Electricity Restructuring and Regional Air Pollution

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RESEARCH SUMMARY

This paper investigates the regional air pollution effects that could result from new opportunities for inter-regional power transmission in the wake of more competitive electricity markets. The regional focus is important because of great regional variation in the vintage, efficiency and plant utilization rates of existing generating capacity, as well as differences in emission rates, cost of generation and electricity price. Increased competition in generation could open the door to changes in the regional profile of generation and emissions.

We characterize the key determinant of changes in electricity generation and transmission as the relative cost of electricity among neighboring regions. In general, low cost regions are expected to export power generated by existing coal-fired facilities to higher cost regions. The key determinant of how much additional power would be traded is the uncommitted electricity transfer capability between regions, including its possible future expansion. The changes in emissions of NO_x and CO_2 that result are modeled as a function of the average emission rate for each pollutant in each region, coupled with assumptions about the extent of displacement of nuclear or coal-fired generation in the importing regions. Finally, we employ an atmospheric transport model to predict the changes in atmospheric concentrations of nitrates as a component of particulate matter (PM10) and NO_X in each region (but not changes in ozone), as a consequence of changes in generation for inter-regional transmission.

In the year 2000, we estimate national emission changes for NO_X could increase by 213,000 to 478,900 tons under the scenarios we think most likely, compared to the baseline. Under our benchmark scenario, we find national emissions of NO_X would increase by 349,900 tons. The changes in NO_X emissions should be considered in the context of an expected *decrease* in annual emissions nationally of over 2 million tons that will result from full implementation of the 1990 Clean Air Act Amendments over the next few years. The increase in emissions that we estimate serve to undo a small portion of the expected improvement in air quality that would occur otherwise. Nonetheless, these changes would yield relative increases in atmospheric concentrations of particulates with measurable adverse health effects.

We estimate the consequences for increased national CO_2 emissions will range from 75 to 133.9 million tons. Our benchmark suggests an increase of 113.50 million tons, equal in magnitude to about 40% of the reductions needed by the year 2000 under the Climate Change Action Plan.

Our estimate of NO_x emission changes is less than other studies, with the exception of the FERC EIS, primarily because we explicitly take into account capacity constraints on inter-regional transmission and use different emission rates. Our estimate is greater than the FERC EIS because we allow for a portion of the power generated for inter-regional transmission to meet new demand stimulated by an anticipated decline in price. Second, we allow a portion of imported power to

back out higher cost nuclear rather than fossil baseload. These are important economic changes that we believe will characterize a more competitive industry, and which point toward potentially more significant environmental consequences than recognized in the FERC EIS. Because we focus on increased generation from coal facilities, we characterize our findings as a worst case interim outcome under restructuring. However, we also think it is the most likely result of increased competition resulting from industry restructuring over the next few years. Our estimated emission changes are compared with those of previous studies in Table 13. The features of these various studies are summarized in Table 1.

Our analysis of alternative scenarios yields considerable variation in the predicted levels of emissions and where they occur. This leads us to offer our results with caution, and to have less confidence in the outcomes of previous studies because of the sensitivity of results to the variety of factors that we think important.

One of the central questions in the restructuring debate concerns what would happen to air quality in regions neighboring those where generation may increase, with special concern focused on potential changes in the Northeast. We find the changes in pollutant concentrations resulting from changes in NO_X emissions (excluding secondary ozone changes) would be substantially greater in regions where generation is increasing than in neighboring regions. The region likely to experience the largest adverse changes in air quality resulting from changes in generation is the Ohio Valley (the ECAR power pool region). For instance, in our benchmark scenario, the population weighted changes in atmospheric concentration of nitrates is 2-3 times as great in the Ohio Valley and the Southeast (SERC) as in the Mid-Atlantic region (MAAC) and 3-4 times as great as in the Northeast (NPCC). These results are reported in Tables 11a and 11b, and illustrated graphically in Figure 2 of the conclusion.

The likelihood of adverse impacts on NO_X and nitrate concentrations in some regions as a result of restructuring suggests the need for a policy response to ensure that electricity restructuring does not lead to significant environmental degradation in any one area. If these changes merit a regulatory response, the regional variation in effects, and various sources of uncertainty about effects that may result, suggest the need for a flexible policy. One flexible approach that would ensure that changes do not lead to significant environmental degradation in any one area, while also avoiding unnecessary investments where emission changes do not occur, would be an intra-regional cap and trade program for NOx emissions from electric utilities. However, such an industry-specific program should be eclipsed if a more comprehensive program can be implemented by EPA permitting cost savings from inter-industry trades.

Key Words: air pollution, electricity restructuring, transmission

JEL Classification No(s).: L94, Q25, Q28

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Karen Palmer and Dallas Burtraw[†]

I. INTRODUCTION

Electricity generation contributes significantly to air pollution in the U.S. Power plants currently are responsible for about 33 percent of all nitrogen dioxide (NO_2) emissions, 70 percent of all sulfur dioxide (SO_2) emissions and over one-third of the greenhouse gas emissions (e.g. carbon dioxide, CO_2) in the U.S. While SO_2 emissions are capped at a national level which will fall dramatically in the coming years (as Title IV of the 1990 Clean Air Act Amendments is fully implemented), future emissions of other air pollutants from the electricity sector are less certain. Much of this uncertainty stems from the fundamental changes taking place as federal and state regulators open up the industry to more competition in generation and, in some states, retail sales as well.

The environmental implications of increased competition in electricity markets and the associated "restructuring" of the industry depend on how electricity sellers and buyers respond to the opportunities created by a more open industry structure. For example, greater access to the transmission grid would provide generators that have excess capacity with the ability to sell to previously inaccessible distant markets; so emissions from these generators could rise while emissions in the purchasing region could fall. If competition leads to lower electricity prices, then

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overall demand for electricity could rise. This could, in turn, result in higher overall emissions from electricity generation. On the other hand, more competition in generation may accelerate investment in low-cost, relatively clean gas combined cycle or combustion turbine units leading emissions in the aggregate from the electricity sector to fall in the long run.

The vast uncertainty concerning the effects restructuring will have on technology and fuel use in electricity generation, growth of transmission capacity, electricity prices and electricity demand makes analysis of the environmental impacts of restructuring difficult. Ideally, we would like to know what restructuring will mean along all of these dimensions before attempting to model or predict what it will mean for the environment. However, the anticipated changes in the industry go well beyond the bounds of current experience upon which any model would be based. Therefore, we simplify the task by focusing on one prominent aspect of the restructuring debate— the regional changes in emissions likely to stem from inter-regional power trading and their regional effects on the environment.

The regional focus is important because of great regional variation in the vintage, efficiency and plant utilization rates of existing generating capacity, as well as differences in emission rates, cost of generation and electricity price. Subject to regional constraints on transmission capacity, open access transmission promises to serve as an equilibrating factor with respect to differences in capacity utilization and costs.

Average emission rates in each region, on the other hand, may become more disparate if — as some predict — regions with relatively less utilized, older and "dirtier" capacity increase the utilization of their least utilized, oldest and dirtiest units. If this occurs, air quality in these regions is likely to decline. This environmental degradation may be offset to some degree by the economic rewards of increases in plant utilization. However, one of the central questions in the restructuring debate concerns what would happen to air quality in neighboring regions. A seemingly perverse outcome, from a national perspective, could occur if pollution from the supply region were transported long distances and led to a net decline in air quality in both regions.

This paper addresses these issues by focusing on the changes in generation that could result from new opportunities for inter-regional power transmission in the wake of more open transmission access. We explicitly model the capabilities of the existing inter-regional transmission system and its possible future expansion. In addition, we employ a reduced-form version of an atmospheric transport model to predict the changes in atmospheric concentrations of various pollutants in various regions as a consequence of changes in generation for inter-regional transmission. Though we focus primarily on the air quality impacts of changes in NO_X emissions on regional ambient concentrations of NO_X and particulates, we also analyze implications for CO_2 emissions.

It is important to note that we do not account for the effects of changes in emissions on ozone formation or transport. To do so would involve considerably greater effort due to the nonlinear aspect of ozone chemistry. However, we expect relative changes in NO_X emissions and ambient concentrations to provide an indication of relative changes in ozone.[1] Furthermore, although ozone is of important concern to attainment of National Ambient Air Quality Standards,

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[1] One reason this may not be strictly true is that increases in NO_X emissions may reduce ozone concentrations in the local area around the source of those emissions, even as it contributes to increased ozone concentrations at more remote locations. We conjecture that the large area of the regional aggregation in our analysis probably overwhelms the local ozone scavenging phenomenon, so that on average relative changes ozone concentrations may follow relative changes in NO_X concentrations. However, this conjecture should be subject to scrutiny.

the environmental and health literatures suggest that the lion's share of economic costs of air pollution are captured by measuring changes in particulate concentrations. In an appendix we provide an estimate of these economic costs.

Our analysis focuses on increased generation activities precipitated by greater access to inter-regional transmission facilities to distant markets, as is likely to result from FERC Order 888 (April 1996) on open transmission access. However, we do not limit our consideration to the environmental effects of the FERC Order. Competition at the retail level is likely to lead to even more power trading. Our findings are consistent with the scope of competition, be it wholesale or retail, that would lead to a maximum amount of inter-regional power trading subject to transmission capacity constraints.

The next section of this paper provides a discussion of the recent literature on the potential environmental consequences of restructuring. Section III describes our own efforts to model inter-regional power transmission and its potential air quality impacts. In Section IV, we report the results of this modeling effort. In Section V, we summarize our results and prioritize issues for further research that should inform the public policy. In Appendix A, we provide a table of significant uncertainties, omissions and biases we identify in our analysis. In Appendix B, we illustrate some of the health effects that may result from these changes.

II. EXISTING LITERATURE AND UNANSWERED QUESTIONS

Few studies have been conducted that attempt to analyze or predict the environmental effects of electric utility restructuring. The largest and most ambitious analysis to date is the FERC's Environmental Impact Statement (EIS) of its 1995 Open Access NOPR, which subsequently became

FERC Order 888 (FERC 1996). This study, prepared by ICF Inc., uses a detailed national electric utility forecasting model, the Coal and Electric Utilities Model (CEUM), in concert with EPA's air quality model (UAM-V), to conduct a sophisticated analysis of the environmental effects of Order 888 only. The study compares the post-888 utility sector emissions and air pollution concentrations to those in a base case wherein transmission access for wholesale power trades is granted on a case-by-case basis through existing FERC procedures. The primary environmental concern addressed in the study is increased NO_x emissions and their implications for ozone concentrations.[2] The study concludes that "the proposed rule is not expected to contribute significantly" to the pre-existing ozone problem in the Northeast (FERC, 1996, p ES-11).

The major problem with the EIS is its limited scope. By incorporating expanding competition into its baseline scenarios, the EIS primarily addresses the environmental consequences of accelerating the transition to more open and competitive wholesale markets through a general rulemaking. In comments on the draft version of the EIS, the Center for Clean Air Policy (1996a) suggests that the impact of restructuring on NO_x emissions in 2005 may be understated by as much as 400,000 tons, which would constitute an eight percent increase in NO_x emissions relative to a base case with no restructuring. However, in the final EIS FERC compares implementation of order 888 to a base case absent incentives for productivity change created by allowing transmission access on a case-by-case basis (specifically no improvements in fossil plant availability and no drop in reserve margins over time) and they find national NO_x emission increases of roughly one-third that magnitude.

