The Impact of Electricity Restructuring on NOx Emissions Affecting the Environment in Maryland

Draft Final Report

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Abstract:

The American electric power industry is undergoing dramatic changes in the way it is structured and regulated. As of June of 1998, state utility regulators, state legislatures or both in 17 states had made the decision to implement retail competition within 5 years or less. Competition in electricity markets and associated new opportunities for expanded inter-regional electricity trading could result in substantial changes in the mix of generation technologies employed to produce electricity, in the efficiency of power plant operations, and in the price and quantity of electricity traded in the marketplace. All of these changes could in turn have potential implications for NOx emissions, with associated potential impacts on air quality in Maryland and nitrate deposition in the Chesapeake Bay. This report focuses on how restructuring and concurrent potential environmental policies could affect emissions. The report draws on a national electricity model to characterize the changes that are likely to take place under alternative scenarios for regulatory and environmental policy.

Absent new NOx regulation, electricity restructuring is likely to result in up a 4% increase in annual NOx emissions nationally from the electricity sector by the year 2003, the timeframe considered in this study. The bulk of this increase would occur in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN). The impact on NOx emissions in MAAC is smaller than in the Eastern Region as a whole, with only a 2.5% increase under aggressive restructuring.

The NOx policies that are investigated would impose a substantial cost in the aggregate. However, they would have a minimal impact on the national price of electricity or on the price in individual NERC regions. Though electricity price seems to be quite responsive to the pace of restructuring, it is quite unresponsive to the strictness of NOx regulation.

The most costly NOx regime considered in this study is an Old Source Performance Standard applied to the five Eastern regions leading to a 50% reduction in national NOx emissions from the electricity sector. Even in this case, real electricity prices would rise by less than 1% nationally, compared to the same restructuring scenario in the absence of the NOx control policy. In MAAC the effect of NOx policy leads prices to rise by no more than 1.1% compared to the same restructuring scenario in the absence of the policy. Under each of the market structure scenarios, NOx control is significantly cheaper (about 10% nationally and about 6% in MAAC) under a tradable NOx allowances regime than under the Old Source Performance Standard regime.

I. Introduction

The American electric power industry is undergoing dramatic changes in the way it is structured and regulated. For much of its 100 year history, the industry has been organized largely as a collection of local integrated monopolies that generate, transmit, distribute and sell electricity at regulated prices to captive customers within a franchised service territory. Currently the industry is going through a period of unbundling of functions whereby the generation and retail sales markets are increasingly being opened up to competition. As of June of 1998, state utility regulators, state legislatures or both in 17 states had made the decision to implement retail competition within 5 years or less. Under retail competition, electricity consumers will be allowed to pick their electricity suppliers, but the delivery of that electricity to the customer's premises will continue to be handled by the regulated local distribution utility.

Allowing competition in electricity markets and associated new opportunities for expanded inter-regional electricity trading could result in substantial changes in the mix of generation technologies employed to produce electricity, in the efficiency of power plant operations, and in the price and quantity of electricity traded in the marketplace. All of these changes could in turn have potential implications for emissions, particularly of NOx and CO_2, and for environmental quality.[1] For example, if competition results in accelerated turnover of the generating capacity stock, then NOx emissions could be expected to drop as newer gas combined cycle units have substantially lower NOx emission rates than older units, particularly coal-fired units. On the other hand, if competition leads to more generation at older, higher-emitting coal-fired facilities, as some predict it will, then emissions of NOx could increase as a result of restructuring. To the extent that competition leads to lower electricity prices, demand for electricity could increase and yield an increase in NOx emissions.

The impact of electricity restructuring on NOx emissions from electricity generators is of particular interest to the State of Maryland, both because of potential impacts on air quality in Maryland and because of potential impacts on nitrate deposition in the Chesapeake Bay.[2] This report focuses exclusively on how restructuring and concurrent potential environmental policies could affect NOx emissions from the electric power sector in the early part of the next decade as represented by the year 2003. The ultimate impact of these emissions on the environment in Maryland depends on atmospheric transport of pollutants and atmospheric chemistry. The emissions impacts of restructuring identified by our model are being transferred to ERM who in turn will run them through their Calpuff model to obtain impacts of different electricity restructuring and environmental policy scenarios on the environment in Maryland.

The remainder of this report is organized as follows. The next section contains a brief review of the existing literature on the environmental impacts of restructuring and some discussion of the unique contributions of this study. The following section describes the RFF HAIKU model used in this study. Sections IV and V describe the electricity restructuring scenarios and the environmental policy scenarios analyzed in this study. Section VI presents the results and section VII concludes.

II. Review of Prior Studies/Contribution of This Study

This study is not the first to consider the potential environmental impacts of electricity restructuring. A number of papers (Palmer 1997, Brennan et al 1996, Energy Modeling Forum 1998) have provided a general overview of the potential environmental impacts of restructuring, both negative and positive. Other studies (Lee and Darani 1995, Center for Clean Air Policy

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[1] Total emissions of SO2 are capped under the requirements of Title IV of the 1990 Clean Air Act Amendments.

1996a, 1996b and 1996c, Rosen et al 1995, EIA 1996) have attempted to quantify the potential impacts of increased inter-regional power trading on emissions. Palmer and Burtraw (1997) look at the potential impact of restructuring on emissions of NOx and CO_2 and on atmospheric concentrations of NOx and nitrates.

The policy debate over the potential environmental effects of restructuring really took off with the issuance of the FERC proposed rule to allow open access to the transmission grid that was issued in the spring of 1995. A primary purpose of the proposed rule, ultimately issued as FERC Order 888, was to require all transmission-owning utilities to allow competing generators to gain access to their transmission grids under comparable terms and at identical rates to those the utility charges itself for transmission services. This rule facilitates expanded trading of electric power at the wholesale level so that, for example, municipal utilities that do not own sufficient generation capacity to meet their customers' demands can solicit bids to supply electricity from distant generators.

When Order 888 was initially proposed, environmentalists became concerned that facilitating greater inter-utility trading of power could lead to increased emissions of NOx and CO_2 from low-cost, older, and previously underutilized coal-fired generators in the Midwest. As a consequence of their age, these plants are exempt from new source performance standards, and as a consequence of their location they are exempt from controls required of plants located proximate to metropolitan areas that exceed air quality standards for ozone (NOx is a precursor to ozone). However, their emissions are thought to affect air quality in these distant metropolitan areas. The expectation was that open transmission access would provide these plants with access to distant higher priced markets into which they could sell their excess generation. The resulting

[2] Nitrogen oxides (NOx) from the air are a major source of nutrient enrichment in the Chesapeake Bay, comprising anywhere from 20% to 35% of the Bay's controllable nitrate loads (Dennis, 1997).

increases in NOx emissions were predicted to have adverse effects on air quality, particularly on concentrations of ozone, in areas downwind of these power plants. This issue was analyzed in the FERC's Environmental Impact Study (EIS) of the proposed rule that ultimately became Order 888. The FERC EIS concluded that the impact of Order 888 on NOx emissions from the utility sector and on ozone concentrations in the east was likely to be very small.

The FERC analysis is far from the last word on the environmental impacts of restructuring for several reasons. We highlight two of those reasons here.[3] First, the EIS failed to consider the possibility that allowing open access might lead to more rapid growth in inter-regional transmission capability. Large inter-regional differences in generation costs (and associated wholesale power prices) suggest that in a world of open access there will be strong economic forces pushing for expansion of transmission capacity. These forces are likely to be even stronger under retail competition than when competition is limited to wholesale markets.

The second major limitation is that the EIS analysis was limited to the environmental impacts of wholesale competition only. With wholesale electricity competition firmly in place and several proposals in congress, including one backed by the Clinton Administration, to expand retail competition nationally, the policy debate has shifted to concern over the additional environmental impacts of retail competition. Allowing retail competition not only expands the potential for inter-regional electricity trading by vastly expanding access to competitive power markets, but it also increases the economic forces pushing for rapid growth in inter-regional transmission capability. In addition, the greater degree of competition provides economic pressure to enhance the efficiency of generator performance. Improvements in generator heat rates will reduce emissions per unit of electricity generated with an uncertain impact on overall

[3] For a more detailed review of the shortcomings of the FERC EIS see Palmer and Burtraw (1997).

emissions. On the other hand, reductions in O&M costs could be expected to lead to greater utilization and associated increases in emissions.

Moving from wholesale to retail competition also increases the magnitude of the expected declines in retail prices and is expected to lead to greater access to time-of-day pricing of electricity (Bohi and Palmer 1996). These changes in price levels and price structure are likely to have impacts on the mix of generation technologies and the quantity of electricity generation that could have associated impacts on emissions.

This study incorporates these and other effects of moving from wholesale to retail competition in electricity markets for the early part of the next decade (2003). In addition to allowing for faster transmission capacity growth and greater access to time-of-day pricing of electricity, the move to retail competition is expected to accelerate the pace of retirement of existing inefficient nuclear and coal-fired facilities. Retail restructuring is also expected to improve the efficiency – lower heat rate and fewer outages – and lower the operating costs of existing generators. In the short run, the impacts of restructuring on electricity prices will be determined in part by the extent of stranded cost recovery which, in turn, will have implications for electricity demand and the overall level of emissions from the generation sector. These different potential effects of restructuring and characteristics of restructuring policy (such as stranded cost recovery) are represented in two restructuring scenarios which are described fully in Section IV below.

Any increases in NOx emissions from the electric power sector that may come about as a result of retail restructuring are likely to be at least partly offset by new environmental policies designed to reduce NOx emissions from the electric power sector.

In this study we evaluate the implications for emissions and pollution control costs of combining different NOx policies with different assumptions about restructuring. The results shed light both on the relative size of the impacts on emissions (i.e. the extent to which increases in emissions resulting from restructuring are offset by reductions in emissions resulting from new environmental policies) and how restructuring affects the environmental efficacy and cost-effectiveness of different environmental policies.

III. The RFF HAIKU Model

The RFF HAIKU Model is a simulation model of regional electricity markets and inter-regional electricity trade with a fully integrated algorithm for NOx emission control technology choice. The model can be used to simulate changes in electricity markets stemming from public policy associated with increased competition or environmental regulation. The model simulates electricity demand, electricity prices, the composition of electricity supply, inter-regional electricity trading activity, and emissions of key pollutants such as NOx and CO_2 from electricity generation in different regions. The model can also be used to identify the mix of NOx emission control technologies on generators that achieve specified target levels of emissions under various environmental policies (technology-based policies, emissions taxes or regional emissions trading).

Two components of the HAIKU model are the Intra-regional Electricity Market Component and the Inter-regional Power Trading Component. These components are described in more detail below.

Intra-regional Electricity Market Component

This model component uses a reduced-form dispatch algorithm to develop electricity supply curves for each NERC region during each of three seasons (summer, winter, and spring/fall). The supply curves are constructed using information on capacity (net of planned and unplanned outages), operating and maintenance costs (including pollution control costs) and fuel costs for several "model plants" each of which represents a group of generating units aggregated by region, fuel type, technology and vintage classifications. The operation of model plants in each time period is determined according to a market equilibrium identified by the intersection of the supply and demand curves for that time period (and subsequent opportunities for inter-regional power trading which are described below). The market price of electricity is determined according to the specified regulatory institution in the scenario. Average cost pricing and marginal cost pricing can both be represented. Under marginal cost pricing, for example, the equilibrium price is equal to the sum of the market clearing price of electricity generation and the additional costs of transmission and distribution services, including intra-regional transmission losses.[4] The demand, supply and emissions components of this model and the underlying data are described in more detail next.

Demand

Using data from the U.S. Energy Information Administration (EIA), the demand component classifies annual electricity demand by three customer types (residential, commercial and industrial), by three seasons (summer, winter, fall/spring), and by three time blocks (peak, middle and off-peak hours). Demand within each block is represented by a price-sensitive demand function where each customer/season/time block is characterized by an elasticity value that is usually unique.

Supply

The model plants that populate the supply component of the model are constructed using information at the generating unit level on generating capacity and engineering characteristics drawn from three different EIA databases: EIA 860, EIA 759 and EIA 767. This information is aggregated to the "model plant" level based on the fuel type, technology (including boiler type for some coal-fired boilers) and vintage of each unit. The model plant definitions used in this model are adapted from those developed by the U.S. EPA for the Clean Air Power Initiative project (EPA 1998). As a part of that project, EPA's contractor, ICF, Inc., developed prototypical operating cost information for each model plant category. This information is combined with regional fuel cost, the costs associated with endogenously selected NOx control technologies (and, in the case of emission allowance trading, the cost of NOx allowances) and unit availability (reflecting planned and unplanned outages) to develop regional supply curves. The geographic location of each model plant is determined by generation weighting the latitude and longitude information for each constituent plant.

