithstanding cost reductions and technical advances in the efficiency of combined-cycle plants.[6] Rather than causing existing units to shut down, restructuring could lead to extended operation of these high-emitting units at higher capacity factors to meet electricity demand as it grows.

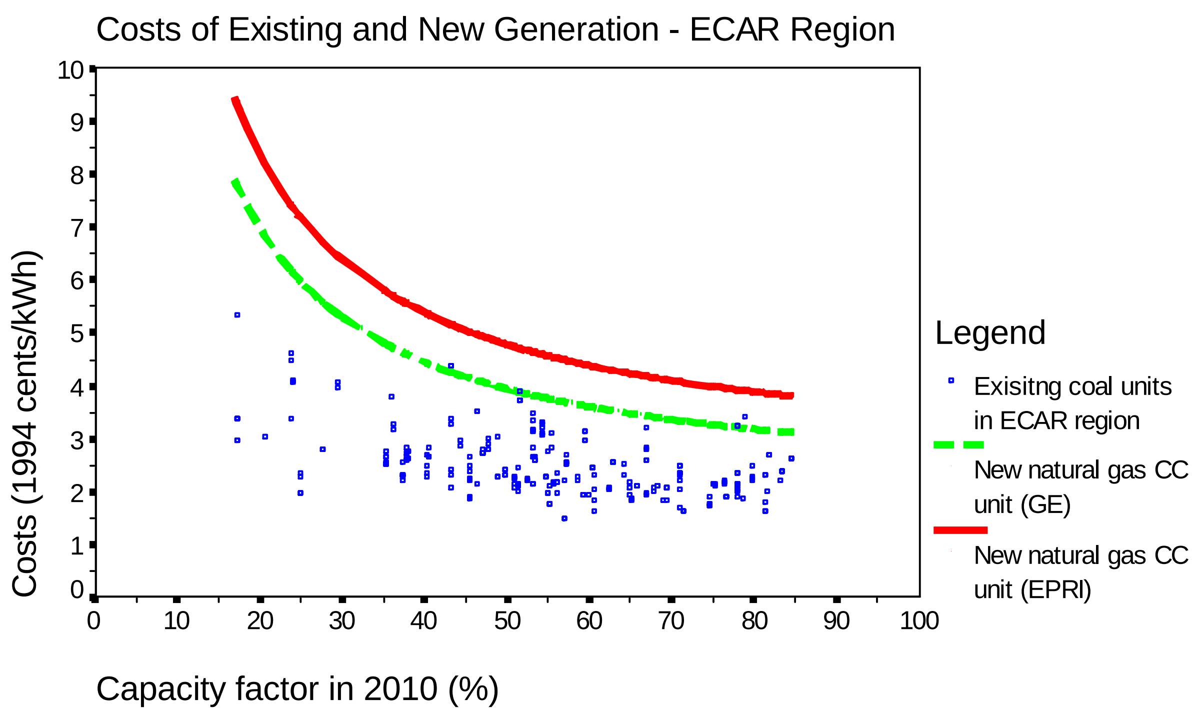
The consequences of increased power production from existing fossil plants are clearly negative for the environment. Older power plants tend to have higher heat rates and significantly higher emission rates than more recently constructed plants. Several studies have attempted to predict the increase in emissions resulting from competition by looking at the effects of increased utilization of existing generating facilities. For example, Harvard Electricity Policy Group report estimates that a relatively modest average capacity factor increase among U.S. coal-burning facilities from 64 percent to 67 percent would have the net impact of increasing SO_2, NO_x, and CO_2 emissions in the year 2000 by 1,113,000 tons, 492,300 tons, and 42,929,000 tons, about 11, 8 and 2.5 percent, respectively (Lee and Durani 1995). As the full availability of existing coal plants is generally more than 80 percent, there is potential for even greater increases in these emissions. Another recent study has estimated that if American Electric Power were to increase the average capacity factor of all its coal units to 80 percent, then the incremental NO_x emissions in the five-month ozone season would amount to 52,900 tons in the year 1999 (Center for Clean Air Policy 1996).

These conclusions are corroborated by a recent study (Bernow et al. 1996) whose findings are summarized in Figure 2, which provides the comparative costs of operation of essentially all coal plants in the ECAR system and new NGCCs for the year 2010, using high-end SO_2 compliance costs and NO_x control cost.[7] It shows that most existing plants generate at costs between 10 and 30

[6] And also notwithstanding operating efficiencies that utilities are beginning to implement in existing fleets.

[7] In 1994 these ECAR coal plants operated at a 56 percent capacity factor and generated 425,000 GWh, about 14 percent of all generation in the U.S. It also produced about 3.2 million tons SO_2 and 1.4 million tons NO_x, about 18 and 20 percent, representively of utility emission of these pollutants. The projections in the figure assume that the capacity factors of coal units grow to match EIA projections of 64 percent by 2010. All costs are levelized over 10 years to reflect a shorter financial

mills/Kwh, while a small portion at higher running costs operate at low capacity factors and thus make a relatively low pollution contribution. The figure also shows that generation from the existing fleet of fossil plants will be less costly than new clean NGCCs in a competitive power market for the foreseeable future. Thus, they would not likely be retired or displaced as some have predicted; rather, as their capacity factors are well below their maximum availabilities, in the absence of other constraints or market costs for pollution, they could provide even more generation and pollution as demand grows.[8]



While this important issue of increased air emissions from existing fossil power plants, particularly in the Midwest, has received quite a bit of attention recently, there are variety of mechanisms through which restructuring poses threats to the environment throughout the U.S. A recent report for NARUC (Tellus Institute 1995) identifies the following:

- **Decreased DSM** -- Utility efficiency and load management programs have already been scaled back, and there is pressure to cut further in order to keep prices as low as possible.

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time horizon in a competitive market, and the high and low NGCC curves reflect current (EPRI TAG 1993) and projected (EIA 1996) costs and characteristics. Finally this high case assumes SO_2 and NO_x compliance costs would be \$500/ton and \$1000/ton, reflecting scrubbers and selective catalytic reduction technologies, respectively.

[8] Competition could, indeed, accelerate demand growth, by providing lower cost electricity, engaging in sales promotion, or both.

- **Sales promotion** -- Electric utilities may find it increasingly feasible and attractive to market incremental sales of electricity through promotional rate designs and new packaging of services.

- **Shifting load profiles** -- To the extent that competition involves pricing on a finer time scale (e.g., hourly or "real time" pricing) customers may buy more electricity during off-peak periods and less during peak periods, a shifting that for many systems would result in reduced generation from gas and oil units offset by increased generation from coal units, with net environmental harm.

- **Nuclear plant retirement** -- To the extent that uneconomic nuclear units are forced into retirement by market pressures, there will be environmental benefits of less nuclear waste, and environmental harms of increased fossil plant air emissions.

- **Changing plant mix** -- More market-oriented capacity expansion may involve higher costs of capital and higher discount rates associated with new construction, thereby favoring options with costs that tend to be lower in the near term and higher in the future. This would shift the mix of new generating additions away from traditional baseload units (with relatively higher construction costs) towards peaking units (with relatively higher fuel costs). It would also tend to decrease the economic attractiveness of investments in certain renewables and DSM. The net effect of this would be that existing, high polluting units would tend to run at higher capacity factors and increased air emissions.

- **Inefficient dispatch** -- With centralized, cost-based dispatching of all resources in a power pool, an overall economic system utilization of generators is achieved. Changing this system to a bid-based dispatch and/or overlaying bilateral contracts the system could result in a sub-optimal dispatch, with generally (although not always) negative environmental impacts.