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[2] Other concerns including SO_2, TSP and CO_2 emissions and visibility effects were also addressed.

The EIS has other methodological weaknesses that limit its usefulness. The study makes some questionable and potentially inconsistent assumptions about transmission capacity. The study adopts recent estimates of inter-regional transfer capabilities from the North American Electricity Reliability Council (NERC)[3] and incorporates currently planned increments to transmission capacity; however, it assumes that there will be no change in transmission capacity as a result of increased transmission access in its primary analysis.[4] This is troubling because the rule requires that transmission-owning utilities expand their transmission systems as necessary to accommodate requests for transmission access. Moreover, opening up the transmission grid is likely to increase the opportunity cost of transmission capacity as open access places more demands on this fixed resource. This could create incentives for upgrading capacity, both through construction of new lines and through efficiency improvements in the existing system.[5] Such incentives are more likely to arise when electricity is priced at opportunity cost and transmission service providers face competition from neighboring systems or from potential entrants.[6] The EIS and Order 888 also

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[3] These estimates have been derated by 25 percent to account for the impact of simultaneous power transfers not reflected in the NERC estimates. This assumption is questioned extensively in comments by the Center for Clean Air Policy (1996a) and the U.S. Environmental Protection Agency (1996), both of which suggest that the NERC inter-regional transfer capability estimates are constructed under conservative assumptions and, therefore, may understate the true capability of the existing transmission system to transfer power.

[4] The EIS incorporates some scenarios that include expanding transmission capacity over time. However, the FERC makes this assumption for both the base case scenarios and the increased competition scenarios. The FERC explicitly dismisses suggestions that the proposed rule will lead to expansion of transmission capacity. They argue that as long as transmission continues to be a regulated monopoly, incentives to increase transmission capacity will be no greater under the proposed rule than they would otherwise be.

[5] For instance, new power electronic controllers that form the basis of flexible ac transmission system (FACTS) technology hold the potential to increase the capacity of particular transmission lines by as much as 50% while reducing stability problems throughout the grid. Douglas (1994), 11.

[6] Loopflow problems will limit incentives to expand transmission capacity since the transmission-building utility will not be able to capture the benefits of its new investment which accrue to everyone who is attached to the interconnected grid. Bohi and Palmer (1996) suggest that this disincentive to invest in the grid will be smaller under wholesale competition than under retail competition.

assume that transmission continues to be priced according to embedded costs. However, this approach to transmission pricing may prove unsatisfactory if regulators and industry participants want a pricing mechanism that identifies where transmission expansions would be most valuable.

A third major weakness of FERC's EIS is its failure to consider the impacts of the proposed open access rule on electricity demand.[7] Competition in electricity markets is desirable primarily because it will lead to lower electricity prices,[8] which in turn would spawn increased demand for electricity that would also have implications for emissions. The FERC EIS uses unamended NERC demand forecasts in both the base case and post-888 scenarios that do not take into account price changes resulting from competition. However, the study does consider changes in investment in generation facilities.

In a much more narrowly focused study, the Center for Clean Air Policy (1996b) adopts a case study approach to analyze the economic and environmental impacts of increased power exports from the American Electric Power (AEP) system. They motivate this analysis with several observations about the AEP system, including the assertion that it has lower costs than most neighboring utility systems and sufficient excess capacity to be able to export large quantities of electricity. The Center finds that increasing utilization rates to 80 percent at all major AEP generating units leads to generation increases of approximately 25 percent and increases in NO_x emissions of more than 40,000 tons during the five month summer ozone season in 2005. The

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[7] The Center for Clean Air Policy (1996a) also points out this flaw.

[8] A recent study by Berkman and Griffes (1995) suggests that electricity prices could fall by an average of 38 percent nationally.

Center also finds substantial increases in CO_2 emissions that could offset more than 75 percent of the national CO_2 reduction target for the year 2000 under the U.S. Climate Change Action Plan.

The Center's AEP case study has two important weaknesses.[9] First, the study fails to explicitly account for transmission capacity constraints that might limit AEP's ability to export power.[10] In contrast with assumptions behind FERC's EIS, the study argues these constraints are likely to become less binding over time, for many of the same reasons we mentioned previously. However, the rate at which transmission capacity is likely to grow is highly uncertain, so that at the very least it would be useful to know how much expansion in capacity is required to achieve the growth in exports included in the model.[11]

Second, the Center's study fails to take into account what is happening to emissions in the importing regions. The study explicitly states that "from an air quality standpoint, it does not matter who buys AEP's additional generation." (Center for Clean Air Policy, 1996b, p. 12.) This is incorrect. If electricity imports are substituting for generation within the importing region, then

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[9] A recent critique of the Center for Clean Air Policy study by Putnam, Hayes and Bartlett (1996) for American Electric Power suggests that the Center's study overestimates future available coal-fired capacity in the AEP system. In a rebuttal to the Putnam, Hayes and Bartlett critique, the Center for Clean Air Policy (1996c) points out that the most recent AEP Resource Plan forecasts greater use of existing coal-fired facilities to meet faster growing native electricity demand which leads to increases in NO_x emissions similar to those found in the Center's study.

[10] The Center's study finds that over 31,000 additional GWh of electricity would be available for export from the AEP system in 1999 and suggests that this power might be sold into markets in the northeast, particularly in New York State. However, our model shows that even assuming a high rate of transmission expansion of over 6 percent per year, there will only be enough additional transmission capacity available in the year 2000 to ship an additional 3,600 GWh from the entire ECAR region into the MAAC region and points further east, about 85 percent less than the Center's study attributes to AEP, which is responsible for one-quarter of total generation in ECAR. However, under the same high transmission capacity growth assumptions, roughly 28,000 additional GWh of electricity could be exported from ECAR to SERC.

[11] This type of analysis would involve a more explicit consideration of who is importing the power than currently included in the study. However, such an analysis may be necessary to more accurately assess the environmental impacts of increased imports as we indicate in the next paragraph.

emissions reductions in the importing region need to be taken into account in any complete analysis of air quality impacts. If this region is also downwind from AEP, these reductions could partially or even completely offset the additional pollution that might come from increased generation at AEP or any other units.

In another report prepared for the National Association of Regulatory Utility Commissioners, Rosen *et al*. (1995) suggest that two important determinants of the impact of restructuring on national emissions of key pollutants from electricity generation are what happens to nuclear power plants and what happens to utilization rates at currently under-employed pre-1971 coal facilities. Rosen *et al.* suggest that if 10 nuclear facilities are shut down and replaced by generation from existing pre-1971 vintage coal facilities, then national emissions of NO_x could increase by two percent. Exempt from the requirements of New Source Performance Standards under the Clean Air Act, these older coal facilities can have emission rates for NO_x that are as much as ten times greater than comparable new facilities. These facilities also have much lower utilization rates than newer coal facilities, suggesting that they offer the greater potential for increased generation. If utilization rates at these older facilities were to rise to levels experienced at newer coal facilities, then emissions of NO_X could rise an additional nine percent above current levels.

A fourth study rounds out much of what we know about the likely environmental impacts of restructuring. Lee and Darani (1995) attempt to quantify the emissions impacts of several widely anticipated outcomes of electric utility restructuring, including the demise of utility DSM programs and preferential treatment of renewables, early retirement of large quantities of uneconomic nuclear capacity, and increased utilization of existing coal capacity. Focusing on SO_2, NO_x and CO_2, Lee and Darani compare their findings to emission reduction goals specified in the 1990 amendments to the Clean Air Act or, in the case of CO_2, in the Climate Change Action Plan. Unlike the FERC EIS, the methodology used in this study is very transparent, as the authors employ "spreadsheet" models that allow for easy identification of what is driving their results.

Lee and Darani do not apply an explicit geographic resolution to their study. They find that early retirement of nuclear plants and increased utilization of existing coal capacity, absent any account of their location, would have substantially greater emissions impacts than the loss of utility-sponsored DSM or of special preferences for renewable generation. For example, they find that if the wholesale price of electricity falls to 3.5 cents/kWh, about 6,000 MW of existing nuclear capacity becomes uneconomic and would be removed from service. They estimate that replacing the lost energy with generation from existing fossil units will create between 79,000 and 118,000 additional tons of NO_x and between 27 and 38.5 additional tons of CO_2 per year, depending on how much existing coal-fired generation is employed.

In addition, in their analysis of the impacts of increased utilization of existing coal plants, they find that raising the average capacity factor from 64 to 67 percent by increasing generation at the dirtiest coal-fired plants could lead to an additional 500,000 tons of NO_X emission and 43 million tons of CO_2 emissions.[12] In their analysis only one-third of the additional electricity from coal plants goes toward new electricity demand, with the rest substituting half for gas peaking units and half for generation from clean coal facilities.

[12] This analysis employs a NO_x emission rate that is more than twice as large as that used for existing coal-fired generation in the nuclear retirement example. The justification for this assumption is that these coal facilities tend to have lower costs than cleaner coal facilities and therefore are more likely to be dispatched. The NO_x emission estimates derived from this exercise should be considered a worst case estimate.

The virtue of the Lee and Darani study lies in the simplicity of the methodology and the explicitness of their assumptions. However, as a result of its simple approach the study has several important limitations. First, there is no recognition of transmission constraints and how these might limit increases in generation from existing coal facilities. Second, there is no regional detail in the model to indicate where increased emissions are coming from, where they may be transported to and where off-setting emission reductions may take place. Third, the study deals only with emissions and offers no insights about actual air quality impacts of changes in generation methods.

Finally, in their analysis of post-restructuring increases in coal utilization rates, Lee and Darani are conservative about changes in demand. This is important because if restructuring were to lead to a significant decline in price, we would expect there to be a significant increase in demand, leading to relatively greater generation and associated emissions. Taking the net change in demand of 26,000 gigawatt hours estimated by Lee and Darani, and a short-run price elasticity of demand of -0.3, Lee and Darani implicitly assume that restructuring leads to a 3 percent drop in the price of electricity.[13] While this assumption is consistent with the consumer savings predicted to result from the adoption of FERC Order 888, it is probably a lower bound estimate of the price changes likely to result from allowing competition at the retail level as proposed in many states.[14] While Lee and Darani are silent on this issue, such a small implied price change suggests that they

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[13] This price elasticity of - 0.3 is based on research summarized in Bohi and Zimmerman (1984). These authors report a consensus long-run elasticity of -0.2 for residential consumers, but no consensus estimates for other customer classes. However, the results of the individual studies of commercial and industrial electricity demand that they report indicate that these classes of customers exhibit elastic demand for electricity. Therefore, we adopt -0.3 as the overall elasticity of demand for electricity.