The version of the HAIKU model employed in this study does not incorporate endogenous investment and retirement decisions, except with respect to investments in NOx control technology.[5] This means that the model in unable to shed light on how changes in electricity market policy or environmental policy will affect retirement of older generating facilities or investment in new generating facilities. However, the model does incorporate parametric assumptions about plant retirement and investment and these assumptions vary under different restructuring scenarios. Since this study looks at the effects of restructuring in the

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[4] For purposes of setting electricity prices, intra-regional transmission losses are assigned to the exporting regions.
[5] A longer-run version of the model that incorporates endogenous generating plant retirement and investment is currently under development.

early part of the next decade (2003), it incorporates changes in the stock of generating capital that are likely to take place in the interim.

Emissions

The model contains emission factors for NOx, SO_2 and CO_2 for each model plant that is constructed using information from U.S. EPA and EIA on plant performance and total emissions. This project focuses primarily on NOx emissions.[6] Information on the costs of NOx emission control is obtained for all generating facilities and aggregated to the model plant level. NOx control strategies are chosen endogenously and the costs of these controls feed into the calculation of NERC region-wide electricity supply functions. This interaction between endogenously chosen emission control costs and emission factors with electricity supply allows the model user to analyze the effect of alternative environmental policies on inter-regional power trading and other market outcomes, as well as their effect on emissions. See Appendix A for more information about emission control technologies and cost data, and the algorithm used to solve for pollution control investments in the model.

The effects of alternative environmental policies are indicated by changes in electricity prices, quantity of electricity produced, amount of electricity generated using each model plant technology and levels of emissions of NOx and other pollutants by model plant and by region. The geographic location of emissions can be specified at two levels of detail. At an aggregate level they are located at the physical site of the model plant; at a disaggregated level they are assigned to the constituent generating units for each model plant based on the 1995 generation of these units and emissions are then located at these locations.

[6] Electric power industry-wide emissions of SO2 are capped under Title IV of the 1990 Clean Air Act Amendments and CO2 emissions are a global environmental issue, that is outside the scope of this project.

Inter-regional Power Trading Component.

This model component solves for the level of inter-regional power trading necessary to equilibrate differences in regional equilibrium electricity prices (gross of transmission costs and power losses) across different NERC regions. These transactions are constrained by the assumed level of available inter-regional transmission capability as reported by NERC, and they reflect inter-regional transmission loses and transmission fees.

Transactions are determined by the excess energy supply function for exporting regions and the excess energy demand functions for importing regions. The marginal cost of generation for export in supplying regions is determined after solving (or resolving) for equilibrium prices within the region. Hence, price discrimination is assumed in that native customers within a supplying region pay a different (lower) price for generation than customers in other regions that receive imports from the supplying region. The model user is free to vary parameters such as the amount of transmission capability between different NERC regions or the cost of transmission service in order to determine the impact on power trading, electricity prices and ultimately on emissions.

IV. Definitions of Market Structure Scenarios

The effect of electric power industry restructuring on emissions of NOx and other pollutants will depend on how restructuring affects the incentives and behavior of different participants in electricity markets including generators, transmission owners and electricity consumers. Some of the expected changes are likely to lead to higher emissions. For example, increased competition in electricity markets is expected to lead to lower electricity prices and an associated higher level of electricity consumption which in turn could result in higher emissions than would have occurred absent restructuring. On the other hand, restructuring is also expected to result in efficiency improvements at existing generating facilities such as declines in heat rates which could reduce emissions, holding all else constant.

A priori, the characteristics of the post-restructuring electricity industry and market are highly uncertain. We characterize that uncertainty in a limited fashion by considering two different restructuring scenarios: one that represents relatively moderate impacts of restructuring on a variety of technological parameters and market institutions and another that represents more dramatic impacts. These two scenarios are called “Moderate Restructuring” and “Aggressive Restructuring.” These scenarios are contrasted to an Average Cost Baseline scenario and all three scenarios are set in the year 2003. These three market structure scenarios are described in the subsequent three sub-sections. Table IV.1 contains an overview of the assumptions that characterize each market structure scenario.

Each scenario is defined by a number of technological parameters and a few demand-related parameters that are all expected to change as a result of restructuring. The technological parameters that vary across scenarios include the rate of retirement and new investment in fossil fueled generating units, the rate of retirement of nuclear power plants, the reduction in unscheduled outages, the rate of improvement in maximum capacity factor (reduction in scheduled outages), heat rate and operating cost at existing plants, and the rate of growth in transmission capability. The demand-related parameters include the method of determining prices and the extent of stranded cost recovery.

	Baseline ***(incorporates wholesale competion)***	***Retail Restructuring with Moderate Efficiency Effects***	***Retail Restructuring with Aggressive Efficiency Effects***
Pricing Assumptions			
Stranded cost recovery	90% recovery in regions (NPCC and WSCC) with competition	90% recovery (rest largely mitigated)	75% recovery (rest largely mitigated)
Method of calculating prices	average cost pricing under traditional rate design by customer class (time of day pricing for industrials only) (except in NPCC and WSCC)	variable cost pricing of generation with substantial fixed cost recovery (see above); time of day pricing for industrials only	variable cost pricing of generation with limited fixed cost recovery (see above) and time of day pricing for all customer classes
Technology Parameters			
Fossil Steam Unit Retirements	based on AEO 98 reference case (RC) aggregate retirement of 50.8 GW by mid 2000's; replace by mix of coal and gas per AEO 98	accelerate fossil steam retirements from AEO 98 RC to 53.5 GW total by mid 2000's; replace by mix of coal and gas per AEO 98	accelerate fossil steam retirements from AEO 98 RC even more to 56.3 GW total by mid 2000's; replace by mix of coal and gas per AEO 98
Nuclear Unit Retirements	based on AEO 98 RC; 9.6 GW retired nationally	1/2 of AEO 98 "low nuclear case"; 16.2 GW retired nationally	full AEO 98 "low nuclear case"; 22.8 GW retired nationally

Table IV.1 Assumptions characterizing different market structure scenarios.

	Baseline (incorporates wholesale competion)	***Retail Restructuring with Moderate Efficiency Effects***	***Retail Restructuring with Aggressive Efficiency Effects***
Technology Parameters			
Net New Investment in Generating Capacity	based on AEO 98 RC; 98.3 GW added nationally; 71% gas turbine (GT), 22% combined cycle (CC), 7% scrubbed coal	91.7 GW added nationally (lower net investment due to higher nuclear retirement) (same technology percentages apply)	based on 75% of AEO 98 RC; 73.2 GW nationally (same technology percentages apply)
Rate of Improvement in Maximum Capacity Factor	AEO 98 RC assumes 82% max. capacity factor for steam units beginning in 1998; we assume 82.6%	3% improvement over forecast period due to consolidation of scheduled outages and reduction of forced outages	5% improvement over forecast period due to consolidation of scheduled outages and reduction of forced outages
Rate of Improvement in Coal-Fired Unit Heat Rate	none per AEO 98 RC	2% reduction in average heat rate over forecast	4% reduction in average heat rate over forecast
Improvement in Fossil Generating Unit Operating Costs	18% decline for O&M and G&A over entire forecast period (AEO 98)	25% decline in O&M and G&A over entire forecast period	35% decline in O&M and G&A over entire forecast period
Transmission Capacity Growth (Inter-region transmission capacity defined as .75*season-specific FCTTC in 1997)	7.5% growth over forecast period	24% growth over forecast period	43% growth over forecast period

Table IV.1 Assumptions Characterizing Different Market Structure Scenarios (cont'd).

Baseline Scenario

A defining feature of the different market structure scenarios that we consider is the institution that governs the pricing of electricity. In the baseline scenario we assume that the electricity market continues to be predominantly served by regulated entities that price at average cost. In this case the penetration of retail competition and associated marginal cost pricing of electricity is limited to the two regions of the country that are already well on their way to moving to retail competition: NPCC and WSCC.[7] In the two regions that have marginal cost pricing, we assume that 90% of stranded costs (the portion of annualized fixed costs not recovered through the market price) will be recovered in electricity rates through access charges spread uniformly over all kWh sales. We also assume that only industrial customers have access to time-of-day pricing of electricity.

The technology assumptions for the average cost baseline including the assumptions regarding fossil steam unit and nuclear unit retirement as well as investment in new capacity are taken largely from the 1998 Annual Energy Outlook (AEO 98) reference case.[8] The AEO 98 reference case retires existing generating units as scheduled, plus all other generating units with operating costs in excess of 4 cents per kWh evenly over a ten year period. In our baseline scenario, we adopt the AEO 98 retirement assumptions and retire 50.8 GW of fossil steam capacity by 2003, replacing it with a mixture of 7% scrubbed coal-fired and 93% gas-fired capacity. We also assume that 9.6 GW of nuclear capacity will be retired nationally. In addition to the capacity necessary to replace retirements, we adopt the AEO 98 assumptions that 108 GW

[7] As of June of 1998, PUCs, state legislatures or both in all of the states of NPCC (which includes all of New England and New York State) had decided to implement retail competition by or before the middle of the next decade, the time period modeled in this study (The Vermont State Corporation Commission's restructuring plan requires legislative approval which is still forthcoming). In the WSCC, the states of California, Nevada, Montana and Arizona ,which constitute well over 50% of the electricity consumption in the region, have all either already implemented retail competition (California) or are expected to have done so by the middle of the next decade.

of net new generating capacity will be added nationally with 71% gas turbine, 22% gas-fired combined cycle and 7% scrubbed coal-fired capacity.

In RFF's HAIKU model, the maximum capacity factor is defined at the model plant level by combining information on planned and unplanned outage rates by technology from the NERC GADS data base (NERC 1997). We assume that about 10% of planned outages occur in the summer, about 25% in the winter and about 65% in the Spring/Fall. Unplanned outages are allocated equally to all seasons according to the season's length. Using this method, the maximum capacity factor for a steam-fired generator in 1998 is 82.6% which is approximately equal to the 82% level assumed in the AEO 98. For the baseline scenario, we adopt the AEO 98 assumption that the maximum capacity factor of existing fossil fuel units will not improve over time. We also adopt the AEO assumption that recent declines in O&M costs at utility generators will continue into the future producing an 18% decline in O&M costs between 1995 (the year of our data) and 2003. We also assume that the recent 1.2% per year rate of growth in overall transmission capacity will continue into the future yielding a 7.5% cumulative increase in transmission capability between 1998 (the year for which we have data) and 2003.[9]

Moderate Restructuring Scenario

Both the moderate and aggressive restructuring scenarios adopt a variable cost pricing approach to electricity pricing for all NERC regions. Under this approach, the generation portion of the electricity price is defined by marginal cost (or, in the absence of time-of-day pricing, the weighted average of marginal costs that obtain across load blocks within a season) while the transmission and distribution portion of price is still defined on the basis of average cost. As indicated previously, with moderate restructuring, time-of-day pricing remains available only to

[8] The EIA only reports national retirements by capacity type in the published AEO 98 report. We obtained a NERC regional breakdown of retirement data from the EIA.

industrial customers. The short-run price impact of allowing competition on electricity prices is muted somewhat by the assumption that 90% of the utilities' stranded costs are recovered in retail prices. In the case of electricity traded between regions, stranded cost recovery is applied in the importing region.

Compared to the baseline scenario, the moderate restructuring scenario assumes more aggressive retirement of both fossil-steam units and of nuclear plants. Under this scenario, 50% of the remaining quantity of fossil capacity with costs in excess of 4 cents per kWh are assumed to retire by 2003 bringing total fossil retirements to 53.5 GW. Nuclear retirements are pegged at a level that results in a level of nuclear capacity half way between that assumed under the AEO 98 reference case and that assumed in the AEO 98 "low nuclear" scenario. Net additions to capacity are somewhat lower as a result of this increased level of nuclear retirement, but the technology and fuel composition of replacement and net new capacity is the same as in the baseline.

This scenario does assume that retail restructuring will lead to reductions in plant outages, improvements in heat rates and more aggressive reductions in operating costs compared to the baseline scenario. Specifically, we assume that reductions of scheduled and forced outages will lead to a 3% improvement in maximum capacity factors over the forecast period. We also assume that as a result of increased competitive pressures, heat rates will improve on average by 2% and operating costs at all existing units will fall by 25%, 7% more than under the baseline. Transmission capacity is also expected to grow by 16.5% more under moderate restructuring, resulting in a 25% increase in transmission capability between all NERC regions over the forecast period.

