Time and Location Differentiated NO_X Control in Competitive Electricity Markets Using Cap-and-Trade Mechanisms*

Katherine C. Martin, Paul L. Joskow, A. Denny Ellerman

April 16, 2007

MIT

Abstract

Due to variations in weather and atmospheric chemistry, the timing and location of nitrogen oxide (NO_X) reductions determine their effectiveness in reducing ground-level ozone, which adversely impacts human health. Electric generating plants are the primary stationary sources of NO_X in most regions of the United States. In the Eastern U.S. they are subject to a summertime NO_X cap and trade program that is not well matched to the time and locational impacts of NO_X on ozone formation. We hypothesize that the integration of weather and atmospheric chemistry forecasting, a cap and trade system in which the "exchange rates" for permits can be varied by time and location based on these forecasts, and its application to a competitive wholesale electricity market, can achieve ozone standards more efficiently. To demonstrate the potential for reductions in NO_X emissions in the short run, we simulate the magnitude of NO_X reductions that can be achieved at various locations and times as a consequence of redispatch of generating units in the "classic" PJM region taking supply-demand balance constraints and network congestion into account. We report simulations using both a zonal model and an optimal power flow model. We also estimate the relationship between the level NO_X emission prices, competitive market responses to different levels of NO_X prices, and the associated reductions in NOx emissions. The estimated maximum potential reductions, which occur at NO_X prices of about \$125,000/ton, are about 8 tons (20%) hourly in peak electricity demand hours and about 10 tons (50%) in average demand hours. We find that network constraints have little effect on the magnitude of the reductions in NO_X emissions.

---

* Katherine C. Martin is a candidate for a Ph.D. in Technology, Management, and Policy from the Engineering Systems Division at the Massachusetts Institute of Technology (MIT) (corresponding author: martink@mit.edu), Paul L. Joskow is the Elizabeth and James Killian Professor of Economics and Management and Director of the Center for Energy and Environmental Policy Research (CEEPR) at MIT, and A. Denny Ellerman is a Senior Lecturer with the Sloan School of Management at MIT. Funding for the research reported in this paper has been provided jointly by the U.S. Environmental Protection Agency (EPA) and the National Oceanic and Atmospheric Administration (NOAA) of the U.S. Department of Commerce under NOAA Contract No. DG1330-05-CN-1308, as well as by MIT's CEEPR. The authors are indebted to a number of useful comments and for encouragement in response to presentations of aspects of this work at EPA, NOAA, the PJM Interconnection, and at the Energy and Environmental Policy Workshops of MIT CEEPR, the Institut d'Economie Industrielle, "Conference on Energy Markets" in Toulouse, France, and the MIT Industrial Organization Workshop. The authors would especially like to thank Mark Gilrain and Andrew Ott at PJM and Nathan Lang and Andrew Stevens at DC Energy for their useful advice and assistance. The usual disclaimer applies.

Section 1. Introduction

The generation of electricity accounts for a large fraction of the nitrogen oxide (NO_X) emissions from stationary sources in the United States. The effects of nitrogen oxide emissions on the formation of ground-level ozone (O_3) vary over time and location due to fluctuations in weather and atmospheric chemistry (see, for example, Tong 2006). Moderate and high concentrations of ground-level ozone detrimentally affect public health (Bell *et. al*. 2004, U.S. EPA 2006a). Hence, when NO_X emissions contribute to elevated levels of ozone, public health is damaged; however, the marginal damages of NO_X emissions vary with the location of the source and the time of emissions as a consequence of variations in weather, atmospheric chemistry, and exposure. The population's exposure to ozone, and thus the damages caused by it, also depends on demographics, which vary geographically, and on winds that sometimes carry pollution from rural areas downwind to densely populated ones.

The environmental economics literature recognizes that the regulation of environmental externalities should address time and locational variations in marginal damages of pollutants.[1] In practice, however, environmental regulations have tended to ignore such variations. Conventional environmental regulation typically requires sources to adopt a specific emissions control technology or to place a limit on their emission rates. These regulations may be spatially differentiated, although frequently they are not, but in all cases the constraint on emissions is invariant during the year. More recently, the use of market-based, cap-and-trade programs has increased but these are generally based on annual emissions caps (with and without "banking" of emissions permits to future years). One notable exception is the United States NO_X Budget Program (and its predecessor Ozone Transport Commission (OTC) or Northeastern Budget Program) that applies only during the summer months when ozone formation is a problem in the Northeastern United States. While an improvement over an annual program for ozone

[1] Montgomery (1972) discusses the potential need for "ambient permits". Following him, Mendelsohn (1986) discusses the need to treat emissions as heterogeneous when their marginal damages (on health or the environment) warrant such treatment. See Tietenberg (1995) for a summary.

control in the Northeast, this program fails to differentiate at the fine temporal and locational resolution that would be appropriate for this pollutant in an ideal world.

The literature has called for a more finely differentiated regulation of NO_X emissions to address the temporal and locational variation in the contribution of NO_X to ozone formation and associated damages to human health and welfare (Chameides *et. al.* 1988, Ryerson *et. al.* 2001, Mauzerall *et. al.* 2005, and Tong *et. al.* 2006). But these studies do not discuss how such a program could be implemented. The difficulties associated with implementing conventional regulations that explicitly deal with the variable impacts of emissions are a central reason why these impacts are typically not addressed (e.g., Tietenberg 1995).

We hypothesize that four recent developments now make it possible to implement a regulatory system that takes better account of time and locational variations in the impact of NO_X emissions on ambient air quality and on human health and welfare. The four developments are improved weather and air quality forecasting, hourly emissions monitoring equipment that has already been placed on large stationary sources of NO_X, the potential to vary redemption ratios in cap-and-trade programs in time and space, and the existence of liberalized wholesale day-ahead and real time electricity markets that are based upon a security-constrained, bid-based dispatch and locational electricity prices that vary to reflect the marginal cost of production (including the price of emissions allowances bought and sold through a cap and trade system) and the marginal costs of congestion and of losses. We also hypothesize that taking advantage of these developments to implement a more finely differentiated regulatory system would achieve ozone ambient air quality standards more cost effectively than would further reductions in annual or seasonal limits on NO_X emissions from electric generators. Higher costs would be imposed only during the relatively small number of days and hours when the ozone standards are now exceeded at a relatively small number of locations instead of over a broad region throughout the year or season.

The research reported in this paper is part of a larger project to evaluate the feasibility of such a time and location differentiated cap and trade system for controlling NO_X emissions. Here, we examine one of the necessary conditions for such a system: that generators would have sufficient flexibility to reduce NO_X emissions more than trivially if faced with higher NO_X prices on relatively short notice on hot summer days when ozone formation is a problem. This inquiry is motivated by a commonly held misperception that there exists little capability to reduce NO_X emissions at the relevant times because of the near full utilization of all available generating capacity and the higher likelihood of transmission congestion associated with summertime days with high electricity demand. These conditions could limit opportunities to substitute electricity from low-NO_X emitting generators for electricity from high-NO_X emitting generators. If such substitutions were not possible, the higher NO_X price would not lead to significant NO_X reductions and only affect the level and distribution of locational prices for electricity.[2] In addition, there is the concern that reductions in one or several areas would create "hot spots" or higher NO_X emissions in another area.

Our findings suggest that these arguments are misplaced. We find that there is considerable heterogeneity in the emission rates and variation in commitment among generators at proximate locations, even during peak-demand periods. This creates the opportunity for economic incentives and wholesale electricity market mechanisms to induce redispatch of generators to decrease NO_X emissions, and to do so on a local scale that reduces transmission problems and avoids hot spots. Heterogeneity in emission rates is often overlooked because models of NO_X emissions from power plants typically use emission rates that aggregate over region, month, and rarely by time of day or in response to specific operating conditions. This type of aggregation does not capture the full range of variation in power plant utilization and in heterogeneity of emission rates.

Moreover, the complex relationship between NO_X emissions, temperature, and atmospheric conditions and chemistry means that there can be a time lag between when NO_X emissions actually take place and when they impact the formation of ozone at various downwind locations. For example nocturnal low-level jets (or nighttime winds)

[2] Of course, this argument also ignores the potential effects of higher prices for NO_X emissions on the demand for electricity as it is affected by variations in electricity prices. Since few consumers presently are charged their locational prices for electricity we leave this issue for further research and focus on the supply side in this paper. However, we want to make it clear that as demand response programs mature, higher spot electricity prices reflecting higher NO_X prices during critical ozone formation periods will reduce the demand for electricity and the quantity of electricity that is required to meet it, further reducing NOx emissions from what can be achieved by working with the supply-side alone. This is another potential benefit of time and locationally differentiated NO_X prices.

are common in the Eastern U.S. and these can carry ozone and its precursors from the Southern and Central East coast to the Northeastern states (see research summarized by U.S. EPA 2006a, page 2-10). Thus, in some situations, reductions in nighttime NO_X emissions will do more to mitigate peak ozone concentrations than reductions in daytime emissions; hence the use of large portions of generating capacity to meet peak demand on hot afternoons is not necessarily a constraint on the ability to redispatch generating units to reduce the NO_X emissions with the most impact on ozone formation. In addition, generators appear to have some control over the NO_X emissions rates of their generating units by changing the utilization of existing NO_X control equipment, by changes in boiler combustion attributes and through fuel switching. In the longer run, time and locational differentiated NO_X prices can affect investments in NO_X control equipment, boiler and turbine equipment.

In this paper we focus primarily on potential generator redispatch to reduce NO_X emissions in response to time varying NO_X emissions prices. Specifically, we report on our initial efforts to simulate the *potential* magnitude of reductions in NO_X emissions in the "Classic" PJM[3] area that can be achieved at various locations at critical times as a consequence of redispatch of generating units while still meeting electricity demand and transmission network constraints with available generating capacity. The simulations use recent historical data on generation, network congestion and NO_X emissions for fossil-fueled generators located in this area. We used both a simplified zonal model and a security-constrained optimal power flow (SCOPF) model of the Classic PJM network to perform the simulations. We find that there are significant physical opportunities to reduce NO_X emissions without violating transmission network constraints or the constraint that supply and demand are balanced in real time.

We also present preliminary order-of-magnitude estimates of the level of NO_X emissions prices that would be needed to induce redispatch to achieve various levels of NO_X reduction within the physically feasible set, assuming that NO_X prices are

[3] We define "Classic" PJM as generating units located primarily in Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia. The PJM system operator also refers to this area as PJM-East and Mid-Atlantic PJM. In the last few years PJM's footprint has expanded to include portions of West Virginia, Virginia, Ohio and Illinois.

incorporated into generators' bids. These estimates are also performed using a simplified zonal model and a more refined optimal power flow model and rely on simplified marginal generation cost-curves for the generating units in Classic PJM. We also provide a brief discussion of the potential for long run investment responses to NO_X prices of these magnitudes and the potential for using time and location differentiated NO_X prices to improve linkages between regulation governing stationary sources and market-based approaches to controlling NO_X emissions from mobile sources.

The next steps in our research will be to match the effect of these price-induced reductions in NO_X emissions on ozone concentrations. Then changes in ozone concentrations can be matched to estimates of marginal damages from the literature (e.g., Mauzerall *et. al.* 2005). This will enable us to evaluate the economic opportunities to use time and locational variations in emissions prices to take advantage of the physical opportunities to reduce NO_X emissions.

The remainder of this paper proceeds as follows. In Section 2 we briefly summarize background information on the ozone problem and policies that the Eastern U.S. states and the EPA have used to address it. We also show that some power plant operators vary emission rates per unit of output considerably during the summer ozone season (May through September) and that this abatement behavior does not correspond to periods of high ozone concentrations. We also describe our hypothesized time- and location-differentiated cap-and-trade program in greater detail. Section 3 describes the methods we used to simulate the potential reductions in NO_X emissions from redispatch. Section 4 discusses the results of the simulations and some implications for potential long run investment incentives for NO_X control equipment. The final section contains concluding comments.

Section 2. Background

Policy background

Ozone was officially recognized as a problem in 1970 when the U.S. Congress categorized it as one of six "criteria pollutants" in the Clean Air Act (CAA) of 1970.[4] The CAA mandated that the Environmental Protection Agency (EPA) set health-based National Ambient Air Quality Standards (NAAQS) for criteria pollutants and that the states develop State Implementation Plans (SIPs) to control source-specific emissions at levels that would ensure attainment of the NAAQS.[5] The EPA first set the standard for ozone in 1971 and revised it in 1997.[6]

Electric generating plants are the primary stationary sources of NO_X emissions and they contribute 97% of NO_X emissions from large stationary sources in the Eastern United States.[7] Mobile sources (cars and trucks) also produce significant NO_X emissions and have been subject to a variety of regulations on tailpipe emissions and the composition of gasoline they burn.[8] However, increases in miles driven have largely offset advances in controls affecting mobile sources (U.S. EPA 2003). This has left cap-and-trade programs for stationary sources as the primary mechanism policymakers have relied upon to achieve significant NO_X reductions in the Eastern states.[9]

The first of these programs was the Ozone Transport Commission (OTC) NO_X Budget Program, which began in 1999 and included eleven Northeastern states and the

---

[4] Congress identified criteria pollutants as those having the greatest effect on public health and welfare. The six criteria pollutants are NO_X, ozone, sulfur dioxide, lead, carbon monoxide, and particulate matter.

[5] CAA §108(a)(2) states: "Air quality criteria for an air pollutant shall accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of such pollutant in the ambient air, in varying quantities."

[6] The original ozone standard was that ozone concentrations could not exceed a 24-hour average of 0.12 parts per million more than once per year. The new ozone standard, set in 1997, is that the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations each year must not exceed 0.08 parts per million.

[7] Calculated from EPA Continuous Emissions Monitoring data at http://cfpub.epa.gov/gdm/.

[8] Mobile sources contribute about 59% of NO_X emissions in the Eastern states and stationary sources about 22% (U.S. EPA 2006b). Power plants emit about 97% of this 22% from stationary sources.