- **Cost pressure on plants** -- Market pressure to trim costs at power plants could translate into declining environmental performance, as owners may be increasingly reluctant to invest in emissions reduction equipment.

- **Less reliance on IRP** -- Integrated resource planning practices tend to promote the evolution of an electric system toward low, cost and clean resource mix. If competition is extended to the retail level, and IRP is weakened or eliminated, there would tend to be negative environmental implications.

To the extent that restructuring of the electricity industry moves forward and competitive forces are relied upon to replace regulatory oversight, it is essential that a truly competitive market materialize. Particularly for small customers who may not have other options, it is important to have an active market with minimized barriers to entry, open access to wires service, reasonable transaction costs and low levels of concentration of ownership in generation.

While this is foremost a consumer issue related to price (see Stutz et. al. 1996), market power has some environmental implications as well. For example, as noted earlier, electric system air emissions would tend to be reduced if new, clean resources can compete with exiting dirtier plants. Yet, incumbent utilities may be able, through control of the distribution wires or predatory pricing, to block or discourage new entrants to the market. In such a scenario, the innovative new companies offering "green power" portfolios (with new, efficient gas generation, renewables and/or DSM) would have trouble competing, and additional electricity generation would come from increased operation of existing power plants, with their relatively high emission rates.[9] Policies to address market power in electricity, such as limiting the concentration of ownership of generating resources in a region or providing new entrants with access to distribution can be helpful, to the extent that they enable new, clean resources to compete.[10]

That there are barriers to the use of renewable generation and efficient end-use technologies is not new. The factors that have historically presented obstacles to cost-effective energy efficiency investments include lack of information, limited access to capital, troublesome institutional relationships (e.g., landlord/tenant issues, utility incentives to avoid lost revenue). For renewable resources, some of these market barriers are compounded by technical difficulties such as ascribing appropriate capacity value to intermittent resources. It was these barriers towards which IRP was addressed. With restructuring, and the uncertain role of IRP, it appears that investment decisions will focus upon even shorter time horizons with little guarantee that cost-effective efficiency and renewables, and environmental goals and costs, will be reflected in electric sector resource decisions.

Many of the environmental harms of our energy system have long-term aspects. Radioactive waste, climate change, bio-accumulation of toxics in ecosystems occur over decades, even centuries. Competitive electric power markets may bring some welcome benefits in terms of near-term productivity gains. However, an unconstrained electricity market will not address the legitimate concern for long-term sustainability; indeed it could exacerbate risks to sustainability. Thus, if and as restructuring takes place, there is a need for complementary policies and mechanisms to ensure that energy efficiency, renewable resources and environmental protection are afforded their legitimate places in the process.

The opportunity in electricity restructuring is to use market forces where appropriate, removing barriers so that the market can work most effectively, while constraining the market where

[9] The ability of new cleaner resources to compete is a *necessary* condition for their contribution to emissions reductions. As shown earlier, it may not be *sufficient* to ensure a large contribution.

[10] In its recent orders, the FERC has been making progress to ensure that there will be open access to electricity markets.

appropriate, setting targets within which the market must function. Barriers and disincentives can be addressed through programs to provide access to reliable information and funds for investment in efficiency measures, or programs to provide incentives for efficient decision-making. Targets constraining the market can take the form of resource portfolio standards (such as a sustained orderly development approach for renewable resource commercialization) or air emissions caps (such as the CAAA sulfur dioxide allowance trading system.

Technological

Advanced Fossil and Low Emissions Technologies. Important advances have been made in the costs and operating characteristics of fossil fuel technologies, leading to improved heat rates and lower emissions rates. Moreover, coal prices, including those of low sulfur coal, have remained stable, while the escalation rates expected for natural gas prices have come down considerably from those projected throughout the 1980s and early 1990s. Thus, even as some renewable technologies have become more attractive economically and environmentally, so too have some fossil technologies. The expected heat rate of coal power plants (500 MW pulverized coal) has decreased in EPRI estimates from 10,150 in 1982 to 9736 in 1993, while capital costs (in 1993$) have decreased from $1665 per kw in 1986 to $1421 per kw. The latest EIA projections entail further cost decreases and heat rates around 8,000 for advanced technologies (IGCC) with sufficient production and deployment in the next decade. For natural gas combined cycle (NGCC) plants expected heat rates have declined from 8,140 in 1986 to 7,520 in 1993, while capital costs have declined to about $595 per kw. Further developments expected by EPRI and embodied in NEMS would lead to heat rates of 5,687 and capital costs of about $500 per kw in the first decade of the next century.

Clean Air Act Compliance. Title IV of 1990 Clean Air Act Amendments (CAAA) established nationwide emission limits for both SO_2 and NO_x. Under Title IV, the *acid rain program* introduced an innovative, market-based approach for complying with SO_2 regulations, in the form of unrestricted emission allowance trading under a nationwide cap. The aim of the program is to reduce SO_2 emissions by 50% relative to 1980 levels by the year 2000, to an annual cap of 8.95 million tons of SO_2 in 2000 and beyond. Owing to the discovery of large seams of low sulfur coal in Wyoming, and the sharp decline in rail transport costs (Burtraw, 1996; Ellerman, 1996), compliance with the Title IV SO_2 limits has been much less costly than was predicted at the outset of the program. Current allowance costs are below $100 per ton rather than the $1000 per ton or greater that had been anticipated. Future costs will be in the range of about $100 per ton (Biewald and Duckworth, 1996) -- if economical low sulfur coal remains available and the number of banked allowances stretches well into the next decade -- to about $500 per ton (both in 1994 dollars) if flue gas desulfurization (scrubber) equipment becomes the widespread compliance option of choice (Rubin et al, 1995; Bernow et al, 1996). Even this high-end cost is lower than was previously foreseen, as technology costs and efficiencies have improved.

Compliance strategies with the Title IV NO_x limits are not as well developed, since EPA is yet to set specific limits to reflect its goal of an overall emissions reduction of 2 million tons by the year 2000. Nonetheless, it appears that the technologies that would meet currently proposed limits (emissions rates ranging from 0.3 to 0.9 lb per MMBtu, depending upon the boiler) and rules, will be low-NO_x burners, perhaps with overfire-air retrofits, at estimated costs of $400 per ton (1994 dollars) (Bernow et al, 1996; Tran and Frey, 1996) In the event that these NO_x standards are tightened, or in ozone non-attainment areas, control technologies such as SNCR and SCR may be required, at costs in the region of $1,000 per ton (Bernow et al, 1996). One consequence of these developments is that compliance with Title IV limits for SO_2 and NO_x will not likely entail significant carbon emission reductions, as would have been the case had fuel-switching and improved efficiency been more widely used options. This could, however, be reversed if more stringent restrictions are placed on SO_2 and NO_x emissions in the future.

Renewable Electricity Sources. Renewable electricity sources include hydro, wind, biomass (wood and other plant matter), solar, and geothermal sources. Since the early part of this century, hydropower plants have supplied a substantial, though declining, portion of US electricity demand about 10 percent in 1993. The others have been developed to a much smaller degree, however. Biomass and municipal solid wastes presently generate about 2.4 percent of the nation's electricity[11], geothermal plants about 0.6 percent, wind 0.1 percent, and solar a negligible fraction.