[14] FERC estimates that Order 888 will result in savings to consumers of between $3.8 and $5.4 billion per year which amounts to between a 1.9 and 2.7 percent drop in the average price of electricity. However, the New Hampshire Public Utility Commission predicts that its competition pilot program, to be initiated in late May 1996, could produce immediate price declines of as large as 10 percent. (Kerber and Holden, May 13, 1996).

are assuming substantial recovery of stranded costs which would mitigate against price declines during the first several years under a restructured industry.

The features of these four studies and our analysis are summarized in Table 1. Our analysis builds on the work of Lee and Darani (1995). We develop a regional model of economic power trading that incorporates existing inter-regional transmission capacity, and we allow that capacity to grow over time at exogenously specified rates. We use this model of inter-regional transmission to identify which NERC regions are likely to be net exporters and net importers in a world with a restructured electricity sector. The model enables us to estimate emissions changes resulting from increased power trading at the regional level. Finally, we simulate air quality impacts in all affected regions using a reduced-form matrix of transfer coefficients that predicts changes in atmospheric concentrations of several pollutants of interest. We also characterize these changes on the basis of population weights to indicate the magnitude of exposed populations and associated health effects. In an appendix, we use a model of air-health epidemiology to illustrate the potential health effects of our modeled changes in air quality, and their economic cost.

III. THE MODEL

We have developed a simulation model of power trading and associated air pollution effects called PREMIERE (for "Primary Regional Environmental Model in Electricity Restructuring"). The objective of the model is to take the greatest possible advantage of all economic power trading opportunities, subject to limits imposed by inter-regional power transfer capabilities and available generating capacity in exporting regions. The model also simulates the air pollution impacts of changes in emissions that result. The model has five basic components: power trading, generation and demand, emissions, air quality and health effects. The health effects component is described in an appendix.

Table 1. Comparison of Methods and Assumptions in Studies of Air Quality Effects of Electricity Restructuring

	FERC EIS*	**CCAP**	**Rosen, *et al.***	**Lee and Darani**	**Palmer and Burtraw**
Scope	National - Transmission access (Order 888) only	Single utility - AEP	National - Restructuring generally	National - Restructuring generally	National - Restructuring generally
Regional Generation	Census regions	AEP only	No	No	NERC regions
Treatment of Transmission	Existing capacity; no growth in capacity resulting from open access	No	No	No	Existing capacity; future growth in capacity resulting from restructuring
Demand Effect	No	Yes	Not explicit	Yes	Yes
Nuclear Effect	No	N/A	Scenario analysis	Scenario analysis	Yes
Investment Effect	Yes	No	No	Scenario analysis	No
Emissions	NO_x, SO_2, TSP, mercury, CO_2	NO_x, CO_2	NO_x, SO_2, CO_2,	NO_x, SO_2, CO_2	NO_x, CO_2
Air Quality Effects	Concentrations of primary and secondary pollutants, visibility (no particulates)	No	No	No	Concentrations of primary and secondary pollutants (no ozone)
Regional Air Quality	Census regions	No	No	No	NERC regions
Methodology	ICF's CEUM utility dispatch model with plant-specific data; EPA's UAM-V air quality model	Scenario analysis of increased coal plant utilization using plant-specific and general information	Scenario analysis of increased coal plant utilization using average national data for pre-1971 facilities	Scenario analysis using average national data for older coal facilities	PREMIERE - regional power trading model using average regional data; reduced form ASTRAP air model

* The FERC EIS includes information about effects other than air quality such as acid deposition, sludge disposal, land and water use, etc.

Power Trading

Economic power trades are identified on the basis of average generation cost or average electricity price differences between contiguous NERC regions.[15] Currently the model can only address power trading between NERC regions and therefore, it ignores any increases in power trading within NERC regions that might result from restructuring. A map of the NERC regions is displayed in Figure 1. Trades between the two contiguous regions with the greatest cost differences are executed first, followed by those with the next greatest cost difference and so on. The quantity of power traded is constrained by the amount of uncommitted inter-regional transmission capacity and the maximum possible utilization rate of generation facilities.[16] Power trades over multiple regions are modeled as a sequence of bilateral trades. A region may be involved in more than one trade, and it may import from one region and export to another.[17]

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[15] The cost data were derived from the EIA (1991). Average costs were derived from source data for a sample of 73 hydroelectric, 50 fossil-fueled steam-electric, 71 nuclear, and 50 gas turbine plants. Price data were derived from EIA (1995a), Table 7. An area-based function was used to convert state level data to NERC region data.

[16] Uncommitted inter-regional transmission capability is the minimum of two numbers: NERC's reported "First Contingency Incremental Transfer Capability" and a maximum utilization coefficient multiplied by the "First Contingency Total Transfer Capability" minus normal base power transfers. We use the average of winter and summer numbers for each of these three measures. (NERC, 1995a, p. 9; and NERC, 1995b, p. 11.) The first represents unused capacity, the second represents the ability to use total capacity effectively and the third represents current power transfers. The maximum utilization coefficient is assumed to be 0.75 as in FERC's EIS. Transmission capacity is also allowed to grow over time and the rate of growth is varied in different scenarios.

The maximum utilization rate for generation facilities is a variable in the model and allowed to increase over time representing an incentive in a competitive environment to improve utilization of existing capital through tighter scheduling of maintenance, capital improvements, etc. Current utilization for 1994 is derived from EIA (1995b), Table 13. Utilization for 1995, 2000 and 2005 was derived from NERC (1995c).

[17] In principle the algorithm employed by PREMIERE could miss profitable trades along a contract path that was nonmonotonic in prices. For instance, imagine three regions along a path are indicated by the sequence (A,B,C) and the ordering of relative costs from lowest to highest is (A,C,B). The first trade executed would be A to B because it captures the greatest difference in cost. If there was unutilized generation capacity in A after exhausting demand in B, then A might want to trade with C. However, in almost every case transmission capacity between A and B is exhausted so a subsequent trade along this path between A and C is not possible. Instead, C might increase generation to trade with B to capture the unutilized transmission between B and C. Hence, PREMIERE "fills the grid" with economic trades. An important limitation to this algorithm is that electricity does not flow according to contract path but rather fills up the grid in a nonlinear manner. The NERC estimates of uncommitted inter-regional transmission capacity reflect this.

Figure 1.

Figure is available from authors
at Resources for the Future.

Generation and Demand

The Generation and Demand component of the model is premised on the assumption that where cost or price differences exist between regions, there is ample demand in the importing region to exhaust transmission capabilities. The model employs information on costs of generation using different technologies in the importing regions, and assumptions supplied by the user, to allocate imported power between increased electricity demand and decreased generation from particular technologies within the importing region.

Emissions

Changes in emissions that result from increases or decreases in generation are estimated in PREMIERE on the basis of average emissions rates for each region for three pollutants — SO_2, NO_X and CO_2 — and for each fuel type.[18] Trends in emission rates for SO_2 and NO_X have been declining over recent years and can be expected to continue to do so, in part due to regulatory pressure and in part due to technological change. Our use of average emission rates in 1994 does not reflect this trend through the year 2000. On the other hand, as anticipated by some previous studies, it is possible that the facilities that are used to meet new market opportunities as a result of restructuring are relatively "dirtier" than the current average. Our 1994 data capture Phase 1 of Title IV NO_X controls, but not Phase 2 controls, which remain uncertain. Also, these data do not reflect the Memorandum of Understanding in the Northeast Ozone Transport Region. To the extent coal is backed out in this region, then our data *under*estimate net emission changes. Due to

[18] Average emission rates for each NERC region are derived from EIA (1995b), Table 25.

the national emissions cap for SO_2 we limit attention here primarily to changes in NO_x emissions, and secondly to changes in CO_2 emissions.

Air Quality

The air quality component of PREMIERE translates changes in emissions of NO_x and SO_2 to changes in ambient concentrations of NO_x and nitrates (NO_3/HNO_3), SO_2 and sulfates (SO_4) in all affected regions. The emission transport coefficients for these pollutants were calculated using the Atmospheric Transport Module of the "Tracking and Analysis Framework" (NAPAP, 1996). The TAF coefficients were computed for a state to state matrix using the Atmospheric Statistical Trajectory Regional Air Pollution (ASTRAP) model.[19]

The region-to-region air transport model apportions changes in pollutant concentrations in receptor regions back to particular source regions. The matrix is displayed in Table 2 for changes in ambient NO_x concentrations and Table 3 for changes in NO_3/HNO_3 concentrations. Source regions appear as rows and receptor regions appear as columns. The coefficients represent the average change in pollutant concentrations (micrograms per cubic meter) in each receptor region for a one thousand ton increase in average emissions in the source region in a given season. Tables 2 and 3 refer to summer. For instance, Table 2 indicates that a one thousand ton increase in NO_X emissions during the summer season in ECAR will lead to an increase of 0.0029 micrograms of NO_X per cubic meter in ECAR. Although there is significant evidence that drift of NO_X (and ozone) contributes to

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[19] Shannon, *et al.* (1996) describe the modeling of sulfate concentrations, and Shannon and Voldner (1992) describe the modeling of NO_X and nitrate concentrations, used in ASTRAP. To change the data to a NERC region to NERC region source-receptor matrix, two adjustments had to be made. The source NERC region was configured for each of the receptor states by averaging the transfer coefficients from each of the states in the NERC source region, weighted by 1994 baseline state emissions. The coefficients were then averaged over the states in the NERC receptor region, weighted by state area. Change in affected population in each region over time was also modeled (NAPAP, 1996).

Table 2: Summer regional source-receptor NO_x atmospheric transport coefficients

(micrograms (NO_x)/cubic meter/thousand tons NO_x emissions per season)

Source	Receptor								
	ECAR	ERCOT	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC
ECAR	0.0029	0.0000	0.0010	0.0004	0.0000	0.0002	0.0001	0.0000	0.0000
ERCOT	0.0000	0.0062	0.0000	0.0003	0.0001	0.0000	0.0000	0.0029	0.0000
MAAC	0.0006	0.0000	0.0064	0.0000	0.0000	0.0007	0.0001	0.0000	-
MAIN	0.0010	0.0000	0.0001	0.0053	0.0002	0.0000	0.0001	0.0003	0.0000
MAPP	0.0003	0.0000	0.0000	0.0024	0.0030	0.0000	0.0000	0.0002	0.0000
NPCC	0.0000	0.0000	0.0028	0.0000	0.0000	0.0048	0.0000	0.0000	-
SERC	0.0003	0.0000	0.0002	0.0000	0.0000	0.0000	0.0027	0.0001	0.0000
SPP	0.0002	0.0008	0.0000	0.0023	0.0003	0.0000	0.0003	0.0041	0.0001
WSCC	0.0000	0.0001	0.0000	0.0000	0.0006	0.0000	0.0000	0.0008	0.0022

Table 3: Summer regional source-receptor NO_3/HNO_3 atmospheric transport coefficients

(micrograms (NO_3/HNO_3)/cubic meter/thousand tons NO_x emissions per season)

Source	Receptor								
	ECAR	ERCOT	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC
ECAR	0.0006	0.0000	0.0006	0.0001	0.0000	0.0002	0.0001	0.0000	0.0000
ERCOT	0.0001	0.0015	0.0000	0.0003	0.0002	0.0000	0.0001	0.0011	0.0001
MAAC	0.0002	0.0000	0.0011	0.0000	0.0000	0.0003	0.0000	0.0000	-
MAIN	0.0005	0.0000	0.0001	0.0009	0.0000	0.0001	0.0001	0.0001	0.0000
MAPP	0.0003	0.0000	0.0001	0.0008	0.0007	0.0001	0.0000	0.0001	0.0000
NPCC	0.0000	0.0000	0.0004	0.0000	0.0000	0.0008	0.0000	0.0000	-
SERC	0.0002	0.0000	0.0001	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000
SPP	0.0002	0.0003	0.0001	0.0007	0.0002	0.0000	0.0002	0.0008	0.0001
WSCC	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0006	0.0015

air pollution in areas away from the source of emissions, at the regional level we find the greatest source of emissions affecting pollutant concentrations in any region are its own emissions. However, one can see that significant pollution comes from other regions. This is particularly true for NO_3/HNO_3 which on average is present at greater distances from the emission source than NO_X.