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[9] This estimate comes from the EPA's comments on the FERC EIS of Order 888 (EPA 1996).

Aggressive Restructuring Scenario

Under this scenario, retail competition and time-of-day pricing of electricity are assumed to be pervasive: all customer classes in all NERC regions buy electricity in competitive markets and face time varying electricity prices. Since the amount of stranded costs is calculated in the model, it varies between the Aggressive Restructuring and Moderate Restructuring scenarios. The impacts of competition on retail prices are also larger under this scenario due to the assumption that only 75% of stranded costs are recovered. Again, in the case of electricity traded between regions, stranded cost recovery is applied in the importing region.

This scenario assumes more aggressive retirements and less aggressive investment, due in part to higher expected capital costs. Under aggressive restructuring, the total amount of fossil generation with operating costs in excess of 4 cents per kWh is assumed to be retired by 2003 resulting in 5.5 additional GW of retirement relative to the baseline scenario. In addition, nuclear retirements are assumed to mirror those assumed in the AEO 98 "Low Nuclear" scenario yielding a total of 22.8 GWs of retirement nationally, 13.2 GW more than in the baseline. Net new investment is about 75% of the level assumed in the baseline scenario due largely to a reduction in reserve margins.

Improvements in generating unit performance and costs and growth in transmission capacity are also larger under aggressive restructuring than under moderate restructuring or the baseline. A 5% improvement in maximum capacity factors is assumed and average heat rates at fossil-fired units are assumed to improve by a full 4% by 2003.[10] Also, unit operating costs

[10] The DOE policy office also assumes a 4% improvement in average heat rates in its analysis of the President's Comprehensive Electricity Competition Plan which envisions nationwide adoption of competitive retail electricity markets by 2003. Roberts and Goudarzi (1998) find that average heat rates could improve by as much as 8% to achieve industry best practice.

(excluding fuel costs) are assumed to fall by 35% between 1995 and 2003.[11] Inter-regional transmission capability is assume to grow by 43% which is consistent with the high transmission growth scenario in the FERC EIS (1996) and in Palmer and Burtraw (1997). This higher rate of transmission capacity growth is almost twice as fast as that assumed under moderate restructuring and nearly 6 times as fast as that assumed under the baseline.

V. Environmental Policy Scenarios

A second focus of this study is on the relationship between electricity restructuring and new proposed environmental policies to limit NOx emissions from the electric power sector. Increased competition and increased inter-regional power trading is expected by some to lead to increases in NOx emissions, at least in the short run. However, new environmental regulations expected to take effect over roughly the same time period could lead to substantial reductions in NOx emissions from the electric power sector. Some proposals would use the occasion of electricity restructuring to expand environmental regulations to ensure that NOx emissions do not increase as a consequence of restructuring.

One current proposal is the so-called “NOx budget” specified in a memorandum of understanding (MOU) among members of the northeastern Ozone Transport Commission (OTC). The MOU establishes a budget for NOx emissions from large stationary sources for the northeastern states in an 11 state region and the District of Columbia stretching from the District to Maine.[12] The program is designed to facilitate interstate trading of NOx emission allowances in the region. A second proposal from the EPA, titled the Ozone Transport Rulemaking, would establish NOx emission reduction targets for large stationary sources in an expanded set of 22

[11] EIA (1997) assumes a 40% decline in operating costs as a result of the move to retail competition over the same period.

states (plus the District of Columbia) that lie east of the Mississippi (excluding Maine and Florida). In addition, some of the proposed legislation now before congress that would establish retail electricity competition include provisions to require reductions in emissions of NOx and other pollutants from existing generators. Other proposals that have been suggested would establish an "old source performance standard" (OSPS) by extending performance standards that are applied to new stationary sources to existing sources. This would essentially treat all sources in a comparable fashion with respect to an allowable emission rate, with or without the possibility for trading. While the OTC MOU and EPA's Ozone Transport Rulemaking both propose NOx emission reductions that are applicable only in a five month summer season, all of the environmental policy scenarios considered in this study assume a NOx policy that is applicable year round.

To capture the features of these various proposals that are most relevant for Maryland we consider four alternative environmental policy scenarios. One is a baseline that characterizes the 1990 Clean Air Act Amendments (CAAA). The second is an old source performance standard (OSPS) requirement, *without* NOx emission allowance trading, affecting all generators in the five eastern NERC regions (approximately equal to the 22 eastern states and DC). The third is a NOx emission allowance trading regime (based on the quantity of NOx emissions resulting from the OSPS regime) across generators in the same five eastern NERC regions. The fourth is an OTC MOU scenario with NOx emission allowance trading for the two northeastern NERC regions (approximately equal to the 11 northeastern states and DC). Relevant features of each of these scenarios appear in the following several paragraphs and are summarized in Table V.1. Each of these four scenarios is combined with each of the three market structure scenarios to yield twelve scenarios analyzed in total.

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[12] The state of Virginia is part of the OTC but they have not yet signed on to the MOU.

Scenario Name	NERC Regions Covered	NOx Compliance Options	Average Emission Rate Goal	NOx Trading?
1990 CAAA Baseline	All.	Combustion controls only; see Appendix A.	varies by technology; see Appendix A.	NO.
OSPS in Eastern States	NPCC, MAAC SERC, ECAR MAIN.	Post combustion options include SCR, SNCR, and Hybrid methods.	.15 lbs. per MMBTU heat input.	NO.
NOx Allowance Trading in Eastern States	NPCC, MAAC SERC, ECAR MAIN.	Post combustion options include SCR, SNCR, Hybrid methods, and allowance purchases.	.15 lbs. per MMBTU heat input.	Yes, among all utility sources in region.
NOx Allowance Trading in Northeast States	NPCC, MAAC.	Post combustion options include SCR, SNCR, Hybrid methods, and allowance purchases.	.15 lbs. per MMBTU heat input.	Yes, among all utility sources in region.

Table V.1 Overview of environmental policy scenarios.

1990 CAAA Baseline

In this scenario we assume that by 2003 all coal-fired generating units have adopted relevant controls (see Appendix) necessary to comply on a unit by unit basis with emission reductions required under phase II of Title IV of the 1990 CAAA. This is a fairly restrictive representation of strategies to achieve these goals since the EPA actually does allow interstate averaging of NOx emission across facilities owned by the same utility. This scenario does not incorporate additional NOx controls required under the OTC MOU. Also, these controls are based on emission rates applicable to individual units. Since there is no emissions cap, total emissions grow with increases in generation or the addition of new capacity, which is assumed to comply with NSPS for NOx.

OSPS in Eastern States (without trading)

This scenario imposes an emission rate standard of 0.15 lbs. of NOx per MMBtu on all existing fossil steam generators in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN). This group of NERC regions corresponds closely to the 22 states included in the ozone transport rulemaking region.[13] The emission rate standard is implemented in the model by forcing all fossil-fuel boilers in these five regions to adopt the least expensive NOx control technologies that will bring them to a NOx emission rate no greater than 0.15 lbs. of NOx per MMBtu. For those units that are unable to reduce NOx emissions to that level, we require them to reduce by as much as they possibly can. All of these additional controls are post-combustion controls and are added on top of the controls assumed in the 1990 CAAA baseline scenarios. We assume that existing generators will be able to recover the cost of these additional controls. Even under competition, they are assumed recoverable as a part of a stranded cost recovery package.[14] The resulting level of NOx emissions from the electricity sector in this eastern region (and across the country) will differ across the three market structure scenarios because of the variation in generating plant performance and costs and in electricity demand across the three scenarios.

NOx Allowance Trading in Eastern States

The level of the NOx cap under each market structure scenario (baseline, moderate and aggressive) is determined from the prior set of OSPS scenarios without trading. In this scenario electricity generators (model plants) are allowed to trade emission allowances. The model identifies a solution wherein plants with high marginal abatement costs obtain allowances from plants with low marginal abatement costs, and plants with low marginal abatement costs "over-

[13] The five NERC regions exclude from the 22 states region a small portion of western Missouri. It includes the eastern half of Mississippi, Florida, Vermont, New Hampshire and Maine, which are not part of the 22 state region. However, the three included New England states are part of the eastern region covered by the OTC MOU and the reconciliation of these two programs may involve their ultimate participation.

comply" to free up the allowances that are transferred. Investments in NOx abatement and additional operating costs are included in the dispatch order by marginal cost in the generation supply curve, allowing the utilization of facilities to adjust as another means of compliance. A third means of compliance can occur through reduced electricity demand, to the extent NOx control increases the cost of electricity. Hence, the model identifies a least cost solution for obtaining the specified level of NOx emissions, with the cost born by NOx abatement, changes in dispatch order, and changes in demand. This approach will yield an estimate of control costs that is biased low to the extent emission allowance markets work less efficiently than a textbook model would suggest (Carlson, *et al.* 1998). There is evidence of this in the context of SO_2 controls under cost of service regulation. This bias should be less apparent as we move into retail restructuring.

While the approach to modeling NOx trading does not differ across the different market structure scenarios, the way NOx allowance costs and other NOx control costs affect the price of electricity does vary across scenarios. Under the average cost pricing (baseline), we assume that NOx allowances are distributed for free (grandfathered) and that state regulatory commissions would not allow utilities to keep any profits associated with allowance transactions. That is, allowances are valued at original cost (rather than market value) for cost recovery purposes. Also, utilities would be allowed to recover the cost of permits purchased for compliance but this is offset by revenue accruing to the selling utility that is used to offset investment in emission control at its sites. This means that on net utilities are allowed to recover only the costs of emission control equipment and its operation.

[14] Unlike other stranded costs, we assume that NOx control costs are fully recovered under an OSPS regulation without emissions trading.

Under retail competition, we assume that electricity generators will fold the full opportunity cost of NOx allowances into the price of electricity and thus prices charged to consumers will reflect this opportunity cost. Therefore, while NOx trading should reduce the aggregate compliance costs of achieving the NOx emissions cap, trading is likely to have a greater impact on electricity prices, at least under competitive electricity pricing, than a uniform emission rate standard. Because the granting of allowances at zero cost, based on a fraction of historic emissions, constitutes a significant compensation to the utility, we do not allow for recovery of NOx control costs under the permit trading regime.[15]

NOx Allowance Trading in Northeastern States

This scenario parallels that in the previous one (OSPS in Eastern States with Trading) except that it is limited to the Northeastern states. In this scenario we determine a NOx emissions cap by first forcing all fossil fueled boilers in the NPCC and MAAC regions to adopt the least expensive approach to achieving a NOx emission rate no greater than 0.15 lbs. of NOx per MMBtu of heat input. We then rerun the model by imposing a cap on total NOx emissions from electricity generators equal to the total NOx emissions revealed in the previous model run and allow all generating units within the region to trade NOx emission allowances. The treatment of NOx allowance and control costs in the calculation of retail electricity prices is the same as under the NOx Allowance Trading in Eastern States scenario.

VI. Results

Retail restructuring of electricity markets and the concurrent introduction of new, more stringent, NOx regulations will have economic and environmental impacts in Maryland and

[15] To both give the utilities valuable NOx permits for free and to allow full recovery of NOx control costs creates potentially large profit making opportunities for utilities that install large amounts of control equipment (with full

surrounding states. The most salient impacts of the extent of retail restructuring will be on the electricity price, the quantity and composition of electricity generation, the levels of emissions of NOx and other pollutants and associated impacts on air quality and nitrate deposition. The most salient impacts of new NOx regulations will be on NOx emission levels and environmental quality and on the cost of additional NOx controls, which could in turn have impacts on the price of electricity.

The RFF HAIKU model can shed light on all of these issues. The impacts of restructuring and new NOx policies on electricity price, the quantity and composition of electricity generation and on the cost of NOx control are results of the HAIKU model. The ultimate impact of these policies on the environment in Maryland depends on the extent of changes in NOx emissions, the location of those NOx emissions changes, and the transport of NOx into and out of Maryland. The transport of NOx is beyond the scope of the RFF contribution to this study, but estimates of the changes in NOx emissions is a product of the HAIKU model and will be discussed further.

