98-615 ENR

CRS Report for Congress

Electricity Restructuring: The Implications for Air Quality

Updated January 4, 2001

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ABSTRACT

In the context of federal and state proposals to restructure the electric utility industry, this paper analyzes forces and policies affecting utility generation that may have consequences for emissions of air pollutants and of greenhouse gases. Key concerns are potential increases in nitrogen oxide emissions, raising questions about the effectiveness of the Clean Air Act to regulate a restructured industry, and in carbon dioxide emissions, which are not currently regulated but could be if the U.S. ratifies the Kyoto Agreement. These issues may be raised in the context of electricity restructuring legislation. For ongoing legislative activities, see CRS Issue Brief IB10006, Electricity: The Road Toward Restructuring. This report will be updated as events warrant.

Electricity Restructuring: The Implications for Air Quality

Summary

The electricity generating industry is currently undergoing change, both from new generating and transmission technologies and from shifting policy perspectives with respect to competition and regulation. As the industry is a major source of air pollution as well as of greenhouse gases, the changes underway are being closely examined for their potential environmental effects. At issue is whether proposed legislation to restructure the industry should include environmental protections.

Future electricity demand and implementation of air quality regulations will determine air emission impacts from electricity restructuring. Projected increases in electricity demand in the short- to mid-term suggest that restructuring may further encourage utilities to renovate a sizeable amount of existing coal-fired capacity, which generally produces more air pollutants and greenhouse gases than alternative types of generation. The analysis indicates that renovating existing coal-fired facilities is often very cost-effective compared with new, less polluting construction, portending the potential for an increase in emissions of some air pollutants, especially nitrogen oxides, and of carbon dioxide, a greenhouse gas.

The Clean Air Act regulates emissions of conventional air pollutants from electric utilities. While it has historically focused on new construction in applying its most stringent standards, several current and prospective regulations and enforcement actions could significantly increase controls on existing, coal-fired facilities. These controls may diminish the attractiveness of renovating older, more polluting facilities, but the effectiveness of the regulations in coping with a restructured industry remains to be seen. In addition, greenhouse gas emissions are not currently regulated, so any increases in carbon dioxide would not be controlled under existing authorities.

Thus the environmental effects of restructuring depend on whether, for conventional air pollutants, the existing regulatory regimen will work effectively as the industry structure changes. For some pollutants, such as sulfur oxides, a nationwide emissions "cap" seems secure; but for others, particularly nitrogen oxides, the state-led implementation process may have difficulty coping with regional disparities in emissions. For carbon dioxide, any controls would be contingent on future ratification of the Kyoto Agreement to curtail emissions and on domestic legislation.

The potential for environmental deterioration from restructuring electricity generation is difficult to project — both because various technical and economic changes are affecting the industry at the same time and because of an evolving policy context. Those focused on preventing environmental deterioration tend to take a precautionary stance, to propose immediate preventative measures, and to argue that such measures be attached to available legislative vehicles. In contrast, those who believe the substantial regulatory structure in place will suffice tend to take a wait-and-see position. Further complicating this picture is that attitudes about restructuring are embedded in and partly a surrogate for a more fundamental debate that is underway because of global climate change concerns — about the future direction of energy use in the U.S. and the federal role in affecting it.

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Introduction

Electricity generation is a major source of air pollution as well as of greenhouse gases. As a result, changes in the electric utility industry raise concern about environmental consequences. Such changes are currently in the offing, both from new generating and transmission technologies and from shifting policy perspectives with respect to competition and regulation. Whether legislation to restructure the industry should include environmental protections has become an issue. Several bills were introduced in the 106th Congress to incorporate such protections into any potential federal restructuring legislation.[1] More legislative proposals are expected to be introduced in the 107th Congress.

This paper reviews the changes now underway in the utility industry from the perspective of their environmental implications — specifically, the potential for electric utility restructuring to increase emissions of air pollutants regulated by the Clean Air Act (CAA) and of greenhouse gases that could be affected by the Kyoto agreement to address climate change.[2] The paper is divided into six parts.

- The *Overview* provides background on the electric utility industry and current restructuring efforts, the industry's emissions, and the fundamental argument with respect to current restructuring activities and potential air pollutant effects. It identifies electricity demand and air quality regulation as critical to determining air emission impacts from electricity restructuring.
- *The Utility Industry* examines the electricity demand component in more detail. Estimating electricity demand increases in the short- to mid-term and discussing the implications of transmission capacity for interregional electricity transfers, the analysis suggests that restructuring may encourage current trends among utilities to renovate a sizeable amount of existing coal-fired electricity, which generally produces more air pollution and greenhouse gases than alternative kinds of electricity generation.
- *Environmental Regulation* provides background on current air pollution regulations affecting electric utilities and on the resulting complex system of

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[1]For a current review of legislation, see Larry Parker and Amy Abel, *Electricity: The Road Toward Restructuring*, Issue Brief IB10006, updated regularly. For a comparison of initiatives introduced in the 106th Congress, see: Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326, updated July 26, 2000.

[2]For current information on the status of the Kyoto agreement and related legislation, see Wayne A. Morrissey and John R. Justus, *Global Climate Change*, Issue Brief IB89005.

federal and state, pollutant-by-pollutant controls. It discusses regulatory implications for existing capacity and new construction, noting that while the CAA has historically focused on new construction in applying its most stringent standards, several current and prospective regulations would significantly increase controls on existing, coal-fired facilities. It also notes that an increasingly competitive generating market may present significant challenges to the state-directed environmental regimen of the CAA.

- *The Effects of Restructuring and Environmental Actions on Emissions* analyzes the cost-effectiveness of existing coal-fired facilities versus new construction and the environmental effects of increased utilization of existing coal-fired facilities. The analysis indicates that renovating existing coal-fired facilities is generally very cost-effective compared with new, less polluting construction, pointing to a potential for increasing emissions of some air pollutants, especially nitrogen oxides, depending on regulatory actions, and of the greenhouse gas carbon dioxide, which is not regulated.
- *Assessing the Impacts of Restructuring* examines the Federal Energy Regulatory Commission's attempt to estimate the environmental impacts of introducing competition into the wholesale electricity market, and reactions to that analysis. It notes the considerable difficulties in attempting to isolate the potential impact on emissions of restructuring the electricity generation from other technological and policy trends occurring in the industry.
- The *Conclusion* reviews possible responses to potential risks to the environment arising from electricity restructuring. Critical issues are: (1) For conventional air pollutants, whether the existing regulatory regimen will work effectively as the industry structure changes; for some pollutants, such as sulfur oxides, a nationwide emissions "cap" seems secure, but for others, particularly nitrogen oxides, the state-led implementation process may find it difficult to cope with increasingly regional utility industry and environmental challenges. And (2) for greenhouse gases, any controls are contingent on future ratification of the Kyoto Agreement to curtail emissions and on domestic implementation legislation.

Overview

The Electric Utility Industry and Air Emissions

The industry is massive, with 1996 assets totaling $696 billion, retail sales of $212 billion, and wholesale sales (sales for resale) of $47 billion. It consists of 3,195 utilities — 243 investor-owned, 2010 publicly owned, 932 cooperatives, and 10 federal entities. It is difficult to overestimate the importance of electric service to the nation's economy and individuals' quality of life. In 1996, the average residential customer paid $861 to buy 9,707 kilowatt-hours (809 Kwh monthly) of electricity.[3]

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[3] Based on revenues. Statistics from: Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities: 1996*, DOE/EIA-0437(96)/1 (Washington, D.C.: December 1997); and Energy Information Administration, *Statistics of Major U.S. Publicly Owned Electric Utilities: 1996*, DOE/EIA-437(96)/2 (Washington, D.C.: March

The industry is also a major source of air pollution. The combustion of fossil fuels, which account for 67% of electricity generation, results in the emission of a stream of gases. These gases include several pollutants that directly pose risks to human health and welfare, including sulfur oxides (SO_2), nitrogen oxides (NOx,), particulate matter (PM), volatile organic compounds (VOCs), carbon monoxide (CO), and various heavy metals, including lead and mercury (Hg). Other gases may pose indirect risks, notably carbon dioxide (CO_2), which may contribute to global warming.[4] (See table 1.)

Of the fossil-fired steam generators, coal-fired facilities contribute a disproportionately large share of these gases. While coal accounts for about 84% of fossil-fuel fired electricity generated, it accounts for 90% or more of the gases listed in table 1 (99% of the Hg). Besides the fuel, the location of a generator can also have important consequences for air pollution impacts (for CO_2, source location is immaterial). Location can be important both with respect to local ambient conditions and, because of long-range transport, to downwind areas. For example, with prevailing air movement from west to east, nonattainment of the ozone air pollution standard in the Northeast has directed attention to the concentration of coal-fired generating facilities in the Midwest as possible contributing sources, particularly of NOx, which is a precursor of smog-forming ozone, among other effects.

Utilities are currently subject to an array of environmental regulations, which differentially affect both the cost of operating existing generating facilities and of constructing new ones. In particular, air pollution controls impact the construction and operating costs of fossil-fuel fired facilities — hydropower, nuclear, solar, wind, and other nonfossil-fueled fired electricity sources produce essentially zero air pollutants (although they have other environmental impacts). Generally, air quality regulations impose the greatest costs on coal-fired facilities and the least on natural gas-fired ones. This disparity would become greater *if* the U.S. were to accept the greenhouse gas reduction goals of the Kyoto Agreement. Table 2 illustrates the variation among fossil fuels for emissions of NOx and CO_2.