The renewable energy industry has gone through several boom and bust periods. There was enormous interest in renewable energy during the oil crises of the 1970s and early 1980s. This led to a spurt of government and private research into new and updated technologies such as wind turbines and solar (photovoltaic) cells. Some of these technologies experienced considerable commercial success with the help of federal- and state-level tax breaks and price supports. For example, about 15,000 large wind turbines were installed in California with a private investment of several billion dollars, and today wind power provides about 1 percent of California's electricity. A number of solar and geothermal power plants were also built in this period, and residential solar collectors became quite popular in some parts of the country. When oil and gas prices plummeted in the 1980s, however, the nation's passion for renewable energy faded along with them.

In the late 1980s and early 1990s, private and government investment in renewable technologies rose once again. This time the renewed interest was fueled not by any popular sense of energy crisis or high fossil-fuel prices but by the growing economic competitiveness of renewable technologies coupled with strong public concern about environmental issues such as air pollution and global warming. Government spending on renewable energy research which had dropped precipitously in the 1980s climbed every year from 1990 to 1994. In 1992, as part of the Energy Policy Act (EPAct), the Congress enacted a production incentive of 1.5 ¢/Kwh for wind energy and sustainable (or closed-loop) biomass energy systems, and made permanent a 10 percent tax credit for commercial and industrial solar investments. Most significantly, power companies and other private businesses

[11] About 0.8 percent in MSW plants, 0.4 percent in wood-fired plants, and 1.2 percent in cogeneration facilities.

began investing again in a variety of renewable technologies, especially wind, geothermal, and photovoltaic systems. The future for the renewable energy industry appeared bright.

In the mid-1990s, however, the near-term prospects for renewable energy once again are threatened. Continued low fossil-fuel prices, combined with uncertainty over utility restructuring, have undermined much of the progress made in reducing the costs and improving the performance of renewable technologies. The case of wind power, one of the most cost-effective renewable electricity technologies today, is illustrative. Despite achieving costs as low as 4-5 ¢/Kwh (and even lower in some cases, according to published reports), total wind energy capacity grew by only 40 megawatts in 1995, a 2.4 percent increase on an installed base of about 1700 MW.[12]

The Market Context. Why do renewable energy sources face such difficulty in penetrating the US electricity market? Two relatively recent problems are having a profound effect:

- **Competition from natural gas.** The average price of natural gas paid by electric utilities has been low (about $2.30/MMBtu) since the mid-1980s, and is widely expected to remain so for the next 10 years or longer. In addition, gas-fired combined-cycle plants have become inexpensive and highly efficient, making this technology often the least-cost option for new electricity supply. For example, according to AEO '95 assumptions, the 30-year levelized cost of power from a gas-fired combined-cycle unit is expected to be about 3.5 ¢/Kwh in the year 2000.

- **Uncertainty over electric utility restructuring.** The nation-wide movement to restructure the electric utility industry has discouraged utility investments in new power plants, especially capital-intensive ones such as those fueled by renewable resources. The problem is not competition itself, which could create some near-term new investment opportunities if it allowed customers to express a preference for cleaner sources of power through their choice of electricity supplier. Rather, it is the tremendous uncertainty surrounding the scope and nature of the industry reforms now being discussed that inhibits investments in renewable technologies.

  In addition, several long-standing issues confront the commercialization of renewable energy technologies:

- **Financing barriers.** Financing for independent renewable energy projects is expensive and often difficult to obtain. Technological uncertainties play a part, but the bigger problem is that independent renewable energy companies are generally undercapitalized and have weak financial track records. These hurdles are compounded by the relatively high initial capital costs of renewable projects (per unit of capacity) and the corresponding need for greater returns in early years.

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[12] Kenetech, the largest wind developer in the U.S. has just declared chapter 11.

- **Institutional barriers.** Utility companies have historically been reluctant to embrace renewable energy technologies (other than hydropower). A basic reason for this is a lack of familiarity and experience with the technologies and their sometimes unusual characteristics, such as intermittence and seasonality. An example is continuing uncertainty over the capacity value of intermittent resources such as wind and solar power.

- **Market failures.** Probably the most serious market failure affecting renewable energy sources is the fact that environmental impacts are accorded insufficient value in the market. In particular, no fees or taxes are placed on emissions of greenhouse gases and no special subsidies or tax breaks are given specifically to resources that do not produce such gases. Other pollutants, such as toxic metals, are also presently unregulated and their costs to society not internalized in the market.

- **Regulatory failures.** Under the rate-of-return regulation that has been practiced in most jurisdictions until now, utility decisions on new power plants are dictated in large part by rules established by state-level public utility commissions. These rules often ignore key benefits of renewable energy sources, such as modularity and fuel diversity. Since utilities are protected under present regulation from many of the risks of the market, they have had little incentive to take such factors into account.

Policy Interventions. Despite the bleak near-term prospects for renewable energy sources, their long-term future appears bright as their costs are likely to continue to decline while natural gas and other fossil fuels will eventually become more expensive. Policy interventions can greatly accelerate the process of commercializing renewable energy technologies, however, by helping to overcome some of the barriers they face. A basic aim is to create conditions leading to the *sustained, orderly development* of renewable energy technologies. This essentially means creating a market that grows in a predictable fashion for a sufficient time that industry growth can become self-sustaining. The existence of a predictable and growing market will help companies secure financing for new projects and justify investments in research and development, leading to technological innovation and cost reductions.

Three renewables-specific policy interventions that might be considered are: extension of the renewable energy tax credits embodied in EPACT; collection and of a small system benefits charge on all energy sales and its allocation to "buy down" renewable electric technology cost to a competitive position relative to new fossil plants; establishment of renewable energy portfolio standards (i.e., national, regional, or state targets for a percentage of electricity sales by certain dates), with authorized credits that could be traded, thereby allowing resource poor regions to meet their obligations at costs reflecting the broader resource base. Green pricing is not, strictly speaking, a policy option in a highly competitive environment, as it is an option open to private developers and suppliers of electricity as part of their marketing strategies; green investment through public or private renewables energy authorities could play a role. Options which cut across all resources and would influence renewables penetration, include CO_2 tax and/or externalities taxes. Imposing a fee or tax on emissions of carbon dioxide would make fossil-fuel resources more expenses and thereby significantly improve the prospects of renewable energy technologies, depending on the amount of the tax. (This could reflect a national carbon tax system or be restricted to the electric sector.) Alternatively, a cap/trade system could be established to limit carbon emissions in the sector and/or nationally. A tax of $10 per ton, for example, would increase the perceived cost of a gas-fired combined cycle unit by about 10 percent, or 0.35 ¢/kWh. It would raise the cost of coal-fired power plant by about 25 percent, or 1 ¢/kWh. The first three policies have been modeled in this study, with encouraging results.

Policies

A variety of polices will be needed, as the electric industry is restructured, to ensure that the sector-specific and societal aims of integrated resource planning -- increased use of renewables and end-use efficiency, robustness in the face of uncertainty, internalization of environmental externalities, and the realization of climate change and other environmental goals -- are preserved.

Extension of tax credits. Under current law, the 1.5 ¢/kWh production incentive for wind and closed-loop biomass technologies will no longer be available after 1999. In addition, the incentive does not apply to open-loop biomass and geothermal technologies.[13] Extending the production incentive to 2010 and allowing it to apply to the other resources would give these technologies a significant boost.

Green Pricing. Another means of enabling greater development of renewables than would be cost effective in regulated utility terms, and thereby providing market pull towards commercialization, is “green pricing.” Green pricing may be defined as any mechanism whereby electric customers voluntarily elect to pay a rate premium to cover the incremental capital and/or operating costs of renewable energy over conventional energy. In return, the power supplier agrees that a proportion of the customer’s energy corresponding to the amount funded will come from renewable sources. The idea is that some customers will be willing to forego least cost electrical service in order to pay for the environmental and other external benefits conferred by renewable energy.