This discussion of the results of this study is organized as follows. First we present the impacts of restructuring in the absence of additional NOx policies. Then we discuss the impacts of new NOx policies within the context of the average cost market structure baseline. Last, we discuss the implications of different restructuring scenarios for the performance of NOx policy. All results are for the year 2003 and all dollar amounts are reported in 1995 dollars.

The Impact of Retail Restructuring

Restructuring is likely to have a negative impact on the average price of electricity and that impact is expected to be larger in MAAC (the region including Maryland) than for the nation as a whole. Table VI.1 shows that under the assumptions of the moderate restructuring scenario,

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cost recovery) and then sell permits and keep the revenue.

the price decline should be just over 6 % nationally and 8.5% for MAAC, compared to predicted prices under the baseline scenario. Prices fall substantially further under aggressive restructuring with an expected decline of nearly 11% nationally. Prices in MAAC seem to be more responsive to restructuring than for the nation as a whole, and are expected to fall by 14%.[16]

Geographic Region	Baseline		Moderate		Aggressive	
National	6.79	NA	6.36	-6.3%	6.05	-10.8%
MAAC	8.54	NA	7.81	-8.5%	7.34	-14.0%

Table VI.1 Average retail electricity price (cents/kWh) and percent change from baseline for 1990 CAAA scenario.

These decreases in electricity prices will yield increases in electricity demand and in generation. The two restructuring scenarios also assume increases in transmission capability and accelerated rates of retirement for nuclear and old coal-fired facilities, which would be likely to produce changes in the composition of electricity generation even in the absence of an increase in demand. All of these influences combine to produce the changes in electricity generation reported in Table VI.2.

Table VI.2 shows that national generation increases by just under 2% with moderate restructuring and by just over 3% with aggressive restructuring. Moderate restructuring has a much larger impact on generation in MAAC than it did nationwide, resulting in a 2.5% increase in generation. However, the difference between the impacts of aggressive restructuring and moderate restructuring is much smaller in MAAC than it is nationwide.

[16] These results are similar to those found in other studies. A recent analysis of the Clinton Administration's Comprehensive Electricity Competition Act (DOE 1998) finds that national average electricity prices are 12% lower in 2010 as a result of the plan and that prices in MAAC are 13.2 % lower than they would otherwise be.

Geographic Region	Baseline		Moderate		Aggressive	
National	3,464	NA	3,526	1.8%	3,575	3.2%
MAAC	249	NA	255	2.5%	256	2.9%

Table VI.2 Total generation (TWh/yr) and percent change from baseline for 1990 CAAA scenario.

It is difficult to make a prediction *a priori* about the impact of restructuring on NOx emissions. On one hand, more aggressive restructuring will give rise to an expanded transmission grid that will encourage old, inexpensive and more polluting coal generators to operate as they gain greater access to high-priced markets. On the other hand, restructuring will put a premium on efficiency, which will tend to cause older, more polluting, and inefficient coal generators to retire more quickly.

Table VI.3 summarizes the results of this experiment. HAIKU reveals that the accelerated retirement of inefficient coal facilities will usually not offset the increased use of other older coal generators due to expanded transmission capability and higher electricity demand. Without new NOx regulation, we can expect electricity restructuring to result in up to 4% more NOx emissions from the electric power sector nationally per year. The entirety of this increase will occur in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN) where NOx emissions will increase by 2.8% under moderate restructuring and a 5.6 % under aggressive restructuring. The impact on NOx emissions from electricity generation in MAAC is smaller than in the Eastern Region as a whole, with only a 2.5% increase under aggressive restructuring.

Geographic Region	Baseline		Moderate		Aggressive	
National	4,605	NA	4,683	1.7%	4,783	3.9%
Eastern NERC Regions	3,202	NA	3,291	2.8%	3,380	5.6%
MAAC	346	NA	353	1.9%	354	2.5%

Table VI.3 NOx emissions (thousand tons/yr) and percent change from baseline for 1990 CAAA scenario.

The impacts of restructuring on regional NOx emissions, absent new NOx regulations, are presented in the maps in Figures VI.1 and VI.2. Shading in these maps indicates changes in emissions, expressed in tons per year, that are expected in each region. Within each region the percent change from emissions under the baseline is also reported.

The first map illustrates changes in emissions predicted to result under a moderate restructuring market scenario, with environmental policy held at the CAAA baseline. The regions with the greatest total increase in emissions are MAIN and SERC. MAAC joins three other regions with more moderate emissions increases. Three regions, including NPCC, are predicted to have emission decreases. This decrease in NPCC is expected to result from the accelerated retirement of older facilities and the increased transmission of power into the region. The greatest change in percentage terms is expected in MAIN, which would experience an increase of 11% in annual emissions.

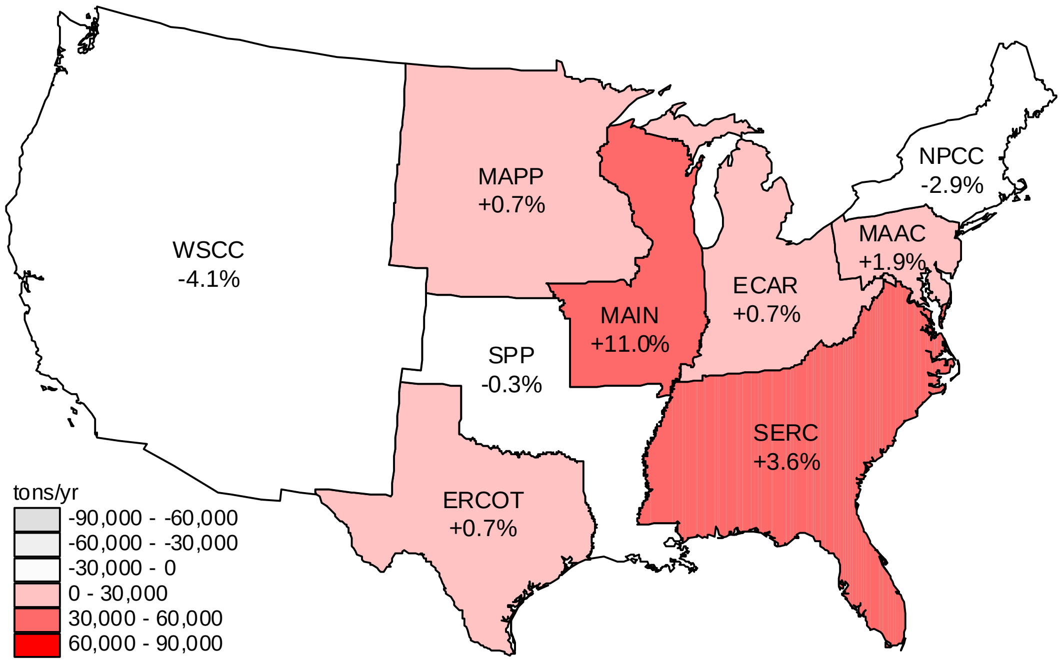

Figure VI.1 Annual NOx emissions change (tons/yr) from baseline to moderate restructuring and percent change for the 1990 CAAA scenario.

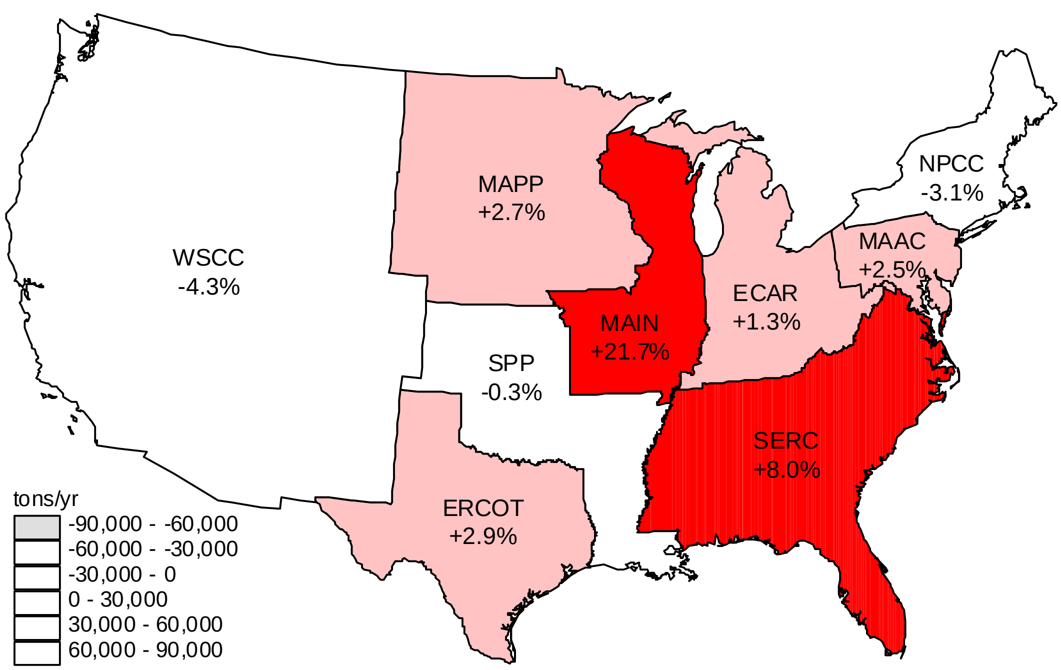

Figure VI.2 Annual NOx emissions change (tons/yr) from baseline to aggressive restructuring and percent change the 1990 CAAA scenario

The second map illustrates changes in emissions under a more dramatic shift to the aggressive restructuring market scenario. In this case MAIN and SERC are again the regions with the greatest total increase in emissions; however the magnitude of this increase is substantially greater than under the moderate scenario, while other regions are relatively naffected by the difference between moderate and aggressive restructuring. The region with the greatest change in percentage terms once again is MAIN**.**

The Impact of New NOx Emission Policies

The previous section discussed results of alternative market structure scenarios under the single environmental policy regime of full compliance with Title IV of the 1990 Clean Air Act Amendments. In this section we explore the potential impact of alternative environmental policy regimes under the single baseline market structure scenario of average cost pricing (In the next section we vary market structures and environmental policies simultaneously).

Within the baseline market structure scenario, the alternative NOx policies that we explore have a dramatic impact on NOx emissions from the electric power industry in the regions targeted by those policies. Table VI.4 summarizes those impacts for broad geographic regions. The two NOx policies that target the five eastern NERC regions result in a greater than 50% reduction in *national* NOx emissions from a total of 4,605 thousand tons under the CAAA baseline. The two policies result in a 75% reduction in the *targeted region* from a regional total of 3,202 tons under the 1990 CAAA baseline. The results of policies designed to achieve these emissions under a performance standard are presented in the first set of columns of data in Table VI.4. The results for a system of allowance trading are presented in the second set of columns.

The third set of columns in Table VI.4 present a scenario with additional NOx controls and trading of emission allowances limited to the two Northeastern NERC regions. There are no additional NOx controls beyond the CAAA baseline for the rest of the country. The impact on NOx emissions from the electric power industry in this case is limited to a decline of 7.4% nationally, and emissions in the entire eastern region (the five region area targeted by policies in the first two sets of columns) fall by just over 10%.

Geographic Region	NOx OSPS - East		NOx Trading - East		NOx Trading - Northeast	
National	2,207	-52.1%	2,208	-52.1%	4,264	-7.4%
Eastern NERCs	805	-74.9%	805	-74.9%	2,861	-10.6%
Northeastern NERCs	111	-75.4%	115	-74.6%	111	-75.4%

Table VI.4 Annual NOx emissions (thousand tons/yr) and percent change from 1990 CAAA scenario for the baseline.

The impacts on NOx emissions of the OSPS and trading policies in the market structure baseline for the five Eastern NERC regions are displayed in Figures VI.3 and VI.4. The first of these illustrates the emission changes from electricity generators across the NERC regions that are expected to occur under an OSPS policy in the five eastern NERC regions. The greatest absolute decline in electric power sector emissions is predicted for ECAR. Changes in percentage terms, relative to emissions under the CAAA baseline, are also reported on the figure. In percentage terms MAAC is expected to have the greatest decline.

Figure VI.4 compares electric power sector emission reductions under OSPS, illustrated in Figure VI.3, with emission reductions under a trading policy for the same region. In this case total emissions in the region are equal to those under the OSPS policy, but the allocation of emissions will change. Trading leads to a further reduction in emissions in MAIN and an approximately equal increase in emissions in ECAR. Electricity sector emissions in the rest of the five state region are relatively unaffected at the regional level.