The Argument about Restructuring and the Environment

After many decades of operating in a comprehensive, regulated market structure, the electric utility industry is facing significant change, both from new generating and transmission technology and shifting policy perspectives with respect to competition and regulation. At issue is whether these changes will increase air pollution emissions.

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[3](...continued)
1998).

[4]Steam-electric utilities produce only minor amounts of VOCs, CO, and lead — on the order of 2% or less of all sources.

Table 1: National Estimated Emissions from Fossil-Fuel, Steam-Electric Utilities — 1996

	CO_2		NOx		PM_{10}		SO_2		Hg	
	1000 short tons	% all sources	1000 short tons	% all sources	1000 short tons	% all sources	1000 short tons	% all sources	tons	% all sources
Electric Utilities	2,209,287	36	6,103	25	302	11	13,217	67	52	33
Coal	1,911,627		5,395		273		12,426		51.6	
Oil	100,895		208		9		730		0.2	
Gas	195,868		344		1		2			
Other/Internal Combustion	897		156		19		60			

Sources: CO_2 — DOE, Energy Information Administration, *Electric Power Annual 1998*, Vol. II, p. 42; NOx, PM_{10}, SO_2 — EPA, *National Air Quality and Emissions Trends Report, 1998* EPA 454/R-00-003 (March 2000), Tables A-4, A-6, and A-8 [http://www.epa.gov/oar/aqtrnd98/fr_table.html]; Hg — EPA, *Mercury Study Report to Congress*, Vol. 1, "Executive Summary" EPA-452/R-97-003 (December 1997), p. 3-6 [Hg data estimated annual emissions 1994/1995].

Table 2: NOx and CO_2 Emission Rates by Fuel Source

Fuel	NOx Emissions (lb./mmBtu)	CO_2 Emissions (lbs. carbon/mmBtu)
Coal	0.1 - >2	55.9
Natural Gas	0.005 - >1	31.7
Residual Fuel Oil	0.05 - >1	46.8

Range for NOx reflects the difference between best available control technology and emissions from an uncontrolled existing power plant.

Sources: NOx — Larry Parker, *Nitrogen Oxides and Electric Utilities: Revising the NSPS*, CRS Report 96-737, July 25, 1997; CO_2 — EIA, *Emissions of Greenhouse Gases in the United States: 1987-1992* (Washington, D.C., 1994), Appendix A; and EIA, *Emissions of Greenhouse Gases in the United States: 1987-1994* (Washington, D.C., 1995), p. 18.

Technology. The advent of new generating technologies, particularly natural gas-fired combined cycle, has both lowered entry barriers to competitors of traditional utilities and lowered the marginal costs of those competitors below that of some traditional utilities. As noted by the Federal Energy Regulatory Commission (FERC), smaller and more efficient natural gas-fired, combined cycle generation plants can produce power on the grid for between 3 cents and 5 cents per kilowatt-hour (Kwh). This is typically less than for the larger coal-fired (4-7 cents/Kwh) or nuclear (9-15 cents/Kwh) plants built by traditional utilities over the past decade.[5] Indeed, it is less than the average generating costs of some utilities. Coupled with advances in generating technology have been advances in transmission technology that permit long distance transmission economically and permit increasingly coordinated operations and reduced reserve margins.

This technological advancement has been combined with legislative initiatives, such as the Energy Policy Act of 1992 (EPACT), to encourage the introduction of competitive forces into the electric generating sector. This shift in policy continues with the promulgation of FERC Order 888 encouraging competition in the wholesale electricity market and implementation by some states of retail competition initiatives.

Restructuring. The policy shift underlying the changes occurring in the electric utility industry is a growing belief that the rationale for the current economic regulation of electric utilities at both the federal and state levels — that electric utilities are natural monopolies — is being overtaken by events, and that market forces can and should replace some of the current regulatory structure. Regulation and rate-of-return ratemaking[6] arguably exist as a partial substitute for the marketplace. The emerging trend in the industry suggests that regulation is an imperfect substitute for the marketplace and that with emerging new generating and transmission technologies, real self-regulating market forces are now able to replace government regulation in many instances. This substitution could result in a more efficient allocation of the country's resources and provide consumers with more accurate price signals regarding the actual cost of electricity.

The restructuring effort attempts to reduce and alter the role of government in electric utility regulation by identifying transactions, industry segments, regions, or specific activities that might no longer be the subject of economic regulation. Current proposals to increase competition in the electric utility industry involve segmenting electric functions (generation, transmission, distribution) that are currently integrated (or bundled) in most cases (both in terms of corporate and rate structures). The overall purpose of restructuring is to promote economic efficiency, which will presumably lead to lower overall rates.

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[5] FERC, "Promoting Wholesale Competition ... [Final Rule]," 61 *Federal Register* (May 10, 1996), 21544.

[6] Rate-of-return ratemaking means that a regulatory body allows the utility to obtain a guaranteed rate of return on investment. The regulatory body specifies a utility's legitimate costs and approves rates that allow the recovery of those costs plus a regulatorily determined acceptable profit. Wholesale sales are regulated by FERC; retail sales are regulated by state Public Utilities Commissions, which may also regulate investment and debt.

Some argue that this singular focus on economic efficiency could come at the expense of other values that the regulatory system traditionally has balanced against economic efficiency, particularly equity and environmental considerations. The environmental concern with respect to restructuring is that the new economic signals being given by a competitive generation market could result in increased emissions of undesirable pollutants for two basic reasons: (1) lower baseload prices resulting from restructuring would increase electricity demand and, therefore, increase generation and emissions; and (2) the restructured generating market's revaluation of existing facilities to the marginal cost of constructing new capacity (along with their low operating costs) would encourage the rehabilitation and full utilization of these older, more polluting generating facilities.

Proponents of restructuring argue that it would increase efficiency and reduce electricity costs. To the extent greater competition and lower costs translate into lower prices, demand can be expected to rise (and incentives to conserve electricity and for new technologies such as renewable energy can be expected to decline). More demand would require more generation, resulting in more emissions. How much emissions might increase would depend on what facilities generate the additional power and on controls imposed by existing or prospective Clean Air Act requirements, as discussed below. Some cost studies indicate that the lion's share of cost savings from restructuring would come from the increased use of existing coal-fired capacity[7] — which is disproportionately more polluting than alternative sources of power. If true, then the need for new (cleaner) generating capacity could be delayed by restructuring, as production from existing capacity is maximized.

Based on the above, the general scenario goes as follows. A competitive generating sector would result in a revaluation of generating assets — i.e., moving from a traditional embedded-cost valuation scheme to a market valuation scheme, which would increase the value of some generating capacity and decrease the value of other generating capacity. Competition would tend to move the value of generating capacity to the marginal cost of constructing new capacity, generally represented at the current time by a new natural gas-fired, combined-cycle facility. In general, older facilities that have been fully depreciated would tend to have market values greater than their current book value under regulation; in contrast, newer, capital intensive facilities (such as some nuclear plants) would have market values less than their current book value. (Case-by-case valuation would be affected by location, availability of alternatives, and electricity demand.) In addition, the Clean Air Act typically imposes its most stringent pollution controls on new powerplant construction, permitting existing capacity to meet less stringent and less costly standards. This differential impact may give some older facilities a competitive operating cost advantage to complement their low, depreciated cost basis.

The new valuation, combined with low operating costs, would encourage operators to maximize generation from their existing facilities. The trend toward increased utilization have already begun. In 1995, coal-fired facilities operated at a

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[7] For example, see Michael T. Maloney and Robert E. McCormick, *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Industry*, prepared for the Citizens for a Sound Economy Foundation (1996).

62% capacity factor. By 1999, operation of coal-fired capacity had increased to 67%. The upper limit here is unclear -- the economic and environmental advantages of new technology, such as natural gas-fired, combined-cycle technology (a very clean technology) may be sufficient in some cases to overcome the advantages of expanding use of existing plants.

Environmental Implications. It is this renewed attractiveness of existing capacity under restructuring, specifically of coal-fired capacity, along with the potential that demand for electricity may rise (and energy conservation slacken) if prices decline, that raises environmental concerns. Absent effective controls, burning more coal will produce more emissions than alternative sources of electricity generation — and much of that coal capacity is in the Midwest, which is currently a center of attention for reducing NOx emissions.

Except for CO_2, the regulatory regimen of the Clean Air Act provides authorities for controlling the potential increase in emissions — assuming they are effectively implemented. Existing controls "cap" SO_2 emissions in the 48 contiguous states and the District of Columbia, and there is no reason to question the effectiveness of the cap in the future, regardless of the changes underway in the utility industry. For NOx emissions, control and implementation is more complicated, primarily because implementation of much of the process lies with the states. Any increase in NOx emissions in the Midwest could complicate an already difficult process underway to reduce the region's NOx emissions, which contribute to ozone nonattainment in the Northeast.[8] How this regional, state-implemented process would be affected by restructuring is not certain.