[9] Environmental regulators are presently discussing the application of tighter caps and/or technology standards for electric generators to reduce the number of days and hours when the ozone standards are not being achieved.

District of Columbia.[10] In 2004, this program was extended to an additional ten Eastern and Midwestern states in response to EPA's call for revision of State Implementation Plans (the "NO_X SIP Call") and it is now called the NO_X Budget Trading Program.[11] Both of these programs aim to reduce NO_X precursor emissions and the interstate transport of ozone from upwind to downwind areas in the Eastern United States. In being regional and seasonal, the initial Northeastern and later, extended NO_X Budget Programs make some recognition of the spatial and temporal variability in the effect of NO_X precursor emissions on ozone formation, but the differentiation is very coarse.

The extended NO_X Budget Program has brought two-thirds of the previously non-attainment areas in the Eastern U.S. into attainment with the ozone NAAQS; however, the remaining third of the Eastern U.S. areas, including the most densely populated ones, still are not in compliance with the ozone NAAQS during one or more days each year.[12] Moreover, the recent Clean Air Interstate Rule (CAIR), which will significantly reduce the cap on NO_X emissions from stationary sources[13], is not expected bring all the Northeastern states into full compliance (U.S. EPA 2006b, NESCAUM 2006). This expectation raises the question of whether changes in the current cap-and-trade system that would better recognize time and locational variations of the impact of emissions on

[10] These states were CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT. This program was in effect in a summer ozone season (May through September) and it affected fossil fuel fired boilers with a rated heat input capacity of greater than or equal to 250 mmBtu/hour and all electric generating facilities with a rated output of at least 15 MW.

[11] In 1998, the EPA called for revision of NO_X State Implementation Plans (SIPs) in light of the 1997 ozone NAAQS. This SIP Call required 22 states and the District of Columbia to submit revised SIPs to "prohibit specified amounts of emissions of … NO_X – one of the precursors to ozone (smog) pollution – for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States." States could choose to comply with the SIP call by participating in the NO_X Budget cap-and-trade program. *Federal Register*, Vol. 63, No. 207, Tuesday, October 27, 1998, or by submitting a plan for source-specific NO_X emission rate limits. The expanded NO_X Budget Program became effective May 31st of 2004 after delays from lawsuits. The additional participating states are: AL, IL, IN, KY, MI, NC, OH, SC, TN, VA, WV. Parts of GA and MO will be included in 2007.

[12] In 2004, the EPA designated 126 areas in the U.S. as non-attainment for the 8-hour ozone standard based on 2001-2003 data. Of these areas, 103 areas were in the eastern U.S. and are home to about 100 million people. Based on data from 2003 through 2005, however, two-thirds of these areas are now in attainment, but problems persist in the remaining third of the areas where about 81 million people live (U.S. EPA 2006b, pg. 23).

[13] CAIR will add an annual cap-and-trade program for NO_X in Eastern and Midwestern states in 2010 for the purpose of reducing the contribution of NO_X emissions to fine particulate matter pollution. See Federal Register, Vol. 71, No. 82, Friday, April 28

ozone formation could bring the region closer to compliance with these standards and reduce total compliance costs from stationary sources.

The chemistry of ground-level ozone

The chemistry of ozone formation suggests that the lack of finer spatial and temporal differentiation in these programs may be limiting their effectiveness. Nitrogen oxides are one of the key precursors of ozone pollution but nonlinear interactions of NO_X with reactive volatile organic compounds (VOCs), sunlight, and wind complicate the chemistry of how concentrations of ground-level ozone change over time as a function of NO_X emissions. The chemistry of the formation and transport of ground level ozone is formidable but it is worth noting a few points that emphasize the complications that are particularly relevant to the regulation of ozone precursor emissions.

Ground-level ozone forms in the lowest level of the earth's atmosphere, the troposphere.[14] The basic reactions involve VOCs that create compounds that react with nitric oxide (NO), which is emitted from the burning of fossil fuel, to form nitrogen dioxide (NO_2) (see Borrell 2003 for more details). The NO_2 created by these reactions, absorbs sunlight during the daytime. This creates an extra oxygen atom that can combine with O_2 to form ozone (O_3):

$$NO_2 + \lambda\ (400\ nm) \rightarrow NO + O$$

$$O + O_2 \rightarrow O_3$$

In areas of high concentrations of NO_X, the concentrations of ozone are kept low by a reaction called the titration reaction:

$$NO + O_3 \rightarrow NO_2 + O_2$$

[14] See the EPA's "Basic Concepts in Environmental Sciences," Chapter 6: Ozone at http://www.epa.gov/eogapti1/module6/ozone/formation/formation.htm.

These three reactions depend on the relative concentrations of VOCs and NO_X (NO + NO_2), on the temperature, and on whether or not it is sunny. It is also important to note that these conditions only rarely combine to produce ozone concentrations that are above the air quality standard. The periods of high ozone concentrations, called ozone episodes, typically last for a few hours and at most a few days.[15]

Areas, or times, characterized by high concentrations in NO_X and relatively low concentrations of VOCs, are said to be VOC-limited. This means that a reduction in VOCs will likely reduce ozone formation but a reduction in NO_X will stop the titration reaction and actually *increase* ozone concentrations. Most areas in the Northeastern U.S. are NO_X-limited, meaning that reductions in NO_X will decrease ozone formation, although this does vary with time, as the amount of sunlight and the temperature vary. Additionally, in the Eastern U.S., ozone's lifetime is typically less than or up to two days (Fiore *et. al.* 2002). This is long enough, however, to make the transport of ozone from areas conducive to its formation to downwind areas a problem. The wind patterns in the Eastern U.S. typically mean that ozone is transported from west to east.

Experience and the literature have highlighted the policy implications of this complicated chemistry. For example, the counterintuitive relationship that very high concentrations of NO_X can suppress ozone formation explains the "weekend effect" in the Los Angeles air basin: ozone concentrations were higher on weekends when NO_X emissions from diesel trucks were lower (CARB 2004). Ryerson *et. al.* (2001) also found that ozone is *less* likely to form in the concentrated plumes from the largest power plants compared to the plumes from smaller plants. In addition, reductions of NO_X from power plants located near natural sources of VOCs, like oak forests, reduce ozone formation more than reductions from those far from VOC sources (Ryerson *et. al.* 2001, Chameides

[15] For example, in the Northeastern and Mid-Atlantic states, counties in nonattainment areas violated the 8-hour standard on about 4 days per year on average between 2003 and 2005. The county with the most daily exceedances during this three-year period was Ocean County, New Jersey. Ozone readings from this county's single monitor exceeded the 8-hour standard on 30 days during the three-year period (9, 7, and 14 times in 2003 through 2005 respectively). The monitors in the broader Philadelphia-Wilmin-Atlantic "moderate" nonattainment area, which includes Ocean County, recorded an average of 3.6 days per year that exceeded the 8-hour standard.[15] The area's population is over 7 million people and "moderate" is the worst level of nonattainment in the Eastern U.S. currently, areas of California suffer "serious" or "severe" nonattainment. Figures calculated from data retrieved from the EPA's AirData website (http://www.epa.gov/air/data/index.html).

*et. al.*1988). Ryerson *et al.* (2001) summarize that a reduction of one ton of NO_X from a dilute power plant plume into an area with high ambient VOCs concentrations would result in at least twice the amount of reduction in ozone formation as a reduction of one ton of NO_X from a concentrated plume in an area with low ambient VOC concentrations.

More recent papers have used techniques that integrate atmospheric chemistry modeling with economic and demographic data in order to link the variable role of NO_X emissions in ozone formation to human exposure and health impacts. Mauzerall *et. al.* (2005) examined differences in health effects of ozone formation and exposure from NO_X emissions from large point sources at different locations and times that captured relevant ranges of variation in temperature and local biogenic VOC emissions. They found that the ozone produced from the same amount of NO_X emissions at these different times and places can vary by up to a factor of five. The public health impacts of the NO_X also depend on locational variations in demographics that influence exposure (Mauzerall *et. al.* 2005). Tong *et. al.* (2006) used similar techniques to study the ozone-caused NO_X damages around Atlanta. They found that the marginal damages of NO_X emissions vary greatly across the Atlanta metropolitan area because of ozone formation chemistry, including the effects of the titration reaction. While both papers note that the current cap-and-trade programs for NO_X fail to take these variations into account and call for a more differentiated form of regulation, neither discusses the details of how such a program might be implemented.[16]

[16] Mauzerall *et. al.* (2005) do suggest a program that would create *ex post* fees for emissions that correspond to damages in order to encourage sources to use modeling techniques to forecast the ozone effects of their NO_X emissions. They do not discuss the practicalities associated with implementing such a program.

Poorly-timed NO_X reductions under the OTC NO_X Budget Trading Program[17]

The current undifferentiated cap-and-trade system is problematic not only because it fails to take the complex chemistry of ozone formation into account during the summer season, but also because it appears to encourage abatement at the wrong times due to variations in the price of electricity during the summer season. Observed behavior, such as that shown in Figure 1, suggests that the owners of at least some generating units have found it more attractive to reduce NO_X emissions in May and June instead of in the warmer months of July and August when ozone formation is more likely to be a problem.

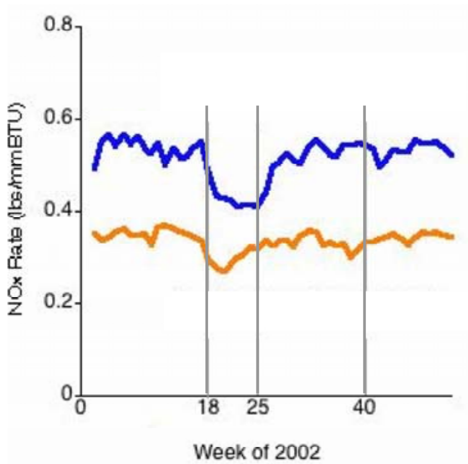

Figure 1 NO_X rates of two companies' coal-fired generating units over the weeks of 2002. Week 18 corresponds to the first week of May and week 40 to the last week of September.

One possible reason that plants might prefer to reduce emissions in May and June instead of July and August is that power prices are typically lower in these months. For example in 2002, the PJM load-weighted average real-time LMP was greater than \$100/MWh for 80 hours and for some hours as high as \$1000/MWh (the price cap then in effect). Seventy-three percent of these hours occurred in July and August while only 9% of them occurred in May, June, and September.[18] When electricity prices are high, so is the opportunity cost from any reduction in generating efficiency or capacity that occurs from operating NO_X control technologies. Some of the NO_X control technologies utilized by coal-fired generating units can adversely impact the units' heat rates and lead to increased production costs or reduced output. In these cases, controlling NO_X emissions creates a tradeoff between reducing those emissions and utilizing less fuel to generate a given amount of power. Also, the tradeoff can be more extreme when it results in an

---

[17] This is the topic of another paper in progress at the Center for Energy and Environmental Policy Research at MIT.

[18] PJM real-time LMP data available on PJM website, "Real Time Energy Market Data" at http://www.pjm.com/markets/energy-market/real-time.html.

effective reduction in capacity. A further explanation for the observed early reductions is that plant operators reduce emissions early in the season to reduce the risk of not having enough allowances or having to pay high allowance prices at the end of the season.[19] Additionally, the effectiveness of combustion control technologies may degrade over the course of the summer from when they are initially tuned at the start of the ozone season.

This evidence suggests that, when NO_X emissions within the months of May through September are treated alike, sources will reduce emissions when it is least expensive and most convenient for them to do so. That is, the incentives in an undifferentiated seasonal cap-and-trade program do not guarantee that reductions in NO_X emissions will occur when they will most likely mitigate ozone formation. The observation of changes in generating units' NO_X emission rates over periods of a few weeks also suggests that plant operators may chose to alter emission rates by changing the way they use NO_X control technologies, or by tuning combustion, in response to time and locational differentiated incentives. Although we do not attempt to analyze the magnitude of these responses here, it is fairly clear that a time and locational differentiated cap-and-trade program could also provide the incentives for plant operators to reduce emission rates given the existing stock of capital equipment when it would most likely impact ozone formation. This implies that the estimates of the NO_X reductions that are feasible through generator redispatch alone are lower bounds on the short-run potential for NO_X reductions from a time differentiated pricing mechanism.

A time- and location-differentiated cap-and-trade program for NO_X

The four components noted earlier – forecast modeling of weather and ozone formation, NO_X emissions monitors, a cap-and-trade program with hourly monitoring and variable redemption ratios, and liberalized wholesale electricity markets organized around a locational pricing system – could be combined to create a time- and location-differentiated cap-and-trade program for NO_X that would overcome the challenges heretofore associated with implementing a more finely differentiated system of NO_X

[19] The limits on banking between annual summer seasons, known as Progressive Flow Control, may contribute to this problem. Unused NO_X allowances from early in the summer season can be used later in the same season without discount whereas those from earlier summer seasons are not fully equivalent.

emission control. We hypothesize that such a program would be more environmentally effective and less costly than the current, blunt, seasonal cap-and-trade programs in the Eastern United States.

The regulatory system we envisage would be initiated by weather forecasting models that would provide advance warning of the times when meteorological conditions are expected to be conducive to the formation of high ozone concentrations in critical receptor areas (for instance, those in non-attainment) and of the locations or zones of the precursor NO_X emissions that would have an impact on ozone formation during those critical times and at the critical receptor areas. Power plant operators would then be notified of the times and locations when a pre-set allowance surrender ratio greater than one-to-one would be imposed on NO_X emissions. Generators would then modify their bids in the day-ahead and real time markets in response to the higher cost of NO_X emissions and engage in further abatement where the capability exists to do so on short notice. The day-ahead and real time markets would then lead to patterns of locational prices that reflect the prevailing NO_X emissions permit exchange rates and result in generator dispatch and abatement that would reduce the relevant NO_X emissions.