Once again, we note that the simulations reported do not present a comprehensive picture of all the ways in which changes in emissions from additional electricity generation might impact air quality and human health in the different regions. Notably absent is an estimate of changes in ozone formation and transport. Evidence from many health epidemiological analyses of air pollution indicates that fine particles are the overwhelmingly predominant source of morbidity and premature mortality. For that reason, omitting ozone from our analysis is not likely to bias our findings as much as one might think. In addition, the set of air quality changes we do consider provides a reasonable proxy of the regional patterns, if not the full magnitude, of the likely impacts of changes in emissions associated with changes in electricity generation.

Assumptions in and Justifications for Our Analysis

The PREMIERE model employs several implicit assumptions that shape our results. By assuming that all the additional power for export is generated using existing coal facilities, we focus on a "worst case" air pollution scenario. This assumption seems justified because every region has coal facilities that could increase production at relatively low variable costs. In every region the average variable cost of coal generation is less than that of nuclear generation. Nuclear variable costs include a significant fixed operations and maintenance component, so the choice facing system operators may not be only whether to dispatch nuclear, but whether to run the facility at all.

The average variable cost of coal generation is also less than the probable total of fixed plus variable costs for new gas facilities. In the longer term, these gas facilities may prove to be the least expensive alternative for new generation, but we assume their costs are greater than the variable costs of underutilized coal facilities for the interim.

The key determinant of *how much* additional power is traded is the uncommitted electricity transfer capability between regions. We adopt the assumption used in the FERC EIS that the total transfer capabilities between NERC regions should be multiplied by 0.75 to more accurately represent sustainable simultaneous transfer capabilities. Some observers have criticized this coefficient as arbitrary and too high, given the premium that may be placed on transmission capacity as a scarce resource. However, this coefficient helps to offset a potential bias overstating transmission, to the extent there are periods of time when transmission capacity is slack.

We consider two different transfer capability scenarios. In the first, we assume that the capacity of the transmission grid will grow over time at a rate of 1.2% per year as it has over the past 5 years, an assumption we view as conservative.[20] In an alternative scenario we increase the rate of growth of transmission capacity to 6.16% per year reflecting its increasing scarcity value in a restructured industry as well as requirements for transmission capacity expansion when requested under Order 888. This rate of growth was chosen to make our assumption regarding additional transmission capacity available in 2000 consistent with that adopted in the expanded transmission scenarios in the FERC EIS.

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[20] EPA (1996) footnote 16, p. 31.

The key determinant of *the direction of* trade — which regions act as exporters and which as importers — is the cost of electricity generation within a region relative to the cost in neighboring regions. We exercise the model using three different estimates of electricity cost: the average revenue per retail kWh sold by utilities within the region, the average operating cost for fossil-fired generation within the region and the average operating cost for all baseload generation (including nuclear) within the region. Table 4 illustrates these cost differences between adjoining regions. For example, the first row indicates that the average retail price in ECAR is 20.17 mills/kWh less than in MAAC. The average operating cost for fossil-fired generation is 0.89 mills/kWh greater in ECAR than in MAAC, and the average operating cost for all baseload generation is 1.17 mills/kWh less in ECAR than in MAAC.

Table 4: Price, baseload cost, and fossil fuel cost differences between neighboring NERC regions (difference is indicated cost measure in first region minus same measure in second region) (mills per kWh).

NERC Region	NERC Region	Price	Fossil Operating Cost	Baseload Operating Cost
ECAR	MAAC	-20.17	0.89	-1.17
ECAR	MAIN	-9.28	4.35	2.30
ECAR	SERC	-2.02	-4.26	-3.39
ERCOT	SPP	1.67	0.07	-0.80
MAAC	NPCC	-25.70	-8.13	-7.36
MAAC	SERC	18.16	-5.15	-2.22
MAIN	MAPP	12.52	1.79	3.54
MAIN	SERC	7.26	-8.61	-5.69
MAIN	SPP	6.73	-3.33	-1.17
MAPP	SPP	-5.79	-5.12	-4.71
MAPP	WSCC	-9.21	-3.43	-4.32
SERC	SPP	-0.53	5.28	4.52
SPP	WSCC	-3.42	1.69	0.39

A preferable method for predicting trade and changes in plant utilization might be to compare operating cost at individual facilities that may increase or decrease generation in a more competitive environment.[21] However, our data on operating costs are drawn from a survey of plants that may not be representative of facilities most affected by changes in transmission. Therefore, in our benchmark scenario we adopt average price as the basis for determining trades in subsequent analysis, under the assumption that relative average price is a better predictor of actual relative cost than variable cost estimates based on our small sample of plants. This choice does not affect the quantity of new generation for transmission, but only its direction. Subsequently, we discover that the use of relative average price is a conservative assumption in that it leads to lower estimates of changes in emissions than does use of variable costs from our sample of plants. Throughout the analysis we carry forward all three comparisons to illustrate the potential sensitivity in results that hinge on this comparison.

The amount of additional coal-fired generation available for export from each region is constrained by the difference between the assumed maximum potential utilization rate for coal-fired generating capacity and the expected utilization rates in the absence of expanded competition. Estimates of the latter come from NERC region forecasts of coal-fired capacity and coal-fired generation for each of the NERC regions. These estimates vary from a low of 38 percent in NPCC

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[21] Currently, short-run or economy bulk power trades between utilities in different control areas are based on differences in marginal energy costs or so-called system lambdas between dispatch control areas. Utilities will import "economy" energy when its price is below the utility's marginal cost of generation. While highly disaggregate data on system lambdas are available for all the control areas within each NERC region, the task of aggregating these data to the NERC region level is beyond the scope of this paper. Also, the additional electricity trading that we model is likely to be a mix of short run energy transactions and longer-run capacity contracts. In the case of the latter, power trades would be based on a more long-run price concept such as the long-run avoided cost of electricity generation.

to a high of 69 percent in SERC. We assume a maximum potential utilization rate for coal-fired facilities of 80 percent in 1995, growing at a rate of 0.5 percent per year as a result of incentives to increase utilization that flow from increased competition in generation markets.

We assume expanded generation at existing facilities has no effect on the planned construction of new facilities. This conservative assumption potentially leads us to understate emissions, because an increase in imports of electricity affords an opportunity to delay construction of new facilities that would have lower emission rates than older existing coal-fired facilities either due to new source performance standards, or because they are fired by natural gas.

Importing regions allocate new electricity to meeting expanded consumer demand that is a direct result of changes in price, as well as to displacing more expensive fossil or nuclear generation in the region. We assume changes in consumer demand occur instantaneously, which implies that prices adjust instantaneously in a competitive setting to the availability of less costly generation. The benchmark scenario, following similar assumptions in Lee and Darani, is for net imports to be allocated one third to new consumer demand. Unlike Lee and Darani, who assume the remaining two-thirds displaces gas peaking and new clean coal units, we adopt a benchmark wherein imports first back out generation from higher cost nuclear facilities to the extent possible followed by existing coal generation in the importing region. As it turns out, importing regions always have sufficient high cost nuclear generation to be able to use two-thirds (or even all) of the imported generation to back out native nuclear generation. We vary this benchmark assumption in the sensitivity analysis to consider the air quality impacts of using imported coal generation to back out higher priced coal generation in the importing region.

As a check on the plausibility of the assumption that one-third of imported electricity is used to meet new demand, we calculate the implied change in price given this change in consumption using a midrange estimate of short-run demand elasticity. We also simulate the environmental effects of increased power trading when all imports are used to back out existing generation in the importing region.

We ignore transmission charges in modeling changes in transmission activity. The FERC EIS uses a benchmark transmission charge of 3 mills per kWh as a "postage stamp" fee that does not vary with distance of transmission. In most cases for both the price-based and fossil cost-based trading scenarios, this difference appears to be insignificant to our results.

The greatest limitation of our analysis of potential changes in air pollution at a regional level that would result from industry restructuring is our use of regional averages for generation cost, electricity price, plant utilization and emission rate estimates.[22] Doing so leads us to understate changes in emissions if new generation comes from the dirtiest and potentially least utilized plants; but it may also cause us to understate the costs of operating these older and typically less efficient facilities. The two biases would appear to be offsetting. Nonetheless, our data affords only a bounding exercise and not an accurate prediction of likely outcomes of restructuring.

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[22] We use the average regional price and cost estimates as indicative of the motivation and direction for trading. In every pairwise comparison of prices among neighboring regions there exists at least one state in the high cost region with a price that are less than that in one state in the low cost region. However, a large majority of the prices observed at the state level in high cost regions are greater than all observed prices in lower cost neighboring regions, and *vice versa*. Of course, there may be even greater diversity in price within states. We conducted a similar comparison among costs observed in our sample of plants, and can always find a plant in the high cost region with a production cost less than for a plant the low cost region, but a majority of plants in high cost regions (not quite as large of a majority as in comparison of prices among states within each region) have a cost greater than the all observed cost in lower cost neighboring regions. Nonetheless, our comparison of relative costs is limited in an important way by our limited sample of plants.

IV. OBSERVATIONS FROM PREMIERE SIMULATIONS

We use the PREMIERE model to simulate a number of different scenarios that vary in the prediction of which regions act as exporters or importers of power after restructuring and the quantity of additional power that is traded. These scenarios have differing implications for emissions of NO_x and other air pollutants and for the impacts of these emissions on regional air quality.

In the next sections, we present some observations based on several simulations that combine different measures of regional electricity cost with different assumptions regarding growth in the capacity of the transmission system. All of these observations are for the year 2000, the same year chosen in the Lee and Darani analysis of the environmental effects of expanding capacity factors at existing coal plants.

Power Trading and Generation

Who exports and who imports power depends on which measure of electricity cost is being used to determine profitable inter-regional trades. Power exports and imports under different scenarios are summarized in Tables 5a and 5b. Our benchmark scenario in these and subsequent tables is indicated by shading. As shown in the Table 5a, when trades are based on differences in the average price of electricity, the exporting regions are ECAR, SERC and MAPP, with 90% of the exported electricity coming from ECAR and SERC. MAPP is the region with the lowest average price; however, limits on outbound transmission capacity restrict the region's ability to export power. The major power importers under this scenario are MAIN, NPCC and SPP. Small amounts of electricity are also imported into ERCOT, MAAC and WSCC.