In theory, green pricing allows individual electricity customers to express their actual willingness to pay for the external values of renewable energy through direct payments of their monthly utility bills. This approach solves problems with regulatory evaluations of external costs and benefits, and avoids the need for the establishment of cumbersome and costly regulatory administrative bodies. It also allows utilities/suppliers to encourage renewables development at no competitive cost to themselves, or to customers uninterested in renewables. For this reason, green pricing can be implemented alongside either an RPS or a SBC.

[13] At present costs, the 10 percent tax credit for solar technologies is actually worth more than a 1.5 ¢/kWh production credit.

On the other hand, there are drawbacks to green pricing. To begin with, green pricing creates a false impression that renewable energy is always, and perhaps permanently, more expensive than conventional resources. This in turn reduces the onus on utilities to pursue renewable opportunities that are cost effective on their own merits. Green pricing also implies that customers will receive environmental benefits from their purchases. In fact, few public benefits will accrue directly to the individual purchaser, and rarely is there any link between the purchaser and the benefits of renewable energy per se. More importantly, by placing renewables purchasing decisions in individual hands, green pricing implicitly acknowledges that external benefits of renewables are not socially valued. Inevitably, in practice, because of the free rider problem, this means that only a small fraction of those benefits are actually captured.

Evidence about whether green pricing on its own is an inadequate mechanism for achieving even a small (5 percent) national investment in renewable energy is mixed. In general, although surveys suggest that 40 percent to 70 percent of respondents would be willing to pay premiums of between 6 percent and 10 percent for green products,[14] (Holt 1995; Marcus 1995; Byrnes, et al. 1995; Regulatory Assistance Project October 1994 and May 1995) actual participation rates in pilot programs or have been uniformly much lower, even when consumers were asked to contribute only 5 percent or less to their bills.[15] Similar, although slightly better results have been produced by

[14] In two contingent value surveys by Insight Research, Inc. residential customer willingness to pay $2.08 per month for a 20 MW mixed renewables program was over 80 percent and to pay $1.65 per month for a 1.2 MW solar program was 65 percent. A Cambridge Energy Research survey revealed 45 percent willingness to pay $4 per month in taxes for the "Development of new energy sources such as solar and wind power." The Associated Press conducted a poll showing that almost 60 percent of consumers would pay $5/month surcharge on fossil fuel to "prevent global warming." Gordon Black found that about 40 percent of consumers would pay as much as $50/month on bills "if it meant that electricity could be produced in a cleaner way that would reduce air pollution." Cambridge reports conducted a survey for the Edison Electric Institute indicating almost 80 percent willingness to pay $6/month to "have your electricity come from sources that are less harmful to the environment." An opinion poll by Hart-Teeter Research Companies showed almost 60 percent willingness to pay $10/month to enforce stricter air quality regulations. A focus group conducted by the New England Electric System in 1992 unanimously supported increasing NEES's renewables mix. Through a survey and interviews Niagara Mohawk determined that a 30 percent customer awareness level would result in 24 percent of the utility's customers agreeing to pay between $3 and $6/month. And through a process of focus group, telephone, and mailed surveys the Massachusetts Electric Company found that 44 percent of respondents would pay more for renewable energy, with 10 percent of respondents willing to pay a premium of up to 20 percent. Surveys reveal that a percentage of even those customer unwilling to pay for green power themselves may prefer providers who have a green portfolio (even if it is paid for by other customers).

[15] For example, the program by Public Service Company of Colorado inviting customers to pay $1.78/month for a 20-MW mixed renewables development led to around 10 percent participation among the 4 percent of customers aware of the program. The response to SMUD's PV program was initially around 2 percent, but has now risen to around 29 percent. The program run by Traverse City Light and Power costing $7.50/month led to a 3 percent participation rate. Detroit Edison has so far had very little participation in their $6.50/month pilot. Niagara Mohawk has had a less than 1 percent participation rate for their $6/month pilot scheme. Two PGE schemes led to a 1 percent and 2 percent response rate. In one scheme, customer sign-ups for US Bank products (a CD, a credit card, and a debit card) had a 1 percent response; in the other scheme, described earlier, in which customers rounded up their bills to the nearest dollar, the participation rate was 2 percent.

computer market simulations modeling not just how much consumers say they are willing to pay, but also arrangements to collect payment[16] (Byrnes, et al. 1995; Holt 1996).

If the low participation rates so far encountered by green pricing schemes prove to be the result of poor program design, then a combination of program improvements, time, more aggressive green marketing tactics and better communication with customers may lead to participation rates nearer to those suggested in surveys. If on the other hand, survey results prove to be wrong, either because of problems with the surveys themselves, subtle issues of trust, or inherently lower participation rates in voluntary programs to acquire such public goods than political acceptance rates for collective funding of public benefits programs, then green pricing alone may never be capable of creating the kind of market pull necessary to commercialize renewable technologies. If so, other mechanisms, including an RPS, and/or a SBC will be necessary.

Green Investment. A promising form of (or variation on) green pricing is "green investment", in which the customers buying renewable power actually own a share of specific facilities. In this way, the connection is made more concrete between the consumer's action and the power system. As a partner in the facility, the customer would be entitled to the renewable generation, thereby avoiding exposure to the risk of fossil fuel price increases, possibly gleaning tax advantages, and experiencing other rights and responsibilities of ownership. Perhaps existing and new renewable resources of various types could be bundled together, and handled as a green investment portfolio.

Renewable Portfolio Standard. The "Renewable Portfolio Standard (RPS)" is a market-based mechanism for ensuring a minimum level of renewable energy development in the electric generation portfolios of power suppliers in an implementing jurisdiction (e.g., a state). As originally proposed by Nancy Rader, a consultant for the American Wind Energy Association, it would entail the creation of a secondary market in tradable certified renewables credits. Sellers could meet their obligation through direct ownership of renewable generation, contracts for power from renewable generating facilities, and/or purchase of credits for sufficient renewable kilowatt hours in the secondary market.

The California Public Utilities Commission (CPUC) adopted an RPS mechanism in its December 20, 1995 electric utility restructuring order. A Working Group of interested parties was assigned the task of attempting to develop a consensus on implementation details, scheduled to be filed with the CPUC by July 1, 1996.

There are many possible variations on RPS implementation. Fundamentally, the minimum renewables obligation could be placed either on distribution companies subject to state utility regulations, or on all retail suppliers – including direct access generators selling at retail, municipal

[16] Simulations by Insight Research, Inc. revealed customer participation levels ranging from 0.4 percent to 9.4 percent of those customers aware of the programs.

utilities, and market aggregators – under an industry structure allowing retail competition. It could be applied at national or regional levels.

The RPS can be implemented with one overall requirement for all types renewables to maximize renewables generation at the lowest possible cost. Alternatively, development of a more diverse set of technologies could be encouraged by defining minimum levels for technology bands (e.g., solar); or by defining maximum market shares (e.g., no one technology may earn more than 60 percent of available credits); or by coupling the RPS with a system benefit charge targeted to research, development and commercialization support for less mature technologies. Other significant implementation issues include:

- determining the appropriate minimum level of renewables;

- establishing the period within which the target should be reached, and appropriate intermediate targets and dates;

- defining eligible technologies – types of renewables; whether credits are assigned to all renewables, or to renewables developed after commencement of the program; and how broadly to define the renewables credit trading area;

- assigning ownership of credits for existing renewables projects among project developers, utilities and ratepayers;

- designating an agency and a process for certifying renewables credits; and

- designing enforcement responsibilities and procedures.