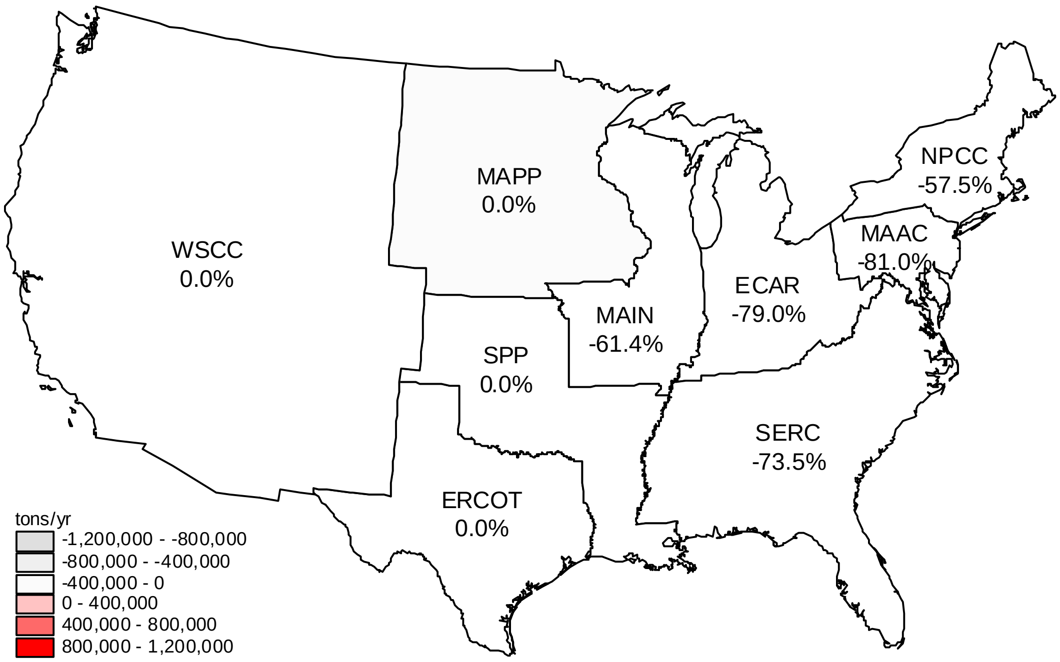

Figure VI.3 Annual NOx emissions change (tons/yr) from 1990 CAAA scenario to NOx OSPS-East scenario and percent change for baseline

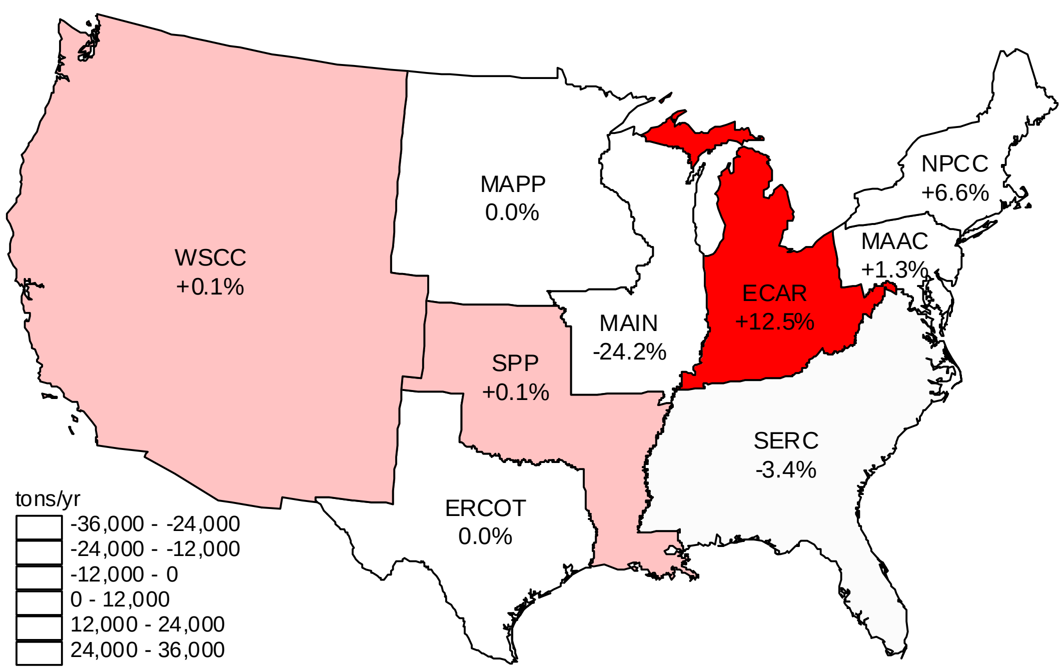

Figure VI.4 Annual NOx emissions change (tons/yr) from NOx OSPS-East scenario to NOx Trading-East scenario and percent change for baseline.

The control costs of the different NOx policies are presented in Table VI.5. The total cost for the OSPS policy in the five Eastern regions is nearly $1.9 billion per year. This cost is reduced to $1.7 billion per year, a reduction of 11%, through emission trading. The cost of trading for emission reductions limited to the two Northeastern regions is $0.2 billion per year.

	NOx OSPS - East	NOx Trading - East	NOx Trading - Northeast
Total Cost ($million/yr)	1,881	1,680	237
Average Cost in Target Region ($/ton reduced)	785	701	694
Total Cost in MAAC ($million/yr)	188	176	177

Table VI.5 NOx control costs under different NOx control policies in the absence of restructuring.

Average cost per ton falls considerably in the move from OSPS to emission trading among the five Eastern regions. The average cost per ton is lower still for an emission trading policy limited to just the Northeast. This result is counter-intuitive, since the Northeast is commonly thought to be a region facing relatively high costs of emission reduction. The reason for this result is that the metric of *average cost* within the trading region masks differences in cost among the NERC regions. The cost per ton of NOx emission reductions in the NPCC are indeed among the highest in the nation, but the average cost in MAAC is the lowest among the five regions included in the Eastern trading program. When NPCC and MAAC are coupled in a program that affects only those two regions, the average cost is lower because a greater percentage of emission reductions are achieved in MAAC than when larger emission reductions are pursued over the larger five-NERC region area. The inclusion of relatively more expensive regions (ECAR, MAIN, SERC) in the average raises the average cost, despite the fact that trading is even more beneficial in terms of cost savings that are achieved with more participants.

The addition of NOx controls imposes sizable costs in the aggregate, but their effect on the average retail price of electricity at the national level and in MAAC is relatively minor as shown in Table VI.6. The predicted price of electricity under average cost pricing (the baseline market structure scenario) and under the 1990 CAAA baseline for environmental policies is 6.79 cents/kWh at the national level, and 8.54 cents/kWh in MAAC. From this level, the average price for the nation under the policies affecting the five Eastern NERC regions would increase by less than one percent. If NOx policy is limited to emission trading in the two Northeastern regions, national electricity price would increase by only one-tenth of one percent.

Prices in MAAC are affected by a comparable magnitude under NOx policies affecting the five Eastern regions as shown in the second row of Table VI.6. A slight increase in price is predicted to result from emission trading compared to the OSPS policy in MAAC, even though we witness a decline of about 6% in control costs in MAAC (see Table VI.5). The reason for this higher price impact is that despite lower control costs under an allowance trading regime, the price of electricity reflects both the costs of reducing emissions and the opportunity cost of the emission allowances. This opportunity cost is not reflected in electricity prices under the OSPS policy.

Geographic Region	NOx OSPS - East		NOx Trading - East		NOx Trading - Northeast	
National	6.84	0.9%	6.84	0.8%	6.79	0.1%
MAAC	8.62	1.0%	8.63	1.1%	8.60	0.8%

Table VI.6 Average retail electricity price (cents/kWh) and percent change from 1990 CAAA baseline in the baseline

Restructuring and the Performance of NOx Policies

While the previous two sections examined changes in market structure and changes in NOx policies in isolation, in reality there is likely to be a confluence of changes affecting the electricity industry. In this section we explore these changes in tandem. In particular, we seek to evaluate the performance of NOx policies under the potential alternative scenarios for the structure of the industry.

Electricity Price and Demand

Our expectation a priori is that more aggressive electricity restructuring will lower the price of electricity leading to an increase in the quantity of electricity demanded, and that more stringent NOx control will raise the price of electricity with an associated decrease in quantity demanded. The HAIKU results show exactly that, both nationally and in MAAC.

The impact of restructuring and different NOx control policies on national average electricity price for the complete comparison of market structure scenarios and environmental policies is shown in Table VI.7 below. Results described in the previous sections are repeated in this table for ease of exposition. For instance, the first row in the table reproduces the results from Table VI.1 illustrating the affect of alternative market structures with the 1990 CAAA baseline for environmental policy. The first column reproduces the results from Table VI.6 illustrating the affect of alternative environmental policies under the average cost baseline market structure scenario. The remainder of Table VI.7 fleshes out the combinations of policies and market scenarios that were investigated.

This table shows that the impact of restructuring on national average price is an order of magnitude greater than the impact of an Eastern NOx policy and two orders of magnitude greater than the impact of NOx trading in the Northeast. The effects of the OSPS and NOx trading in the Northeast on electricity price are similar across the different market structure scenarios.

However, the impact of trading on national average electricity price is greater under moderate restructuring than under each of the other two market structure scenarios.

	Baseline		Moderate		Aggressive	
1990 CAAA	6.79	NA	6.36	-6.3%	6.05	-10.8%
NOx OSPS - East	6.84	0.9%	6.42	-5.4%	6.11	-10.0%
NOx Trading - East	6.84	0.8%	6.39	-5.8%	6.10	-10.1%
NOx Trading - Northeast	6.79	0.1%	6.35	-6.5%	6.05	-10.9%

Table VI.7 National average retail electricity price (cents/kWh) and percent change from baseline with 1990 CAAA scenario.

Table VI.8 reports the results for the MAAC region. This table shows that while NOx trading leads to slightly higher prices than OSPS under the baseline market structure scenario, it leads to slightly lower prices under Moderate and Aggressive restructuring. This is because under restructuring as a result of greater transmission capability, there are more opportunities for reducing emissions through redispatch than under the baseline scenario, reducing the need for expensive control technologies.

	Baseline		Moderate		Aggressive	
1990 CAAA	8.54	NA	7.81	-8.5%	7.34	-14.0%
NOx OSPS - East	8.62	1.0%	7.89	-7.6%	7.41	-13.2%
NOx Trading - East	8.63	1.1%	7.87	-7.8%	7.40	-13.3%
NOx Trading - Northeast	8.60	0.8%	7.86	-7.9%	7.40	-13.3%

Table VI.8 MAAC average retail electricity price (cents/kWh) and percent change from baseline with 1990 CAAA scenario.

Though electricity price seems to be quite responsive to the rate of restructuring, it is quite unresponsive to the strictness of NOx regulation. Even under the most costly NOx regime considered in this study (NOx OSPS in the five Eastern regions), electricity prices will rise by less than 1% nationally, compared to the same restructuring scenario in the absence of the NOx control policy. In MAAC the effect of NOx policy leads prices to rise by no more than 1.1% compared to the same restructuring scenario in the absence of the policy.

NOx Emissions

Under all of the policies involving new NOx regulation, there is a similar pattern of significantly less NOx emissions from the electricity sector in the regions targeted by the policy and very slight changes in emissions in the other regions. The following three tables report the emissions under the combinations of market structures and environmental policies we have investigated. Table VI.9 reports emissions at the national level. Table VI.10 reports emissions in the five Eastern regions affected by two of the candidate environmental policies. Table VI.11 reports emissions in the two Northeastern regions that are affected by all three of the candidate environmental policies. In each table emissions are reported as tons per year, and also as a percent of the value in the first cell for the table, representing the baseline market structure and 1990 CAAA environmental policy.

The tighter NOx regulations may apply only to the northeast. Restructuring in this case would result in the greatest increase of NOx emissions nationally (up to more than 4%) and in the east (up to more than 6%). This is because the NOx emissions in the northeast would be displaced to heavily polluting plants in other eastern regions where no NOx policy is in place.

At the national level, Table VI.9 indicates that NOx emissions increase with restructuring under any of the environmental scenarios, but the effect is small. In the two environmental scenarios targeting the five Eastern regions, the increase due to restructuring is less than one percent of baseline emissions. This contrasts with reductions of over fifty percent in these scenarios due to the environmental policies. For the other two cases the effect of restructuring yields emission increases of up to four percent of baseline emissions in the aggressive restructuring scenario.