CO_2 is not currently regulated. Any increase in fossil fuel-fired generation will increase CO_2 emissions, with coal producing about 75% more carbon emissions than natural gas on a Btu basis. *If* the U.S. were to ratify the Kyoto Agreement, which would require the U.S. to reduce greenhouse gas emissions to below 1990 levels, any increases would have to be rolled back or offset.[9] The effort required would be increased if restructuring differentially advantaged coal.

Ultimately, whether developments in electricity generation and demand lead to increased emissions of air pollutants depends on the implementation of the CAA (and on any new requirements that might be enacted); while for CO_2, increases are likely unless Congress ratifies the Kyoto Agreement and enacts implementing legislation (an uncertain prospect). Those who are focused on preventing environmental deterioration tend to take a precautionary stance, to propose immediate preventative measures, and to argue that such measures be attached to available legislative vehicles. In contrast, those who doubt that there will be significant environmental

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[8]For a discussion of those efforts, see Larry Parker and John Blodgett, *Air Quality: EPA's Ozone Transport Rule, OTAG, and Section 126 Petitions — A Hazy Situation?* CRS Report 98-236, updated July 14, 2000.

[9] For a discussion of U.S. global climate change policy, see Larry Parker and John Blodgett, *Global Climate Change Policy: From "No Regrets" to S. Res. 98*, CRS Report RL30024, January 12, 1999.

effects and/or who are focused on the substantial regulatory structure in place tend to take a wait-and-see position.

The current attention on increased emissions from coal-fired generation may address the clearest and most quantifiable risk to the environment from restructuring, but with so many changes underway, the ultimate outcome remains uncertain. Some trends are already manifest, such as renovation of existing coal-fired capacity. Others are just emerging, such as a "green market" in California, in which consumers can take into account environmental costs in their purchasing decisions. Some effects remain to be determined in the future, such as the implications of new price signals for demand and conservation; the implication of new cost valuations for the choice of new generating technologies; developments in transmission capacity; and the effectiveness of ongoing environmental programs. These complexities and their interactions are explored in more detail in the following discussions.

The Utility Industry

Utility industry variables affecting emissions include: overall demand for electricity, which will respond to any changes in prices; the mix of fuels, which will be strongly affected by demand, especially for baseload capacity; and transmission capacity, which will affect what generators can respond to demand. Also crucial are environmental regulations that set limits on certain emissions and/or shift costs among generating facilities. This interactive matrix makes it difficult to separate out the environmental effects of any one component, such as restructuring.

Meeting Future Electricity Demand

In general, the United States has more electric generating capacity than it needs to maintain reliability. Currently, capacity margins[10] of between 12% and 17% are considered necessary to maintain adequate reliability.[11] Nationwide, U.S. capacity margins average 15% — varying from about 13% to 18% on a regional basis.[12] These capacity margins are expected to fall in the future as demand increases. The planned capacity margin in 2008 is 9.1%, unless announced new merchant plant capacity comes on line as intended. In that case, the 2008 capacity margin would be 15.6%.

[10]Capacity margins should not be confused with reserve margins. Capacity margin is the difference between generating capacity and peak load expressed as a percent of generating capacity. Reserve margin is the difference between generating capacity and peak load, expressed as a percent of peak load. Thus, a 17% capacity margin is roughly equivalent to a 20% reserve margin.

[11]Capacity margins are generally set according to a Loss of Load Probability (LOLP) calculation — a measure of the long-term expectation that a utility will be unable to meet demand. A 1 day in 10 year LOLP is typical.

[12]Data for 1999. North American Electric Reliability Council, *Reliability Assessment: 1999-2008* (Princeton, NJ: NERC, May, 2000), p. 14.

On the surface, these numbers would suggest that there would be a general need for new capacity in the short- to mid-term (5-10 years), providing opportunities for different generating technologies, such as natural gas combined-cycle technology, coal-fired technologies, renewables, and nuclear power. However, this may not be the case for some regions. Much of the planned construction to meet the capacity growth needs identified above is designed to meet anticipated peak load, not baseload needs.[13] Capacity that is not dispatchable on demand, such as some renewables and nuclear power, may not fit the demand curve over this time period. For example, utilities representing the southeastern U.S. estimate that nearly 90% of the projected 26,990 Mw of new capacity coming on line over the next 10 years will be non-baseload capacity. Similarly, the utilities representing the industrial Midwest estimate that 94% of the projected 13,500 MW of new capacity coming on line will be combustion turbines (a technology typically used for meeting peak load).[14]

This lack of planned construction for new baseload generating units reflects, in part, an existing surplus of baseload capacity, particularly coal-fired capacity.[15] In 1995, coal-fired capacity operated at a 62% capacity factor. By 1999, this had increased to 67%.[16] If demand and economics justified it, this average could improve to 75% or more. An increase to 75% capacity would be equivalent to about 23,000 Mw of baseload capacity — sufficient to meet increases in aggregate baseload demand for a couple of years, depending on transmission capacity constraints. (An increase to 85% capacity would be equivalent to about 53,000 Mw.) Thus, it would appear that under current expectations, existing baseload facilities, such as nuclear plants, and new baseload construction, such as natural gas combined-cycle, may in many cases be competing against existing coal-fired facilities for the next 5-10 years.

Transmission Capacity

The degree to which existing coal-fired capacity competes against other baseload technologies will be partially dependent on transmission capacity. Under ideal economic conditions, the price of providing baseload electricity would tend to levelize across the country, reflecting a nationwide market for such electricity. In reality, this is unlikely to occur until and unless substantial improvements are made in transmission capacity and the robustness of the transmission grid. An increase in market forces in the generating sector does not necessarily translate into the increased transmission

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[13]Baseload refers to the minimum amount of electric power delivered or required over a given period at a constant rate. Baseload powerplants, like nuclear plants, are designed to operated whenever they are available (generally over 60% of the time).

[14]North American Electric Reliability Council, *Reliability Assessment: 1996-2005* (Princeton, NJ: NERC, October 1996).

[15]The lack of planning also reflects the shortening of lead-times for new construction, uncertainty about future demand, and uncertainty about the future structure of the generating sector.

[16] It is this trend in coal-fired generation utilization that caught the attention of EPA and the possibility for action under the New Source Review requirements of the Clean Air Act. For more information, see Larry B. Parker and John E. Blodgett, *Air Quality and Electricity: Enforcing New Source Review*, CRS Report RL30432 (January 31, 2000).

capacity and robustness that would allow consumers to fully exploit potential generation savings.

Under current restructuring proposals, the transmission sector remains a monopoly controlled by rate-of-return regulation. The history of this approach to transmission planning has resulted in a system focused on and justified by local reliability concerns, not a system concerned with maximizing economic efficiency on a nationwide or even interregional basis. How well and how completely the regulatory structure can be changed to facilitate the dynamics of a deregulated generating sector is difficult to predict. Market prices may regionalize, reflecting the increasingly regional control of transmission, but large-scale interregional transactions may be several years away.

If transmission barriers result in largely regional markets, marginal costs for baseload capacity may differ between regions. For example, regions with substantial excess coal-fired capacity may have low marginal costs based on the incremental costs of increased capacity utilization. Other regions, with substantial increasing demand, may have marginal costs based on new construction costs, such as building a natural gas-fired combined-cycle plant or a coal-fired fluidized bed combustor. Depending on price, a generating technology that is competitive “on average” may not be competitive within a specific region, because of low-cost alternatives; likewise, a “higher cost” generating technology that is non-competitive “on average” may be competitive within a specific region because of the higher cost of alternatives.

Implications of Utility Developments

All of these factors will be summed up in the price for baseload power. It is generally assumed that deregulation of the generating sector will encourage the development of marginal cost pricing.[17] In particular, deregulation will clearly expose the substantial cost differences between baseload generation and peak generation. While baseload facilities generally run at over 60 percent capacity, peak demand facilities run at under 20 percent capacity. This substantial difference in utilization, among other differences, means that peak power will cost more under restructuring than it does now, when the cost is generally rolled in with the less expensive baseload power.[18]

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[17]Marginal cost has been used by some public utility commissions to determine appropriate rates between different customer classes for several years, and utilities have also experimented with “time-of-day” rates that reflect marginal costs across time. Under restructuring, generating costs may move more in the direction of “time of day” pricing as more reflective of actual costs than the current average cost method.

[18]As stated by a study done for the American Gas Association study of future electric generation: “In principle, retail deregulation and retail wheeling, should radically change the current pricing structure for end-use electricity. Peak pricing will increase sharply and off-peak pricing will decrease sharply.” Harry Chernoff, *Existing and Future Electric Generation: Implication for Natural Gas*, Study prepared for the American Gas Association, Policy Analysis Group, by Science Applications International Corporation (October 1996) p. 23.

At least in the short-term, this stratification of electricity pricing may mean that the market price for baseload power will be considerably lower than the current average electricity price would indicate. This would encourage the use of existing baseload capacity with low operating costs (e.g., coal-fired capacity) and discourage constructing new baseload facilities, particularly those technologies requiring substantial investment (e.g., nuclear power). Low baseload prices may also discourage development of non-dispatchable power sources (e.g., some renewable technologies) and installation of some conservation technologies. Higher prices for peaking power would encourage technologies designed for such load (e.g., combustion turbines), and technologies designed to reduce such loads (e.g., load management techniques). In the long term, if prices for electricity decline, electricity use is likely to increase and incentives to conserve electricity are likely to decrease. Long-term declining prices could also reduce incentives for new technologies, including some renewable energy technologies.