The RPS has two primary advantages for promoting renewables. First, it provides the greatest assurance of meeting the level of renewables development sufficient to achieve desired public policy objectives, such as new technology commercialization, preservation or creation of renewables industry infrastructure, preservation or expansion of fuel diversity levels, and capturing environmental benefits. Second, it utilizes a market mechanism to achieve those objectives at the lowest cost. The RPS provides strong incentives for suppliers to find the lowest-cost, most reliable renewables projects, and to find the niche applications and customers where the projects will have the greatest value.

Also, if applied to all retail sellers, it is competitively neutral. The RPS avoids having to create an administrative agency or procedure for distributing funds, by internalizing the renewables premium in the marketplace. It provides a predictable market for renewables, which can be expected to drive technology costs down rapidly. In addition, because the standard is a floor, not a ceiling, it allows marketers to sell renewable energy to consumers wishing to exceed the standard.

A potential disadvantage of an RPS is that the amount of money needed to accomplish the objectives is not as well defined. This disadvantage could be eliminated, however, if necessary, through implementing a cost cap. A maximum price per kWh could be defined for projects eligible for renewables credits. Alternatively, retail suppliers could be allowed to petition the designated enforcement agency to delay the date for achieving the goal, and/or to reduce interim year targets, if retail sellers could demonstrate that they have tested the market and sufficient renewables were not available to meet the target within the cost cap.

Some observers have also questioned whether the RPS can be implemented by individual states or regions, or whether such implementation would be precluded by either the Commerce Clause of the U.S. Constitution, or by Federal Energy Regulatory Commission pre-emption.

Modeling the RPS. Modeling the cost of implementing a Renewables Portfolio Standard at various levels was beyond the scope of the present investigation. An approximation of the cost of the RPS could be made by looking at the inverse of the results found for the System Benefit Charge. Where it was found that a SBC of x mills per kWh yielded new renewables equal to y percent of sales, it could be inferred that an RPS of y percent would cost approximately x mills per kWh.

The actual cost of an RPS, especially in early years, however, is likely to be lower than what would be inferred from the SBC analysis. First, the RPS market mechanism is likely to produce lower cost projects. Second, the RPS is likely to ferret out market niches and customers which place a premium value on renewables, reducing the cost to other customers. Third, the RPS produces some annual incremental renewables cost (or benefit) over the life of a renewables project. Because an SBC may be in place for only a limited period of time, such as during a transition to a more competitive industry structure, it may be desirable to front-load the SBC, effectively buying down the incremental revenue stream for the life of each project in the year each project is installed.

A market mechanism, such as an "Auctioned Renewables Credit," could also be used to reduce the cost of implementing a renewables system benefit charge, thereby reducing the cost of SBC implementation. However, the RPS places the responsibility on retail suppliers to find the lowest-cost highest-value projects, whereas the SBC places the responsibility on renewables developers to find highest-value markets for their projects. Because retail suppliers are likely to have more resources, more familiarity with the overall generation market, and much more information on the preferences of retail customers, the RPS is likely to be more efficient in this regard.

System Benefit Charge. System benefits are defined as a class of investments or expenses made by today's regulated utilities that provide services that are in the "public interest" but may not necessarily be profitable and therefore provided "naturally" in a market-based electricity supply system. Although the specific investments or services included in the definition of system benefits are not universally accepted, most definitions include one or more of the following: low-income customer services, conservation investments, renewable energy resource acquisition, and research and development funding. Although market purists argue that many or all of these activities will ultimately be funded under a more competitive electric utility system, the documented response of many utility companies anticipating restructuring has been to cut these investments and expenses wherever possible, and there are inherent market barriers and failures which will likely lead to sub-optimal spending. In light of this situation, it appears essential that policymakers develop effective mechanisms for assuring that "system benefits" are maintained during any transition to a restructured electric utility industry and to evaluate the performance of markets in supporting these public interests.

In today's regulated electric utility industry customers receive electric bills that cover a plethora of costs relating to utility activities. The majority of these charges cover the costs of building, operating, and maintaining the power system assets including power plants, transmission and distribution lines, service vehicles, and personnel. A small part of the customer's bill covers utility activities loosely defined as "system benefits". These include the costs of investments and services that are in the public interest in the short-term, like low-income customer payment plans, lenient service disconnection policies, company contributions to local charities or public events, etc. System benefits may also include investments in the research, development, and demonstration of energy resources that are promising in the long-term and exhibit payback periods longer than some of the conventional utility resources. In recent years, the cost increases due to energy efficiency and load management program implementation have also come to be considered as system benefits.

The magnitude of these costs varies from utility to utility depending on a long history of integrated resource planning, regulation, and ratemaking. The Regulatory Assistance Project (RAP) estimates that the current cost of "system benefits" ranges from 1 percent to 5 percent of the average bill (Regulatory Assistance Project 1996, p. 36). RAP also suggests that these costs are often allocated on a "volumetric" basis proportional to kilowatt-hour consumption, kilowatt demand, or both. These charges could also be allocated on a per customer basis although this approach is less common.

The issue of collecting the funds necessary to support system benefits has received considerable attention from policymakers in the US during the ongoing debate on electric industry restructuring. There are also some examples of utility systems where system benefit charges have been successfully implemented. Policymakers have identified several attributes that any scheme for funding system benefits should have. First, the system benefits charge should, to the maximum extent possible, be competitively neutral meaning that the existence or magnitude of the charge does not change the economic decision made by a customer. An important element of competitive neutrality is making the charge non-bypassable. Every electric customer regardless of their size or type of service should contribute their fair share to pay for system benefits.[17]

[17] Self-generators that rely on the interconnected utility system for back-up power or other service would be expected to contribute as well.

A fundamental characteristic of a system benefit charge approach is that the total fund to be collected is defined in advance so that customers and policymakers know the costs of “benefits” precisely. These funds are then used to pay for as many “benefits” as they can support.[18] Mechanisms for accomplishing this have been given a variety of names including: wires charge, access charge, universal service charge, public goods charge, or distribution charge (Regulatory Assistance Project 1996, p. 36). A system benefits charge can be developed and administered through a collaborative process, although implementation issues include who should collect and disburse the fund, and through what mechanisms. Options for administration include the distribution company, or an independent administrative authority. If the distribution company administers the fund, it is important to include regulatory provisions that encourage the use of the fund for off-grid, distributed applications.

One disbursement mechanism that insures maximum acquisition of system benefits at the predetermined cost is some form of competitive bidding. For renewable energy, an “Auctioned Renewables Credit” would allow developers to submit bids to the fund administrator to utilize system benefit funds.[19] Use of such a competitive mechanism would reduce the cost of support per kWh, but would make it more difficult to fund less mature, and therefore more expensive technologies. Caution would have to be exercised to avoid a “winner-take-all” scenario, either by reserving portions of the fund for bidding by specific technologies, or ensuring that no more than 60 percent of the fund could be won by a single technology. Alternatively a portion of the SBC could be set aside specifically to fund research, development, and demonstration of technologies that are less commercially advanced. In that function, at least, it could be combined with a renewable portfolio standard.

Modeling the System Benefit Charge. In our analysis, we employed the revenues raised by a 2 mill per kWh SBC (2 mill per kWh multiplied by each year's electricity consumption) through the year 2010, to buy down the projected capital costs of the renewable generating options to levels competitive with conventional alternatives in the year of installation.[20] These revenues amounted to about $6 billion per year, which could buy down about 60,000 MW phased in by 2010 by $1000/kw (or $100/kw-year). Based on the level of deployment of each renewable technology achievable through this policy, the model used predicts the level of market penetration likely to be achieved by each technology in competitive interaction with conventional generating resources. A key benefit of this policy, reflected in the models employed here, is the amplification of the strictly SBC results by the learning and technological improvement that further reduces capital costs with greater levels of penetration and manufacture of the technology.