The effectiveness of the system that we envision rests on four necessary conditions. The first is that weather and atmospheric chemistry forecasting can predict the conditions conducive to ozone formation with sufficient accuracy and lead-time (at least 48 hours) to influence electricity markets. The second is that the spatial zones and time intervals in which the surrender ratio for the NO_X emissions permits would be varied can be identified with sufficient regularity that a reasonably simple and stable system of differentiated permit exchange rates triggered by reliable and transparent indicators of weather and atmospheric chemistry can be implemented. The third is that there exists sufficient flexibility in the redispatch of generating units of differing NO_X emissions rates and in NO_X emissions control that significant NO_X reductions can be accomplished on relatively short notice and without violating transmission network and supply/demand balance constraints. The fourth condition is then that the magnitudes of NO_X reductions that could be effected in the specified areas and times in response to differentiated permit exchange rates would reduce the likelihood of high ozone levels in areas that would not otherwise be in attainment with ambient air quality standards and where the associated incremental damages to human health and welfare are relatively high.

The literature suggests that the first two of these conditions are feasible. For example, slow-moving, high-pressure systems drive the worst ozone episodes in the Eastern U.S. (NRC 1991 citing RTI 1975, Decker *et. al*. 1976). This means that forecasting ozone episodes requires forecasting these high-pressure systems. The latter are generally predictable with a lead-time of 3 to 5 days (NRC 1991 citing Chen 1989, van den Dool and Saha 1990). Our research will eventually use weather and atmospheric chemistry modeling to address these two conditions in detail. In this paper, however, we consider only the third condition on which our general hypothesis of the feasibility of a more finely differentiated system rests – that there is sufficient short-term flexibility to reduce NO_X emissions appreciably given realistic assumptions about the electricity markets and physical network in which they operate.

In the short run, the emissions of electric generators could be altered by two means in response to changes in the permit exchange rate. Power plant operators could change emissions rates by changing the utilization of emission control technologies that have already been installed on the plants. For example and as noted above, observation of historical compliance with the seasonal cap-and-trade programs suggests that power plant operators can alter the NO_X rates of some units – especially those employing combustion-altering technologies – on the time scale of a few weeks.[20] It may be less costly, however, for short-term reductions to come through changes in dispatch. In either case, these changes would result from decentralized, profit-maximizing responses by generators to the higher NO_X price and the resulting higher locational electricity prices in the day-ahead and real-time wholesale electricity markets. In the long run, power plant owners may invest in alternative emissions control technologies. We focus here on the potential magnitude of reductions in NO_X emissions that can be achieved at various locations at critical times in the short run as a consequence of redispatch of generating units while still meeting electricity demand and transmission network constraints. In doing so, we set

[20] It must be remembered that when emission controls, such as low-NO_X-burners, are adopted under cap-and-trade systems, plant operators are not required to utilize them at all times.

changes in emission rates resulting from investment in and utilization of alternative emissions control technologies aside in this paper.

Marginal Damages and Thresholds

Our research is motivated by the observation that the source-receptor (or emission-concentration) relationship between precursor NO_X emissions and the ozone concentrations that affect public health is highly variable with respect to both time and location. For example, winds can increase ozone formation by carrying NO_X from areas with low VOC concentrations to areas with higher VOC concentrations where ozone is more able to form. Also, winds can increase exposure by carrying ozone from rural regions to densely populated ones, thereby increasing the damages attributable to a particular source's NO_X emissions (Mauzerall *et. al.* 2005, pgs. 2859-61). The contribution of a particular NO_X source to high ozone concentrations at certain places and times can vary greatly on a daily or even hourly basis.

The source-receptor relationship is not the only highly variable relationship related to ozone; the relationship between a given ozone concentration and its total public health damages also varies because of demographics. The literature often models the damage function for the exposure of individuals to ozone as linear or log-linear based on the level of concentration (i.e. without a threshold below which exposure is safe).[21] But, the marginal damages of high ozone concentrations on the broader public health in any given area vary due to geographical variations in population density.

In U.S. air emission regulation, a threshold level that is established to protect public health with "an adequate margin of safety" determines the NAAQS for ozone (0.08 ppm).[22] Technically, ozone attainment status is determined by a three-year average of the 4th highest daily maximum 8-hour average ozone observation in three consecutive years. While the frequency and level of 8-hour average observations exceeding 0.08 ppm is important both with respect to damages and legal attainment status, the existing

---

[21] See, for example, Tong *et. al*. 2006 using the concentration-response function estimated in Bell *et. al*. 2004. The limitations of epidemiological research and available data at low exposure levels make it difficult to detect this type of threshold for ozone but it does not mean that one does not exist; at this stage, there is not conclusive evidence either way (EPA 2006a, pages 7-154–159).

[22] This is true for all criteria pollutants under the Clean Air Act, Section 109, 42 U.S.C. § 7409

structure of air emission regulation does not make further distinctions about the differentiated damages from any given observation of ozone concentration. In effect, a three-year average of 0.79 ppm has very different potential legal consequences from one of 0.81 ppm and the latter is as serious legally (i.e. in terms of nonattainment) in a sparsely populated area where the damages would be relatively low as in an urban area where they would be much higher.[23]

At the present stage of our research, we are focusing on the emissions-concentration link and using the regulatory threshold of 0.80 ppm as a standard that policymakers will seek to achieve. If our hypothesis that a time and location varying regulatory system addressing the highly variable source-receptor relationship is feasible and more effective than the current undifferentiated system (whether cap-and-trade or command-and-control) is correct, adjusting surrender ratios to reflect more accurately the marginal damages associated with given ozone concentrations in various locations will be a relatively simple extension of our work.

Section 3. Methodology

We use two complementary methods to simulate the potential magnitude of reductions in NO_X emissions that can be achieved at various locations and at critical times as a consequence of redispatch while electricity demand and transmission network constraints are still met. Both methods use generating unit-level emission rates and balance electricity supply and demand. We use a "zonal" method that accurately incorporates emission rates and historical load characteristics to demonstrate the physical potential for significant NO_X reductions through redispatch. We then use a more refined security constrained optimal power flow (SCOPF) simulation model to estimate both the physical feasibility to redispatch generators to reduce NO_X emissions and the levels of NO_X permit prices required to induce various levels of economic redispatch – and therefore NO_X reductions – through wholesale market mechanisms. The second method, that uses the PowerWorld Simulator, more accurately simulates network constraints than does the zonal model. The two methods yield reasonably consistent results. Since there is little

---

[23] It must be noted however that more ambient air concentration monitors are located in urban areas.

evidence of significant market power in PJM today, the NO_X price simulations assume that generating units engage in Bertrand competition and bid their marginal costs into the PJM markets.[24] The capabilities of PowerWorld will allow us to explore the implications of market power in future research.[25]

Zonal analysis of NO_X reductions from redispatch

For any given hour, the economic dispatch of generating units to meet electricity demand on a network results in the transfer of electricity between network nodes according to complex but well understood physical laws. On an electric power network with no transmission constraints and no physical losses, economic dispatch would imply that all nodes on the network would have the same price for electricity. In this case, any possible pattern or level of demand could be served by the lowest cost generation available. Additionally, a dispatch of generating units that minimizes generating costs (primarily fuel costs) while also taking into account any price placed on NO_X emissions would be possible for the same levels of demand.

In reality, however, the lowest cost, unconstrained generator dispatch may not be feasible due to network constraints (thermal and contingency). The efficient dispatch of generating capacity must take these constraints into account. Moreover, transmission network constraints may limit the physical capability to substitute generation from low-NO_X rate units for generation from high-NO_X rate units while continuing to balance supply and demand at all locations. In a wholesale electricity market context where generator dispatch decisions are decentralized, this can be accomplished by organizing spot markets around a security constrained bid-based dispatch auction mechanism that yields a compatible set of locational prices for electricity. The wholesale electricity spot markets in the Northeastern and Midwestern states are now based on security-constrained

---

[24] The independent market monitor for PJM does not believe market power to be a significant problem in PJM, see PJM (2006) pages 59-69 and 83-93.

[25] For examples of work on the interactions of market power and emissions in PJM see Mansur 2006a and 2006b. Mansur (2006a) found that the exercise of market power in the PJM region leads to lower emissions and that, in this situation, a tradable permit system is superior to a tax in terms of welfare effects. Mansur (2006b) also found that electricity restructuring and the accompanying exercises of market power explained about one third of the emissions reductions observed when PJM restructured in 1999 and when the NO_X cap-and-trade program first took effect in the ozone transport region.

bid-based auction mechanisms that produce a schedule for generator dispatch and set of locational spot prices for electricity that reflect generator bids and network constraints simultaneously (Joskow 2006). Prices at different nodes on the network then vary to account for the marginal cost of congestion (and the marginal cost of losses in some markets).[26]

We first use a simplified zonal model to identify portions of the Classic PJM network that are reasonable approximations of areas where the transmission system is capable of handling the exchange of generation between units without causing "trans-zonal" congestion or severely altering network flows between zones. This analysis considers units within the zones of the network that we identify to be good physical substitutes for each other. Substitution between zones is assumed to be infeasible if it requires increasing generation from one zone to another zone where network constraints are already binding.

There has been a debate in the academic literature over the relative merits of zonal and nodal pricing systems (e.g. Stoft 1997 and Hogan 1999). The literature shows that the complexities caused by flows over parallel lines in electricity networks, and the variations in those flows over time due to fluctuating demand, make it difficult to create consistent zones by collecting nodes that have the same or similar LMPs (Stoft 1997). We recognize these complexities, but the zonal model allows us to capture many of the details of the Classic PJM power system that are important for estimating potential NO_X reductions – like the actual emission rates of generating units in PJM and the locations of generation and of congested lines – while using only publicly available data and a relatively simple characterization of the topology of the transmission network.

In order to capture a richer characterization of network power flows and constraints we next proceed to use PowerWorld's SCOPF capabilities, parameterized to match the classical PJM network, as a second method to estimate the physical capabilities to reduce NO_X emissions. This model allows us to take a more refined account of the

[26] The wholesale electricity spot markets in New England and New York include the marginal cost of losses in locational prices. The PJM Interconnection, which we focus on here, does not yet include the marginal cost of losses in its locational pricing mechanism.

physical complexities, constraints, contingencies and parallel flows on the network. By comparing the results of the two approaches we can also obtain an estimate of the benefits of relying on more complex representations of the network to examine how generators will respond to changes in NO_X emissions prices.

Construction of the zonal model

Publicly available data on the PJM transmission system[27] – data on the name, type (e.g. generator, load), and voltage of each bus and the buses to which each connects – were used to create an abstract representation of congestion patterns on the PJM system, or a network graph.[28] The network graph represents the substations, as nodes, and the inter-substation transmission lines between the nodes. We define substations broadly as closely connected collections of electrical equipment. Examples are a power plant with multiple generators and transformers, multiple power plants, or a switching station.

The data were matched by substation name into a system that includes over 900 nodes and over 8500 connecting lines. We then used the substation names and information on voltages and equipment at substations to match the generators in the EPA's Continuous Emissions Monitoring System (CEMS) to the nodes.[29] Hourly generating unit operation data, like heat input, generation, and emissions, are available from the CEMS data. These data are available for fossil fuel-fired generating units with rated capacities of at least 15 or 25 MW, depending on the state. The same EPA website houses data on the characteristics of emission sources like their location, technology type (e.g. dry bottom wall-fired boiler), types of fuel burned, the sources' emission control technologies, and when they installed these control technologies. Less detailed data on

[27] The data at PJM, "Transmission Facilities," available at http://www.pjm.com/services/transm-facilities.jsp.

[28] Network graphs are used in the mathematical field of graph theory, computer science, and social network theory. They are abstractions that model pairwise relationships between objects using nodes (e.g substations) and "edges", "arcs", or "lines" (in this case transmission lines). For other applications of network theory to electric power systems see Watts (1998).

[29] See Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) (unit generation and heat input data) and data on emissions and characteristics of regulated sources at http://cfpub.epa.gov/gdm/.

the rated capacities of other types of generating units (e.g. nuclear, hydro, and municipal waste) and smaller units are available from the Energy Information Association (EIA).[30]

Using these publicly available data sources, we were able to match approximately 49.1 GW of fossil fuel-fired capacity (rated summertime capacity) in the EIA's database of existing capacity to the appropriate substation in the PJM network graph. The 2005 PJM State of the Market Report states that there were about 50.6 GW of fossil capacity in PJM in 2005 (PJM 2006), so our matching process covers about 97% of the fossil capacity in PJM. Of the 49.1 GW capacity in the EIA database, about 96% of it (47.2 GW) reports emission data to the EPA's CEMS database. This gives us detailed data on the emissions from about 93% of the fossil fuel-fired capacity in PJM.

We then use two criteria to create zones in the PJM network within which congestion rarely occurred. In its State of the Market Report, PJM discusses the impact of frequently congested lines on market concentration (PJM 2006). For 2005, it lists thirteen transmission lines and transformers that were congested for over 100 hours in 2005. In addition, the State of the Market Report discusses three other lines and one other transformer that were frequently congested in 2004. The first criterion we use to identify zones within PJM is that these 17 lines must be located on the borders <u>between</u> zones and not within the zones.

The second criterion uses historical hourly locational marginal price (LMP) data to define zones. This is a more refined method for defining zones, as it creates smaller zones than the first criterion alone. Hourly LMP and zonal demand data for PJM are available on the PJM website and we matched them to the network graph.[31] The second criterion is that the standard deviation of the LMP's within each zone must be <$10/MWh for at least 90% of a sample of 144 summertime hours in 2005. This criterion was selected because differences in LMP of less than $10/MWh rarely indicate congestion. More typically, they indicate other differences in marginal cost between

---

[30] See EIA "Form EIA-860 Database: Annual Electric Generator Report," available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

[31] PJM website "Real Time" energy market data at http://www.pjm.com/markets/energy-market/real-time.html.

nodes.[32] Additionally, we only required the zonal model to capture the most frequent patterns of congestion, not every pattern that occurred. Many of the identified zones easily met the last criterion. For example, in the largest zone of 117 nodes, the standard deviation of LMPs was less than $5/MWh in 90% of the hours and less than $10/MWh in 98% of hours.