Table VI.10 indicates that within the five Eastern regions a similar but somewhat accentuated pattern emerges. The effect of restructuring in these regions is to increase NOx emissions by less than one percent of baseline emissions, while the two environmental scenarios targeting these regions yield reductions of nearly seventy-five percent. For the other two cases restructuring produces NOx emission increases of nearly six percent of baseline emissions.

Table VI.11 indicates the same pattern for the two Northeastern regions, but less accentuated than above. Here the effect of restructuring is to increase emissions by slightly more that one percent of emissions in the baseline for the 1990 CAAA policy and the two policies affecting the larger Eastern region. Across all three restructuring scenarios, NOx emission in the Northeast are lower under a NOx trading policy focused on the Northeast than they are under a broader Eastern regional trading regime.

	Baseline		Moderate		Aggressive	
1990 CAAA	4,605	NA	4,683	1.7%	4,783	3.9%
NOx OSPS - East	2,207	-52.1%	2,217	-51.9%	2,240	-51.4%
NOx Trading - East	2,208	-52.1%	2,221	-51.8%	2,250	-51.1%
NOx Trading - Northeast	4,264	-7.4%	4,342	-5.7%	4,443	-3.5%

Table VI.9 National NOx emissions (thousand tons/yr) and percent change from baseline with 1990 CAAA scenario.

	Baseline		Moderate		Aggressive	
1990 CAAA	3,202	NA	3,291	2.8%	3,380	5.6%
NOx OSPS - East	805	-74.9%	821	-74.4%	835	-73.9%
NOx Trading - East	805	-74.9%	821	-74.4%	836	-73.9%
NOx Trading - Northeast	2,861	-10.6%	2,943	-8.1%	3,039	-5.1%

Table VI.10 Eastern (five regions) NOx emissions (thousand tons/yr) and percent change baseline with 1990 CAAA scenario.

	Baseline		Moderate		Aggressive	
1990 CAAA	453	NA	457	0.8%	458	1.2%
NOx OSPS - East	111	-75.4%	111	-75.6%	112	-75.3%
NOx Trading - East	115	-74.6%	115	-74.5%	119	-73.7%
NOx Trading - Northeast	111	-75.4%	112	-75.3%	112	-75.4%

Table VI.11 Northeastern (two regions) NOx Emissions (thousand tons/yr) and percent change from baseline with 1990 CAAA scenario.

The effects of the NOx policies on emissions by NERC region under an aggressive restructuring scenario are presented in figures VI.5 and VI.6. The first of these figures is analogous to figure VI. 4 and illustrates the emission changes from electricity generators across the NERC regions that are expected to occur under an OSPS policy in the five eastern NERC regions. The findings are quite similar to those under the average cost pricing scenario with a couple of exceptions. First the absolute level of emissions decline due to the OSPS policy is greater in SERC with restructuring than it was without. Second, under aggressive restructuring there is a greater tendency for emissions to shift to the Midwest as a result of an eastern OSPS than there was in the base case as evidenced by the small increases in emissions in MAPP and SPP.

Figure VI.6 (analogous to figure VI.4) compares electric power sector emission reductions under OSPS, illustrated in figure VI.5, with emission reductions under a trading policy for the same region. In this case total emissions in the region are equal to those under the OSPS policy, but the allocation of emissions will change. In this case, trading leads to even greater shifts of emissions to regions to the west than occurred under the standard. In addition, emissions increase by a larger percentage in NPCC than they did with the introduction of trading under the average cost baseline, although the actual changes in quantities remain small.

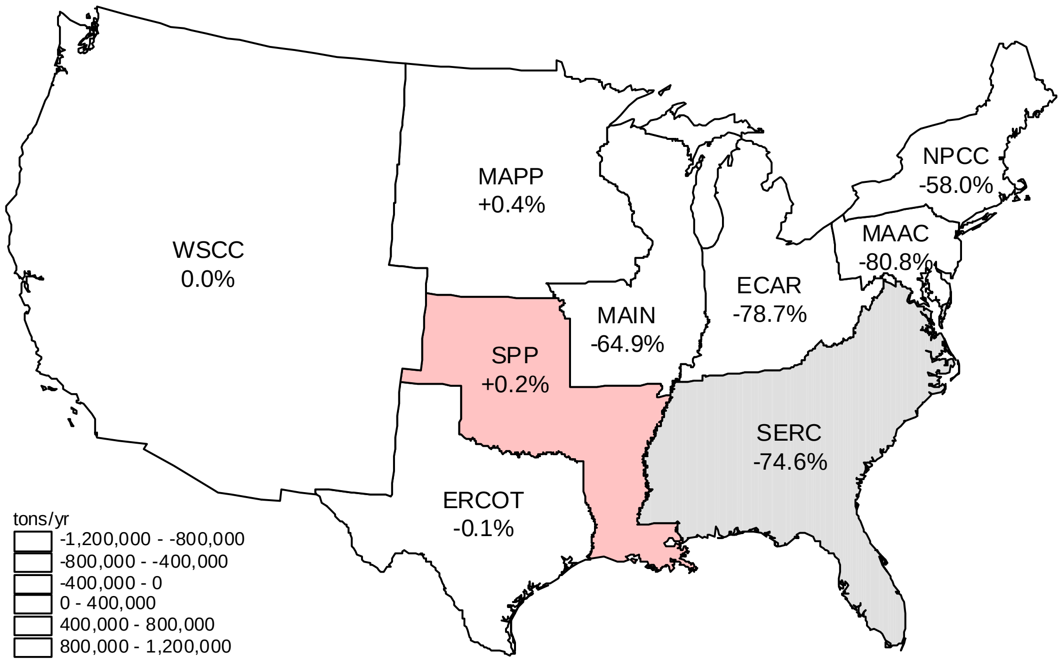

Figure VI.5 Annual NOx emissions change (tons/yr) from 1990 CAAA scenario to NOx OSPS-East scenario and percent change for moderate restructuring.

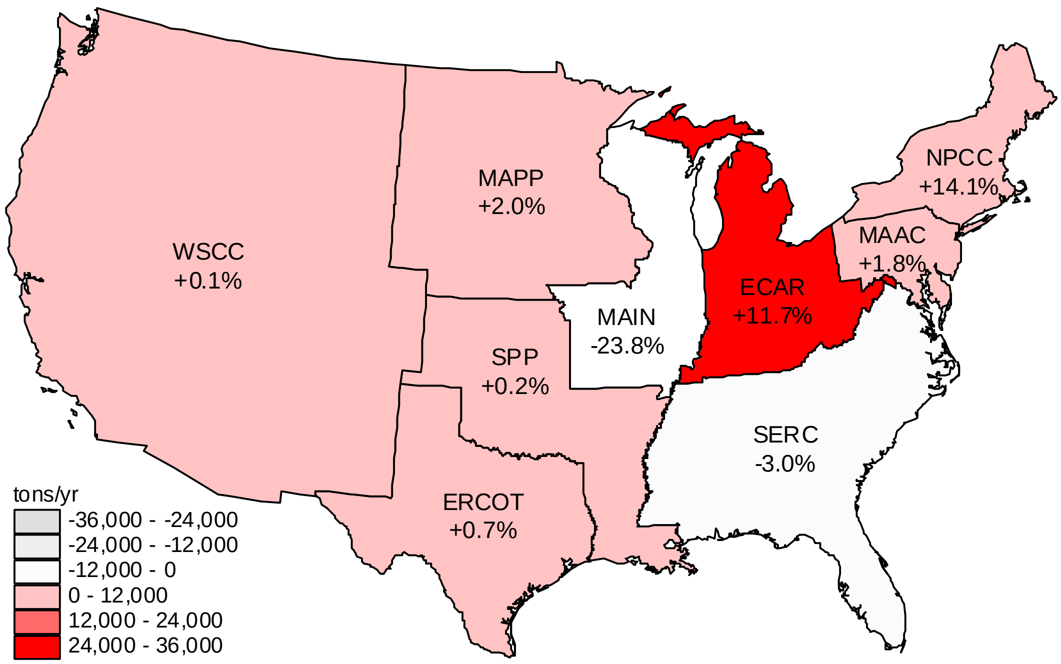

Figure VI.6 Annual NOx emissions change (tons/yr) from NOx OSPS-East scenario to NOx Trading-East scenario and percent change for moderate restructuring.

Cost of NOx Control

The average cost of NOx control in the nation and in MAAC is summarized in Table VI.12. Total cost for the nation and MAAC are summarized in Table VI.13. Cost savings from trading in the five Eastern regions range from $170-$220 million. The total cost of a trading program in this region is about $1.7 billion per year. As expected, eastern NOx control is significantly cheaper (about 9-12% nationally and about 7% in MAAC) under a tradable NOx allowances regime than under the Old Source Performance Standard regime, regardless of the pace of restructuring. Also, NOx control will be significantly less expensive per ton in MAAC than it will be in the rest of the nation. However, under an OSPS regime, a faster pace of restructuring will tend to push MAAC's control cost more in line with the national average control cost. This is because an OSPS will make some generators in other regions prohibitively expensive to operate, and with the capability to import power from other cheaper regions (MAAC), those generators will choose to retire instead of controlling NOx. Therefore with increased transmission capability under more aggressive restructuring, costs will drop in other regions faster than they will drop in MAAC.

	National			MAAC		
	Baseline	**Moderate**	**Aggressive**	**Baseline**	**Moderate**	**Aggressive**
NOx OSPS - East	784	767	749	672	664	666
NOx Trading - East	701	679	684	629	619	624
NOx Trading - Northeast	695	679	689	632	625	628

Table VI.12: Average cost of NOx control ($/ton reduced).

	National			MAAC		
	Baseline	**Moderate**	**Aggressive**	**Baseline**	**Moderate**	**Aggressive**
NOx OSPS - East	1,881	1,891	1,904	188	190	191
NOx Trading - East	1,680	1,671	1,732	176	177	178
NOx Trading - Northeast	237	232	234	177	178	181

Table VI.13 Total cost of NOx control ($million/yr).

VII. Conclusions

Dramatic changes underway in the electric power industry could result in substantial changes in the mix of generation technologies employed to produce electricity, in the efficiency of power plant operations, and in the price and quantity of electricity traded in the marketplace. All of these changes could in turn have potential implications for NOx emissions, with associated potential impacts on air quality in Maryland and nitrate deposition in the Chesapeake Bay.

This report focuses on how restructuring and concurrent potential environmental policies could affect emissions. The report draws on a national electricity model to characterize the changes that are likely to take place under alternative scenarios for regulatory and environmental policy.

Restructuring is likely to have a negative impact on the average price of electricity and that impact is expected to be larger in MAAC (the region including Maryland) than for the nation as a whole. A moderate pace toward industry restructuring is expected to lead to a price decline of just over 6% nationally and 8.5% for MAAC by the year 2003, compared to predicted prices under the baseline scenario. Prices fall substantially further under aggressive restructuring with an expected decline of nearly 11% nationally and 14% in MAAC. These decreases in electricity prices will yield increases in electricity demand and in generation of just under 2% with moderate restructuring and by just over 3% with aggressive restructuring.

Absent new NOx regulation, electricity restructuring is likely to result in up to 4% more NOx emissions nationally per year. The bulk of this increase will occur in the five eastern NERC regions (NPCC, MAAC, SERC, ECAR and MAIN). The impact on NOx emissions in MAAC is smaller than in the Eastern Region as a whole, with only a 2.5% increase under aggressive restructuring.

The study considers a number of combinations of possible outcomes for changes in the market structure of the industry and for NOx control policies. We consider an Old Source Performance Standard (OSPS) and an emission allowance trading program in the five Eastern NERC regions that would achieve reductions of over 50% in national NOx emissions, and a 75% reduction in the targeted region. These percent reductions are compared to emissions that would occur under various market structure scenarios absent NOx regulations. Hence, the policies we consider yield reductions that dramatically offset increases in emissions expected as a consequence of restructuring.

The trading program would lead to a moderate reallocation of emissions within the region compared to OSPS, and a slight increase in emissions in the MAAC region. However, it would also result in a cost savings of about $200 million (1995 $), or about 10% nationally, and 7% in MAAC, compared to an OSPS policy. The total cost of a trading program would be about $1.7 billion per year.

Though electricity price seems to be quite responsive to the pace of restructuring, it is quite unresponsive to the strictness of NOx regulation. Even under the most costly NOx regime considered in this study (NOx OSPS in the five Eastern regions), electricity prices will rise by less than 1% nationally, compared to the same restructuring scenario in the absence of the NOx control policy. In MAAC the NOx policy leads prices to rise by no more than 1.1% compared to the same restructuring scenario in the absence of the policy.