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[18] In contrast, the portfolio standard approach specifies the physical quantity of resources to be acquired precisely and accepts some uncertainty regarding the ultimate cost of these resources.

[19] Dan Kirschner of EDF has been a proponent of this approach.

[20] Note that poll results show that more than 74 percent of voters support paying up to an extra 2 percent of their bills for renewables, and more than 50 percent support paying up to 5 percent more. (Research /Strategy/ Management, Inc. 1996.) The 2 mill system benefits charge adds about 3 percent to electricity prices.

Results. The 2 mill per kWh system benefits charge was applied to capital cost reductions as shown in Table 2.

The 2 mill system benefits charge results in about 22,000 MW of non-hydro renewable capacity by 2000 (about double the Base Case) and 88,000 MW by 2010 (more than five times the Base Case).[21] While non-hydro renewables contribute about 11 percent to total installed capacity in 2010, total renewables contribute about 21 percent (169,000 MW). By 2010 about 10 percent of generation is from non-hydro renewables and about 18 percent is from all renewables.

Table 2
2 Mill Systems Benefit Charge
Capital Cost Impacts ($1992/KW)

	1998		2010	
	Base	SBC	Base	SBC
Wind	$1,027	$ 881	$ 750	$ 711
Solar Thermal	$2,125	$1,537	$1,481	$1,377
PV Central	$2,954	$ 861	$2,061	$1,998
PV Distributed	$3,840	$3,840	$2,679	$2.064
Biomass	$2,333	$ 350	$1,383	$ 216
Geothermal	$3,157	$2,439	$3,157	$2,330

Electric sector carbon emissions in this policy case are reduced in 2010 by about 31 million metric tons or 5.5 percent, and NO_x emissions by about 5 percent. These reductions are realized at additional costs in 2010 of about $25 per ton of CO_2 and $1000 per ton of NO_x, respectively.

Emissions Reduction Policies. Current policies embodied in the Clean Air Act will limit emissions of some pollutants from the electric sector. New source performance standards, the SO_2 cap and allowance trading, improved efficiencies of new power supply facilities, and greater use of natural gas and renewables, will contribute to keeping emissions of SO_2, NO_x, CO_2 and other pollutants below their recent levels on a per kWh basis and, in the case of SO_2, below historic levels in absolute terms. Nonetheless, as noted earlier, emissions problems will persist, and perhaps become exacerbated by the emergence of competition in the electric sector, largely from generation by the existing fleet of fossil plants, particularly coal plants. Carbon dioxide emissions continue to

[21] It should be remembered that from the standpoint of system reliability, the capacity equivalent (fraction of installed renewable capacity that contributes the same system reliability as fossil capacity) is relatively low for intermittent resources such as wind and solar (Bernow et al 1994). Thus, with renewables a greater amount of capacity is needed. Here, the 88,000 MW (almost three-quarters wind and solar) could have an equivalent capacity as low as about 40,000 MW.

grow, by about 20 percent between 1992 and 2010, despite our FCCC commitments to stabilize these emissions.

Moreover, there is ample reason to limit further the emissions of SO_2 below the targets (9 million tons per annum, and an emissions rate average of 1.2 lb per MMBtu) established by Title IV of the Clean Air Act Amendments of 1990 as well as NO_x below its target of about 6 million tons per year, particularly in the ozone forming season. These pollutants present regional health and environmental concerns beyond those addressed by the existing legislation. Sulfur and nitrogen oxides undergo atmospheric transformations that result in the formation of acidic fine particulates which have been linked to excess mortality risks. Recent investigations have found an association between human health and small particulate air pollution in metropolitan areas. In particular, Dockery has concluded that fine particulate air pollution (i.e., less than 2.5 microns in diameter) contributes to excess mortality in U.S. cities (Dockery 1991; Schwartz 1991). Moreover, currently unregulated mercury emissions persist in the environment, and are linked to risks to pregnant women upon ingestion of methyl mercury as well as reduced populations of certain wildlife species. Other toxics (including, for example, mercury, lead, chromium, magnesium and beryllium) with known adverse health effects are released in the combustion of coal and petroleum.

The EPA has recently made public the results of an analysis of the costs of approaches to reducing pollutant emissions associated with electric power generation (EPA 1996). Known as the Clean Air Power Initiative (CAPI), its purpose is to develop the basis for an integrated regulatory strategy to meeting environmental targets at least cost. It covers utilities, non-utilities, and cogenerators, and takes account of competitive pressures in the electric industry, over the period ending in 2010. The EPA study focused on SOx, NOx, and Hg emissions, owing to the impacts these have on health and the environment. In two separate studies, the EPA is examining the health impact of mercury emissions from electric utilities.

The CAPI analysis examined electric generation, emissions of the three pollutants, and compliance costs under three scenarios; base, lower emissions, and higher emissions. The *Base Case* assumed existing Title IV SO_2 and NO_x rules[22], and a *traditional approach* that assumes continuation of cap and trading system for SOx and command/control for NOx and Hg, a *national trading/banking for all three pollutants* that relies on national cap and trading system for all three pollutants; and *NOx/Sox trading/banking* that removes Hg control, keeps the same NO_x standard, and lowers the 2010 cap on SO_2.[23] A comparison between emissions in year 2010, under the *base case*, *traditional*,

[22] Coal generation in 2010 is 1824 Twh, 1964 Twh, and 2071 Twh under AEC96 (i.e., ours) EPA, and AEO96, respectively. Our Base Case is 7% under and EIA is 5% over the EPA estimate. Also analyzed were a *Higher Emissions Case* which assumes higher electric demand, greater reductions in nuclear capacity, longer coal-fired unit lifetimes, higher gas prices, and slower NGCC improvements over time; and a *Lower Emissions Case* which assumes greater reductions in electricity demand after 2000 from the Climate Change Action Plan, greater nuclear generation from units that do not retire, higher renewable energy costs, and lower regional transmission capability.

[23] The traditional approach lowers the current 2010 Sox cap by 60%, seta the NOx standard at 0.16 lbs/mmbtu in 2005 for all fossil, and applies BACT for coal units greater than 250 MW for Hg. The national trading for three pollutants applies a summer/winter emissions cap for NOx in 2000, lowers the summer NOx cap in 2005; sets an annual Hg cap in 2005 at 50%

and *national trading/banking,* is given in Table 3 below (with SO_2, NO_x, and CO_2 in million tons and Hg in tons). The study showed that a national trading system controlling all three pollutants is most effective for sulfur dioxide, and is marginally inferior to the traditional approach for NOx and Hg.

Table 3
EPA CAPI Study: Emissions in 2010[24]
(Million Metric Tons)

	SO_x	NO_x	CO_2	Hg
Base Case	9.3	6.0	2460	60
Trading	6.2	4.1	2243	21

The annual costs of controlling these emissions using a national trading/banking system for NO_x, SO_2 and mercury was estimated at $5.3 billion in 2010 (roughly 35% lower than the traditional command/control approach). This translates into average control costs of $1661/ton, $2536/ton, $24.3/ton, for SO_x, NO_x and CO_2, respectively, if reckoned separately. If the three pollutants costs were weighted at the ratio their approximate marginal costs of control in 2010 ($500, $1000 and $25/ton)[25] the allocated control costs of this policy would be $290, $580 and $14.5 per ton, respectively, making it an economically attractive policy.