These two criteria created 35 zones with between 117 and 4 nodes in each. The network graph was then used to match generating unit emissions and generation data to the zones. This matching allowed us to estimate the potential reductions in NO_X from redispatch while taking account of the constraints caused by the most frequent patterns of network congestion in 2005. To estimate the maximum potential NO_X reductions (the technical upper bound on NO_X reductions from redispatch) we minimized the NO_X emissions from the fossil fuel-fired generating units in Classic PJM subject to five constraints for each hour of analysis:

1. Total generation from the generators is held constant.
2. The generation from any unit operating in the hour can only be reduced to 20% of its rated capacity; it cannot be reduced to zero.
3. Generating units not initially operating in the hour can "turn on" and generating units can produce power up to 100% of rated summer capacity.[33]
4. The total generation from all the generating units in zones on the high-LMP side of congested lines and transformers cannot decrease.
5. The total generation from all the generating units in zones on the low-LMP sides of congested lines and transformers cannot increase.

The second of these constraints reflects the high start-up costs that prevent some generators from being turned off often, maintains levels of operating reserves, and avoids

[32] PJM lists both LMPs and data on "real time constraints" or "transmission limits". The LMPs between nodes often vary up to $30/MWh without the line between those nodes being listed as a constraint. See "PJM Operational Data" at http://www.pjm.com/pub/account/lmpgen/lmppost.html or "Real Time Transmission Constraints 1998-2005" at http://www.pjm.com/markets/energy-market/real-time.html.

[33] The summer rated capacities used in these simulations do not reflect forced outages. In PJM for 2005, the demand equivalent forced outage rate was about 7.3% (PJM 2006). The forced outage rates are not available for the summer months when high electricity prices provide an extra incentive for plants to be available and operational. The fact that some plants might not be able to turn on or up to 100% of their capacities makes estimates that do not account for outage rates optimistic. We include some simulations that account for annual average forced outage rates. These estimates are slightly restrictive because summertime forced outage rates tend to be lower than the annual rates.

the added complexities of unit commitment. The fourth constraint is necessary because a decrease in the net generation from units on the high-LMP side of a constraint would cause an increase in the power flowing over a congested line. Similarly, the fifth constraint is necessary because increasing the net share of power from units on the low-LMP side of a constraint would necessitate an increase in the power flowing over the congested line. It is possible, however, to increase the generation from units on the high-LMP side of a congested line while reducing that from the generators on the low-LMP side. This would decrease the flow of power over that line (i.e. create counterflow), thereby relieving congestion.

An additional assumption used in this analysis was that the NO_X rates for the units generating electricity in a given hour do not change from those observed in that hour, regardless of any changes in the quantity generated by that unit or changes in the utilization of NO_X control equipment or changes in combustion attributes. If the unit was not initially operating in an hour, its NO_X emissions were estimated based on its average NO_X rate for the hours between May 1st and September 30th, 2005. This assumption is likely to underestimate the potential NO_X reductions because many of the coal units with the highest emission rates have emission rates that decrease with decreasing utilization and, as we discussed above, generators have some flexibility to vary NO_X emissions rates in the short run. We discuss this phenomenon in Appendix A.

We estimated the possible NO_X reductions for a 24-hour diurnal period between August 3rd, 2005 at 2pm and August 4th, 2005 at 2pm as well as for various other hours during the summer of 2005. We also performed three variations of this analysis to test the impact of the above constraints on our results. First, we relax the fourth and fifth constraints to estimate the potential NO_X reductions that are possible if network constraints were not a factor; we call this the "unconstrained" case. In the second variation, we de-rate the capacities of generating units by the forced outage rate for PJM in 2005.[34] Last, we strengthen the third constraint and use only the unused ("excess") capacity of generating units that are already operating in each hour to estimate potential NO_X reductions.

[34] See infra note 33.

The zonal analysis has three major limitations. First, it does not consider new network overloads that the redispatch of generating units might cause. Second, it does not consider the loop flows at the borders of zones that might require units on the either side of a constraint to increase or decrease their output in order to avoid an increase in the flow over a congested line. Third, it does not consider contingency constraints. The second method using a security constrained optimal power flow (SCOPF) model of the PJM network, described immediately below, helps to address these issues.

Analysis of NO_X prices to induce redispatch using PowerWorld Simulator®

PowerWorld Simulator contains a security constrained optimal power flow (SCOPF) analysis package that can solve power flows for large electricity systems while optimally dispatching generators and enforcing transmission limits, interface limits, and contingency constraints.[35] We used PowerWorld to simulate how a range of uniform NO_X permit prices for Classic PJM, incorporated into linear cost curves for generators, changed the security constrained economic dispatch. In doing so we estimated the NO_X prices needed to achieve a range of NO_X reductions up to the maximum level when further increases in NO_X prices caused little additional reductions. This analysis gives us both a measure of the physical capability to alter NO_X emissions from redispatch and the NO_X prices required to induce different levels of NO_X emissions through redispatch of generating units.

To perform reasonably realistic simulations of the PJM network, we used the information on network elements from the load flow model used for the PJM Financial Transmission Rights (FTR) auctions.[36] The base-case power flows for the FTR model include data like the voltages and impedances of lines for most of the elements in the

[35] PowerWorld uses a full Newton-Raphson AC load flow algorithm or a DC approximation to solve the power flow. The optimal power flow capability simulates economic dispatch by iterating between solving the power flow and minimizing total system operating cost, using generator cost-curves, while enforcing system constraints like line and generator operating limits. Thus, the security constrained optimal power flow simulates economic dispatch while enforcing both normal operating limits and ensuring that there are no operating limit violations during specified contingencies (PowerWorld Corporation at http://www.powerworld.com/). For more explanation of the widely used algorithms behind optimal power flow models such as PowerWorld Simulator see, for example, Sun *et. al.* (1984).

[36] PJM, "FTR Model Information," see http://www.pjm.com/markets/ftr/model-info.html. The available model information includes a list of contingency constraints that PJM considers. We only loaded the constraints for which at least one element was situated in Classic PJM, about 1600 contingencies out of about 4300 for all of PJM.

PJM network. This information allows PowerWorld simulator to solve for the power flows across the lines in PJM given the injections of power at generation buses and the withdrawals of power at load buses. PowerWorld can also use generator cost information to perform optimal power flow simulations, which minimize total operating cost subject to constraints.

As in the zonal model, we compared the NO_X emissions resulting from three cases: 1) an “unconstrained” case where the generation from units in Classic PJM was dispatched economically without enforcing network constraints, 2) the constrained case (optimal power flow “OPF”) in which the network constraints, like line limits, were enforced, and 3) the security constrained case in which both network and contingency limits were enforced (security constrained optimal power flow “SCOPF”). In this way, the PowerWorld analysis complements the zonal analysis, which did not address security constraints or whether redispatch created new congestion.

For the simulations, we designated only combustion turbine units as “fast start” generators. This means that the dispatch algorithms could turn on and off combustion turbines, but all other generators could only increase or decreases their output. In addition, we constrained the generation from steam turbines and combined cycle units to be at least 20% of their capacity if they were already operating. Units could generate up to their summertime rated capacities. We also held the generation from all units outside Classic PJM and imports and exports constant.

We created linear cost curves (i.e. constant marginal cost) for the Classic PJM generating units and imported them into PowerWorld in order to simulate security-constrained economic dispatch.[37] The linear cost curves were defined simply by:

$$c_i\ (\$/\text{MWh}) = H_i(p_{fi} + p_{ni}N_i) + O\&M_i$$

where, for each generating unit *i*, H_i is its heat rate (mmBTU/MWh), p_{fi} is the price of fuel ($/mmBTU), p_{ni} is the price of NO_X permits ($/ton), N_i is the unit’s NO_X emission

[37] The generation and load in areas of PJM outside the Classic PJM footprint were held constant between the base case and the “redispatched” cases. The generation and load in the areas surrounding the larger PJM were zero in the base case and subsequent cases; thus imports and exports to and from PJM as a whole were assumed to be zero.

rate in (tons/mmBTU), and $O\&M_i$ is the unit's variable O&M costs in ($/MWh). For each level of demand in question, the units were "dispatched" in order of least cost according to these cost curves. The NO_X price was applied uniformly to all units in PJM and was varied between $2000/ton and $125,000/ton.[38]

To generate these curves, we utilized data on the average delivered cost of fuel for natural gas, coal, petroleum products, and petroleum coke to the electricity sector from the EIA's Electric Power Monthly for August 2005. We matched these data to the generating units by state and fuel. The variable O&M data were from the Annual Energy Outlook for 2006 matched roughly by technology type and fuel, including rough costs for nuclear and hydro-powered units.[39] We also used EPA data on 2005 ozone-season heat rates and NO_X emission rates and EIA data on August 2005 fuel and variable operation and maintenance (O&M) costs.[40]

Compared to the zonal model, the PowerWorld analysis requires two additional assumptions. One, discussed below, concerns the peak-hour demand and generation patterns. The other involves generator capacities and NO_X rates. The network information in the FTR model base cases does not provide details on the generators in PJM, only that the generators exist at certain buses and that some produce a given amount of power in the modeled hour. Also, the generating unit identifiers in the PJM FTR model and the EPA and EIA capacity and NO_X rate data are not the same so matching the EPA and EIA data with the correct buses in the FTR model is a challenge (see Appendix B).

The FTR base case power flows simulate hours with average levels of total electricity demand, around 38 GW in Classic PJM.[41] The electricity demand in nighttime and early morning hours is typically about this level in Classic PJM during the hottest parts of the summer, when ozone formation is most likely to be a problem. NO_X reductions in these hours may be important for ozone formation because, for example, winds can transport nighttime NO_X emissions to highly populated areas where ozone can

---

[38] In August of 2005 these prices were around $2500/ton. Prices are currently about $1000/ton.

[39] (EIA 2006) Table 38, page 77.

[40] EIA's *Electric Power Monthly*, Tables 4-10 through 4-13, available at http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html.

[41] For the analyses reported in this paper, we used the Annual FTR load flow case that PJM posted in February 2007.

form during the day. The integration of this work with atmospheric chemistry models will show whether NO_X emission reductions during nighttime or daytime hours will most effectively reduce ozone concentrations.

Daytime electricity demand is typically higher than nighttime demand. In peak afternoon hours, electricity demand reached about 60 GW in Classic PJM in 2005. The higher demand requires more complete utilization of generating units than in average-demand hours. If the generating units with low NO_X emission rates were fully utilized to meet demand in these hours there would be little flexibility to reduce emissions so it is important to simulate potential NO_X reductions in peak demand hours. In addition, if demand is higher in areas with little generation, or with only costly generation, then the higher demand can increase the likelihood of congested transmission lines. If the low-NO_X generation were also located far from high-demand areas then network constraints could similarly limit NO_X reduction potential. In order to simulate these high demand conditions using the Powerworld Simulator, we scaled the PJM FTR model to approximate the higher demand hours studied with the zonal model (see Appendix C).[42]

We developed three scaled cases that had similar levels of total demand, fossil generation, and NO_X emissions as those observed in historical peak demand hours in Classic PJM. The first of these cases mimicked the historical LMP patterns observed on August 4th at 2pm ("Matched LMPs"). The Matched LMPs case started with two binding constraints in the security constrained optimal power flow. In the second case, we altered the nodal load data until there were 9 initially binding constraints, four of which PJM reported as active on August 4th at 2 pm. In the third case, the units for which cost curve information was available filled a higher proportion of the demand in Classic PJM. This final case resulted in a base case in which this set of units contributed more generation and emissions than was observed in Classic PJM during the summer of 2005 ("High Fossil Gen"). The High Fossil Gen case simulates conservative estimates of potential

[42] We have also applied for access to a peak load flow case for use with PowerWorld through the Freedom of Information Act, Critical Energy Infrastructure Information process. Our results will be updated if we gain access to these data.

NO_X reductions because it requires the set of generators that can be redispatched in response to NO_X prices to generate more overall.

For the PowerWorld simulations we used the DC approximation to the AC load flow. Both the AC and DC methods solve for the power flows over the network, but the former does not consider reactive power flows or line losses.[43] The literature suggests that DC SCOPF is sufficient for most economic analyses of electricity networks. Schweppe *et al.* (1988) proposed the DC load flow as a tool for economic analysis. Overbye *et al.* (2004) analyzed the accuracy-tractability trade off between using the full AC load flow and the DC SCOPF for LMP studies for the 13,000-bus model of the Midwest U.S. transmission grid. They found that DC SCOPF performed reasonably well: although the power flows were not identical, the DC method identified very similar patterns of constraints and the average LMP only differed by about $2.40/MWh (lower in the DC case). The DC approximation found that some lines were only about 99% loaded while the AC load flow found them to be congested, causing the observed difference in LMPs. Given this finding, any inaccuracies resulting from the use of a DC approximation are likely overshadowed by our use of linear cost curves, our choice only to model Classic PJM and not the entirety of the PJM network, matching the generators to the FTR case buses, and the necessity of scaling the FTR cases to better represent peak demand conditions.

Section 4. Results and Discussion

This section discusses the results of our estimates of the maximum technical potential for NO_X reductions by redispatch in PJM and of our preliminary examination of the magnitude of the NO_X prices that would be needed to achieve various levels of NO_X reduction up to that maximum. We first discuss the relevant background characteristics of capacity, generation, and NO_X emissions in PJM and Classic PJM. Because of the temporal- and locational-variations in the impact of NO_X emissions on ozone formation, we present our results in terms of their temporal and locational characteristics.

[43] According to Overbye *et al.* 2004, the major simplifications of the DC power flow are that it 1) ignores the reactive power balance equations, 2) assumes identical voltage magnitudes of one per unit, 3) ignores line losses, and 4) ignores tap dependence in the transformer reactances.