When power trades are based on differences in generating (including fuel) costs of fossil-fueled generators or of baseload generators, also shown in Table 5a, the major exporters are

Table 5a. Exports (Billion kWh) for a given Transmission Expansion Rate

	Transmission Expansion Rate				
	1.2%			6.16%	
	Price	Baseload Cost	Fossil Cost	Price	Fossil Cost
ECAR	53.30	0.00	0.00	67.71	0.00
ERCOT	0.00	5.26	0.00	0.00	0.00
MAAC	0.00	38.08	38.08	0.00	38.08
MAIN	0.00	69.84	69.84	0.00	78.54
MAPP	11.39	11.39	11.39	14.47	14.47
NPCC	0.00	0.00	0.00	0.00	0.00
SERC	48.10	0.00	0.00	61.11	0.00
SPP	0.00	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00	0.00
National	112.79	124.57	119.31	143.29	131.09

Table 5b. Imports (Billion kWh) for a given Transmission Expansion Rate

	Transmission Expansion Rate				
	1.2%			6.16%	
	Price	Baseload Cost	Fossil Cost	Price	Fossil Cost
ECAR	0.00	4.81	7.67	0.00	9.74
ERCOT	6.02	0.00	6.02	7.65	7.65
MAAC	5.99	0.00	0.00	7.61	0.00
MAIN	67.18	0.00	0.00	85.34	0.00
MAPP	0.00	0.00	0.00	0.00	0.00
NPCC	19.55	19.55	10.16	24.83	2.62
SERC	0.00	70.79	77.31	0.00	98.21
SPP	8.59	29.10	17.83	10.91	12.47
WSCC	5.47	0.32	0.32	6.95	0.40

MAIN, MAAC and MAPP with 65% of the additional generation for export coming from MAIN and MAPP. In these scenarios, the major importers are SERC, SPP and NPCC. These scenarios based on generating costs also result in more additional generation for export than the price-based scenarios. This additional generation occurs because MAIN, the major exporting region in this scenario, has substantially more uncommitted outbound transmission capability than do the regions that export the most when trading is based on differences in electricity prices.

The electricity exchanged between regions and the relative contributions of different regions to total power exports also depends on the rate of growth in transmission capacity. Indeed, Tables 5a and 5b show that when transmission capacity is assumed to grow at 6.16% per year instead of 1.2%, the total amount of additional electricity generated for export is greater under the price-based scenario than under the fossil cost-based scenarios. This reversal occurs because coal-fired generators in MAAC and MAIN, the two major exporting regions under the cost-based scenarios, reach their maximum capacity utilization factor before exhausting the larger capacity of outbound transmission lines.

Electricity Demand and Implications for Prices

The PREMIERE model executes all feasible profitable electricity trades subject to limits on transmission capability and on generating capacity. The impact on the environment of this increased electricity trading depends in part on how much of this additional electricity is being used to meet new demand. To repeat, our benchmark assumption is that one third of imported power is being used to meet new demand.

One way to evaluate this assumption is to use demand elasticity estimates from the literature to calculate the percentage change in electricity price implied by the assumed change in demand. The results of this exercise using an assumed demand elasticity of -0.3 are reported in Table 6 (Bohi and Zimmerman, 1984).

Table 6. Implied Percent Change in Price for a given Transmission Expansion Rate

	Transmission Expansion Rate				
	1.2%			6.16%	
	Price	Baseload	Fossil	Price	Fossil
ECAR	-----	-0.88	-1.42	-----	-----
ERCOT	-2.36	-----	-2.36	-3.00	-1.79
MAAC	-2.30	-----	-----	-2.91	-3.00
MAIN	-28.45	-----	-----	-36.15	-----
MAPP	-----	-----	-----	-----	-----
NPCC	-7.15	-7.15	-3.73	-9.09	-----
SERC	-----	-8.58	-9.36	-----	-0.97
SPP	-2.70	-9.18	-5.61	-3.45	-11.88
WSCC	-0.85	-0.06	-0.06	-1.06	-3.94

These calculations suggest that the percentage change in electricity prices implied by our demand assumptions tends to be fairly moderate. In about 65% of the cases, the implied price change is 5 percent or less. The most notable exception occurs in MAIN where price would have to fall by 28 percent in our benchmark scenario to produce the assumed change in demand. While this change may seem large, it is comparable to the differences between regulated electricity prices and competitive electricity prices reported in Berkman and Griffes (1995). These authors suggest that competition could lead to a 31% electricity price decline in MAIN and price drops as great as 50% in New England.[23]

NO_x Emissions

The extent to which increased inter-regional power trading leads to additional NO_x emissions depends on which regions are exporting power and on whether or not imported power is being used to displace generation from existing dirty facilities in the importing region. The regional profile of additional NO_x emissions also varies depending on which regions are importing power and the extent of displacement of nuclear and coal-fired generation in the importing regions.

Looking across the columns of Table 7, we find NO_x emission impacts at the national level would be lower were some portion of imported electricity used to back out native coal generation instead of native nuclear generation in the importing regions. At one extreme, which includes our benchmark scenario, if 33% of imports were used for new demand and all of the remainder were used to back out existing nuclear generation (effectively our benchmark scenario) the sum of additional NO_x emissions across all regions would be 349,900 tons under a price-based scenario and 431,600 tons under a fossil cost-based scenario. (The same would result if 100% of imports were used to back out nuclear generation with no change in demand.) If, instead, the two-thirds of imports not serving new demand were used to back equal amounts of nuclear and coal-fired generation, another likely scenario, the sum of additional NO_x emission would be 213,000 tons under a price-based scenario and 316,500 under cost-based trading. This range of possible

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[23] See also footnote 14.

outcomes, including our benchmark scenario, encompasses what we feel are the most likely changes in national NO_X emissions in the year 2000 as a result of restructuring.

Table 7. National NO_x Emissions (Thousand tons)

Trading Scenario	Annual Transmission Expansion Rate	Allocation of New Generation			
		33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each of Nuclear and Coal	No New Demand, 33% Backing Out Nuclear, 67% Backing Out Coal	No New Demand, 100% Backing Out Coal
Price	1.2%	349.90	213.00	76.13	-58.72
Baseload Cost	1.2%	447.60	324.27	204.60	84.85
Fossil Cost	1.2%	431.60	316.50	201.40	88.07
Price	6.16%	444.50	270.60	96.71	-74.59
Fossil Cost	6.16%	478.90	353.80	228.80	105.60

For illustration, we consider other possibilities. For example, at the other extreme, if imports were used 100 percent to back out coal-fired generation with no change in demand, the change in national NO_x emissions would be -58,000 under a price based scenario and 88,070 tons under a fossil cost-based trading scenario.

As illustrated in Table 7, national NO_x emissions tend to be higher when MAIN is an electricity exporter (cost-based trading) than when MAIN imports electricity (as in our benchmark price-based trading scenario). This finding derives from the fact that MAIN has a substantially higher average NO_x emission rate at coal-fired facilities than any of the other NERC regions. If none of the additional generation for export were being used to displace existing fossil-fired generation in the importing region, total national emissions of NO_x would be 28 percent higher when MAIN is exporting than when MAIN is importing.[24] This difference between the two scenarios becomes even greater when importing regions, all of which have lower average NO_x emission rates than MAIN, use electricity imports partially to offset generation from existing coal-fired generators within the region.

Table 8 shows the regional distribution of changes in NO_x emissions. In the price-based scenarios, emissions would increase in ECAR, SERC and MAPP, while in the cost-based scenarios emissions would rise in MAIN, MAAC and MAPP. Regional emissions from exporting regions generally would be larger under the scenarios that allow for faster growth of transmission capacity than under those with slow growth. The one exception to this finding is MAAC which exhausts its excess coal generating capacity under the slow transmission growth scenario and, therefore, could not increase its generation for export even under the high transmission growth scenario.

Importing regions would see a decrease in NO_x emissions if some portion of the imported electricity were used to back out existing native coal-fired generation. Table 9 illustrates what happens to emissions when we assume that 33 percent of imported electricity is backing out existing coal-fired generation. The implications of these reduced emissions for air quality in the

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[24] Some portion of this increase is due to the fact that additional electricity is generated for export when MAIN is exporting than when it is not because of its ability to export more than it can import, according to current transmission capabilities. However, the average national emission rate for NO_x for additional coal-fired generation in the two scenarios contrasted here increases from .00310 tons per MWh when MAIN is importing to .00359 tons per MWh when MAIN is exporting.

importing and exporting regions depend on the extent to which these reductions can offset atmospheric transport of additional emissions from electricity-exporting regions.

Table 8. Change in NOx Emissions by Region (33% New Demand, 67% Backing out Nuclear) (Thousand tons)

	Annual Transmission Expansion Rate				
	1.2%			6.16%	
	Price	Baseload Cost	Fossil Cost	Price Cost	Fossil Cost
ECAR	178.40	0.00	0.00	226.60	1.46
ERCOT	0.00	15.95	0.00	0.00	0.00
MAAC	0.00	100.60	100.60	0.00	100.60
MAIN	0.00	289.50	289.50	0.00	325.60
MAPP	41.55	41.55	41.55	52.78	52.78
NPCC	0.00	0.00	0.00	0.00	0.00
SERC	130.00	0.00	0.00	165.10	0.00
SPP	0.00	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00	0.00

Table 9. Change in NOx Emissions by Region (33% New Demand, Nuclear, 33% Backing out Coal) (Thousand tons)

	Annual Transmission Expansion Rate				
	1.2%			6.16%	
	Price	Baseload	Fossil	Price	Fossil
ECAR	178.40	-5.47	-8.73	226.60	-11.08
ERCOT	-6.21	15.95	-6.21	-7.88	-7.88
MAAC	-5.38	100.60	100.60	-6.83	100.60
MAIN	-94.68	289.50	289.50	-120.30	325.60
MAPP	41.55	41.55	41.55	52.78	52.78
NPCC	-17.37	-17.37	-9.03	-22.06	-2.33
SERC	130.00	-65.03	-71.02	165.10	-90.22
SPP	-10.38	-35.17	-21.54	-13.19	-15.07
WSCC	-4.92	-0.28	-0.28	-6.25	-0.36

Atmospheric Transport and Air Quality

The source-receptor matrices presented in Tables 2 and 3 illustrate how an additional thousand tons of NO_x emissions during the summer in each region affects NO_x and nitrate concentrations in all regions.[25] Much of the policy debate about the air quality impacts of utility restructuring has focused on the effects of emissions from additional electricity generated for export in the Midwest on air quality in the Northeast and other downwind states. Table 2 indicates that summer NO_x concentrations in the Northeast NPCC region would be most affected by an additional unit of NO_x emitted in NPCC, MAAC or ECAR (listed in order of relative contribution per unit of emission) while concentrations of NO_x in the Northeast MAAC region would be most affected by an additional unit of emissions in MAAC, NPCC, ECAR and SERC.