A number of specific electric sector policies could be employed to meet the goals of reduced carbon, SO_2, NO_x, and mercury. Among these are establishing old source performance standards for SO_2 and No_x (e.g. on a utility system, regional or national basis), making the existing SO_2 cap more stringent or setting a lower cap in future years, establishing a similar system for NO_x, establishing a sector-specific carbon cap, employing carbon and externalities taxes, retiring older and less efficient units. In this study, we have been able to model some of these, including: $10 and $25/ton CO_2 carbon tax, externalities taxes on SO_2, NO_x and particulates, and setting an SO_2 cap at 6 million tons (0.6 lb/MMBtu) by 2010.

In our NEMS analyses, a more stringent SO_2 cap (going from 8.2 to 5.6 million tons in 2010) was possible (using low sulfur coal and scrubbers) at an incremental cost of about $370 per ton, and an

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of 2000 coal unit emissions (subsequently lowered in 2010 by 50%), and lowers the existing 2010 SO2 cap by 50%. The national trading/banking option for Sox and NOx removes HG control, keeps the same NOx standard of 0.16 lbs/mmbtu, lowers the 2010 cap on Sox to 50% and, in a separate scenario, lowers it to 60% from existing level.

[24] The NO_x reductions are in summer emissions, by about two thirds.

[25] We take levelized costs of control technologies required for reductions beyond Title IV in 2010 at $500/ton for SO_2 scrubbers and $1000/ton for SCR or SNCR.

electric price increase of about 0.3 mills per kWh (or 0.4%). As might be expected for this single pollutant approach, this is comparable to, but somewhat higher than, the costs of sulfur reductions to 6.0 million tons in the CAPI study.

A tax of $25 per ton CO_2 would affect coal generation and, consequently emissions of CO_2, SO_2 and NO_x. Carbon emissions in 2010 are reduced by 69.7 million metric tons or, 12.2 percent for the sector, at a cost of about $15 per ton (and about 0.1 cents per kWh net of the tax itself). But SO_2 and NO_x are also reduced, by 15 and 13 percent respectively. If one assumes that these two pollutants have marginal costs of reduction in this regime of $500 and $1000 per ton, respectively, and that marginal costs of carbon dioxide reduction are $25 per ton, the resulting marginal costs are $246, $492 and $12.3 per ton, respectively.[26] This is a somewhat better result than obtained by the CAPI study for SO_2, NO_x and CO_2.[27]

Another policy option is retirement of older less efficient fossil power plants. To test this option, we modeled retirement of all coal and oil-steam plants with heat rates greater than 10.0 MMBtu/Mwh when they exceeded 40 years of age. The retired coal units were replaced in the model mostly by new NGCCs, with some new coal and CTs in the mix. This resulted in a decrease in carbon emissions of 51.3 million metric tons, or about 9 percent for the sector, at a cost of about $45/ton of CO_2. This is a more costly carbon reduction option than a $25/ton carbon dioxide tax.

A final approach to pollution reduction in the electric sector is use of emissions taxes. This was discussed in an earlier chapter in the context of cross-cutting policies -- a carbon tax or cap, and externalities taxes or caps -- coupled to broader tax and fiscal reform. In this sector, the emissions externalities are dominated by SO_2, NO_x and fine particulates. With SO_2 taken into account with the cap/trade system, we take the contributions from NO_x and particulates, about 2 cents per kWh for existing coal and oil and about 0.2 cents per kwh for existing gas.[28] These externalities taxes are assumed to be phased in linearly over ten years, beginning in 1996 and reaching their full value in 2005.

The result of this policy is to decrease carbon emissions in 2010 by about 30.4 million metric tons or about 5 percent. For carbon reductions alone the cost is about $17.9 per ton of CO_2, while if allocated across CO_2 and the three criteria pollutants, the costs are $15.3, $306, $612, and $2142 per ton, for CO_2, SO_2, NO_x and particulates, respectively.[29] Reductions in SO_2, NO_x and particulates in 2010 are about 1.5, 5.6 and 7.5 percent, respectively.

[26] For a $10 per ton CO_2 tax, the reductions are smaller (about 4 percent) and the costs per ton $128, $256, and $5.1.

[27] These are not comparable, strictly speaking, as we haven't accounted for mercury. Nonetheless, they are indicative.

[28] An additional 3.4 cents per kWh is added for oil supply externalities. New coal and NGCC plants have somewhat lower external costs owing to better heat rates.

[29] Assuming $500 and $1000 per ton as marginal cost of control allocators for SO_2 and NO_x, and $3500 per ton for particulates.

Overall Results

Our combined policies in the electric sector include the system benefits charge of 2 mills per kWh, a more stringent SO_2 cap by 2010, externalities taxes on NO_x and particulates, and an economy-wide tax on carbon dioxide at $25 per ton (see Table 4 below). These are not pure electric sector polices as the economy-wide carbon dioxide tax affects demand for electricity in the buildings, industrial sectors; however, these effects are small compared to the direct effects of these four policies on the electric sector itself.[30]

Table 4
Policy Case Electric Sector Projections
- 1996 Fuel Prices -

	1992	1995	2000	2005	2010
Generation (Million Mwh)					
Utility and IPPs					
Coal Steam	1578	1631	1338	1360	1182
Petroleum	90	76	47	37	28
Natural Gas	280	344	646	697	873
Nuclear	619	621	651	652	591
Pumped Storage	(3)	(2)	(2)	(2)	(2)
Renewable	293	336	449	554	824
Cogen Purchases	107	130	138	148	159
Net Imports	28	42	35	47	27
Total	2992	3178	3301	3494	3684
Sales (Million MWh)	2763	2994	3107	3289	3468
Price (1993 c/kWh)	7.1	6.8	8.7	8.9	9.0
Carbon (Million Tonnes)	475.5	495.9	453.3	461.5	420.1
SO2 (Million Tonnes)	13.6	11.0	7.0	6.4	5.4
NOx (Million Tonnes)	7.1	5.1	5.4	4.7	4.3

The overall effect of these policies is to reduce electricity demand by about 2.5 percent by 2010, to reduce coal generation by about 34 percent, and to increase gas and renewables generation by about 17 and 109 percent respectively. By 2010, renewable resources contribute about 24 percent of total generation from utilities and IPPs, while coal reduced to 33 percent of generation from about 55 percent in 1992.

[30] There is feedback of these policies on demand from the electric sector, insofar as they affect the price of electricity.

Carbon emissions from the electric sector decrease by about 153 million metric tons (or 618 million tons of CO_2) in 2010, or about 27 percent, while SO_2, NO_x, and particulates are reduced by about 2.9, 1.6, and 0.11 million metric tons, or 35, 28 and 25 percent, respectively. If the additional cost of these policies to the electric sector are all allocated to the carbon dioxide emissions reduction alone, the average cost of this reduction in 2010 is $14.4 per ton CO_2. If the costs are allocated to SO_2, NO_x and particulates as well, based on relative marginal costs, the three emissions are reduced at costs of $233/ton, $466/ton, $1632 and $11.7 per ton, respectively.

We did not include in our policy package analyses the extension of EPACT renewables tax credits or the retirement of older, less efficient coal plants, although arguably these polices could be pursued. Moreover, other policies such as renewables power authorities and facilitation of green investment initiatives, might also be explored.

Figures 3 and 4 compare the generation mix for the Base Case and Policy scenario, while Figure 5 compares their carbon emissions projections.