Relevant Background Characteristics

Both demand and fossil fuel-fired generation in PJM and in Classic PJM are highest during the ozone season (May through September). Table 1 displays the average and maximum hourly demand in PJM in 2005 during the ozone season and during the non-ozone season months. The table also shows the average and maximum hourly generation from the fossil-fired generating units in Classic PJM that we used in our simulations (371 units).[44] The maximum-demand hour for all of PJM in 2005 occurred on August 3rd at 5 pm. The demand of about 116 GW in that hour, not including the Duquesne Light Company (DUQ) Control Zone, was about 1.6 times that of the average demand in PJM during the ozone season of 2005. The maximum-demand hour for Classic PJM occurred on July 27th at 4 pm with demand of also about 1.6 times that of the average demand in Classic PJM in the ozone season of 2005.

The average hourly NO_X emissions from the units in Classic PJM in 2005 were about 20 tons per hour (see Table 1). The maximum hourly NO_X emissions in 2005 did not occur during the ozone season in 2005, but occurred in January when the cap-and-trade program for NO_X was not in effect.

Table 1 Average and Maximum demand in PJM and Classic PJM and Fossil Fuel-Fired Generation and Emissions in Classic PJM.

Hourly Data, 2005		**Ozone-Season**	**Off-Season**	**Annual**	
PJM Demand^	avg	74	68	71	*(GW)*
	max	116	97	116	
Classic PJM Demand	avg	36	32	33	*(GW)*
	max	59	46	59	
Classic PJM Fossil	avg	19	16	18	*(GW)*
	max*	36	26	35	
Classic PJM NOx Emissions	avg	19.6	30.0	25.7	*(Tons)*
	max*	44.7	46.2	46.2	

^Does not include the DUQ control area that joined PJM May 1, 2005
*Max from the highest demand hour in Classic PJM in 2005 in the ozone season (7/27/05 16:00) and non-ozone season (1/18/05 19:00) respectively

[44] Our simulations do not model the further possibilities of exchanging hydro or nuclear power for fossil generation – although for nuclear we would expect the possibilities to be small as most nuclear plants are typically run near their full capacity in most hours.

While total generation in the summer peak hour in Classic PJM was about 13 GW or 28% higher than at the winter peak, the summertime peak NO_X emissions were slightly lower, 45 tons in contrast to 46 tons during the winter peak. The increased use of natural gas-fired generation to meet the higher levels of summertime demand can partially explain this: on average, natural gas-fired generators filled about 16% of hourly summer demand but only 10% of hourly demand in the winter. In addition, the average emission rate of coal-fired generation was about 2.15 lbs/MWh in the ozone season and about 4 lbs/MWh outside the ozone season in 2005. The ozone season NO_X price likely explains this lower summertime emission rate for coal-fired units because, in the absence of a price on NO_X, the NO_X emission rates of coal-fired units would likely be higher in the summer because of the increased use of less efficient units to fill the higher peak demand.

An important feature of the Classic PJM area (and of nearly all electricity control areas) is that even during the hours of the highest peaks in demand, there is generating capacity that is in some form of reserve status and not actually generating electricity. Table 2 shows the capacity of the 371 fossil fuel-fired generating units that were used in our redispatch simulations. The total capacity of these units was about 46 GW (or 42 GW if de-rated by the annual forced outage rate for PJM in 2005).[45] The maximum hourly generation from these units during 2005 was about 36 GW, leaving about 6 to 10 GW of capacity that was not generating electricity. Some of this remaining capacity was providing spinning, non-spinning, and supplemental reserve margins for reliability purposes and we assume that units with higher NO_X emission rates that were generating electricity during the peak hours could be exchanged for lower NO_X units in these reserves, at least for short periods of time.

[45] Since the annual forced outage rate may be too restrictive, as noted earlier (infra note 33), the range is presented in Table 2.

Table 2 Capacity and Generation by Fuel-Type in Classic PJM during the 2005 Ozone Season.

Hourly Data, Ozone Season 2005		Coal	Natural Gas	Oil	TOTAL	
Capacity	rated	21	15	10	46	*(GW)*
	unforced^	19	14	9	42	
Generation	avg	15	3.0	1.6	19	*(GW)*
	max*	18	10	8.2	36	
NOx Emissions	avg	15.8	1.2	2.6	19.6	*(Tons)*
	max*	20.2	6.9	17.6	44.7	
NOx Emission Rates	avg	2.15	0.78	3.19	2.02	*(lbs/ MWh)*
	max*	2.24	1.37	4.29	2.46	

Fuel Category Designations from the EPA's Clean Air Markets Database
*Max from the highest demand hour in Classic PJM in 2005 in the ozone season (7/27/05 16:00)
^Derated by the equivalent demand forced outage rate for PJM in 2005 (7.3%) (PJM 2006)

Table 2 also shows that natural gas generation had the lowest average NO_X rate, about half the average for coal-fired generation. Moreover, natural gas-fired capacity represented the largest portion of the unutilized capacity (for both peak and average hours) since a bid-based, security constrained economic dispatch utilizes the highest marginal cost units last and natural gas-fired units tend to have the highest marginal costs due to natural gas prices (which were particularly high in 2005). For all fuel-types, the generation dispatched to fill peak demand had a higher NO_X rate than that dispatched to fill average demand. This is as expected since there is no differentiation in NO_X pricing between peak and other summer hours and the units pressed into service during peak hours are typically those of all fuel types with lower efficiency (higher heat rates).

For a high NO_X permit price to cause redispatch that reduces NO_X emissions in a given hour, unutilized capacity that is available to generate must have a lower NO_X rate than the original generation used to fill demand. The graphs in Figure 2 show cumulative distributions over NO_X emission rate of the generation used to fill demand and the remaining capacity in Classic PJM on August 4th, 2005 at 2 pm (one of the highest demand hours in PJM during 2005). The median NO_X emission rate for this hour was 2.2 lbs/MWh for all units and for coal-fired units. The graphs show that about 42% and 34% of the remaining, undispatched capacity for fossil fuel-fired and coal-fired units, respectively, had a lower NO_X rate than the median for the units used to fill demand in that hour.

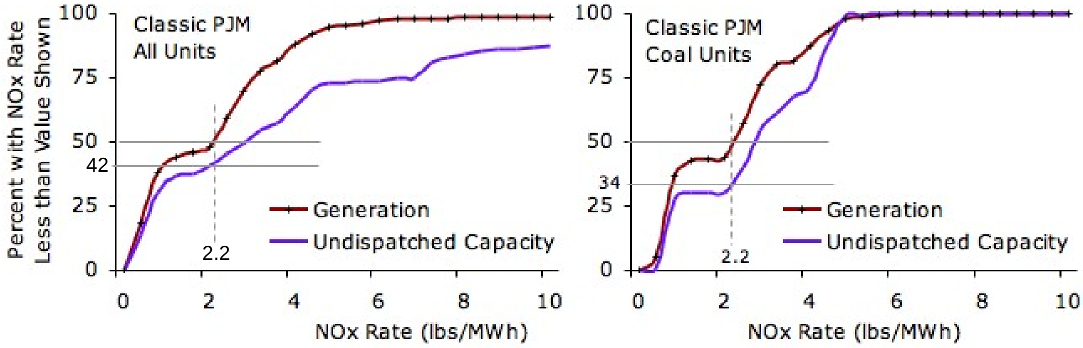

Figure 2 Cumulative distributions of generation and undispatched capacity over NO_X Rate in Classic PJM on August 4th, 2005 at 2pm. The graph on the left is for all fossil fuel-fired generating units in Classic PJM and that on the right is for coal-fired units only. If a heat rate of 10 mmBTU/MWh is assumed, these NO_X emissions rates translate to the equivalent NO_X emission rate in lbs/mmBTU by dividing by a factor of 10.

This result is fairly consistent across other hours and levels of demand. In hours with lower demand, the median NO_X rate of the units that were generating electricity was slightly higher and that of the undispatched capacity was slightly lower. The availability of relatively low-NO_X capacity, even in high demand hours, suggests that redispatch could reduce NO_X emissions if the economic incentives to do so were in place and network constraints did not prevent the utilization of the lower-NO_X rate generation.

Temporal variation in potential NO_X reductions

The potential NO_X reductions from redispatch vary in time primarily because the total demand for electricity varies diurnally and according to the weather.[46] As discussed above in the section on ozone chemistry, the timing of NO_X precursor emissions is important both because of the time lags between NO_X emissions and their impact on the downwind formation of ozone and because meteorological conditions can be such that NO_X emissions emitted locally prior to the peak hour can have as much, and even more, influence on ozone formation than emissions during the peak hour. Table 3 reports the generation, emissions, simulated NO_X “reductions” using the zonal model for Classic PJM for the 24 hours preceding the peak hour.

[46] There will also be some variation due to planned maintenance of facilities which will be scheduled primarily for other than the peak summer demand season.

Table 3 Results of Simulation of Potential Reductions in NO_X Emissions from Redispatch in Classic PJM using the Zonal Model.

Zonal Model Results

	Base Case		***Unconstrained Case***		***Transmission Constraints Case***		***Unforced Capacity^ with Trans. Const.****		***Only "ON" Units with Trans. Const.****	
Date	**Generation**	**NOx**	**Reduction**	**%**	**Reduction**	**%**	**Reduction**	**%**	**Reduction**	**%**
8/3/05 14:00	33	35	8.1	23	7.7	22	6.5	18	6.0	17
8/3/05 16:00	34	38	9.5	25	9.1	24	--	-	--	-
8/3/05 18:00	33	35	9.2	26	8.8	25	7.4	21	6.1	17
8/3/05 20:00	30	29	8.2	29	7.6	26	--	-	--	-
8/3/05 22:00	26	26	10.8	42	10.0	39	9.2	36	6.5	25
8/4/05 0:00	21	21	10.8	52	10.7	52	--	-	--	-
8/4/05 2:00	19	19	9.9	53	9.9	53	9.8	52	3.9	21
8/4/05 4:00	20	20	10.5	52	8.5	42	--	-	--	-
8/4/05 6:00	23	23	10.1	44	9.9	43	9.3	40	4.5	19
8/4/05 8:00	27	26	9.6	37	9.0	35	--	-	--	-
8/4/05 10:00	31	28	7.9	28	7.6	27	6.7	24	0.0	0
8/4/05 12:00	33	33	7.3	22	6.8	21	--	-	--	-
8/4/05 14:00	35	38	9.2	24	9.1	24	7.5	20	7.1	19
	(GW)	*(Tons)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*

* These simulations were only performed for every four hours and have not been completed in PowerWorld.
^ Capacities were derated by the 2005 demand equivalent forced outage rate for PJM of 7.3% (PJM 2006).

The range of total hourly generation for the units we considered in Classic PJM was from about 19 GW per hour, which occurs during hours in the middle of the night, to 35 GW on August 4th at 2pm. The range of initial hourly NO_X emissions covered was from about 20 tons to 38 tons. The reductions ranged from about 7 tons (20 to 25%) during the day to nearly 11 tons (about 50%) in early morning and late night hours.[47] This result is expected both because the network is typically more constrained during higher demand hours and because less capacity is utilized during the lower demand hours.

Two additional simulations are reported in Table 3 in the columns labeled "unforced capacity" and "Only 'ON' units," both of which are intended to represent plausible restrictions on the potential to switch generating units that are additional to transmission constraints. In the former, the summertime rated capacities of all generating units were multiplied by a factor of one minus the forced outage rate of PJM in 2005 to represent the possibility that all capacity may not be available at a level of 100% in all

[47] Since natural gas prices were high during the summer of 2005, observed emissions, and therefore the simulated reductions, might have been higher than in a more normal year. For comparison, we looked at a peak demand hour of 2001 when natural gas prices were much lower. During this hour, there were about 31 GW of fossil generation in Classic PJM (vice 35 during the peak-hour in 2005) and 51 tons of NO_X emissions (vice 38 tons). The potential unconstrained NO_X reductions were about 16 tons or 32%. Both the initial emissions and NO_X reductions were higher in the 2001 peak-hour than in the near-peak hour in 2005 with the same level of fossil generation (e.g. 8/3/05 20:00); however, the percent reduction was about the same.

hours.[48] The last column represents the case where the low NO_X-emitting units that could substitute for higher NO_X emitting units were limited to those providing spinning reserve services. Of these two further limitations, restricting the pool of exchangeable units to operating units with unused capacity in spinning reserves has the greater effect. Moreover, this effect is significantly greater during non-peak hours than in peak hours. Or, stated differently, most of the NO_X-reducing substitution capability during peak hours comes from units in spinning reserve while most of that during non-peak hours is from units that are not generating at those times.

The results of the PowerWorld simulations agree reasonably well with those from the zonal model. Table 4 compares the PowerWorld simulations for high NO_X prices of \$125,000/ton for average demand and peak demand cases to the zonal results for maximum physical substitution (indicated by 125k in the table). NO_X prices above \$100,000/ton caused only small additional reductions in NO_X emissions (see Table 5). In Table 4 the base case in the PowerWorld simulations is the result of SCOPF dispatch with assumed NO_X prices of \$2000/ton (indicated by “2k”). The Zonal Model base case is the observed generation and NO_X emissions from the hour indicated in the table.

Table 4 Comparison of Zonal Model and PowerWorld simulations.

PowerWorld Results								
	Base Case (2k)		***Unconstrained (125k)***		***OPF (125k)***		***SCOPF (125k)***	
Case	**Generation**	**NOx**	**Reduction**	**%**	**Reduction**	**%**	**Reduction**	**%**
Matched LMP	34	35	8.2	*23*	8.0	*23*	8.0	*23*
Constraints	34	35	7.4	*21*	7.4	*21*	7.2	*21*
High Fossil Gen	37	39	7.5	*19*	6.5	*17*	6.4	*16*
Avg Demand	19	20	11.8	*60*	11.9	*60*	11.9	*60*
Zonal Model Results								
	Base Case (Observed)		***Unconstrained***		***Trans. Const.***			
Case	**Generation**	**NOx**	**Reduction**	**%**	**Reduction**	**%**	**n/a**	
3-Aug 2 PM	33	35	8.1	*23*	7.7	*22*		
3-Aug 6 PM	33	35	9.2	*26*	8.8	*25*		
4-Aug 2 PM	35	38	9.2	*24*	9.1	*24*		
4-Aug 2 AM	19	19	9.9	*52*	9.9	*52*		
4-Aug 6 AM	20	20	10.5	*53*	8.5	*43*		
	(MW)	(Tons)	(Tons)	*(%)*	(Tons)	*(%)*		

[48] PJM (2006), page 244, states that the forced outage rate for PJM in 2005 was 7.3% for all generating units. This rate does vary by type of generating unit (steam units have the highest outage rate and combined cycles the lowest of the fossil-fuel fired units). In this analysis, the capacities of all generating units were scaled by a factor of 0.927.

