*Preliminary Draft Not for Citation*

# 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

**January 1, 2007**

MIT

---

[*] 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 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 either requires sources to adopt a specific emissions control technology or places a limit on their emission rates, 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 control in the

---

[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.

Northeast, this program fails to differentiate at the fine temporal and locational resolution that is 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 or whether such a program could be implemented. The difficulties associated with implementing regulations that explicitly deal with the variable impacts of emissions are a central reason why current regulations do not address them (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. We also hypothesize that this can achieve ozone attainment standards more cost effectively than would further reductions in annual or seasonal limits on $NO_X$ emissions from electric generators if the regulation was designed to achieve ambient air quality standards for ozone during the relatively small number of days and hours when they are now exceeded at a relatively small number of locations. 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.[2]

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

---

[2] The wholesale electricity spot market 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.

NOx 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 and electricity demand is at its highest level. This inquiry is motivated by a commonly held misperception that there exists little capability to reduce $NO_X$ emissions at these times because of the near full utilization of all available generating capacity and the higher likelihood of transmission congestion, which could limit opportunities to substitute electricity produced from low-$NO_X$ emitting generators for electricity produced from high-$NO_X$ emitting generators at other locations on the network. As a result, it has been suggested that 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.[3] 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 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. This 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 and heterogeneity in power plant emission rates and commitment that is a prerequisite for a more finely differentiated regulatory system of $NO_X$ control.

---

[3] 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 based at 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 locational differentiated $NO_X$ prices.

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) 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 days 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 this paper we report on our initial efforts to simulate the *potential* magnitude of reductions in $NO_X$ emissions in the "Classic" PJM[4] 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 the Classic PJM region in the United States. We used both a simplified zonal model and an optimal power flow (OPF) 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 $NO_X$ 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 incorporated into generators' bids. These estimates rely on simplified cost-curves for the generating units in Classic PJM and did not consider transmission constraints. Accordingly, the next step in our research will be to examine the magnitude and locations of the $NO_X$-emissions price differences that would be required to yield competitive (and imperfectly

[4] We define "Classic" PJM as generating units located primarily in Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia. PJM 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.

competitive) equilibria in wholesale electricity spot markets, while including transmission constraints. The effect of these price-induced reductions in $NO_X$ emissions on ozone concentrations can then be matched with marginal damage estimates that appear in the literature (for example, see, Mauzerall *et. al.* 2005) 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 that we identify here. Generation owners can also use the time and locational pattern of the resulting prices to evaluate efficient, longer-term responses by generators as they consider the profitability of installing additional $NO_X$ control technology.

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 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 (perverse) abatement behavior does not correspond to periods of high ozone concentrations. In the absence of more finely time-differentiated environmental charges, the timing of $NO_X$ abatement appears to reflect differences in expected electricity prices during the summer season, which are not necessarily correlated with the conditions leading to ozone formation. We also discuss 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. The final section concludes.

## 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.[5] The CAA mandated that the Environmental Protection Agency (EPA) set health-based

[5] 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.

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.[6] The EPA first set the standard for ozone in 1971 and revised it in 1997.[7]

Since 1999, the Eastern states have used seasonal cap-and-trade programs for large stationary sources as one means to try to achieve the ozone NAAQS.[8] 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.[9] 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.[10] However, increases in miles driven have largely offset advances in controls affecting mobile sources. This has left the 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 since the 1980s (Ryerson *et. al.* 2001).[11]

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 District of Columbia.[12] 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

---

[6] 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."

[7] 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.

[8] Specifically, the program is in effect in a summer ozone season (May through September) and it affects 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.

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

[10] Mobile sources contribute about 59% of $NO_X$ emissions in the Eastern states and stationary sources about 22% (U.S. EPA 2006b).

[11] 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.

[12] These states were CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT.

Plans (the "$NO_X$ SIP Call") and it is now called the $NO_X$ Budget Trading Program.[13] 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 Northeastern and 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.

Even so, 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., including most of the densely populated areas, still are not in compliance with the ozone NAAQS.[14] Moreover, the recent Clean Air Interstate Rule (CAIR), which will further tighten constrains on $NO_X$ emissions from stationary sources[15], is not expected bring all the Northeastern states into full compliance (U.S. EPA 2006b).[16] 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 ozone formation could bring the region closer to compliance with these standards and reduce total compliance costs from stationary sources.

---

[13] 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.

[14] In 2004, EPA designated 126 areas as non-attainment for the 8-hour ozone standard based generally on 2001-2003 data. Of these areas, 103 areas lie in the eastern U.S. and are home to about 100 million people. Based on the first three years of the $NO_X$ Budget Program, two-thirds of these areas containing about 20 million people are now in attainment, but problems persist in the remaining third of the areas where most of the affected population live (USEPA 2006b, p. 23).