Tables 10a and 10b illustrate that fossil cost-based trading when MAAC is an electricity exporter and NPCC an importer leads to substantially greater impacts on NO_x and slightly greater impacts on nitrate concentrations in the Northeast (MAAC and NPCC combined) than does price-based trading when both MAAC and NPCC are power importers. Under this latter scenario, most of the additional generation is coming from the neighboring SERC and ECAR regions which have much smaller impacts on NO_x concentrations in the Northeast and somewhat less reduced impacts on nitrate concentrations there than does generation in MAAC and NPCC.

[25] As noted, NO_X emissions contribute to ozone formation. We display results for summer because nonattainment of air quality standards for ozone is largely a summer problem and this may be of interest to some readers.

Table 10a. Change in Average Summer Concentrations of NO_X for MAAC and NPCC combined attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading: Transmission Expansion Rate 1.2%	Price-Based Trading: Transmission Expansion Rate 6.16%	Fossil Cost-Based Trading: Transmission Expansion Rate 1.2%	Fossil Cost-Based Trading: Transmission Expansion Rate 6.16%
ECAR	22.23	28.23	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	62.31	62.31
MAIN	0.00	0.00	3.10	3.49
MAPP	0.24	0.30	0.24	0.30
NPCC	0.00	0.00	0.00	0.00
SERC	1.78	2.26	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	24.25	30.79	65.65	66.10

Table 10b. Change in Average Summer Concentrations of Nitrates (NO_3/HNO_3) for MAAC and NPCC combined attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading: Transmission Expansion Rate 1.2%	Price-Based Trading: Transmission Expansion Rate 6.16%	Fossil Cost-Based Trading: Transmission Expansion Rate 1.2%	Fossil Cost-Based Trading: Transmission Expansion Rate 6.16%
ECAR	14.16	17.99	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	13.99	13.99
MAIN	0.00	0.00	7.20	8.10
MAPP	0.72	0.91	0.72	0.91
NPCC	0.00	0.00	0.00	0.00
SERC	2.08	2.64	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	16.96	21.54	21.91	23.00

(*assuming 33% of imports for new demand and 67% backing out existing nuclear)

The impact of accelerated expansion of transmission capacity on NO_x and nitrate concentrations in the Northeast is greater under price-based trading than under cost-based trading. Under the latter, the MAAC region reaches its coal-fired generating capacity limits at the lower rate of transmission capacity growth, and therefore, is unable to increase its production for export using existing coal-fired facilities. Thus, a five-fold increase in the rate of growth of the transmission grid, which translates to a 27 percent increase in total transmission capacity in 2000, leads to a less than one percent change in the concentrations of NO_x and a less than five percent change in concentrations of nitrates in the Northeast. Tables 10c and 10d describe effects in the ECAR region, and 10e and 10f describe effects in the SERC region. Comparing these tables with 10a and 10b, we note that greater changes in concentrations of NO_X and nitrates would occur in our benchmark scenario in both ECAR and SERC than in the Northeast on average. (However, this ordering does not strictly hold if one examines changes in MAAC separately from NPCC.)

The changes in air quality concentrations that are calculated are uniformly small (measured in nanograms (1/1000 of a microgram)) in comparison to the National Ambient Air Quality Standard for PM-10 of 50 micrograms per cubic meter averaged annually. The total increase in PM-10 concentrations in the Northeast estimated in our benchmark, the shaded scenario, in Table 10b, is about 1/3000 of the national standard, that in the Ohio Valley (ECAR) in Table 10d is 1/2000 of the national standard, and that in the Southeast (SERC) in Table 10f is about 1/3000 of the national standard. The changes in emissions and air quality should be considered in the context of an expected *decrease* of over 2 million tons in annual NO_X emissions nationally that will result from full implementation of the 1990 Clean Air Act Amendments over the next few years. The increases in emissions that we estimate serve to undo a small portion of the expected improvement

Table 10c. Change in Average Summer Concentrations of NO_X for ECAR attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading		Fossil Cost-Based Trading	
	Transmission Expansion Rate		Transmission Expansion Rate	
	1.2%	6.16%	1.2%	6.16%
ECAR	145.40	184.80	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	14.34	14.34
MAIN	0.00	0.00	121.20	136.30
MAPP	10.06	12.78	10.06	12.78
NPCC	0.00	0.00	0.00	0.00
SERC	15.83	20.10	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	171.29	217.68	145.60	163.42

Table 10d. Change in Average Summer Concentrations of Nitrates (NO_3/HNO_3) for ECAR attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading		Fossil Cost-Based Trading	
	Transmission Expansion Rate		Transmission Expansion Rate	
	1.2%	6.16%	1.2%	6.16%
ECAR	19.53	24.80	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	3.08	3.08
MAIN	0.00	0.00	27.39	30.80
MAPP	2.98	3.79	2.98	3.79
NPCC	0.00	0.00	0.00	0.00
SERC	4.21	5.35	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	26.72	33.94	33.45	37.67

(*assuming 33% of imports for new demand and 67% backing out existing nuclear)

Table 10e. Change in Average Summer Concentrations of NO_X for SERC attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading		Fossil Cost-Based Trading	
	Transmission Expansion Rate		Transmission Expansion Rate	
	1.2%	6.16%	1.2%	6.16%
ECAR	13.97	17.75	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	2.05	2.05
MAIN	0.00	0.00	25.14	28.27
MAPP	2.80	3.55	2.80	3.55
NPCC	0.00	0.00	0.00	0.00
SERC	97.22	123.50	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	113.99	144.80	29.99	33.87

Table 10f. Change in Average Summer Concentrations of Nitrates (NO_3/HNO_3) for SERC attributed to source regions (ng/m^3)*

Source Region	Price-Based Trading		Fossil Cost-Based Trading	
	Transmission Expansion Rate		Transmission Expansion Rate	
	1.2%	6.16%	1.2%	6.16%
ECAR	4.47	5.68	0.00	0.00
ERCOT	0.00	0.00	0.00	0.00
MAAC	0.00	0.00	0.80	0.80
MAIN	0.00	0.00	7.73	8.69
MAPP	0.91	1.15	0.91	1.15
NPCC	0.00	0.00	0.00	0.00
SERC	12.77	16.22	0.00	0.00
SPP	0.00	0.00	0.00	0.00
WSCC	0.00	0.00	0.00	0.00
All Sources	18.15	23.05	9.43	10.64

(*assuming 33% of imports for new demand and 67% backing out existing nuclear)

in air quality that would occur otherwise. Nonetheless, the epidemiology literature suggests small changes in atmospheric concentrations of particulates generate measurable adverse health effects.

The seriousness of air pollution and health effects depends largely on the size of the exposed population. If air pollutant concentrations were to increase by the same amount in two regions, but one was more densely populated than the other, the adverse health effects would be greater in the more densely populated region. It is also possible for less polluted regions to experience more pollution-related illness by virtue of larger populations.

To provide a better understanding of the regional impacts of changes in emissions, we report estimates of the population weighted changes in air concentrations of NO_X and nitrates in Tables 11a and 11b. This measure of the magnitude of air quality impacts is composed of the change in atmospheric concentrations multiplied by a population weight reflecting the relative size of the exposed population in the region. The population weights sum to one. (If health effects were strictly linear then this measure would also be an indication of the relative change in health effects among regions.)

Tables 11a and 11b indicate that the regional air quality impacts resulting from increased trading differ across the two pollutants and across trading scenarios. Under price-based trading, our benchmark trading scenario, the region predicted to have the most persons experience the greatest adverse change in NO_x concentrations resulting from increased trading would be ECAR. Under cost-based trading which leads MAIN to export power, MAIN is the most adversely affected region in terms of increased exposure to NO_x resulting from power trading. For nitrates, ECAR always experiences the greatest exposure weighted changes in concentrations of all the regions.

Table 11a. Population weighted changes in concentration of NO_X ((regional pop/total pop) * ng/m^3) according to NERC region with Annual Transmission Expansion Rate of 1.2%.

	Price-Based Trading		Fossil Cost-Based Trading	
	33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each Nuclear and Coal	33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each Nuclear and Coal
ECAR	27.56	20.74	23.43	20.54
ERCOT	0.08	-0.90	0.14	-0.99
MAAC	5.81	3.57	14.74	13.11
MAIN	4.18	-5.73	31.28	30.03
MAPP	1.66	1.33	2.34	2.26
NPCC	3.07	-0.24	4.89	2.00
SERC	20.16	18.21	5.30	-3.91
SPP	0.85	-1.60	2.79	-0.05
WSCC	0.08	-0.68	0.08	-0.07

Table 11b. Population weighted changes in concentration of nitrates ((regional pop/total pop) * ng/m^3) according to NERC region with Annual Transmission Expansion Rate of 1.2%.

	Price-Based Trading		Fossil Cost-Based Trading	
	33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each Nuclear and Coal	33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each Nuclear and Coal
ECAR	4.30	2.70	5.38	4.69
ERCOT	0.05	-0.13	0.08	-0.12
MAAC	1.77	1.33	2.26	1.95
MAIN	0.74	-0.36	3.45	3.20
MAPP	0.24	0.15	0.35	0.30
NPCC	1.03	0.49	1.44	1.05
SERC	3.21	2.62	1.67	0.31
SPP	0.22	-0.21	0.57	0.15
WSCC	0.06	-0.26	0.07	-0.02

These findings are important for two reasons. First, they indicate that the primary constituency affected by simulated changes in emissions is not in the Northeast but instead is proximate to the emission source. This is particularly true for NO_X emissions. Second, they indicate that the Midwest is not homogenous. The Ohio Valley area (ECAR) would be strongly adversely affected by increases in emissions of nitrates in upwind areas of the Midwest (MAIN), as shown in the fossil cost-based trading scenarios of Table 11b. The only exception to this pattern occurs when ECAR is an exporting region and importing regions are using their imports completely to displace native coal-fired generation. In this case, net changes in air quality in ECAR are positive, as it is in many other regions including NPCC. MAIN also sees substantial improvement in air quality when it uses its imports either partially or completely to displace existing coal.

SERC also has a significant measure of population weighted adverse changes in NO_x and nitrate concentrations, except if that region imports power and some portion of that imported power is used to displace coal (shown in the last column of Tables 11a and b). If SERC was to import, and if one-third of the imported power was used to displace coal, then SERC would enjoy improvements in NO_x concentrations as a result of inter-regional trade as shown in the last column of Table 11a.

Emissions of CO_2

The implications of the different trading scenarios for additional CO_2 emissions also depend on both the amount of additional electricity generated under each scenario and on the extent to which imported power backs out electricity generated by coal-fired generators in the importing region. However, total CO_2 emissions are less sensitive to regional differences in generation activity than are NO_x emissions because average CO_2 emission rates vary little across regions.

The findings reported here suggest that if power imports are used largely or exclusively to displace existing nuclear generation in importing regions, the consequences for increased CO_2 emissions could be quite large. Indeed, if transmission capacity grows at the faster of the two rates analyzed here (6.16%), additional CO_2 emissions could equal fifty percent of the reductions needed by the year 2000 under the Climate Change Action Plan. On the other hand, if power imports were being used entirely to displace existing coal-fired generation, there would be only small impacts on CO_2 emissions.