How these different effects play out will determine the potential for increased emissions from restructuring. Although the overall effect on emissions is difficult to assess, involving several currently unquantifiable variables, the most substantial environmental effect in the short- to mid-term is likely to come from enhanced operation of existing coal-fired capacity. Whether one can ascribe that effect strictly to restructuring is debatable, however.

Environmental Regulation

The Clean Air Act imposes a complex regulatory structure on air pollution sources. From an historical perspective, the regulatory environment for a major emission source, like an electric generating facility, has been largely dependent on two factors: (1) Where the facility is located (in an area meeting clean air standards, or in an area not attaining them) and, (2) How old the facility is (new or old source). Other factors, such as facility size and specific pollutants controlled, feed off these two factors. This framework is changing, however, as illustrated in the following case study on NOx.

Example: Nitrogen Oxide Control

Nitrogen oxides, both directly and because they contribute to formation of ozone, raise human health and environmental concerns that bring them under the purview of the CAA. Nitrogen dioxide (NO_2), the index compound for nitrogen oxides, can irritate the lungs and lower human resistance to various respiratory infections, such as influenza. In combination with volatile organic compounds (VOCs) and in the presence of heat and sunlight, NOx forms ozone, for which human health concerns include lung damage, chest pain, coughing, nausea, throat irritation, and congestion. Ozone also exacerbates the effects of bronchitis, heart disease, emphysema, and asthma.[19] In addition, nitrogen oxides contribute to the formation

[19] For a discussion of human health effects of air pollution, see Morton Lippmann, "Health Benefits from Controlling Exposure to Criteria Air Pollutants," in John Blodgett, ed., *Health*

(continued...)

of fine particulates, suspected of significant human mortality and morbidity effects and for which EPA recently set new standards that will become effective in 10 to 15 years.[20]

Environmental concerns about NOx emissions include its transformation into nitric acid, a component of acid precipitation; visibility impairment; and adverse effects of ozone on plant life.[21] In addition, EPA estimates that up to 40% of the nitrogen "loading" in the Chesapeake Bay, resulting in excessive nutrient enrichment, is the result of deposition of air-borne nitrogen oxides. In the West, nitrogen oxides contribute to visibility impairment, particularly in southern California.

These multiple effects result in multiple control measures under the Clean Air Act, as described below.

Air Quality Regulations Impacting on Utilities

Primary **National Ambient Air Quality Standards (NAAQS)** set maximum levels of permitted pollution concentrations nationwide. NAAQS are federally enforceable with specific deadlines for compliance; they are required by Section 109 of the CAA to protect the public health with an "adequate margin of safety." They are periodically reviewed to take into account the most recent health data. Three NAAQS may result in NOx controls: NAAQS for nitrogen dioxide, ozone, and fine particulates.

In 1994, all monitoring locations in the U.S. were in compliance with the NO_2 NAAQS; however, compliance with the ozone NAAQS remains elusive in several parts of the country, particularly in southern California, the Texas Gulf Cost, and the Northeast corridor (from Virginia to Maine). Because NOx is a precursor to ozone formation, NOx control represents an important component in reducing ozone pollution. In recognition of the multi-state nature of the ozone problem in the Northeast, the 1990 CAA Amendments created an Ozone Transport Commission (OTC) to development and coordinate emission reduction efforts for the area. In addition, in 1998, the EPA promulgated a new ozone transport rule that would control NOx emissions for 21 eastern states, and ten states petitioned the EPA to control NOx emissions in the Midwest under section 126 of the CAA.[22]

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[19](...continued)
Benefits of Air Pollution Control: A Discussion, CRS Report 89-161, February 27, 1989, pp. 75-144.

[20]John Blodgett, et al., *Air Quality Standards: EPA's Final Ozone and Particulate Matter Standards*, CRS Report 97-721 (Updated June 19, 1998).

[21] For a discussion of ozone and acid precipitation effects on vegetation, see David S. Shriner, et. al., *Response of Vegetation to Atmospheric Deposition and Air Pollution: State of Science and Technology Report 18* (Washington, D.C.: National Acid Precipitation Assessment Program, December 1990).

[22] For more information, see Larry Parker and John Blodgett, *Air Quality: EPA's Ozone Transport Rule, OTAG, and Section 126 Petitions — A Hazy Situation?* CRS Report (continued...)

For areas in attainment with these NAAQS, the CAA mandates states to require new sources, such as powerplants, to install **Best Available Control Technology (BACT)** as the minimum level of NOx control required of a new powerplant.[23] State permitting agencies determine BACT on a case-by-case basis, taking into account energy, environmental and economic impacts. BACT can be much more stringent than the federal New Source Performance Standard (NSPS — described below), but can not be less stringent than NSPS. Existing sources are not required to install controls in attainment areas.

For areas *not* in attainment with one or more of these NAAQS, the CAA mandates states to require new sources to install **Lowest Achievable Emissions Rate (LAER)** technology. Along with offset rules, LAER ensures that overall emissions do not increase as a result of a new plant's operation. LAER is based on the most stringent emission rate of any state implementation plan or achieved in practice without regard to cost or energy use. It may not be less stringent than NSPS. Existing sources are required to install **Reasonably Available Control Technology (RACT)**, a state determination based on federal guidelines.

A **Prevention of Significant Deterioration (PSD)** program (Part C of the CAA) focuses on ambient concentrations of pollutants (including NO_2) in "clean" air areas of the country (i.e., areas where air quality is better than the NAAQS). The provision allows some increase in clean areas' pollution concentrations depending on their classification. In general, historic or recreation areas (e.g., national parks) are classified class 1 with very little degradation allowed while most other areas are classified class 2 with moderate degradation allowed. Class 3 areas are permitted to degrade up to the NAAQS. New sources in PSD areas must undergo preconstruction review and must install BACT; state permitting agencies determine BACT on a case-by-case basis, taking into account energy, environmental, and economic impacts. More stringent controls can be required if modeling indicates that BACT is insufficient to avoid violating PSD emission limitations, or the NAAQS itself.

A complement to the PSD program for existing sources is the **regional haze** program (section 169A) that focuses on "prevention of any future, and the remedying of any existing, impairment of visibility" resulting from manmade air pollution in national parks and wilderness areas.[24] Among the pollutants that impair visibility are sulfates, organic matter, and nitrates. In 1999, the EPA promulgated a regional haze program, which, would entail more stringent controls on NOx and SO_2. However, like the fine particulate NAAQS, it will be several years before any regional haze program might result in controls.

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[22](...continued)
98-236, updated July 14, 2000. For recent activities with respect to these initiatives, see: Larry B. Parker and John E. Blodgett, *Air Quality and Electricity: Initiatives to Increase Pollution Controls,* CRS Report RS20553, December 28, 2000.

[23] More stringent controls can be required if modeling indicates that BACT is insufficient to avoid violating the NAAQS.

[24]See James McCarthy, et al., *Regional Haze: EPA's Proposal to Improve Visibility in National Parks and Wilderness Areas*, CRS Report 97-1010, updated July 9, 1998.

New Source Performance Standards (NSPS) are federal standards defining the minimum controls necessary for new sources regardless of their location — in contrast to the PSD and NAAQS standards that focus on ambient concentrations of pollutants. EPA's NSPS determinations represent the floor for state BACT and LAER determinations in case-by-case situations.

Required under Section 111 of the CAA, NSPS require major new sources to install the best system of continuous emission reduction which has been adequately demonstrated. In making such an assessment, the CAA requires EPA to take into account "the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements." To keep controls abreast of technological innovations, the CAA originally required EPA to review and revise NSPS every four years. But at the time of enactment of the 1990 CAA Amendments, the last revision of the NOx NSPS for electric and non-electric steam generating units had occurred in 1979. With substantial technological improvements in controlling NOx having occurred during the 1980s, the 1990 Amendments (title IV, section 407(c)) required EPA to promulgate a new NOx NSPS for electric and non-electric steam generating units by 1994 — a deadline EPA did not meet. In September, 1998, EPA did promulgated a new NOx NSPS. It is considerably more stringent than the 1979 standard for coal-fired facilities, but not particularly stringent for natural gas or oil-fired facilities.[25]

The **acid deposition control** provisions of title IV of the 1990 Amendments focus on total emissions from existing sources of sulfur dioxide and nitrogen oxides. For nitrogen oxides, section 407 of title IV requires tangential- and wall-fired (dry bottom, not cell burner equipped) boilers (group 1 boilers) designated to meet 1995 phase 1 reductions to meet an emission limitation based on low-NOx burner technology. Regulations for phase 1 NOx reductions were finalized in 1995. For phase 2 in the year 2000, remaining group 1 boilers are required to meet the same standard (or more stringent if technology and costs permit) as those covered in phase 1, and boilers with other firing configurations (group 2 boilers) are required to meet standards based on available technology that is comparable in cost to low-NOx burners. EPA finalized regulations for phase 2 group 1 and group 2 boilers in 1996 (61 *Federal Register* 245, pp. 67112-67164).

Implications of Air Quality Regulations for Utilities

In the light of changes in the utility industry, this mix of air quality regulations has important consequences for (1) utilities' choices both for construction of new facilities and operation of existing ones, and (2) the potential effectiveness by which federal and state air pollution controls apply to a changing industry structure.