Table 4 suggests that the maximum physical reductions depend on the initial level and pattern of demand and generation and that the potential reductions are between 6 and 10 tons hourly (between about 15 and 50%) in Classic PJM.

Table 5 shows the relationship between NO_X prices and potential reductions in NO_X emissions for the PowerWorld simulations. All simulations economically dispatched the generators in Classic PJM (minimized total operating costs) for ranges of NO_X prices in the average and peak demand hours using the cost curves discussed in Section 3 and the High Fossil Gen case for the peak hour results. The "unconstrained" simulations did not enforce network constraints; the "OPF" simulations enforced physical network constraints; and the "SCOPF" simulations enforced both physical network constraints and the set of contingency constraints for Classic PJM. The simulations reported in the panel labeled "SCOPF" included a set of 64 contingency constraints, each of which had at least one node in a constraint that was actually binding on August 4th at 2pm. The simulations reported in the panel labeled "SCOPF All Constraints" used a larger set of 1455 contingency constraints. Because of the time required to run these simulations, results are only reported for NO_X prices of $2000/ton (2k), $10,000/ton (10k), $50,000/ton (50k), and $100,000/ton (100k).

The simulations suggest that even in the unconstrained case in the average demand hour, NO_X prices of about $50,000/ton would be necessary to obtain the maximum of about 7 tons of hourly NO_X reductions.[49] The NO_X reductions at $50,000/ton in both the average and peak demand cases are similar, about 6 or 7 tons. In the average demand hour, higher NO_X prices caused further reductions by increasing generation from natural gas. In the peak demand case, these natural gas units were already generating; there was less excess capacity to exchange.

[49] If the NO_X emission rate of the marginal generating unit were 3 lbs/MWh then a $20,000/ton NO_X price would add (roughly) $30/MWh to the locational price for electricity. If the marginal generating unit had a NO_X rate of only 0.5 lbs/MWh, the NO_X price would only add about $5/MWh to the locational price for electricity.

Table 5 Results of the PowerWorld simulations for a range of assumed NO_X permit prices. Reductions (absolute and percentages) are calculated from the \$2000/ton (2k) NO_X price case in the corresponding panel. The high demand hour results are for the High Fossil Gen PowerWorld case. The results in the furthest right panel ("SCOPF All Constraints") were not calculated for all NO_X prices due to the computing time.

High Demand Hour NOx Reductions -- PowerWorld

NOx	Unconstrained			OPF			SCOPF			SCOPF All Constraints		
Price	NOx	Reduction	%	NOx	Reduction	%	NOx	Reduction	%	NOx	Reduction	%
2k	39	--	--	39	--	--	39	--	--	41	--	--
10k	35	4.2	*11*	36	3.4	*9*	36	3.5	*9*	37	4.1	*10*
20k	34	5.4	*14*	35	4.6	*12*	35	4.0	*10*			
30k	33	6.0	*15*	34	5.1	*13*	34	5.0	*13*			
50k	33	6.6	*17*	33	5.9	*15*	33	5.8	*15*	36	5.6	*14*
75k	32	7.1	*18*	33	6.3	*16*	34	5.5	*14*			
100k	32	7.3	*18*	33	6.5	*17*	33	5.9	*15*	34	6.9	*17*
125k	32	7.5	*19*	33	6.5	*17*	33	6.4	*16*			
	Tons	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*

Average Demand Hour NOx Reductions -- PowerWorld

NOx	Unconstrained			OPF			SCOPF			SCOPF All Constraints		
Price	NOx	Reduction	%	NOx	Reduction	%	NOx	Reduction	%	NOx	Reduction	%
2k	20	--	--	20	--	--	20	--	--	17	--	--
10k	18	1.9	*10*	18	1.7	*9*	18	1.9	*10*	17	0.5	*3*
20k	17	2.4	*12*	17	2.6	*13*	17	2.6	*13*			
30k	16	3.7	*19*	16	3.8	*20*	16	3.8	*20*			
50k	12	7.2	*37*	12	7.3	*37*	12	7.3	*37*	16	1.7	*10*
75k	10	10.0	*51*	10	9.8	*50*	10	9.9	*50*			
100k	8	11.2	*57*	8	11.3	*58*	8	11.3	*58*	12	5.7	*33*
125k	8	11.8	*61*	8	11.9	*61*	8	11.9	*61*			
	Tons	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*

The set of 64 contingency constraints, reflected in the "SCOPF" panel of Table 5, slightly reduced the estimates of potential reductions in the high demand case at NO_X prices below \$125,000/ton. But, these constraints did not affect the results in the average demand case. Notably, the addition of the larger set of contingency constraints affected the estimates in the average demand case more than in the peak demand case (comparing the panels labeled "SCOPF" and "SCOPF All Constraints" in Table 5). This is not surprising because the peak demand cases were modeled after the conditions on August 4th, 2005 at 2 pm and the 64 initial contingency constraints were those that affected the network in that hour. The average demand case, however, has load characteristics similar to those from an average demand hour in July of 2005 and other contingency constraints were binding given those conditions.

It is also possible that the consideration of the entire set of contingency constraints is overly restrictive. PJM reports on its website that they do not always enforce all contingency constraints and their operating procedures allow for the system operators to use their judgment with regard to whether lines can be overloaded.[50] Even in the case with 64 contingency constraints, some of the contingency constraints that are binding, and therefore affect the dispatch of generating units, occur for lines that are only loaded at about 30% during normal operation (i.e. when the contingency does not occur). The initial levels of NO_X emissions and LMPs in the PowerWorld simulations most closely match those observed, for similar demand, when we utilize the smaller set of contingency constraints (see Appendix C for further discussion). For example, the NO_X emissions are only 17 tons, instead of about 20, for the base case (2k) in the SCOPF simulations with the full set of contingency constraints for the average demand hour.

Understanding The Impact of Network Constraints on Potential NO_X Reductions

The most striking feature of the results reported in Tables 4 and 5 is that transmission constraints do not significantly reduce potential NO_X emissions reductions from redispatch in Classic PJM. There are three primary reasons for this result. The first is related to the spatial heterogeneity in the low and high NO_X generating units in PJM. High NO_X units are not mostly in one area of PJM and low NO_X units in another; they tend to be located together *within* the zones created by transmission constraints. This is particularly important in high demand hours. In these hours congestion is less of a problem if local demand is predominantly filled by local generation. If there is significant local NO_X-rate heterogeneity then NO_X emissions can be reduced without substantial increases in the utilization of transmission lines.

Figure 3 suggests that there is local heterogeneity in the NO_X emission rates of generating units. The figure shows distributions of generation over NO_X rate for all units, for only coal units, and for all units located in Middlesex County, NJ. The two lines represent generation as observed and as simulated when all units have been redispatched to minimize NO_X constraints using the zonal model. As would be expected, the range of the distribution of generation across NO_X emission rates is similar among the three panels and it is not significantly changed in the low NO_X case. The trimodal distribution that is

[50] See PJM's information on Contingencies at http://www.pjm.com/markets/energy-market/lmp-contingencies.html.

observed for all units in Classic PJM is as true for coal units as it is for the entirety of units and it is still evident in the distribution for Middlesex County. The main effect of the Low NO_X Case is to shift generation from the high (> 4 lbs/MWh) part of the distribution to the two lower modes for all three cases. The shift is particularly evident in Middlesex County where the share of generation in the high emission rate segment is reduced by about two-thirds. In cases like this, which occur in many of sub-regions of Classic PJM at the county-scale, transmission constraints are simply not a problem.

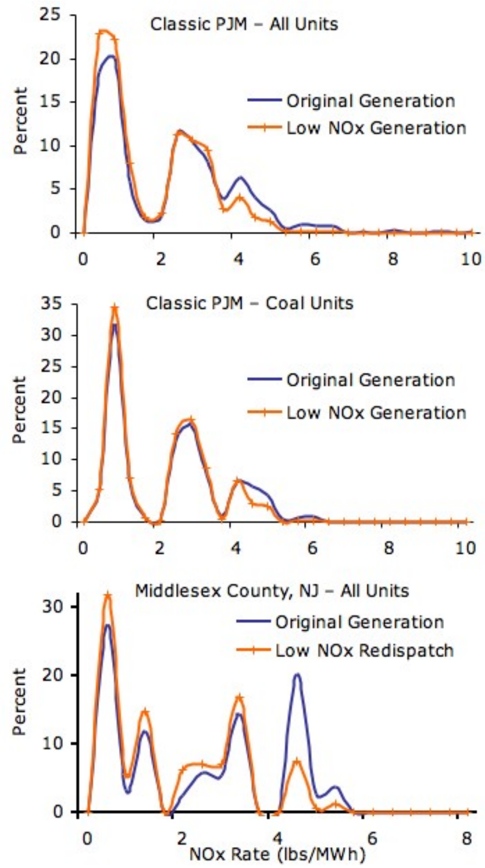

Figure 3 Distributions of generation over NO_X rate for all units in Classic PJM, for coal units in Classic PJM, and for all units in Middlesex County, NJ. If a heat rate of 10 mmBTU/MWh is assumed, these NO_X emissions rates translate to the equivalent NO_X emission rate in lbs/mmBTU by dividing by a factor of 10. Redispatched cases are from the zonal model for August 4th, 2005 at 2 pm.

The second reason for the small effect of transmission constraints is that, to the extent low-NO_X generation is located at one end of a congested line, it tends to be on the high-LMP side of the constraint. For example, the capacity-weighted average NO_X emission rate of the units on the low-LMP side of the frequently constrained 10THST to OST line was 3.1 lbs/MWh in the summer of 2005, while that on the high-LMP side was 1.8 lbs/MWh. On August 4th, 2005 at 2 pm, the generation on the low-LMP side of this constraint had an average NO_X rate of 2.6 lbs/MWh and that on the high-LMP side an average NO_X rate of 1.7 lbs/MWh. Anything that would increase the use of unused low-NO_X generation on the high-LMP side of the constraint in place of the higher-NO_X generation on the low-LMP side will relieve the transmission constraint. Here again, the transmission constraint was not a problem because the NO_X-reducing exchange creates a flow in the opposite direction.

The third and final reason is that NO_X reducing substitutions involve small amounts of generation, especially in the peak hour. In peak demand hours in PowerWorld and the Zonal Model, the simulations exchanged about 4.5 GW of generation to reduce emissions to the physical limit, within a set of units contributing about 35 GW total. In the average demand hour, the simulations exchanged about 8.5 GW of generation out of about 20 GW total generation from the same set of units.

Locational variation in potential NO_X reductions

The location, in addition to the time, of NO_X reductions affects their impact on ozone formation. One of the first criticisms of the cap-and-trade approach was that "hotspots" could result because these programs have not traditionally captured time and locational variations of the impacts of emissions on air quality standards. These hotspots, which have not been shown to occur in any of the currently implemented cap-and-trade programs, would occur when sources in an environmentally sensitive area chose to buy permits for their pollution, rather than taking actions that resulted in abatement.[51] This motivates the question of whether the redispatch of units to reduce NO_X is accompanied by substantial increases in NO_X emissions in some geographic areas.

It is certainly true that on the level of individual plants, some locations will produce more and some will produce less NO_X as a consequence of redispatch. But, at a higher level of aggregation it is not necessarily true that the redispatch, which results in a net reduction of NO_X, will result in areas with significantly higher NO_X emissions. Table 6 shows the original NO_X emissions and generation by county for August 4th at 2 pm. It also shows the changes in NO_X and generation due to redispatch subject to network transmission constraints (the "network-constrained" case only).

The table shows only those counties in which the redispatch reduced NO_X by at least 300 lbs or where it increased NO_X by at least 10 lbs. Net NO_X emissions only increased in 11 counties (of 56) in Classic PJM. In some counties, like Prince George's county in Maryland, total generation increased but total NO_X still decreased. Depending

[51] For a summary of analyses of these issues see Swift (2004).

on the meteorology and atmospheric chemistry conditions these reductions and slight increases in NO_X could affect local ozone formation or that in downwind counties.

Table 6 Original emissions and generation and changes in both at the county-level for simulated redispatch subject to network constraints on August 4th, 2005 at 2 pm in the zonal model. The chart shows counties that had a net reduction in NO_X of at least 300 lbs (negative Delta NO_X) and those that had a net increase in NO_X of at least 10 lbs.

Changes in NOx Emissions by County -- Zonal Model

STATE	COUNTY	NOx	Delta NOx	Generation	Delta Gen
NJ	Hudson	4581	-3153	906	-457
NJ	Middlesex	4651	-1716	1721	-56
PA	Northampton*	6481	-1716	2769	-281
NJ	Burlington	2553	-1557	152	64
MD	Baltimore	2605	-1451	462	-191
DE	New Castle	3650	-1159	1369	-30
NJ	Cape May	1752	-1134	431	-217
PA	Clearfield	1464	-967	348	-229
MD	Charles	5240	-886	1395	-144
MD	Harford	1146	-749	267	39
MD	Prince George's	5283	-715	2097	120
NJ	Mercer	733	22	628	20
PA	Montour	508	23	1474	64
PA	Wyoming	85	26	43	13
PA	Philadelphia	546	32	273	34
NJ	Union	247	49	1530	307
PA	Berks	592	77	215	28
NJ	Ocean	409	80	557	95
PA	Lebanon	0	88	0	475
PA	Venango*	81	213	0	258
PA	Delaware	3141	257	1360	111
DC	DC	613	1011	271	279
		(lbs)	*(lbs)*	*(MW)*	*(MW)*

* The positive NOx emissions (81 lbs) in Vanango County that are accompanied by 0 MW of generation are caused by a generating unit with positive heat input that is likely ramping up or down or supplying auxilary power.