Table 12. National Additional CO_2 Emissions (Million tons)

Trading Scenario	Annual Transmission Expansion Rate	Allocation of New Generation			
		33% New Demand, 67% Backing Out Nuclear	33% New Demand, 33% Backing Out Each of Nuclear and Coal	No New Demand, 33% Backing Out Nuclear, 67% Backing Out Coal	No New Demand, 100% Backing Out Coal
Price	1.2%	113.50	75.11	36.67	-1.19
Baseload Cost	1.2%	126.90	85.01	43.07	1.75
Fossil Cost	1.2%	121.30	81.28	41.27	1.86
Price	6.16%	144.20	95.41	46.59	-1.51
Fossil Cost	6.16%	133.90	89.69	45.52	2.01

V. CONCLUSION

The long-run environmental consequences of electricity restructuring are difficult to predict today. However, industry observers generally agree that allowing greater access to the transmission grid is likely to increase generation and, therefore, emissions of NO_x and CO_2 from existing Midwestern coal-fired generators, especially in the early years of open transmission access and more competitive electricity markets. Our analysis is consistent with these predictions.

Under the scenarios that we think most likely, we find annual emission increases of between 213,000 and 478,900 tons for NO_X, which illustrates the range and uncertainty of the outcome. Our benchmark estimate is 349,900 tons, about midpoint in this range. We find annual increases of between 75 and 133.9 million tons for CO_2 in the year 2000, with a benchmark estimate of 113.5 million tons. These findings are summarized in Table 13, and compared with the results of previous studies. (The features of these studies are compared in Table 1.)

Table 13. Comparison of Benchmark Findings of Air Quality Effects of Restructuring

	FERC EIS*	**CCAP**	**Rosen, *et al.***	**Lee and Darani**	**Palmer and Burtraw**
Annual Emissions Change	national	AEP only	national	national	national
NO_x (thousand tons)	71 - 127.6	36 - 127	896	492	349.9 (112 - 478.9)
CO_2 (million tons)	2.8 - 27.9	9 - 30	327	42.9	113.5 (75 - 133.9)

* The FERC EIS considers only the effects of Open Transmission Access resulting from Order 888.

Our estimate of changes in NO_X emissions are less than other studies, with the exception of the FERC EIS, primarily because we explicitly take into account capacity constraints on inter-regional transmission and use lower emission rates. Our estimate is greater than the FERC EIS because we allow for a significant portion of the power generated for inter-regional transmission to meet new demand stimulated by an anticipated decline in price. Second, we allow for importers of power to back out their highest cost nuclear generation, rather than fossil baseload. If there is little change in price, and imported electricity is allocated to back out fossil fuel generation in the importing region, the environmental consequences of restructuring are likely to be slight. On the other hand, if consumers successfully vie for a share of the cost savings from inter-regional transmission and electricity prices fall, an outcome we think likely, then we would expect to see a significant increase in demand. Further, utilities may respond to competitive pressures by backing out high cost nuclear power first. These are important changes in economic behavior that we believe will characterize a more competitive electricity industry, which point toward potentially more significant environmental consequences than recognized in the FERC EIS.

To summarize the key features of our analysis, the model assumes new generation exhausts sustainable inter-regional transmission capacity, which we expect to grow at least at historic rates. We expect the relative magnitude of variable generation costs to determine the location of new generation and the direction of power trading. In our benchmark scenario, we adopt differences in retail prices as a proxy for relative costs. We model all new generation as coming from existing coal facilities, with emission rates equal to current regional averages. We assume that one-third of new generation for inter-regional transmission will be allocated to new consumer demand stimulated by changes in price, with the rest going to displace higher cost baseload generation which in every region is nuclear.

We report results for alternative scenarios that we think bound the range of likely outcomes. The most sensitive features (and the direction of the potential bias they impart on our benchmark scenario) include the rate of growth in transmission capacity (-), the use of relative price as a proxy for relative cost (-), and the assumption that new generation backs out nuclear power in large part (+). Because we focus on increased generation from coal facilities, we characterize our findings as a worst case outcome under restructuring; however, we also think that on balance, our benchmark case describes the most likely result of increased competition resulting from industry restructuring over the next few years.

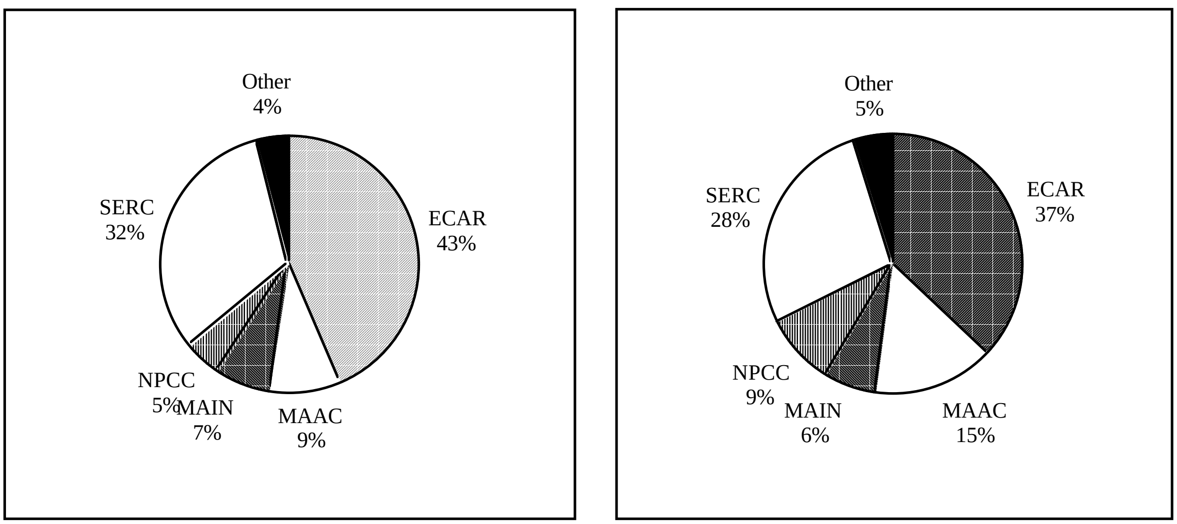
Our analysis of alternative scenarios to our benchmark scenario yields considerable variation in the predicted levels of emissions and where they occur. This leads us to offer these results with caution. One of our most important conclusions is that this analysis leads us to have even less confidence in the outcomes of previous studies, including the FERC EIS, because of the sensitivity of results to the variety of factors that we think important.

Another important conclusion involves the regional distribution of adverse changes in air quality that may result from restructuring. Most attention in the public debate has focused on possible adverse effects in the Northeast stemming from increased generation at facilities in the Midwest. Although such adverse effects in the Northeast are a possibility, they are relatively small compared to the effects in the Midwest proximate to the source of emissions. Indeed, we find the greatest concern about changes in air quality should involve air quality in the Midwest.

The relative burden of adverse changes in air quality weighted by the exposed population is illustrated in the pie graphs in Figures 2a and 2b. These graphs depict our estimates of air quality changes for NO_X and nitrate concentrations in our benchmark scenario. The figures compare these changes at a regional level, taking variations in population into account. The portion attributable to each region is calculated by taking the change in atmospheric concentration per cubic meter, multiplying it by the population in each region, and dividing by the sum of measures for all regions so the values total to 100%. The result is a comparison of the adverse change experienced by the exposed population in each region.

Figure 2: Relative regional burden for population weighted change in atmospheric concentrations.

Panel A: NO_X **Panel B: Nitrates**



In both cases, for NO_X and nitrates, we find the population of the Ohio Valley region (ECAR) will experience the largest share of adverse environmental effects, followed closely by the population of the southeast (SERC). In contrast, persons in the Northeast (NPCC) and Mid-Atlantic (MAAC) regions bear a much smaller portion of the environmental effects. We emphasize that these results are for our benchmark scenario, and the magnitude of the air quality impacts as well as the relative regional burden of those impacts vary with the assumptions of our analysis.

It is also important to note, however, that those effects are small in all locations. The actual changes in pollutant concentrations we estimate represent only about 1/2000 or 1/3000 of the air quality standards for the relevant pollutants. Nonetheless, health epidemiology suggests that small changes in atmospheric concentrations of particulates generate measurable adverse health effects.

In sum, a significant possibility exists that restructuring will have an important impact on the environment, especially in some regions of the country. If this environmental impact merits a policy response, the wide range of potential environmental consequences reflected in this analysis as well as in previous studies highlights the need for flexibility. Amendments to present environmental policy to address these potential consequences should be designed so they will not impose costs on the basis of adverse changes that may not materialize.

We suggest the proper policy response over this period of transition in the industry should involve a cap and trade program for NO_X emissions from the electricity industry that would be impose NO_X emission caps at a regional level to ensure that electricity restructuring does not lead to significant environmental degradation in any particular region. Such a program could be similar to one already being developed by EPA and state governments within the Northeast Ozone Transport Region, extending from Maryland and the District of Columbia north to New England and as far west as Pennsylvania, to reduce the contribution of NO_x emissions within the Northeast to ground-level ozone problems in that region. This program would involve trading of NO_x emission allowances among utilities and large industrial sources of NO_x throughout the multistate region. A similar intra-regional testing program might be implemented within the Midwestern regions affected by restructuring. However, to the extent that total NO_X emissions from Midwestern states (not just those emissions resulting from additional electricity trading) are contributing to ozone and other air pollution problems in the Northeast, then a carefully designed inter-regional trading program encompassing both Midwestern and Northeastern states may be the most cost-effective way to achieve attainment of air quality goals. Any industry-specific approach should be eclipsed if a more comprehensive program can be implemented by EPA that would permit cost savings from inter-state and inter-industry trades.

Policies for addressing changes in CO_2 emissions also should follow this mold. A flexible approach such as cap-and-trade would provide incentives for utilities to invest in the most cost effective means of stabilizing CO_2 emissions. Also, it may provide a vehicle for the maintenance of existing state programs promoting demand side management, conservation, and renewable energy that Lee and Darani (1995) and others note are likely to suffer in a restructured industry.

Our analysis highlights several important areas for further research. First, the amount of available inter-regional transmission capacity and the rate of growth in that transmission capacity will be central factors in determining the environmental consequences of restructuring. In addition, anticipating how electricity prices will change as a result of more open transmission access and more competitive electricity markets is important to predicting the resulting change in consumer demand. Finally, understanding of how a more competitive industry will affect utilization of existing resources, especially dispatch of nuclear facilities, is important to understanding the effects of restructuring on the environment.

To improve the PREMIERE model, we intend to incorporate more disaggregate information about plant characteristics within each region. However, perhaps the more important focus is to improve the understanding of the economic processes including effects on consumer demand and incentives for investment in transmission and new generation. This focus is largely overlooked in the engineering-based models that constitute most of the existing literature. This paper shows they are extremely important to the environmental consequences of restructuring over the next few years.