New Construction and Existing Sources. For constructing new powerplants, the CAA envisions the federal NSPS and the state PSD/BACT program as the baseline for control efforts in attainment areas, and the state-set LAER and federally-based offset requirements as the baseline in nonattainment areas. For SO_2, federal

[25] See Larry Parker, *Nitrogen Oxides and Electric Utilities: Revising the NSPS*, CRS Report 96-737, updated October 13, 1998.

offset requirements overlay these other requirements. The costs of installing NSPS (or BACT or LAER or obtaining offsets) on new construction fall most sharply on coal-fired facilities. This could disadvantage coal in choices among technologies for new generation.

At the same time, the historically less stringent controls on existing coal-fired facilities — none in attainment areas, RACT in nonattainment areas — have clearly advantaged existing sources, particularly coal, in competing with new sources for meeting generating needs. This may be changing. For existing facilities, especially coal-fired facilities, a host of new regulatory initiatives may result in more stringent controls for a number of possible pollutants.

In addition, in what could crucially affect the potential costs of reconditioning and extending the life of existing coal-fired plants, EPA, together with the Department of Justice, has initiated a New Source Review (NSR) enforcement process to reduce pollution from existing sources. The first overt action under this process occurred November 3, 1999, when the Justice Department filed seven lawsuits against electric utilities in the Midwest and South, charging them with violations of the NSR requirements of the CAA. EPA also issued an administrative order against the Tennessee Valley Authority, alleging similar violations.

The crux of the enforcement actions is the "preconstruction" permitting process of the NSR, which is designed to ensure that newly constructed facilities, or substantially modified existing ones, do not result in violations of applicable air quality standards. The question the enforcement actions raise is whether the specified facilities engaged in rehabilitation actions that represent "major modifications" of the plants, in which case the CAA would require the installation of best available control technology – BACT.

The crucial definition of "major modification" derives from an EPA ruling that a life extension project by Wisconsin Electric Power Company (WEPCO) triggered NSR requirements. Since 1992, after considerable litigation and congressional debate, the "test" to determine the applicability of NSR compares whether a facility's projected actual emissions after the modification are more than its actual emissions before the modification. Utilities argue that the "modifications" EPA cites in the suits were just routine maintenance, which does not trigger NSR. If EPA's position in these suits is upheld, this could have the dual effects of increasing the costs to utilities of expanding the use of coal-fired utilities in the future and of reducing the emissions from coal-fired facilities.[26]

Table 3 identifies the range of environmental actions that are beginning to affect or may in the future affect emissions from fossil-fuel fired facilities. As discussed in the next section, these controls could have a substantial influence on the cost of power from coal-fired facilities, making them less attractive in a competitive marketplace.

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[26] On the NSR enforcement actions, see Larry B. Parker and John E. Blodgett, *Air Quality and Electricity: Enforcing New Source Review*, CRS Report RL30432, Jan. 31, 2000.

Table 3: Potential Control on Existing Sources

Pollutant	Potential Controls on Existing Sources
Nitrogen Oxides	Title IV, sec. 407 Ozone Transport Commission (OTC) Rules Ozone Transport Rule Section 126 Petitions Revised Ozone NAAQS Fine Particulate NAAQS New Source Review Enforcement Regional Haze Rule More stringent Legislation[a]
Sulfur Oxides	Title IV Fine Particulate NAAQS New Source Review Enforcement Regional Haze Rule More stringent Legislation[a]
Mercury	Potential EPA regulation as a HAP NE Action Plan on Mercury Potential Legislation[a]
Carbon Dioxide	Potential ratification of Kyoto Agreement Potential Legislation[a]

[a] For information on current legislative proposals relating restructuring to environmental controls, see Larry Parker and Amy Abel, *Electricity: The Road Toward Restructuring*, CRS Issue Brief IB10006. For a review of legislation introduced in the 106th Congress, see: Larry Parker, *Electricity Restructuring: Comparison of Comprehensive Bills*, CRS Report RL30087, July 24, 2000; and, Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326, July 26, 2000.

Implementation under Restructuring. The mix of regulatory authorities results in a complex federal-state process for regulating the industry. The state-regulated utility system meshed reasonably well with the state-implemented air quality controls. As the utility industry becomes more competitive and potentially more regional, and as air quality problems also become more regional (regional haze, long-range pollutant transport), state-directed controls on existing sources may prove less efficient and effective than previously.

These regional challenges may reprise the past inability of the state-led process to control acid rain, the result of long range transport of SO_2, for which utilities are a major source. As a result of the failure of the state-based process to address this problem, Congress in 1990 added the acid rain program to the CAA, which established a national "cap" on emissions. This has proven an efficient program; SO_2 credits are not excessively expensive and the most popular technology for new construction — natural gas-fired combined-cycle technology — produces almost no

SO_2 emissions.[27] The flexibility and straight-forward compliance mechanism of this "cap and trade" program would seem to mesh well with a flexible, competitive utility industry, so electricity restructuring would not appear to create any serious implementation problems for this SO_2 control program.

However, the acid rain program is discrete; there is no comparable nation-wide "cap and trade" program for other pollutants. For example, as noted earlier, the 1990 CAA Amendments did create an Ozone Transport Region in ten northeastern states for addressing ozone transport (and NOx, as a precursor) and it authorized EPA to create others. However, this effort may be inadequate to bring the Northeast into compliance with the Ozone NAAQS. To bring under control additional sources of long-range transport, EPA created a 21-state Midwest-Northeast region (where substantial coal-fired NOx emission increases could occur) subject to the promulgated Ozone Transport Rule, a feature of which is a voluntary, state-implemented NOx "cap and trade" program. However, EPA does not have authority to require the states within the region to act in concert or to impose uniform rules for cap and trade as in the acid rain program. Thus, how this regional effort to control NOx would work in practice remains to be seen; interstate disagreements have surfaced, and industry restructuring could change emissions patterns in ways that could exacerbate them.[28]

The potential for diverse state requirements in the region could lead to inconsistent requirements that could pose barriers to restructuring the industry — or opportunities. Differing requirements could allow utilities to choose which state had the least stringent requirements, while the power could be transmitted to the location of demand; or inconsistent requirements — or uncertain ones — might be an added incentive for construction of generating capacity that is clean and hence not subject to them.

The regulatory dynamic of the Clean Air Act has no direct consequence for potential increases in CO_2 emissions under utility restructuring: CO_2 is not subject to CAA regulation and any controls are prospective, contingent on U.S. ratification of the Kyoto agreement and on domestic implementing legislation. The uncertainty of legislative action on CO_2 compared to the potential for action on restructuring legislation in the next couple of years has led some to find in the restructuring issue a surrogate for a debate on CO_2 controls and global climate change in general. This situation adds complexity to the restructuring debate.

[27]U.S. Environmental Protection Agency, *1996 Compliance Report, Acid Rain Program*, EPA 430-R-97-025 (June 1997).

[28]For recent actions with respect to the Ozone Transport Rule, see: Larry B. Parker and John E. Blodgett, *Air Quality and Electricity: Initiatives to Increase Pollution Control*, CRS Report RS20553, December 28, 2000.

The Effects of Restructuring and Environmental Actions on Emissions

As suggested previously, restructuring involves the interplay of many factors affecting emissions. As indicated, some, such as renovating existing coal-fired capacity, represent a furthering of an existing trend. Others, such as green pricing, represent a new trend created by restructuring. Although the overall effect on emissions is difficult to assess, involving several currently unquantifiable variables, the most substantial environmental effect in the short- to mid-term arises from the potential for enhanced operation of existing coal-fired capacity. However, how much one should ascribe that effect to general trends in the industry vis a vis restructuring is debatable.

Economics and Coal-Fired Generation

A general trend in the electric utility industry for over a decade has been the renovation of existing capacity beyond its initial lifespan (especially coal-fired capacity) in lieu of constructing new capacity. If restructuring results in a stratification of electricity pricing in terms of baseload, intermediate, and peak power, the low price of baseload capacity could provide additional impetus to refurbish existing coal-fired capacity and to maximize operation of such power. Likewise, lower baseload prices would likely reduce incentives to conserve electricity and to develop new non-peaking technologies, including renewable energy. As noted above, substantial amounts of underused coal-fired capacity currently exist. The degree to which it is competitive over the next 5-10 years will depend primarily on two factors — cost of enhanced maintenance to extend the life of the facilities (life extension), and potential for additional pollution control costs (which is discussed in the next section).

Depending on the condition of an existing coal-fired facility, reconditioning can be a very economic means of adding baseload capacity.[29] This reconditioning process, called life extension, can help halt and partially reverse the deterioration of a power plant's efficiency and reliability during continued operation. Over time, the operation and maintenance (O&M) of a powerplant increases, along with its heat rate. For example, based on FERC data, EPA assumes the median O&M costs for coal-fired facilities up to 10 years old is $17.60/Kw , compared with the median costs for a facility more than 30 years old of $31.20/Kw.[30] However, EPA believes that much of this increase (about $9.40/Kw) represents continuous reconditioning efforts to extend the life of the plant — that "life extension" efforts increasingly represent a continuing upgrading process, rather than a one-time reconstruction of the power plant.[31]

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[29]ICF Incorporated, *Repowering and Life Extension: Background Paper*, prepared for the Office of Atmospheric Programs and Office of Air Quality Planning and Standards, EPA (draft report) (February 1995).