Figure 3
Base Case Generation Mix for the Electric Sector

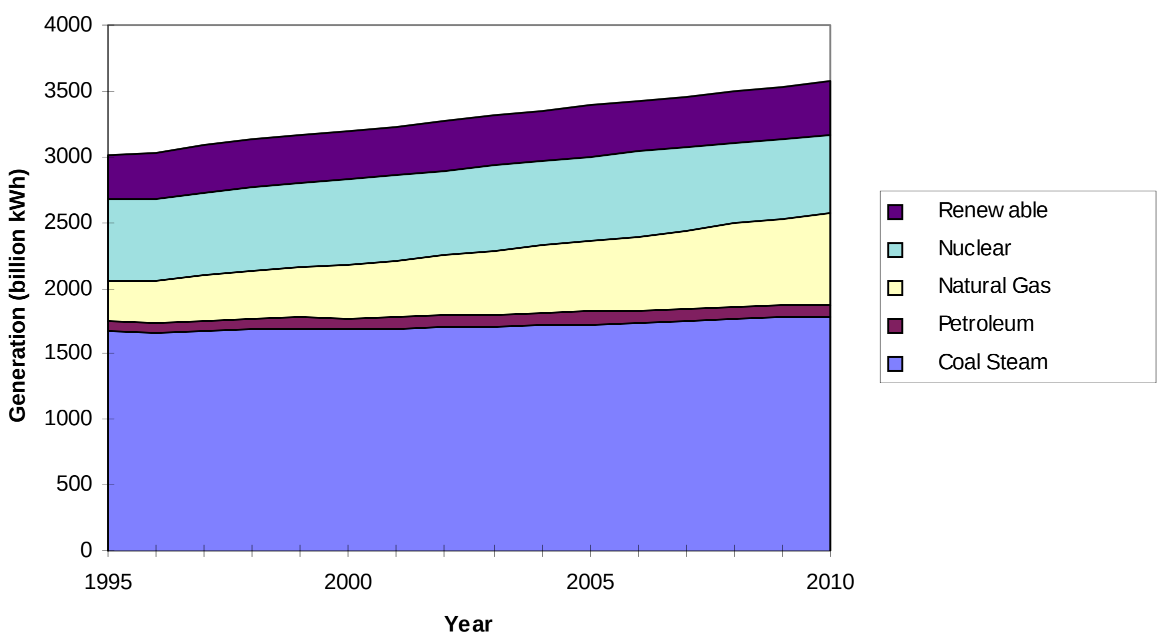


Figure 4
Policy Case Generation Mix for the Electric Sector

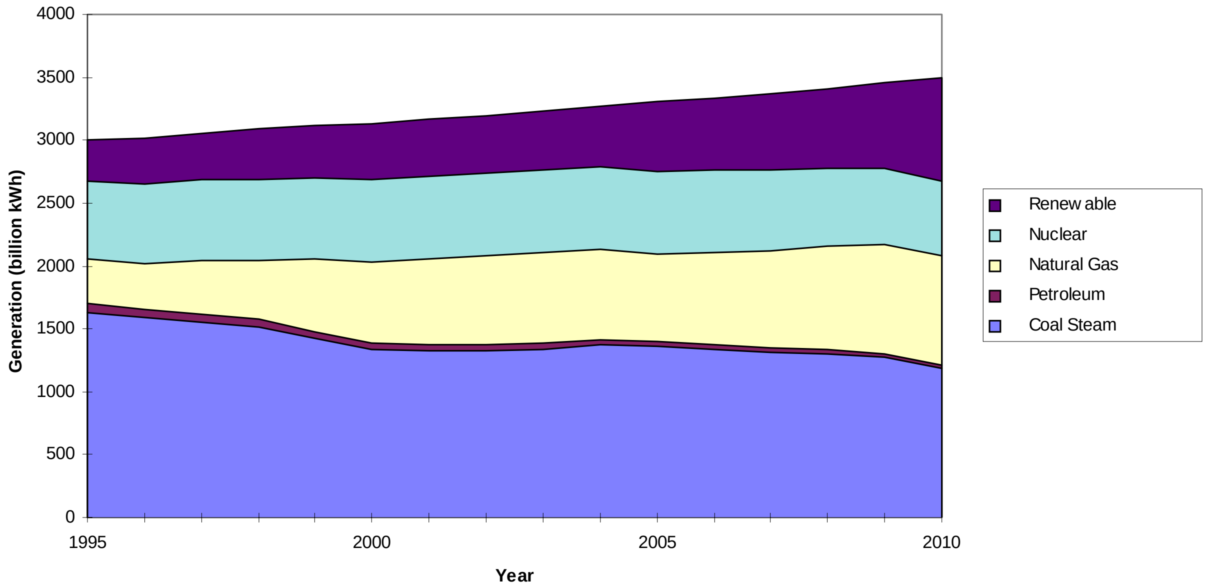
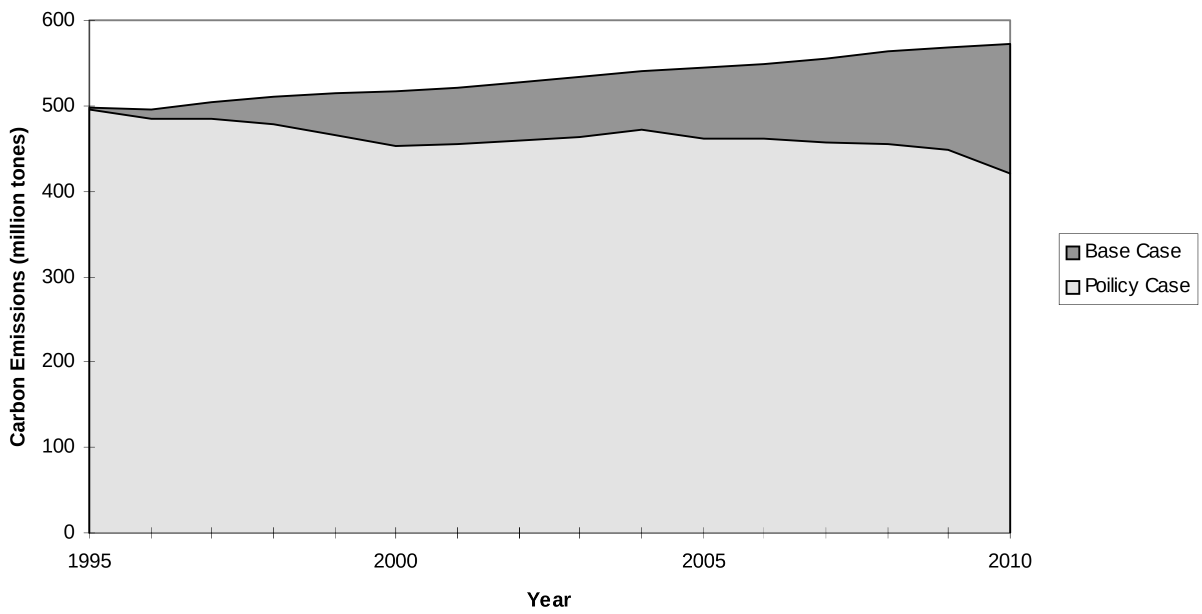


Figure 5
Electric Sector Carbon Emissions for Base and Policy Cases



While these policies cause a reduction in electric sector carbon emissions of about 12 percent from 1990 levels, further declines in the period beyond 2010 will likely require additional policies, perhaps including more rapid retirement of older coal units, especially as nuclear units are phased out. These investigations are underway.

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