APPENDIX A

Key Omissions, Biases and Uncertainties Affecting Estimates of the Level of Additional National NO_x Emissions in Our Benchmark Scenario

Omissions/ Uncertainties/ Biases	Effect	Comments
Transmission		
Quantity of trade depends on available transmission capacity.	**+**	To the extent there are periods of time when transmission capacity is slack this overstates changes in generation and emissions.
Derating of transmission capacity by 25%.	**-**	The purpose of derating is to capture limits on simultaneous use of the grid. Some observers have suggested this derating is too high, implying emissions estimates are biased downward.
Transmission capacity growth at historic rates.	**-**	If, as a result of its increased scarcity value, the effective capacity grows faster in a restructured world, our estimates of changes in emissions will be too low.
Focus on changes in inter-regional transmission only.	**?**	To the extent restructuring opens up the grid within NERC regions there will be incentives for changes in generation beyond the scope of our model.
New Generation		
Direction of trade, and location of new generation, depend on differences in average electricity price as proxy for relative cost.	**-**	Direction of trade is very sensitive to proxy for relative cost. When the direction of trade is based on differences in operating cost estimates from our sample of plants, total emissions are higher.
Small sample of cost data in our alternative scenario.	**?**	
Use of regional averages in price and cost-based scenarios.	**?**	Use of actual distributions would likely reverse the direction of trade during some load periods, with unknown effects on emissions.
Assumption of flat supply curves for power in exporting regions.	**+**	The use of regional average cost or price data implies a flat supply (and demand) curve for imported power. If the supply curve is upward sloping, then power exports may be smaller.
SO_2 permit trading program imparts opportunity costs on coal utilization.	**?**	SO_2 permit costs are small compared to variation in the relative price of fuels, and will have a small effect on technology choice. This opportunity cost discourages an increase in utilization of coal facilities in exporting regions; but it also encourages a decrease in coal utilization in importing regions.

Assumption of maximum capacity factor of 80% in 1995 with growth rate of 0.5% per year.	**?**	
Supply and Demand		
Use of imports to back out nuclear.	**+**	To the extent imports are used to back out coal generation in the importing region, the net emissions effects would be lower.
No change in investment.	**?**	If imports crowd out investment and extend plant lifetime, then we understate emission changes. If new facilities are significantly less expensive with restructuring, investment will be expedited leading to less emissions.
Effect of restructuring on electricity demand.	**?**	Greater increases in demand lead to greater generation and overall emissions.
Net Emissions		
Use of regional average utilization rates.	**?**	We expect changes in generation to come from plants with lower than average utilization rates.
Use of regional average emission rates.	**-**	Emission rates are expected to vary with vintage of plant as well as with the extent to which the plant is subject to local controls. We expect plants brought into greater production to be older, less efficient, and to have higher than average emission rates.
Use of 1994 emission rates data.	**+/-**	These data capture Phase 1 Title IV NO_X controls but not Phase 2 controls which remain uncertain. They do not reflect the Northeast Ozone Transport Region Memorandum of Understanding. To the extent coal is backed out in this region, then by overestimating emission rates our alternative scenario underestimates net emission changes.
Air Quality		
Reduced form atmospheric modeling	**?**	
Overall Impact	**?**	These issues appear to be offsetting in general, providing justification for our benchmark scenario. The large number of uncertainties reinforce our caution in adopting a single prediction, preferring a range of outcomes. They also argue for a flexible policy response.

APPENDIX B

Illustration of Health Effects

The health effects component of PREMIERE maps changes in atmospheric concentrations of the relevant pollutants into predicted changes in human morbidity and mortality. The model is based on a computer program maintained by Alan Krupnick at Resources for the Future (Krupnick 1995). Health effects are estimated using a model of nine morbidity endpoints and mortality. The only health endpoint related to NO_x concentrations *per se* involves days on which individuals report difficulty with phlegm (or "phlegm days"). Other endpoints are the consequence of secondary particulate formation (PM-10).[26]

PREMIERE includes only selected health effects, listed in Table B-1, associated with changes in concentrations of NO_x and nitrates. Therefore, our simulations do not present a comprehensive picture of all the ways in which increased pollution from additional electricity generation might impact human health in the different regions. The model also is capable of calculating the health effects from changes in SO_2 and sulfates, but these are excluded due to the role of the SO_2 allowance trading program.[27] Notably absent is an estimate of changes in ozone. However, evidence from many epidemiological analyses of air pollution indicates that fine

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[26] The epidemiology model we employ assumes that acidic aerosols contribute toward health effects just as would all other particulates, rather than a competing possibility that they play the most important role as a constituent of particulate matter. Our assumption is conservative in that it lessens the health effects attributable to nitrates. Also, we assume there is no threshold below which there would be no health effects from particulates, in contrast with the competing possibility of a positive threshold for particulate concentrations below which no health effects occur. This second assumption increases the health effects attributable to nitrates compared to an assumption of a positive threshold.

[27] The SO_2 allowance trading program caps national emissions of SO_2 from all electricity generators by the year 2000. In order to increase SO_2 emissions above historical levels generators would have to buy allowances from other facilities that plan to reduce their emissions. Therefore, we would need to predict which facilities will be selling allowances to the purchasing generators in order to identify regions where SO_2 emissions are likely to fall.

particles are the overwhelmingly predominant source of morbidity and premature mortality. For that reason, omitting ozone from our analysis is not likely to bias our findings as much as one might think. In addition, the set of included health effects we do consider provide a reasonable proxy of the regional patterns, if not the full magnitude, of likely health effects of changes in emissions associated with changes in electricity generation.

Table B-1: Estimated health effects from changes in NO_x emissions.

Phlegm Days	(NO_x)
Asthma Attacks	(PM-10)
Adult Chronic Bronchitis	(PM-10)
Child Chronic Bronchitis	(PM-10)
Emergency Room Visits	(PM-10)
Restricted Activity Days	(PM-10)
Respiratory Symptom-days	(PM-10)
Respiratory Hospital Admissions	(PM-10)
Child Chronic Coughs	(PM-10)
Mortality Risks	(PM-10)

The health effects listed in table B-1 are valued using willingness-to-pay estimates reported in the recent literature in environmental and health economics based on a variety of valuation techniques (Austin, *et al.*, 1995). The estimated values are presented in Tables B-2a, b and c. Since only a subset of potential health effects are included, the reported values are not meant to represent a complete measure of the environmental costs of increased power trading in a restructured industry. We are cautious in reporting valuation estimates because it invites a misleading comparison with consumer benefits from electricity restructuring. Nevertheless, the values do represent the likely relative change experienced among regions. Also, with the exclusion of the contribution of NO_X to ozone formation, these values do provide a useful means

Table B-2a. Valuation of Estimated (Partial) Health Damages (Cost in Millions of $) with Annual Transmission Expansion Rate of 1.2% by Trading Scenario.

	Price-Based Trading			Fossil Cost-Based Trading		
	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal
ECAR	36.58	22.97	-3.46	45.79	39.61	27.60
ERCOT	0.41	-1.08	-3.97	0.70	-1.03	-4.40
MAAC	15.07	11.35	4.15	19.29	16.80	11.98
MAIN	6.30	-3.06	-21.22	29.33	27.13	22.86
MAPP	2.03	1.30	-0.12	2.99	2.58	1.79
NPCC	8.81	4.13	-4.95	12.25	9.97	5.54
SERC	27.32	22.28	12.49	14.20	1.41	-23.43
SPP	1.90	-1.79	-8.97	4.79	1.21	-5.76
WSCC	0.49	-2.18	-7.36	0.56	-0.17	-1.59

Table B-2b. Valuation of Estimated (Partial) Health Damages (Cost in Millions of $) with Annual Transmission Expansion Rate of 6.16% by Trading Scenario

	Price-Based Trading			Fossil Cost-Based Trading		
	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal
ECAR	46.46	29.17	-4.39	51.56	44.63	31.18
ERCOT	0.52	-1.37	-5.05	0.81	-0.96	-4.39
MAAC	19.14	14.42	5.27	20.36	17.74	12.66
MAIN	8.01	-3.88	-26.96	33.55	31.69	28.06
MAPP	2.58	1.65	-0.16	3.65	3.31	2.66
NPCC	11.20	5.25	-6.29	13.24	11.66	8.61
SERC	34.71	28.30	15.86	16.02	0.75	-28.89
SPP	2.42	-2.28	-11.39	5.52	2.32	-3.91
WSCC	0.62	-2.77	-9.35	0.69	0.03	-1.27

Table B-2c. Per Capita Valuation of Estimated (Partial) Health Damages with Annual Transmission of Expansion Rate 1.2% by Trading Scenario.

	Price-Based Trading			Fossil Cost-Based Trading		
	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal	33% New Demand, 67% Backing Out Nuclear	33% New Demand,33% Backing Out Each of Nuclear and Coal	No New Demand, 100% Backing Out Coal
ECAR	0.83	0.52	-0.08	1.04	0.90	0.63
ERCOT	0.03	-0.07	-0.25	0.04	-0.07	-0.28
MAAC	0.73	0.55	0.20	0.93	0.81	0.58
MAIN	0.35	-0.17	-1.17	1.61	1.49	1.26
MAPP	0.16	0.10	-0.01	0.24	0.20	0.14
NPCC	0.27	0.13	-0.15	0.38	0.31	0.17
SERC	0.56	0.46	0.26	0.29	0.03	-0.48
SPP	0.09	-0.08	-0.41	0.22	0.06	-0.26
WSCC	0.01	-0.04	-0.12	0.01	0.00	-0.03

of comparing across regions the extent of a wide range of important adverse health effects associated with increased emissions of NO_X.[28]

The values reported in Tables B-2a, b and c reveal some interesting findings. First, the region predicted to experience the largest health impacts resulting from increased trading is generally ECAR, in similar fashion to the population weighted health effects reported in the text. The one exception occurs when ECAR is an exporting region and importing regions upwind from ECAR, primarily MAIN, are using their imports completely to displace native coal-fired generation. In this case, net impacts on health in ECAR is positive, as it is in many other regions including NPCC. The

[28] The estimates of health effects for electricity exporting regions may be overstated due to our inability to account for the local ozone-scavenging effects of increased NO_x emissions.

monetary value of adverse health effects in SERC also tends to be quite large except when that region is a power importer and some portion of that imported power is being used to displace coal. Indeed, if SERC is importing, and if all of the imported power is being used to displace coal, then SERC could enjoy substantial health benefits from inter-regional power sales. MAIN also sees substantial health benefits when it uses its imports completely to displace existing coal.

In general the estimated dollar value of the adverse health damages in the two Northeastern regions (NPCC and MAAC) combined tends to be less than in ECAR alone. In our benchmark scenario, the estimated health effects per capita for the exposed population are 84 percent greater in ECAR than the average for the Northeast (NPCC and MAAC combined). Within the Northeast, the per capita effects in the Mid-Atlantic region (MAAC) are almost three times as great as in New York and New England (NPCC). Allowing for an accelerated rate of growth in transmission capacity would lead to substantially higher health damages in the Northeast when MAAC is generating power (price-based trading) than when it is not (fossil cost-based trading).

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