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Appendix A. NOx Control Technologies In and Out of HAIKU

NOx control technologies for electric utility and large industrial boilers can be divided into two basic types, combustion controls and post combustion controls. (Combustion controls for turbines are described in a separate section below.) In general, the combustion controls are older, more established technologies with which there is already considerable commercial experience in the United States. Many of the post combustion controls have had significant commercial application in Europe and Japan, but have been the subject of only a few commercial or research demonstrations in United States. In general, the combustion controls are cheaper than the post combustion controls, but they have lower maximum NOx removal capabilities. These cheaper, older technologies are the ones that have been most often considered "reasonably available" for the purpose of state and federal regulations. Moving beyond compliance with Title IV of the 1990 Clean Air Act Amendments (CAAA) is likely to necessitate widespread installation of the newer post combustion controls.

Combustion controls

Older coal-fired utility boilers were engineered to produce maximum heat from their fuel without requiring a great deal of precision in operating conditions. Compact, hot flames were considered desirable, and were produced by burning fuel in "excess air". Sufficient air was let into the combustion chamber so that all the carbon in the fuel would be sure to be consumed, regardless of day-to-day variations in coal quality or operator behavior.

These conditions, considered ideal at the time of these boilers' design, are precisely the conditions for producing large amounts of NOx. There are two important NOx formation processes that take place in utility boilers. *Fuel NOx* is created by the oxidation of nitrogen contained in the fuel, and is mostly an issue in coal-fired plants rather than at other types of plants. *Thermal NOx* is formed in any burning process, and is caused by the oxidation of the nitrogen in air at high temperatures. Thermal NOx formation, in particular, is very sensitive to the amount of air present during combustion and the temperature at which it takes place. In order to reduce NOx formation, boilers must be essentially re-engineered toward the opposite of their original ideal, to reduce mixing of fuel and air (inhibiting fuel and thermal NOx) and to lower combustion temperatures (inhibiting primarily thermal NOx). The following technologies all use these strategies to inhibit NOx formation during combustion.

Low NOx Burners (LNB)

In this approach combustion occurs in two stages. The primary combustion stage is fuel rich and air lean. The lack of air and resulting low combustion temperature inhibits the formation of thermal NOx, and the chemically reducing (oxygen poor) environment limits the formation of fuel NOx. The secondary stage is fuel lean and air rich. In this stage, the lack of fuel produces a relatively low temperature environment, again inhibiting the formation of thermal NOx.

Because LNB involves a considerable re-engineering of boiler processes, it is not without problems. It may decrease the efficiency at which the boiler operates, increasing fuel use and cost (and increasing CO_2 emissions). Lower efficiency increases the amount of unburned carbon present in the fly ash, which may make it unsalable. LNB may also cause corrosion problems inside the boiler. The degree to which these problems occur has been hotly debated. However, LNBs definitely reduce the range of operating conditions under which the boiler can operate efficiently. Day-to-day variations in the carbon content of coal or in the behavior of plant operators can more easily throw a boiler out of efficient operation.

Overfire Air (OFA)

OFA stages combustion by injecting only a portion of the combustion air into the primary combustion area with the fuel. The remainder of the air is injected through overfire air ports above the top row of burners to create the secondary combustion zone in the upper part of the furnace. This approach can be used alone or in combination with LNB. The delay in final air injection enhances the staging created by LNB alone. For tangentially fired boilers, the combination of LNB and OFA is often referred to as LNC (low NOx coal-and-air nozzles). The occasionally-mentioned distinction between close-coupled and separated OFA refers simply to the placement of OFA ports in the boiler.

Computerized Combustion Controls

Some utilities have found that they can reduce NOx emissions from 10 to 50 percent simply by improving operations through the use of advanced computer control systems. For instance, one company offers a neural network based computer system which "learns" from the behavior of the best plant operators. These controls can be used in place of traditional combustion controls like low NOx burners, or they can be used to improve the efficiency and reliability of LNB equipped plants. Such tune ups and process optimizations have been touted as a cost-effective way to achieve compliance (see for example Makansi, 1995), but NOx reductions and efficiency improvements are highly unit specific. NESCAUM (1998) states that NOx improvements beyond 20 percent should not be expected in general.

Non Plug-in and Other Combustion Controls

LNB and OFA have become so widely used on wall fired and tangentially fired coal boilers that they are frequently available as "plug-in units" -- off-the-shelf technologies which can be inserted into existing boilers without major construction efforts. For cell burners, vertically fired units, and wet bottom units, plug-in controls are generally not available yet.

However, systems based on LNB and OFA concepts can be site specifically engineered for these units. Such systems are frequently referred to as non plug-in controls, or simply combustion controls.

Post Combustion Controls

These controls all destroy NOx in the waste gases after it has been formed. Thus, these controls are also sometimes collectively known as "flue gas treatments". One of them, reburn, uses an additional combustion stage to chemically destroy NOx. The other controls use nitrogen based reagents. These reagent-based processes can all be paired with the combustion controls described above without impairment of the efficiency of either type of control.

Reburn

Reburn creates a second, fuel rich combustion zone in the upper furnace by injecting additional fuel and limited air above the primary combustion area. In this air lean environment, some of the NOx molecules are stripped of their oxygen by the burning carbon. Approximately ten to twenty percent of the boiler's heat throughput will be diverted to this upper zone. The injected fuel may be either coal or natural gas. Use of coal as a reburn fuel may require the installation of additional pulverization and coal handling equipment. The boiler must also be large enough to accommodate the burnout zone in the upper furnace. Coal reburn is therefore expected to have limited application. If a gas pipeline is already available to the plant, use of gas as the reburn fuel will be the cheaper option. Since combustion of the reburn fuel contributes significantly to the heat output of the plant, use of gas reburn will displace some of a boiler's coal consumption, reducing overall SO_2 emissions and generating tradable emission allowances. This technology will be especially useful for cyclone boilers, which are not amenable to the combustion controls described above. (In fact, for the purposes of the HAIKU model, reburn has been grouped with the combustion controls as the default control for cyclone boilers.) Most of these boilers are located in the midwest, where natural gas availability should not be significant problem.

Selective Non-Catalytic Reduction (SNCR)

In this approach, a reagent (typically ammonia or urea) is injected into the stream of waste gases and chemically reduces the NOx to diatomic nitrogen. The term "selective" indicates that the reagent interacts solely with NOx, and not with the many other components of the flue gas stream. There is a window of temperature (~1800-2100 °F) in which this approach is effective. Above this window, oxidation of the reagent to NOx begins to compete as a reaction pathway, and emissions of NOx may increase, rather than decrease. Below this window, temperatures are not high enough to promote the reaction. Because of the need for relatively high temperature, SNCR processes are generally located directly at the furnace exit, upstream of any other pollution control devices.

Effective SNCR will invariably lead to some emission of ammonia, generally referred to as *ammonia slip*. The amount of ammonia slip is a design variable. That is, the process will be designed to produce the greatest possible reduction of NOx emissions, given a certain maximum permissible ammonia slip defined by plant owners or local permitting officials. Ammonia slip is undesirable because it may contaminate the fly ash, making it unsalable and making expensive disposal necessary. It may also combine with SO_2 to produce ammonium bisulfate buildup on boiler surfaces and in filters, interfering with the performance of other pollution control equipment. Large ammonia slips may lead to ammonia odor around the plant or to visible ammonium chloride plumes above the plant. However, in general, ammonia slips should be too low to cause any local harm.

SNCR also produces nitrous oxide (N2O), a greenhouse gas. ICAC (1997b) states that the process can be reengineered to avoid producing nitrous oxide, and that present systems should generate it in amounts not exceeding ten percent of the NOx reduced. (Note that N2O is chemically distinct from NOx. It does not contribute to ozone formation, nor is it easily precipitated out of the atmosphere.)

Because there is no catalyst involved and the retrofit of injection systems is relatively simple, the cost of SNCR is dominated by operating costs -- essentially the cost of the reagent. Therefore it is especially suitable for seasonal controls since it can be shut off simply by not injecting the reagents.

Selective Catalytic Reduction (SCR)

This process is very similar to SNCR, except that a catalyst is used to mediate the reaction. Ammonia is generally used as the reagent. The use of a catalyst allows this process to take place at lower temperature than SNCR (between 350 °F and 1100 °F, depending on the type of catalyst), eliminating competition from the oxidation pathway. This allows for greater NOx reductions and more efficient reagent utilization. The primary variable determining the amount of NOx removed is the volume of air flow past a unit of catalyst. Therefore, with sufficient expense on catalyst, essentially all of the NOx can be removed. In practice, the intersection of regulatory demands and expense has generally limited removal rates on coal-fired plants to 70 to 80 percent, although reductions greater than 90 percent have been demonstrated. This technology has been installed on several gas-fired plants in California, but it has been installed on only a few coal-fired plants in the United States. SCR is likely to be widely used to comply with any new regulations which significantly reduce allowable NOx emissions from coal-fired plants beyond the requirements of Title IV of the 1990 Clean Air Act Amendments.

The primary factor determining the expense of SCR is the expense on catalyst. Therefore expected catalyst lifetimes have been the subject of much debate. There are two different types of lifetimes frequently discussed: guaranteed lifetime and useful lifetime. The guaranteed lifetime is the amount of time that the manufacturer guarantees will pass before a measurable decrease in catalyst performance occurs. Guaranteed catalyst lifetimes are presently around two years. Useful lifetimes are much longer, with proper management. A typical catalyst management system is something like the following. Three areas are provided for catalyst installation in the SCR reaction duct. Initially, only two of these areas are filled. After two years, when the initial catalysts begin to diminish in performance, the third area is filled. Two to four years later, one of the initial areas is replaced. From then on, one of the areas is replaced approximately every three years. In this way there is always some fresh catalyst, but the lifetimes of diminishing catalysts can be extended up to several times their guaranteed lifetimes.

There are several lingering technical concerns about SCR systems for coal-fired boilers. As with SNCR, ammonium bisulfide buildup, caused by the reaction of ammonia slip with SO2 in the flue gas, may be a problem, since it may diminish the activity of the catalyst. Because of this possibility, there has been some concern that SCR will not be practical for units burning high sulfur coal. DOE (1996) has completed a demonstration project using 3 percent sulfur coal, with acceptable performance from several different catalysts. ICAC (1997a) states that only six percent of coal plants burn coal with sulfur contents higher than this, suggesting that it will not be a widespread problem in any case. Other early concerns centered around the possibility of catalyst poisoning by trace heavy metals in flue gas. However, these problems seem to have been resolved with new catalyst designs.

Capital costs for SCR retrofits can be expected to vary widely, even between boilers of the same type. (NESCAUM (1998) reports that commercial and demonstration retrofits have cost $56-$95/kW, with new installations expected to costs 30 percent less.) A full-size SCR system is a large piece of equipment, relative to the available extra space in a typical coal boiler. SCR installation may require construction of considerable additional ductwork, strengthening of the boiler foundation and structure, and even the demolition and relocation of existing boiler equipment. Because of these difficulties, there have been considerable efforts to reduce the size and amount of catalyst needed, or to apply catalyst to existing boiler surfaces, including the air preheater and even the fabric filter. One commonly referred to technique is in-duct SCR, in which catalyst is installed within the existing ductwork, eliminating the need for construction of a separate reactor. In general, an in-duct installation will not provide sufficient catalyst to allow 70 or 80 percent reduction on coal-fired boilers. However, in-duct SCR is expected to be popular on oil- and gas-fired boilers, and on coal-fired boilers in combination with SNCR as described below.

Because SCR is a high capital cost technology, while SNCR is a high operating cost technology, years of service remaining and expected capacity factor should play a significant role in the choice between these two technologies.

Hybrid SNCR-SCR Systems

A hybrid of these two technologies (sometimes called HSR, or Hybrid Selective Reduction) could reduce NOx emissions substantially at a lower cost than SCR alone. In the hybrid approach, waste gases would reach the SNCR reaction first, where a significant reduction in NOx concentration would take place without the need for catalyst. Ammonia slip from the SNCR process would serve as reagent to the SCR process, where the remainder of NOx reduction would take place, using a catalyst surface significantly reduced from that required by

SCR alone. This decrease in required catalyst suggests that SCR could be installed "in duct", meaning without building an additional duct or reactor, further reducing the costs. Because the waste ammonia from the SNCR process is consumed in the SCR process, the SNCR process does not need to be as tightly tuned as it does when operating alone, allowing greater NOx reductions and increased operating flexibility. A hybrid SNCR-SCR system is presently commercially available, and the first commercial installation is currently under construction.