[30]U.S. Environmental Protection Agency, Office of Air and Radiation, *Analyzing Electric Power Generation Under the CAAA* (July 1996), p. A3-11. Estimates in 1995 $.

[31]Part of this represents a strategy by utilities to avoid having to comply with New Source (continued...)

Thus, one-time projections for life-extension costs overestimate the incremental cost of this effort. EPA estimates that the cost to extend power plant life from 40 to 65 years will be on the order of $8.8/Kw per year in additional O&M costs — or 1.4 mills/Kwh. Assuming the power plant has been well-maintained up to now, this cost would appear quite attractive for an additional 20-25 years of operation. Including estimated O&M and fuel costs, such power plants would generate electricity for about 2 cents/Kwh.[32] In general, the potential for rising fuel prices is considered small in the case of coal. There appears to be ample supply of coal available at current prices.

Against existing coal-fired capacity is newly constructed natural gas combined-cycle technology. Conventional wisdom within the industry is that, based on current trends in generating technology and fuel costs, the technology of choice for new construction will be natural gas-fired combined-cycle plants. To illustrate the sensitivity of new natural gas-fired facilities to fuel costs and technology improvements, CRS analyzed four different cases. The results are presented in table 4. CRS estimates the annual costs on a levelized basis for a natural gas combined-cycle plant at about 2.4-2.5 cents/Kwh, with costs rising to 3.4-3.5 cents/Kwh if natural gas prices rise to $3.50/mmBtu compared with $2.25/mmBtu assumed in the base-case calculations. While very competitive for new construction, it is not quite competitive, *in general*, to renovating existing coal-fired capacity.[33]

Table 4. Costs of New Natural Gas-fired Combined-cycle Facility (1995 dollars)

	Base case	High fuel cost case	Higher efficiency base case	Higher efficiency/high fuel cost case
Efficiency Assumption	7,300 Btu/Kwh	7,300 Btu/Kwh	6,800 Btu/Kwh	6,800 Btu/Kwh
Fuel Cost Assumption	$2.25/mmBtu	$3.50/mmBtu	$2.25/mmBtu	$3.50/mmBtu
Total Costs	2.5 cents/Kwh	3.4 cents/Kwh	2.4 cents/Kwh	3.3 cents/Kwh

Other assumptions include capital costs of $593/Kw, fixed O&M of $10/Kw/yr., variable O&M of 0.5 mills/Kwh, capacity factor of 85%, and a real capital charge rate of 10.4%.

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[31](...continued)
Performance Standards (NSPS) at their existing facilities by not triggering the WEPCO rule, which requires existing facilities to achieve NSPS under some circumstances. It is this strategy that EPA and Department of Justice are attacking with the NSR enforcement actions discussed previously.

[32]Calculation assumes heat rate of 10,000 Btu/Kwh, fixed O&M costs of $31 Kw/yr (not including incremental life extension costs discussed in the text), fuel costs of $1.30 Btu/Kwh, and a 70% capacity factor.

[33]For reference, CRS calculates that a new coal-fired steam generator would produce electricity for about 3.5 cents/Kwh, confirming the conventional wisdom with respect to natural gas.

SOURCES: Environmental Protection Agency, Electric Power Research Institute, CRS estimates.

As indicated, the analysis strongly suggests that natural gas pricing is the most important variable in determining generating costs from such plants. In the base-case analyses, fuel costs represent about two-thirds of the total costs (including capital charges). In the high cost analyses, fuel costs represent about three-fourths of the total costs. The importance of fuel costs is lessened a little by continuing improvements in generating efficiency. However, it is likely to remain the dominant cost factor over the time period discussed here. This variable would also have to be factored into any decision about existing coal-fired versus newly constructed natural gas-fired capacity.

Air Quality and Coal-fired Generation

If restructuring further encourages the increased utilization of existing coal-fired capacity in lieu of constructing new capacity and discourages energy conservation and development of cleaner technology because of low baseload pricing or other factors, the short- to mid-term effects could be increased air pollution. Operating an additional 23,000 Mw of coal-fired capacity would have significant air emissions, particularly for CO_2, and, depending on the fate of various EPA rulemakings, on NOx. As SO_2 emissions are currently capped by title IV of the 1990 Clean Air Act Amendments, the effects of restructuring on SO_2 emissions should be negligible.

The most substantial effects of restructuring would be for carbon dioxide emissions, because they are currently uncontrolled. CO_2 emissions from 23,000 Mw of coal-fired capacity would be about 200,000,000 short tons, an increase of about 11% over 1996 CO_2 emissions by coal-fired electricity generation. This compares with emissions from a natural gas combined-cycle equivalent capacity of about 80,000,000 short tons, or a difference of 120,000,000 short tons.

Calculating the potential effects on NOx emissions is more difficult as existing sources could be controlled under several provisions of the Clean Air Act (see table 3). For example, the final rule for the NOx reduction program under section 407 of title IV of the Clean Air Act Amendments of 1990 was promulgated in 1996.[34] The rule will reduce the NOx emission rate of coal-fired facilities examined here to an average of 0.48 lb/mmBtu. Based on this result, emissions from 23,000 Mw would come to about 480,000 tons, an increase of about 9% over 1996 coal-fired NOx emissions. This would compare with emission of 70,000 tons from equivalent natural gas combined-cycle technology, or a difference of 410,000 tons.[35]

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[34]Environmental Protection Agency, "Acid Rain Program; Nitrogen Oxide Emission Reduction Program," 61 *Federal Register* 67111-67264 (December 19, 1996).

[35]Based on an average BACT determination of 0.1 lb./mmBtu. See Larry Parker, *Nitrogen Oxides and Electric Utilities: Revising the NSPS*. CRS Report 96-737, updated October 13, 1998.

As identified earlier, other control possibilities, such as implementation of EPA's Ozone Transport Rule, also could reduce these emissions substantially.[36] Under this regulation, NOx emissions across a 21-state area are "capped" at a specific level beginning September 30, 2007. That level of emissions can not be exceeded regardless of the electric utility industry's structure.

Similarly, successful prosecution of the NSR enforcement actions could impose additional control requirements on existing coal-fired facilities.[37] Under a restructured electric generating market, increased pollution control requirements would adversely affect the economics of affected facilities, which would become more expensive to operate. Increased capital and operating costs would make coal-fired capacity less attractive in a more competitive system.

As discussed above, existing coal-fired facilities are particularly vulnerable to future regulation of several pollutants. To illustrate the sensitivity of these facilities to increased pollution-control costs, CRS analyzed a representative sample of such potential costs. The results are presented in table 5. As indicated, control costs for each of these pollutants would add about 10% or more to the total generation costs from existing coal-fired facilities. Combinations of control measures would raise these costs even more.[38] With new natural gas combined-cycle technology potentially available for 2.5 cents/Kwh, increased air pollution control represents a real threat to the continuing operation of at least some existing coal-fired capacity.

These environmental concerns are not necessarily hypothetical. For example, member states of the Ozone Transport Commission (OTC) have agreed to stringent nitrogen oxide controls on stationary sources, including electric generating plants, in ten northeastern states. Depending on how the states and utilities choose to implement the program, selective catalytic reduction (SCR) or other control devices may have to be installed on some coal-fired power plants. This could also be the result of EPA's Ozone Transport Rule and/or a successful Section 126 petition with respect to interstate ozone pollution.

For natural gas combined-cycle facilities, the major *potential* environmentally related cost increase would be control of carbon dioxide.[39] *If* a new natural gas combined-cycle plant were required to offset all its potential CO_2 emissions under a

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[36]For a discussion of the transport rule, see Larry Parker and John Blodgett, *Air Quality: EPA's Ozone Transport Rule, OTAG, and Section 126 Petitions — A Hazy Situation?* CRS Report 98-236, updated July 14, 2000.

[37]For an update on events surrounding EPA NSR enforcement activities, see: Larry B. Parker and John E. Blodgett, *Air Quality and Electricity: Initiatives to Increase Pollution Control*, CRS Report RS20553, updated December 28, 2000.

[38]Readers are cautioned not to simply add the incremental costs of these control measures together. There may be overlaps or efficiencies to be gained from controlling some of pollutants together that are presented in Table 5.

[39] The costs estimates cited above already include installation and operation of SCR. Natural gas plants emit very minor amounts of sulfur dioxide and mercury.

future emissions cap, it could increase operating costs by about 0.2 cents/Kwh.[40] This would raise the total production costs for such facilities to 2.6-2.7 cents/Kwh, or 3.6-3.7 cents/Kwh if the high-cost gas scenarios were operative.