The magnitudes of the increases in NO_X in the 11 counties were generally small; most increases in NO_X were below 100 lbs. The major exception is Washington DC. An increase in generation of about 279 MW caused an increase in NO_X emissions of about 1000 pounds per hour in DC. If this increase in NO_X in DC were unacceptable due to its impact on ozone formation, the increase in generation could be filled by other generators for a slight penalty in the overall decrease in NO_X. Additionally, if DC were combined with surrounding Maryland counties, the total change in NO_X emissions in the four counties together would be a <u>reduction</u> of about 640 lbs of NO_X.[52]

Atmospheric chemistry and meteorological modeling will be necessary to identify which reductions and increases in NO_X are important for mitigating the formation of ozone in targeted areas. The literature suggests that categorizing the relationships

[52] These counties are Montgomery, Prince George’s, and Charles counties in Maryland and the District of Columbia.

between NO_X emissions, meteorology, and ozone in defined geographic areas is possible. For example, Lehman *et. al.* (2004) studied rural and suburban ozone concentrations in the Eastern United States between 1993 and 2002. They found that the Eastern U.S. could be divided into five distinct regions (e.g. Mid-Atlantic, Great Lakes) that each exhibited distinct temporal patterns (e.g. seasonal trends and persistency) in ozone concentrations. They suggest that their "results imply that there is a statistically based rationale for delineating geographical areas when interpreting O_3 concentrations" (Lehman *et. al.* 2004, page 4368). They propose further work that will categorize the effects of meteorology on ozone concentration in a similar manner. Our research requires this categorization to go one step further by accounting for the effect of regional NO_X emissions on ozone formation in addition to the effects of meteorology.

Benchmark comparisons for NO_X permit prices

The estimates of the levels of NO_X permit prices needed to cause NO_X reductions from redispatch in Classic PJM can be compared to the costs of some alternative NO_X control measures. Generators might consider investing in these technologies in response to NO_X "price spikes" of this magnitude realized during high ozone episodes or, as is the case in the OTC, regulators might provide incentives for their use.

A recent OTC Memorandum of Understanding (MOU) signals an intention by the signatory states to reduce emissions on high electricity demand days.[53] The MOU does not fully define a high electricity demand day. Some related analysis suggests that these are the days on which the high demand requires peaking units that typically generate in less that 10% of annual hours to generate power (NESCAUM 2006). Four of the signatory states are in the Classic PJM region and the MOU requires these states to make total daily NO_X reductions of about 72 tons on high electricity demand days.[54]

[53] The states agreed to make the reductions beginning in 2009 and no later than 2012. See, OTC's "Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electrical Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning," March 2, 2007. See also, infra notes 55, **Error! Bookmark not defined.**, and NESCAUM 2006.

[54] The four signatory states that are in the Classic PJM area are DE, MD, NJ, and PA. The other signatory states are CT and NY.

The MOU does not require specific actions to reduce the peak demand day emissions and it notes that the reductions could come from controls on peaking units or through other measures like energy efficiency or demand response. As an example of action that states could take to control these emissions, EPA calculates that the cost-effectiveness of installing water injection NO_X control technology on peaking units in the Northeastern U.S. would be about $158,000/ton to reduce NO_X by 2.71 tons over a 12-day, high-electricity-demand period for each unit that installed the technology.[55] The increase in total system operating costs per ton of NO_X reduced in the PowerWorld peak SCOPF case for a NO_X prices of $10,000/ton was about $113,000/ton for *hourly* NO_X reductions of 3.5 tons. A NO_X price of $20,000/ton in the average hour SCOPF case cause an increase in total operating cost of about $169,000/ton for hourly reductions of 2.6 tons. For a day with 8 “peak” hours and 16 “average” hours with these NO_X prices, the total NO_X reduction would be about 70 tons daily at an average cost of about $144,000/ton. According to the EPA’s calculation, 310 peaking units would need to install the water injection technology to achieve the same daily reductions.[56]

Redispatch appears approximately comparable on a cost per ton basis with controlling NO_X emissions from infrequently used peaking units, although other control options may also be available. One of the benefits of time varying NO_X prices is that the control decisions could be made through decentralized market incentives rather than by regulatory fiat. Another related benefit is that, with the incorporation of air quality forecasting, these costly reductions could come during the times and locations that would most likely impact ozone formation in critical areas – rather than from a specific, predefined set of generating units.

While the focus here, and the primary focus of regulators, has been on reducing NO_X emissions from electric generators, another option is to tighten controls on NO_X emissions from mobile sources. Accordingly, another potential benefit of a transparent time varying NO_X pricing system is that it will also make the need to undertake

[55] EPA Clean Air Markets Division presentation by Chitra Kumar, “High Electricity Demand Day Attainment Strategies for the OTC,” December 6, 2006.

[56] NESCAUM (2006) states that there are 477 combustion turbine peaking units in the OTC region (pg. 18), the EPA modeled the costs for water injection for uncontrolled combustion turbine peaking units.

potentially economic opportunities to reduce NO_X emissions from mobile sources more transparent. Although this option is not typically discussed as a targeted action, it could be. For example, the variable cost of using selective-catalytic reduction (SCR) on diesel trucks is high due to the cost of urea. The use of these controls could be mandated only in locations and at times when the NO_X reductions would reduce the formation of ozone in highly populated areas. A pricing system could also be used to deter driving during specific periods and in highly populated areas where the resulting reductions in NO_X emissions would reduce the likelihood of high ozone concentrations. Because controlling NO_X emissions from vehicles has not been thoroughly analyzed as an option to target ozone episodes, it is difficult to find cost information to compare to the above estimates of short-term reductions in NO_X from stationary sources. But, because little has been done to reduce NO_X from mobile sources, especially in comparison to the number and stringency of NO_X regulations on stationary sources, it is possible that the reductions would be less expensive than further reductions from stationary sources.[57]

For comparison to these cost examples, Mauzerall *et. al.* (2005) estimated the damages of ozone per incremental ton of additional NO_X emissions to be between about $13,000 and $64,000 per ton.[58] As discussed throughout this paper, the effectiveness and therefore cost-effectiveness of any of these options depends on details of meteorology and atmospheric chemistry. Bluntly mandating the installation of water injection or SNCRs on generating units or the control of mobile source emissions might not reduce NO_X where it would most likely cause reductions in ozone concentrations in highly populated areas. Similarly, flexibility to reduce emissions through redispatch might be very costly in the most important subregions of PJM and other regions of the Eastern United States.

[57] In a general, non-targeted sense, the cost effectiveness of retrofitting heavy-duty on-road vehicles with SCRs is about $5,000/ton over the lifetime of the equipment. EPA, "NO_X Mobile Measures", available at www.epa.gov/air/ozonepollution/SIPToolkit/documents/nox_mobile_measures.pdf.

[58] Mauzerall *et. al.* (2005) page 2863. Estimates converted from 1995 to 2005 dollars with a Consumer Price Index conversion factor of 0.78.

Section 5. Conclusion

Ozone episodes continue to be a problem in some highly populated areas of the Eastern United States and are expected to continue to be a problem despite aggressive regulatory measures to reduce precursor NO_X emissions. The problem may lie in the mismatch between the relatively uniform incentives to reduce NO_X provided by existing regulatory systems and the highly variant temporal and locational impact of NO_X precursor emissions on ozone formation in any given area. Indeed, in related work we have found evidence that NO_X emissions are reduced at times during the summer season when the formation of ozone is unlikely and when the damages caused by ozone are relatively low. We hypothesize that a time- and location-differentiated cap-and-trade program implemented using ozone forecasting to alter NO_X emission permit exchange ratios in a wholesale electricity market that uses bid-based, security-constrained economic dispatch could help the states in the Eastern U.S. reduce the likelihood of peak ozone episodes cost effectively.

As a first step in testing this hypothesis, we simulated the potential magnitude of NO_X reductions from the redispatch of generating units in the area of Classic PJM, while taking transmission constraints into account. We used two methods to perform the simulations and found that hourly reductions of between 6 and 10 tons (or from 15% to 55%) were possible on the highest demand days of 2005 in Classic PJM. The magnitudes of potential hourly reductions depend on the time of day and the corresponding level of electricity demand. These region-wide net reductions are not accompanied by "hotspots" – large increases in NO_X in subareas of Classic PJM.

Future work will link the estimates of potential reductions from power plants to weather forecasting and atmospheric chemistry models in order to determine if the simulated NO_X reductions are of the necessary magnitude to reduce the likelihood of ozone episodes. We will extend the security constrained optimal power flow modeling by modeling peak hours and including more detailed cost curves for large coal-fired power plants.[59] The redispatch analysis reported here involves a significant amount of substitution of relatively low-NO_X rate natural gas units for relatively high-NO_X rate coal units. Given the large differences between coal and natural gas prices in 2005, we will not be surprised if we continue to find that high NO_X permit prices are required to induce significant changes in redispatch mediated through wholesale power markets and higher spot prices for electricity when and where ozone formation conditions trigger high surrender values for NO_X permits.

Ozone is an episodic problem and numerous conditions, including wind, sunlight, and concentrations of VOCs, determine whether a reduction of NO_X at a given time and location will lead to reductions of ozone in a target area. Advances in liberalized wholesale electricity markets, weather forecasting, and cap-and-trade mechanisms provide an opportunity to address the ozone problem in a more cost-effective manner by matching NO_X reductions to when and where they will help reduce ozone formation. Although much work remains, our initial result is encouraging because it suggests that an important pre-condition for the implementation of a time and location differentiated regulatory system is satisfied, namely, the existence of significant flexibility to reduce NO_X precursor emissions through the redispatch of power plants on hot summer days when ozone formation is most likely and the electricity system is most likely to be constrained.

[59] Mobile sources also emit a large portion of NO_X emissions (about 60% of annual NO_X emissions in the Eastern U.S.) and may also be important for reducing ozone. Mobile source emissions are higher in urban areas and during the day and their impacts on ozone, which could be positive or negative, will be a factor in determining where and when hourly NO_X reductions of about 10 tons from power plants could reduce peak ozone concentrations.

References

Bell, M. L., A. McDermott, S.L. Zeger, J.M. Samet, and F. Dominici, (2004), "Ozone and Short-term Mortality in 95 US Urban Communities 1987-2000," *J. Am. Med. Assoc.* **292**; 2372-2378.

Borrell, P., (2003) "The Weekend Effect," *The Royal Society of Chemistry*: *chembytes e-zine,* May (http://www.chemsoc.org/chembytes/ezine/2003/borrell_may03.htm).

CARB: California Air Resources Board, (2004). "The Ozone Weekend Effect in California" at http://www.arb.ca.gov/aqd/weekendeffect/weekendeffect.htm retrieved November 15, 2006.

Chameides, W.L., R.W. Lindsay, J. Richardson, and C.S. Kiang (1988). "The Role of Biogenic Hydrocarbons in Urban Photochemical Smog: Atlanta as a Case Study," *Science* **241**(4872); 1473-1475.

Chen, W.Y. (1989). "Estimate of dynamical predictability from NMC DERF Experiments," *Mon. Wea. Rev.* **117**;1227-1236.

Decker, C.E., L.A. Ripperton, J.J.B. Worth, F.M. Vukovich, W.D. Bach, J.B.-Tommerdahl, F. Smith, and D.E. Wagoner (1976). "Formation and Transport of Oxidants Along Gulf Coast and in Northern U.S." *EPA-450/3-76-003*. U.S. Environmental Protection Agency, Research Triangle Park, N.C.

Energy Information Association. (EIA 2006), "Assumptions to the Annual Energy Outlook," DOE/EIA-0554(2006).

Fiore, A.M., D.J. Jacob, I. Bey, R.M. Yantosca, B.D. Field, and A.C. Fusco, (2002). "Background ozone over the United States in summer: Origin, trend, and contribution to pollution episodes," *Journal of Geophysical Research* **107**(D15); 10.1029.

Hogan, W. (1999), "Transmission Congestion: The Nodal-Zonal Debate Revisited," Harvard University, John F. Kennedy School of Government, available at http://ksghome.harvard.edu/~whogan/nezn0227.pdf, retrieved November 21, 2006.

Joskow, P.L. (2006), "Markets for Power in the United States: An Interim Assessment," *Energy Journal*, **27**(1); 1-36.

Joskow, P.L. and E. Kahn, (2002), "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," *The Energy Journal*, **23**(4); 1-35.

IPCC (1999). "Aviation and the Global Atmosphere," A Special Report of the Intergovernmental Panel on Climate Change Working Groups I and III in collaboration with the Scientific Assessment Panel to the Montreal Protocol on Substances and Deplete the Ozone Layer at http://www.grida.no/climate/ipcc/aviation/index.htm.

Lehman, J., K. Swinton, S. Bortnick, C. Hamilton, E. Baldridge, B. Ender, and B. Cox (2004). "Spatio-temporal characterization of tropospheric ozone across the eastern United States," *Atmos. Environ.* **38**; 4357-4369.

Mauzerall, D.L., B. Sultan, N. Kim and D.F. Bradford (2005). "NO_X emissions from large point sources: variability in ozone production, resulting health damages and economic costs" *Atmospheric Environment* **39**(2005); 2851-2866.

Mansur, E. (2006a). "Prices vs. Quantities: Environmental Regulation and Imperfect Competition", mimeo, July, available at http://www.som.yale.edu/faculty/etm7/ retrieved November 27, 2006.

Mansur, E. (2006b). "Do Oligopolists Pollute Less? Evidence from a Restructured Electricity Market," June 8, *Journal of Industrial Economics*, forthcoming, available at http://www.som.yale.edu/faculty/etm7/ retrieved November 27, 2006.

Montgomery, D.W. (1972). "Markets in Licenses and Efficient Pollution Control Programs," *Journal of Economic Theory* **5**; 395-418.

Mendelsohn, R. (1986). "Regulating Heterogeneous Emissions," *Journal of Environmental Economics and Management* **13**(4); 301-312.