Post Combustion Controls for Oil and Gas-fired Boilers

SCR has been applied to nearly 20 gas-fired plants in California. All have experienced reductions of approximately 90 percent. SNCR and gas reburn are also available for these units. However, except in regions requiring extremely low NOx emissions, NESCAUM (1998) expects combustion controls to provide sufficient reduction at lowest cost.

Combustion and Post Combustion Controls for Combustion Turbines

Three basic types of NOx control technologies are available for combustion turbines. These turbines burn gas or distillate fuel oil to produce electricity through mechanical rotary motion, without the mediation of steam. Although they may burn gas or oil, they are commonly referred to as gas turbines. Combustion turbines produce approximately 165,000 tons of NOx emissions per year, or 3 percent of coal-fired and 22 percent of oil and gas-fired utility boiler emissions (STAPPA/ALAPCO 1994). This figure includes emissions from turbines which do not produce electricity. Because electricity-related turbine emissions are one to two orders of magnitude smaller than utility boiler emissions, NOx controls for turbines are not included in HAIKU. (Cost and removal functions for these technologies are available in STAPPA/ALAPCO 1994.)

Water/Steam Injection

Injection of water or steam into the combustor can be used to lower flame temperatures, inhibiting the formation of thermal NOx. (Since natural gas or distillate oil is typically used as a fuel, fuel NOx is not a concern.) Since some of the combustion heat is diverted to heat water or steam, even a well tuned wet injection system will reduce turbine efficiency by 2 to 4 percent. This technology can reduce NOx emissions by 70 to 90 percent. Above this range of reductions, increased wet injection excessively compromises combustion efficiency and leads to increased emissions of CO and hydrocarbons. Wet injectors are readily commercially available for retrofit and new construction.

Dry Low NOx Combustors

This set of technologies uses air, rather than water or steam, to dilute flames and reduce combustion temperatures. The amount of excess air used, relative to the amount of fuel used, significantly exceeds that used in the uncontrolled coal-fired boilers discussed above, so that it serves to lower, rather than raise, combustion temperatures. These technologies reduce NOx emissions by 60 to 90 percent from uncontrolled levels. They are frequently installed on new turbines, and are available as retrofits on some, but not all, existing turbine types.

Selective Catalytic Reduction

SCR has been installed on several dozen gas turbines in United States, including cogeneration and combined cycle systems. NOx reductions have generally ranged from 80 to 90 percent, with a few applications achieving lower reduction rates. SCR has been installed in combination with wet injection systems to produce very low NOx emission rates. As with other SCR applications, ammonia slip and the consequent possibility of ammonium bisulfate build-up is a concern. However, turbines burning natural gas should not have significant problems.

Turbines burning the slightly higher-sulfur distillate fuel oil may be limited to reductions of 80 percent.

Some turbine applications have required SCR installations in high temperature regions of the turbines, and special catalysts that are tolerant of higher temperatures have been developed for these applications.

NOx Reduction under the CAAA

Title IV of the CAAA set emission ceilings for each of the major types of coal-fired utility boilers. Boilers are grouped into two categories, and reductions were required in two phases. Group I consists of the wall fired and tangentially fired boilers. These boilers produce nearly 85 percent of the electricity from coal-fired boilers in United States. Group II consists of the remaining major coal-fired boiler types, including cell burners, cyclones, wet bottom boilers, and vertically fired boilers. Some Group I boilers (those that were also required to make SO2 reductions) were regulated in Phase I, which required less stringent reductions sooner. The remaining Group I boilers and all Group II boilers were regulated in Phase II. Phase I requirements went into effect in 1996. Phase II requirements will go into effect in 2000. The requirements are listed in Table A.1.

Table A.1: NOx Emission Rate Limits Under Title IV

Boiler Type	Phase I	Phase II	Threshold Size
Wall fired boilers	.50	.46	25 MW
Tangentially fired boilers	.45	.40	25 MW
Cell burners		.68	25 MW
Cyclones		.86	155 MW
Wet bottom boilers		.84	65 MW
Vertically fired boilers		.80	25 MW

(Source: EPA 1998. All emissions measured in lb/MMBtu.)

NOx Reduction in the HAIKU Model

Baseline

The model begins with a baseline that represents full implementation of Title IV of the 1990 CAAA. Each coal-fired boiler type is paired with a combustion control that is expected to be widely used by that type, according to Table A.2. (Gas and oil-fired boilers are not assigned a technology in the baseline.)

Table A.2: Assumed baseline NOx control technology by boiler type.

Coal-fired Boiler Type	Baseline Technology for 1990 CAAA Implementation
Wall fired boilers	LNB
Tangentially fired boilers	LNB with OFA
Cell burners	Non plug-in
Cyclones	Gas Reburn
Wet bottom boilers	Combustion Controls
Vertically fired boilers	Combustion Controls

Some coal-fired plants already have combustion controls installed and any resulting NOx reductions are already reflected in the database of constituent plants. Therefore the NOx removal rates resulting from these baseline controls are applied only to those constituent plants that do not already have them *before* aggregation into model plants within HAIKU. Capital and O&M costs resulting from any existing combustion controls are not reflected in the constituent plant database, so these costs can be applied to model plants within the model without double counting. (Cost and removal functions are derived from three sources, in the following order of priority: OTAG 1997 Attachment C, ICF 1996a, and EPA 1996 Appendix 5).

Beyond the Baseline

Alternative NOx reduction policy regimes in HAIKU are imposed on top of the baseline (full implementation of Title IV of the 1990 CAAA) to represent additional controls expected, for example, as a result of the OTAG process. Currently implemented scenarios include an old source performance standard regime (OSPS), with emissions ceilings below that of the CAAA, a tax regime, and a cap and trade regime. (The baseline scenario can be observed by choosing a tax regime and setting the tax rate to zero). Each regime can be implemented in some or all of the NERC regions.

To meet reduction responsibilities under alternative policy regimes beyond Title IV of the CAAA, coal-fired model plants are able to choose SNCR, SCR or hybrid, or no controls. In all cases baseline controls are assumed to operate; there is no backing out of baseline controls in favor of a post combustion control. All post combustion controls are adopted on top of baseline controls.

Among post combustion control options, gas and oil-fired boilers are able to choose SNCR or SCR. In a performance standard policy regime, the cheapest technology able to get a model plant below its performance standard ceiling will be selected. In a tax policy regime (characterized as a charge per ton of emission), the technology that produces the largest possible reduction at a marginal cost of emission reduction that does not exceed the tax rate will be chosen. In a cap and trade policy regime, emission allowances are allocated to model plants so as to approximately equate (subject to the discete set of technological options available) the marginal cost of emission reduction among plants within the trading region with the permit value while maintaining total emissions below the cap.

For each type of policy regime, the marginal cost per ton of NOx reduction of a given NOx control investment depends on the amount of time the plant will be operated. To account for this, initial estimates of the operation of each model plant in each region is made based on their relative economics and historical precedent. This assumption forms the basis for a candidate portfolio of investment decisions across model plants. The candidate investment decisions are then characterized in the model and the generation portion of the model is solved in order to minimize cost while equating demand and supply in all regions. In the investment decision both capital and O&M costs are considered; however, after a candidate investment is in place, utilization of the facility will depend only on O&M costs. This solution is considered a candidate market equilibrium. The actual utilization of various model plants in this candidate equilibrium is used to update the initial assumption about the amount of time the plant will be operated in the candidate NOx control investment decision, and that decision is revisited. Subsequently the search for a market equilibrium is revisited. This pattern is repeated until convergence to a stable investment decision and market equilibrium is achieved.

The first step in identifying an investment for a given model plant is to identify the set of efficient options for that plant; not all potential compliance options are necessarily efficient. Graphically, the set of potentially efficient investments is identified along the lower envelope of options when plotted with cost on the vertical axis and tons of emissions reduction on the horizontal axis. Within a trading or tax regime, plants have the opportunity to achieve approximately any point along this frontier by investing in a convex combination of discrete compliance options at various constituent plants. Control technologies with marginal costs greater than the marginal cost achieved along this frontier are never considered for a given model plant because they are dominated by a convex combination of more cost-effective options. In this framework, the average cost of control is the ray from the origin to a given control option, or the total cost divided by the total emission reductions for that option. Marginal costs are defined as the ratio of incremental costs to incremental emission reductions that obtain in moving between two control options.

Annotated References

The first three references are the primary sources for quantitative estimates used in HAIKU; other sources provide additional background.

ICF Incorporated, for EPA Office of Atmospheric in Indoor Air Programs, Acid Rain Division. "Distributions of NOx Emission Control Cost-effectiveness by Technology." October 1996.

This document describes the assumptions and data used to construct estimates of per ton cost-effectiveness of different control technologies for the Acid Rain Division. The cost and removal estimates are somewhat different from those in EPA (1996a). This is our primary source of cost and removal functions. The document provides probabilistic distributions for cost-effectiveness over several boiler types.

EPA, Office of Air and Radiation. "Analyzing Electric Power Generation under the CAAA," Appendices Two through Five. April 1996(a).

These documents describe the major economic and technical assumptions made by EPA in constructing their Base Case for analyzing post-CAAA regulations, very similar to our baseline scenario. The cost and removal functions from this source are used only in cases where no information is available from the ICF (1996).

OTAG. "OTAG Trading Analysis with EPA/IPM: Policy Case Paper, Round 3 Analysis of Cap-and-Trade Strategies to Lower NOx Emissions from Electric Power Generation in OTAG," and Attachments A through C. March 1997.

This document describes three different sets of assumptions (from EPA, UARG, and ICAC) regarding costs and removal. Attachment C (ICAC's assumptions) is the source of information in HAIKU for Hybrid costs and performance functions.

Colburn, Ken, for OTAG Control Technologies and Options Workgroup. "States' Report on Electric Utility Nitrogen Oxides Reduction Technology Options for Application by the Ozone Transport Assessment Group." April 1996. (http://www.epa/gov/ttnotag1/finalrpt/chp5/appa.htm)

This document provides a good introduction to regulations, boiler types, and control technologies, with descriptions of the processes, relevant experience, feasibility, and costs of each technology. It provides three cost and removal ranges: actual experience, reports from marketers, and UARG estimates.

DOE Innovative Clean Coal Technology Project. "Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NOx) Emissions from High Sulfur, Coal-fired Boilers," DOE ICCT Project DE-FC22-90PC89652. October 1996.

This document reports the results of a demonstration project showing that SCR can indeed be used on plants burning high sulfur coal. It provides cost and removal estimates (including functional relationships for various parameters) for new, high sulfur-burning units and for retrofits of six existing, low sulfur-burning units. The cost estimates are on the high side, relative to other studies.

EPA, Office of Air and Radiation. "Analyzing Electric Power Generation under the CAAA." March 1998.

This is a revision to EPA (1996), "Analyzing Electric Power Generation under the CAAA, Appendices Two through Five." The cost and removal estimates have not changed, but there is some new information on EPA's method of constructing a baseline.

ICF Incorporated, for EPA Office of Atmospheric and Indoor Air Programs, Acid Rain Division. "Regulatory Impact Analysis of NOx Regulations." October 1996(b).

This document describes in detail the regulations considered and the cost impacts of each.

Institute of Clean Air Companies. "White Paper on Selective Catalytic Reduction Control of NOx Emissions." November 1997(a).

This provides detailed information about SCR, including process description, cost estimates, information about present demonstrations, and answers to questions about technical problems.

Institute of Clean Air Companies. "White Paper on Selective Non-Catalytic Reduction for Controlling NOx Emissions." October 1997(b).

This provides detailed information about SNCR, including process description, cost estimates, information about present demonstrations, and answers to questions about technical problems.

Makansi, Jason. "Work with Existing Hardware to Maximize Emissions Control," *Power*, March 1995, p41-49.

This article describes several evolving low-costs methods to achieve CAAA compliance, including computerized control systems for NOx reduction and innovative locations for catalyst installation.

NESCAUM. "Status Report on NOx: Control Technologies and Cost-effectiveness for Utility Boilers." June 1998.

This report provides an excellent update on compliance strategies, including detailed information about technologies and costs and 14 case studies.

STAPPA/ALAPCO. "Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options." July 1994.

This document provides a semi-technical description of the major boiler types and major control technologies.