Table 5. Potential Pollution Control Cost for Existing Coal-fired Power Plants (500 Mw, 1995$)

Cost Factor	Nitrogen Oxides	Carbon Dioxide	Mercury	Sulfur Dioxide
Capital Costs	$49/Kw	0	$40.5/Kw	$190/Kw
Fixed O&M	$4.27/Kw	0	$6.9/Kw	$6.8/Kw
Variable O&M	0.023 cents/Kwh	0.2 cents/Kwh	0.04 cents/Kwh	0.1 cents/Kwh
Total Costs of Control	0.17 cents/Kwh	0.2 cents/Kwh	0.22 cents/Kwh	0.53 cents/Kwh
Total Production Costs	2.17 cents/Kwh	2.2 cents/Kwh	2.22 cents/Kwh	2.53 cents/Kwh

Control Assumptions: For nitrogen oxides — installation of Selective Catalytic Reduction (SCR) with 70% removal; for carbon dioxide — buying carbon offsets for 50% of emissions at $5 a ton; for mercury — installation of carbon injection with spray cooling and fabric filter; for sulfur dioxide — installation of flue-gas desulfurization (FGD) with 95% removal.

Sources: U.S. EPA, Office of Air and Radiation, *Analyzing Electric Power Generation under the CAAA* (July 1996); and Larry Parker, *Coal Market Effects of CO_2 Control Strategies as Embodied in H.R. 1086 and H.R. 2663*, CRS Report 91-883, December 13, 1991.

Assessing the Impacts of Restructuring

Emissions from electricity generation are determined by an interactive process involving a utility industry and an environmental regulatory system that are both undergoing change. The dynamic linkages between electricity generation, resulting emissions, and pollution control make it difficult to separate out one factor (in this case, electricity restructuring) for analysis. The difficulty in doing this has been illustrated by various studies attempting to estimate the impact of restructuring on the environment.

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[40] This cost is very speculative. For a further discussion, see Larry Parker, *Coal Market Effect of CO2 Control Strategies as Embodied in H.R. 1086 and H.R. 2663*, CRS Report 91-883, December 13, 1991.

For example, an early component of electricity restructuring is the Federal Energy Regulatory Commission's (FERC) Order 888 that promotes wholesale competition through open, non-discretionary access to transmission services to all participants in the wholesale generation market. In developing the Order, FERC conducted an environmental impact statement (EIS) to examine the implications of the proposed Order for emissions of pollutants by affected generating facilities. This assessment covered only a limited part of what would be affected by a comprehensive restructuring of the electricity generating industry; specifically, the Order is limited to the transmission of wholesale electricity, about 10% of total sales. Nevertheless, studies of the rule, including those critical of FERC's analysis, illustrate the difficulties in isolating the impacts of restructuring from other factors present in the system.

FERC issued its findings in a draft EIS[41] in November 1995. From two baselines — projections about electricity generation without the proposed rule — FERC analyzed changes in electricity generation that might result from the proposed rule, and the consequent changes in emissions that would therefore be expected. The two baselines differed in assumptions about the relative prices of gas and coal. Based on the models used by FERC and the assumptions adopted, the analyses indicated that the proposed rule would have a small effect on emissions. In general, through 2010, assumptions that favor gas could slightly decrease overall emissions, and assumptions that favor coal could slightly increase overall emissions. A regional analysis similarly found relatively small effects. Given the modest environmental impacts, FERC concluded that there was no need to undertake mitigation — although it discussed options — and in fact concluded that it had little appropriate authority to require any mitigation.

Comments on the draft were numerous; they are summarized in the final EIS issued in April 1996.[42] Three issues received particular attention. Two sets of comments addressed two aspects of the analyses that commenters argued could have underestimated potential increases in emissions. A third set of comments focused on the issue of mitigation.

One set of these comments concerned the possibility that restrictions built into FERC's analysis on the amount of power that could be transmitted among regions unduly limited projections of the amount of electricity generated and exported from high-emitting, coal-fired sources in the Ohio River valley. These comments[43] suggested that the rule would increase the amount of power transported, leading to additional construction of more transmission capacity if necessary, and would thus result in more emissions than projected. In particular, it would increase NOx emissions that could be expected to affect the Northeast. As a result, for its final EIA,

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[41]Federal Energy Regulatory Commission, *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities (RM95-8-000) ...* Draft Environmental Impact Statement (November 1995) FERC/EIS-0096D.

[42]Federal Energy Regulatory Commission, *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities (RM95-8-000) ...* Final Environmental Impact Statement (April 1996) FERC/EIS--0096, Appendix J.

[43]See, for example, Alliance for Affordable Energy, et al., *Joint Comment on Draft Environmental Impact Statement* (February 1, 1996), p. 32.

FERC added further analysis of this possibility, but concluded the effects would not be significant.[44]

Another set of comments argued that the rule would have the effect of decreasing electricity prices and therefore would likely increase demand, leading to the generation of more electricity than assumed in the base cases. FERC basically said this possibility would be a second-order effect that lay outside appropriate analysis.[45] Despite FERC's response, ignoring demand seems unrealistic. As noted earlier, electricity demand is a critical component in assessing emission-related impacts. However, the model FERC used for its analysis is incapable of analyzing the price-demand effects of restructuring because its demand assumption is exogenous to the model. FERC chose to assume that the lower prices of restructuring would not result in any increase in electricity demand from baseline conditions — an unlikely outcome. To ignore the price-demand relationship reduces confidence in FERC's conclusion.

The third set of comments, on mitigation, ranged from those supporting FERC's conclusion that there was nothing that needs mitigating to arguments that FERC was obligated and has the authority to require mitigation.[46]

Subsequent reports challenge the FERC analysis. In April 1997, the Natural Resources Defense Council, Public Service Electric and Gas Co., and Pace University's Mid-Atlantic Energy Project jointly issued a report evaluating the contribution of utility generating companies to air pollution. Presenting data indicating that "the 'lowest cost' producers of electricity" are often "some of the highest emitters of pollutants," the authors concluded that

> In order to implement fair competition and to prevent a considerable increase in electric utility emissions due to increased use of older, higher-emitting units, the restructuring process should apply consistent environmental standards to all competitors.[47]

In January 1998, the Northeast States for Coordinated Air Use Management (NESCAUM) issued a report concluding that recent trends contradict FERC's finding in the EIS. Specifically, NESCAUM presented data challenging two assumptions that had led to the EIS conclusion that emissions growth would be negligible. Contrary to the EIS analysis, NESCAUM shows that between 1995 and 1996, coal-fired generation increased while natural gas-fired generation declined and that growth in the use of interregional power transmission had "outstripped FERC's longer-term growth assumptions."[48] According to NESCAUM, these

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[44]FERC, Final EIS, pp. J-34 - J-39 and pp. 6-25 - 6-41.

[45]See FERC, Final EIS, pp. J-69 - J-70.

[46]Mitigation is discussed in Chapter 7 of the EIS; comments are discussed in the Final EIS at pp. J-78 - J-105.

[47]Natural Resources Defense Council, et al., *Benchmarking Air Emissions of Electric Utility Generators in the Eastern United States,* 2nd Edition (April 1997), p. 41.

[48]Northeast States for Coordinated Air Use Management, *Air Pollution Impacts of Increased*

(continued...)

> preliminary findings suggest that increased competition is contributing to increased emissions at coal-intensive utilities, and that some form of mid-course public policy correction may be necessary. These findings underscore the need for comprehensive efforts to document the impacts of restructuring on air quality, and lend impetus to state and federal efforts to establish adequate emissions tracking and disclosure systems. Moreover, these findings suggest that equitable environmental standards must be made an integral part of ongoing competitive reforms.[49]

Thus, environmental interest groups continue to warn that FERC underestimated emissions resulting from its rule — and that restructuring portends even greater impacts; and that, therefore, mitigation of the effects of the rule and of restructuring is necessary. However, as suggested above, increased emissions may be the result of existing trends in the industry, and not strictly due to restructuring. As noted, renovating coal-fired capacity has been an increasing trend in the industry for over a decade. As the NESCAUM data reflect a time period before implementation of Order 888, ascribing emission increases solely to restructuring is debatable. This situation illustrates the difficulties in assigning cause to potential emission increases over the next 5-10 years from existing coal-fired facilities.

Conclusion

The relationship between restructuring electricity generation and environmental consequences is not a simple one. The environmental outcome will result from an interactive, iterative process of many changes in existing trends affecting electricity generation. The two most crucial trends are: (1) decisions with respect to meeting future electricity demand, including the renovation of existing generating capacity, choice of new generating technologies for new construction, and enhancement of transmission capacity; and, (2) decisions with respect to implementing existing environmental regulations, and the potential approval of future environmental regulations. Restructuring would influence each of these trends to varying degrees, encouraging some, such as renovating existing capacity, and challenging others, such as existing environmental regulations.

Electricity Demand

Restructuring and the other trends underway point to changes in demand and technological developments that will ultimately be reflected in environmental consequences. To the extent restructuring and the other changes lead to a more efficient generation industry, baseload prices should decline, which would be expected to lead to higher demand and greater consumption. Lower baseload prices could encourage owners of existing coal-fired facilities with low operating costs to extend

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[48](...continued)
Deregulation in the Electric Power Industry: An Initial Analysis (January 15, 1998), p. 1. At [http://www.nescaum.org/about.html]

[49]Ibid., p. 2.

and enhance electricity generation from such facilities rather than risk investing in new construction. CRS estimates that between 23,000 and 53,000 Mw of existing coal-fired capacity is currently underutilized and could be made available if economics and transmission capacity justified such a decision. Renovating existing coal-fired capacity has been an increasing trend in the industry for over a decade. The more competitive generating market of a restructured electric utility industry could further encourage this trend.