Northeast States for Coordinated Air Use Management (NESCAUM 2006). "High Electric Demand Day and Air Quality in the Northeast," *White Paper*, June 5, 2006 at http://www.nescaum.org/documents/high-electric-demand-day-and-air-quality-in-the-northeast/.

Overbye, T.J., X. Cheng, and Y. Sun (2004). "A Comparison of the AC and DC Power Flow Models for LMP Calculations," *Proceedings of the 37th Hawaii International Conference on System Sciences*.

RTI: Research Triangle Institute (1975). "Investigation of Rural Oxidant Levels as Related to Urban Hydrocarbon Control Strategies." *EPA-450/3-75-036.* U.S. Environmental Protection Agency, Research Triangle Park, N.C.

Ryerson, T.B., M. Trainer, J.S. Holloway, D.D. Parrish, L.G. Huey, D.T. Sueper, G.J. Frost, S.G. Donnelly, S. Schauffler, E.L. Atlas, W.C. Kuster, P.D. Goldan, G. Hu, J.F. Meagher, and F.C. Fehsenfeld (2001). "Observations of Ozone Formation in Power Plant Plumes and Implications for Ozone Control Strategies," *Science* **292**(5517); 719-723.

PJM (2006). "2005 State of the Market Report," March 8 (Available at http://www.pjm.com/markets/market-monitor/som.html)

Schweppe, F.C., M.C. Caramanis, M.C. Tabors, D. Richard, and R.E. Bohn (1988). *Spot Pricing of Electricity*, Boston, Kluwer.

Stoft, S. (1997). "Transmission Pricing in Zones: Simple or Complex?" *The Electricity Journal* **10**(1), January/February; 24-31.

Sun, D.I., B. Ashley, B. Brewer, A. Hughes, and W. F. Tinney (1984). "Optimal Power Flow by Newton Approach," *IEEE Transactions on Power Apparatus and Systems*, **PAS-103**, October; 2864-80.

Swift, B. (2004). "Emissions trading and hot spots: a review of the major programs," *Environmental Reporter* **35**(19); 1-18.

Tietenberg, T. H. (1995). "Tradeable Permits for Pollution Control When Emission Location Matters: What Have We Learned?" *Environmental and Resource Economics* **5**(2); 95-113.

Tong, D.Q, N.Z. Muller, D.L. Mauzerall, and R.O. Mendelsohn (2006). "Integrated Assessment of the Spatial Variability of Ozone Impactgs from Emissions of Nitrogen Oxides" *Environmental Science & Technology* **40**(5);1395-1400.

U.S. Army Corps of Engineers, (1998). "Air Pollution Control Systems for Boilers and Incinerators", *U.S. Army Corps of Engineers Technical Manual*, TM 5-815-1/AFR 19-6, May 9. See especially, Chapter 11, "Nitrogen Oxides (NO_X) Control and Reduction Techniques," available at www.wbdg.org/ccb/ARMYCOE/COETM/tm_5_815_1.pdf, retrieved November 24, 2006.

U.S. Environmental Protection Agency (U.S. EPA 2003). "Latest Findings on National Air Quality: 2002 Status and Trends," Research Triangle Park, NC: Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division; *EPA 454/ K-03-001*, August.

U.S. Environmental Protection Agency (U.S. EPA 2006a). "Air Quality Criteria for Ozone and Related photochemical Oxidants," Research Triangle Park, NC: Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office; EPA report no. 600/R-05/004aF, especially Chapters 4 through 8.

U.S. Environmental Protection Agency (U.S. EPA 2006b). "NO_X Budget Trading Program: 2005 Program Compliance and Environmental Results," *EPA430-R-06-013*, September.

van den Dool, H.M., and S. Saha (1990). "Frequency dependence in forecast skill," *Mon. Wea. Rev.* **118**;128-137.

Appendix A

Relationship between NO_X emission rate and level of generator output

The relationship between NO_X formation and combustion temperature causes the NO_X rates of some generating units to increase as the level of generation increases. Figure 4 shows an example of this phenomenon for a coal-fired power plant.

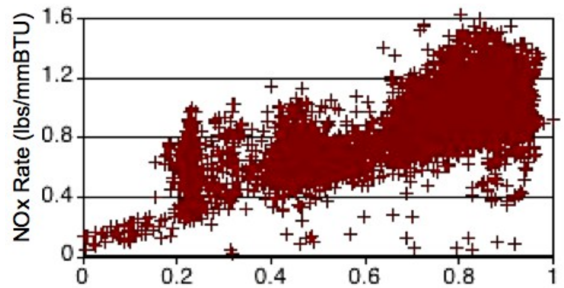

Figure 4 Plot of NO_X rate versus percent of capacity for a coal-fired power plant in PJM.

In power plants, the primary formation mechanism for NO_X is the high temperature fixation reaction of nitrogen and oxygen that occurs in high temperature zones of the furnace. Nitrogen is present in combustion air, in the excess air in the combustion zone, and in fuel. At low combustion temperatures fuel nitrogen contributes significantly, but it is less important at high combustion temperatures because atmospheric nitrogen contributes more to the NO_X-forming reactions. The concentration of NO_X in plant emissions increases with temperature of the combustion gas, the availability of oxygen, and the duration for which oxygen and nitrogen are exposed to peak flame temperatures. Load reduction decreases heat release rate and furnace temperature. Thus, lower furnace temperatures decrease the *rate* of NO_X formation. Lower furnace temperatures do not affect the conversion of fuel-bound nitrogen as much as the formation of NO_X from atmospheric nitrogen (U.S. Army Corps 1998). Future analysis with generating unit marginal cost curves will also use marginal emission rates because of these relationships.

Appendix B

Method for matching generator data to PJM FTR load flow cases

We first matched the EIA and EPA generating unit-level data to the FTR network model by substation. But, within the substations it is sometimes difficult to determine which generating unit should be assigned to which generating bus. Some substations have over ten generating unit buses, which are all located at the same voltage level on the network. But, the buses are not identical because buses within each substation connect to lines with different characteristics and to different buses in the remainder of the PJM network. Given this type of ambiguity, we used a simple method to match the generating units to buses within each substation.

If the FTR model included generation data for a unit, we first matched the units with the same hourly generation in the EPA database for days during the same time of year and level of demand as represented by the FTR model. Then, for the remaining units, we matched those with the largest capacities in the EIA data to those with the highest generation in the FTR model. If all the units in a substation had zero or the same generation in the FTR model, we matched the units to the EPA units at random. Some further changes to the locations of generators were made on a case-by-case basis as described in Appendix C.

Appendix C

Method for scaling the PJM FTR load flow cases to approximate peak demand hours

The monthly FTR base case for July that PJM posted in July 2006 represents an hour with about 77 GW of load in PJM and 35 GW of load in Classic PJM. This was about average for the ozone season of 2005. We refer to this case as the “average demand” case for the PowerWorld simulations. The set of fossil-fuel-fired generating units in Classic PJM for which we have emissions data generated about 19 GW on average during the 2005 ozone season and also generated about 19 GW in this FTR case. We imported cost curve data into PowerWorld for this set of generators; these are the generators that we “dispatch” and those to which the NO_X price applies. We refer to these generating units as the “Classic PJM fossil units” and in each case we hold their total generation constant, the NO_X prices causes the reallocation of this generation to units with lower NO_X rates.

In order to simulate NO_X reductions from redispatch for an hour with peak conditions, and because detailed data on nodal loads during peak conditions were not available to us, we scaled the load data in the average demand case.[60] This was not a straightforward exercise because loads on network do not scale uniformly from average to peak demand hours; the electricity demand increases more in some areas than in others. The patterns of load impact congestion and the corresponding LMP patterns. In order to simulate a peak hour with similar characteristics to observed peak hours we used observed generation data from the fossil-fired units in Classic PJM (from the EPA’s CEMS data) and scaled the loads until we observed LMP patterns and congested lines that were reasonably similar to those observed in Classic PJM in the 2005 ozone season.

Loads of over 50 GW and generation of about 35 GW from the Classic PJM fossil units characterized peak demand hours in Classic PJM in the summer of 2005. The EPA’s CEMS data indicated that the Classic PJM fossil units generated about 33 GW on August 4th, 2005 at 2 pm – one of the peak hours. We used these unit-level data for the initial generation of Classic PJM fossil units and assumed that generation remained constant from nuclear, hydro and other units not included in the EPA’s CEMS data. For the latter units, we used the generation data from the July FTR case. Holding the generation of these units constant is a reasonable assumption for the nuclear plants, which typically generate near their capacities in all hours, but may be a simplification for the other units. This assumption likely only created slight changes in the results because of the small contribution of these other units: EIA data suggest that hydro, wind, and fossil units for which we do not have data contribute about 5 GW of about 67 GW capacity in Classic PJM (about 7%). Additionally, if these units could respond to higher NO_X prices, excluding them from our estimates of potential NO_X reductions makes our estimates conservative.

[60] As mentioned earlier, we will update these results if we gain access to a peak demand load flow base case, see supra note 42. Hourly load data are only available at the zonal level: PJM, “Hourly Load Data”, available at http://www.pjm.com/markets/jsp/loadhryr.jsp.

The zonal model indicated that network congestion created about 11 zones with constant LMPs on August 4th 2 pm. In order to try to recreate these LMP and congestion patterns with PowerWorld, we first calculated the factors by which the generation from Classic PJM fossil units in each zone increased between the average demand case and August 4th 2 pm observed data. We then scaled the nodal loads in zones with higher than average LMPs by factors slightly higher than the corresponding generation scaling factor (and vice versa for zones with lower LMPs). We did this because it is likely that zones on the high-LMP sides of congested lines are net-importers of power because congestion reflects the fact that the high-LMP area is importing as much power as possible from remote generators with lower costs. We scaled the load in Classic PJM to about 53 GW using this method and imported the new load data into PowerWorld.

The inaccuracies inherent in our method of scaling the nodal loads and those in our method of matching generator data to the buses in the FTR case (Appendix B) caused some problems for solving the power flow simulations. The optimal power flow simulations dispatch generators, according to their marginal costs, to meet all loads while minimizing system operating costs and meeting a set of inequality constraints. These inequality constraints include generator and transmission line capacities. In our cases, we do not allow PowerWorld to dispatch the nodal loads: the generating units are the only "controls" that can be changed to minimize cost while holding demand constant. It is sometimes not possible for the generating units to be dispatched to both fill load and meet all the inequality constraints. In this situation, PowerWorld prioritizes filling the load and it reports "unenforceable" line or generator constraints. The flows on lines with "unenforceable" constraints exceed their rated capacities. These overloaded lines may actually occur in reality and be acceptable: lines' capacities vary with external conditions like the weather and the system operator has the discretion to adjust the lines' ratings in real-time while we do not have enough information to do so. Unenforceable constraints in our simulations may also be an artifact created by the inaccuracies of our load and generator data. If, for example, we incorrectly placed a generator at a bus it might cause large flows over a line that was not intended to handle them.

We observed unenforceable constraints in both the average and peak cases. We adjusted some of the locations of the generators and the magnitudes of the scaled loads in the peak case to mitigate these problems, but were not able to remove all of the unenforceable constraints. Depending on the case, we observed between zero and about twenty unenforceable constraints out of over 3100 lines (less than 1%). Because of these inaccuracies, we report our simulation results in relative terms (e.g. we compare the higher NO_X-price cases to the \$2,000/ton NO_X price case) rather than as absolute results compared to observed data for the modeled hour (e.g. August 4th at 2 pm).

Given the matching and scaling inaccuracies, the simplified cost curves, and the fact that PowerWorld does not allow for simulation of ancillary services markets, it was not possible to fully recreate historical conditions. We do reproduce the correct magnitudes of demand, fossil generation, NO_X emissions, and congestion and therefore believe that our results are reasonably representative of a power system similar to Classic PJM. From the scaled load and generation data described above, we created two peak load flow cases that reproduced the general characteristics of historical conditions by adjusting the nodal load data in the scaled case incrementally after loading the data into PowerWorld. One of these cases approximated the patterns of LMP observed on August 4th at 2pm ("Matched LMPs") and the other better approximated the observed contingency constraints ("Constraints"). The Classic PJM fossil units generated about 34 GW and emitted about 35 tons of NO_X in both simulations; the total load was about 53 GW. For comparison, on August 4th at 2 pm the observed total load in Classic PJM was about 59 GW and Classic PJM fossil units generated about 35 GW and emitted about 38 tons of NO_X. On August 3rd at 2 pm, another peak demand hour in PJM, the total load was about 54 GW and the fossil units generated about 33 GW and emitted about 35 tons of NO_X.

On August 4th at 2pm PJM reported active contingency constraints for five lines. We were able to reproduce two of these in the Matched LMPs case and four in the Constraints case, while assuming NO_X prices of \$2000/ton. In addition, in the Matched LMP case we recreated the basic patterns of LMPs. For example, the constraint that caused the most variation in LMP in the observed hour was the Cheswold-Kent line. The nodes on the low side of this constraint had LMPs about 9% below average and those on the high side had LMPs about 60% above average (the observed mean LMP in this hour was \$287/MWh). In the Matched LMPs case the nodes on the high and low side of this constraint also had the largest differences in LMP: 51% below average on the low side and 274% above average on the high side (the mean LMP in this simulation was \$129/MWh). Although the magnitudes of LMPs are different between the simulated and observed cases, the patterns are similar. The inaccuracies discussed above contribute to these differences. In particular, generator cost curves typically increase steeply at high capacity factors and our simplified cost curves do not account for this.

In the third peak case, we increased the share of total generation from the Classic PJM fossil units by decreasing the assumed generation from other units. As in the other two peak cases, the total load was bout 53 GW, but in this case the fossil units in Classic PJM generated about 37 GW and emitted 39 tons of NO_X. This case was intended to simulate a worst-case scenario. The simulations hold the total generation from the Classic PJM fossil units constant and the NO_X reductions in response to the NO_X price can only come from the reallocation of generation between the units. Requiring these units to generate more reduces the flexibility to reduce emissions through redispatch because it reduces the excess capacity of the units that can be redispatched.