Reduced baseload electricity prices also change the signals affecting consumer choices related to energy efficiency. Lower baseload electricity prices could diminish the incentive to invest in increased conservation, such as more efficient refrigerators or insulation. Cost-considerations may also work against power generation by renewables such as solar, wind power, and geothermal, which currently are not cost-competitive with natural gas or coal technologies. It may also work against nuclear, which is a capital intensive technology, and which has contradictory environmental implications — being essentially free of air emissions, but posing waste disposal problems that some see as more hazardous and less controllable. Finally, cost concerns may further encourage natural gas-generated power in new construction (the existing technology of choice), which is more environmentally friendly than coal or oil alternatives.

But at the same time, if prices reflect marginal costs, the price signal is likely to dampen peak demand, which typically is met by the most costly and inefficient generating capacity — thereby leveling the demand curve. Higher prices for peak load power could strengthen the signal for load management — conservation measures that reduce peak usage, such as automatic shutoffs of hot water heating during peak demand. Also, to the degree consumers are given the choice of electricity suppliers, they may create new markets for different types of generation by basing their decisions on factors other than economics, such as environmental ones. One such possibility is "green pricing," where some consumers choose to purchase electricity that costs more economically but costs less environmentally — such as that produced by renewables. Such a "green market" is being developed in California, but it is too early to anticipate the size that it may achieve.

How these differing effects play out will determine the potential for increased emissions from restructuring. As indicated, some, such as renovating existing coal-fired capacity, represent a furthering of an existing trend. Others, such as green pricing, represent a new trend created by restructuring. Although the overall effect on emissions is difficult to assess, involving several currently unquantifiable variables, the most substantial environmental effect in the short- to mid-term is likely to come from enhanced operation of existing coal-fired capacity. Whether one can ascribe that effect to general trends in the industry or to restructuring is debatable.

Air Quality Regulations

Restructuring, combined with the outcome of the other trends, has the potential to increase emissions of some pollutants of concern; the question is whether existing (or proposed) regulatory limits on those emissions would effectively prevent adverse effects.

- For SO_2, restructuring is unlikely to have any effects on emissions. The CAA requirements statutorily "cap" the nation's utility SO_2 emissions, making industry structure essentially irrelevant. Increasing numbers of participants may make monitoring and enforcement more demanding, but the SO_2 program contains substantial penalties for non-compliance, and no compliance difficulties have emerged to date.
- For NOx, the potential of extended and enhanced coal-fired capacity utilization encouraged by restructuring could significantly increase emissions. NOx emissions from an additional 23,000 MW of coal-fired capacity could be in the range of 480,000 tons, compared with about 70,000 tons if that electricity was generated from natural gas. However, several EPA regulatory actions could reduce or eliminate that potential increase. For example, EPA's Ozone Transport Rule would in effect set a "cap" on emissions in 21 eastern states where they currently contribute to unacceptable ozone pollution; these 21 states are where the majority of potential coal-fired related NOx emission increases could occur. However, the primary implementation of the process lies with the states. As a result, the NOx control program would be administratively more complicated and could be less economically efficient than the SO_2 control program. A system of state-based programs to control NOx emissions might dovetail with the current electricity generation system in which state regulation plays a large role; but if restructuring leads to a more regionally-based, competitive electricity generating system, then implementing a NOx control program based on state programs could lead to industry segments being subject to inconsistent requirements in the various states. Indeed, the inconsistencies could constitute barriers — or opportunities — to the restructuring process. But if the process works, then there would be no increase in NOx emissions in the 21-state region, and the structure of the industry would be irrelevant. If this process is delayed, other regimens, including section 126 petitions, are available for relief.
- For CO_2, the potential of extended and enhanced coal-fired capacity utilization encouraged by restructuring could significantly increase emissions. CO_2 emissions from an additional 23,000 Mw of coal-fired capacity would be about 200,000,000 short tons, compared with 80,000,000 tons if that electricity was generated from natural gas. CO_2 emissions are not controlled by the Clean Air Act, nor does there appear to be any readily applicable provision that could used to control such emissions. *If* the U.S. ratifies the Kyoto Agreement, it would effectively "cap" emissions, and restructuring would become irrelevant in terms of emission increases. But how emissions would be controlled and how reductions would be allocated and implemented would remain to be determined by future domestic legislation.
- For Hg, increased utilization of coal-fired capacity would result in increased Hg emissions, although uncertainty exists as to how much that increase would be. Studies have been completed that could be the basis for regulation under existing CAA authorities, if EPA were to conclude controls are necessary.[50] How well these would mesh with a more competitive electric generating market is unclear.

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[50] Specifically, see: Environmental Protection Agency, *Mercury Study Report to Congress*, EPA-452/R-97-003 (December 1997).

Ultimately, whether future developments in electricity generation will lead to pollution increases of health and environmental concern depends on the effectiveness of CAA requirements and of EPA implementation and enforecement (or on future enactments of new controls) — and, in the case of CO_2, on whether the U.S. ratifies the Kyoto Convention and its requirements are implemented.

Responses

If one has confidence that these authorities will prove adequate to protect human health and the environment and will be effectively implemented, one may be comfortable in adopting the stance that "no action" is necessary to address any emissions implications of restructuring proposals. The result might not be as cost-effective as a regulatory regime more tied to a competitive market (such as a SO_2 style "cap and trade" program), but except for CO_2 (for which the need for controls is highly contentious), the CAA provides control authorities — notably for emissions of particular concern, NOx and Hg.[51]

Conversely, if one fears that existing approaches to pollution control will not be effective or not be implemented, or that controls on CO_2 are requisite, then one is likely to press actions for immediate response. Those having such concerns could be expected to pursue several actions to address perceived unacceptable environmental impacts, such as:

- aggressively using the existing regulatory regimen to address environmental deterioration;
- proposing to embed environmental protections in any restructuring programs; and
- proposing revisions of appropriate environmental statutes, in particular, the CAA — and supporting prompt ratification of the Kyoto Agreement and enactment of appropriate implementation legislation.

Those seeking to assure rigorous application of existing air pollution controls could aggressively use the citizen suit or section 126 provisions of the CAA to press their case whenever they perceive inadequate or ineffective implementation. While this may be effective for controlling NOx and Hg emissions, it would not appear to be a fruitful course with respect to CO_2 emissions for which any controls are only prospective.

The case for adding environmental protections to restructuring proposals depends in part on the extent to which restructuring itself is a likely cause of more pollution; or if the restructured industry were to pose implementation, enforcement, or other problems that the current regulatory structure proves ill-equipped to cope with. (For some, attaching environmental issues to restructuring may be a surrogate for debates on a comprehensive review of the CAA or for CO_2 controls.) As indicated by the analysis of this paper, restructuring's role is not clear; it is quite

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[51] While Hg emissions from electric utilities are not currently regulated, the 1990 CAA Amendments provide EPA with the authority to do so based on studies mandated by the Act (section 112(n)).

possible that some utility emissions of concern could increase as a result of other trends underway, and in fact that may be happening. As the NESCAUM report indicates, coal-fired generation appears already to be on the rise, before restructuring efforts such as FERC's rule to promote wholesale competition through open access to transmission services could be having an effect. Likewise, monitoring shows that (unregulated) CO_2 emissions have risen since 1990.[52] Thus, tying environmental protection to restructuring might fail to address actual causes for increased emissions.

Responding to any problems that arise by then revising environmental statutes may seem risky to those who already perceive significant environmental risks from changes in electricity generation. They could point to the history of acid rain legislation as an example of the risk: it took about 10 years from the time legislation was first proposed to address acid rain to enactment of a program — which required movement of a comprehensive set of CAA amendments. The lesson many draw is that consideration and enactment of environmental legislation separate from legislation that might have the potential to cause environmental problems can be delayed and difficult. From this perspective, at least, it could make sense that if Congress is to enact restructuring legislation, to attach to those bills any potentially necessary environmental responses even if the problem is not solely due to restructuring.[53]

All in all, as the preceding analysis and discussion indicates, the potential for environmental deterioration from restructuring electricity generation is difficult to project — both because various technical and economic changes are affecting the industry at the same time and because of an evolving policy context. As a result of this uncertainty, those who are focused on preventing environmental deterioration tend to take a precautionary stance, to propose immediate preventative measures, and to argue that such measures be attached to available legislative vehicles. In contrast, those who doubt that there will be significant environmental effects or who are focused on the substantial regulatory structure in place tend to take a wait-and-see position. Further complicating this picture is that some attitudes about restructuring are related to and partly a surrogate for a more fundamental debate that is underway because of global climate change concerns — about the future direction of energy use in the United States and the federal role in affecting it.

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[52]Larry Parker and John Blodgett, *Global Climate Change: Reducing Greenhouse Gases — How Much from What Baseline?* CRS Report 98-235, March 11, 1998.

[53]For information on legislative proposals relating restructuring to environmental controls, see Larry Parker and Amy Abel, *Electricity: The Road Toward Restructuring*, CRS Issue Brief IB10006 (updated regularly); and Larry Parker, *Electricity Restructuring: Comparison of Comprehensive Bills*, CRS Report RL30087, (updated regularly); and, Larry Parker, *Electricity Restructuring and Air Quality: Comparison of Proposed Legislation*, CRS Report RS20326 (July 26, 2000).