[15] 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

[16] Also see, for example, the summary of recent modeling by the Ozone Transport Commission by NESCAUM that indicates that CAIR and the $NO_X$ SIP Budget Program will not be enough to bring the northeastern states into compliance with the ozone air quality standards, NESCAUM, "High Electric Demand Day and Air Quality in the Northeast," *White Paper,* June 5, 2006 available at http://www.nescaum.org/documents/high-electric-demand-day-and-air-quality-in-the-northeast/

### *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 types of complications particularly relevant to the regulation of ozone precursor emissions.

Ground-level ozone forms in the lowest level of the earth's atmosphere, the troposphere.[17] The basic reactions are reactions of VOCs that create compounds that react with nitric oxide (NO), the latter being 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:

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

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

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

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 only last for between a few hours and a few days.

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 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 *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. These authors suggest that these relationships should be taken into account when designing $NO_X$ permit trading programs in the Northeastern United States.

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. They chose times and locations 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.[18]

### *Poorly-timed $NO_X$ reductions under the OTC $NO_X$ Budget Trading Program*[19]

The current undifferentiated cap-and-trade system is problematic not just 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 of the season because of variations in the profitability of producing electricity with and without $NO_X$ abatement during the summer season. That is, the incentives in seasonal cap-and-trade programs do not guarantee that reductions in $NO_X$ emissions will occur when they will most likely mitigate ozone formation. When all $NO_X$ emissions within the months of May through September are treated alike, we can expect sources to reduce emissions when it is least expensive and most convenient for them to do so.

One possible reason that plants might prefer to reduce emissions in the May, June, and September rather than in July and August, when ozone formation is a greater problem, is that power prices are typically lower in the months when temperatures are

---

[18] 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.

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

lower. 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 many cases the impact of $NO_X$ creates a tradeoff between reducing $NO_X$ emissions and utilizing less fuel to generate a given amount of power. But, in some cases the tradeoff is more extreme. For some generating units the tradeoff results in an effective reduction in capacity while $NO_X$ emissions are abated. Electricity prices can be very high in July and August. 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.[20] When electricity prices are high, so is the opportunity cost from any reduction in capacity that occurs from operating $NO_X$ control technologies. Plant operators might also reduce risk by reducing emissions early in the season. 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.

The observed behavior, like that shown in Figure 1, suggests that for the owners of at least some generating units have found it more attractive to reduce $NO_X$ emissions only in May and June and not in the later months. However, ozone formation is more likely to be a problem in the warmer months of July and August than in the earlier months. This evidence suggests that at least some of the abatement actions taken under an undifferentiated seasonal program are not well timed with respect to the potential impact of $NO_X$ reductions on ozone formation.

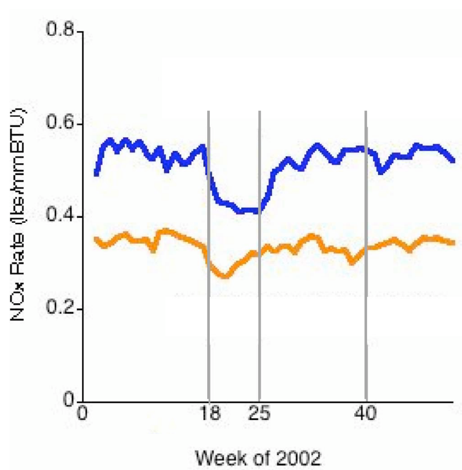


**Figure 1** $NO_X$ rates of two companies' coal-fired generating units over the weeks of 2002. Week 18 corresponds to the first week of May and week 40 to the last week of September.

[20] 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.

### *A time- and location-differentiated cap-and-trade program for $NO_X$*

We hypothesize that the integration of the three components noted earlier – forecast modeling of weather, a cap-and-trade program with hourly monitoring and variable redemption ratios, and liberalized wholesale electricity markets organized around a locational pricing system – could help overcome the challenges of implementing a time- and location-differentiated cap-and-trade program for $NO_X$ and that such a program would be more cost effective than the current, blunt, seasonal cap-and-trade programs in the Eastern United States.

The regulatory system we envisage would be initiated by a forecaster who would provide the independent system operator (ISO) with advance ozone alerts indicating the times and locations when meteorological conditions are conducive to the formation of high ozone concentrations in critical areas (for instance, those in non-attainment), especially those favorable to ozone formation. The ISO would then notify generators that, during a specified time period, $NO_X$ emissions would require the surrender of allowances at a ratio higher than one-to-one for sources located in spatial zones that would be likely contributors to the formation of high ozone concentrations in the critical areas. The relevant emissions permit surrender ratios would be approved in advance by environmental regulators and the authority to implement the approved contingent surrender ratios delegated to the ISO. 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 generator dispatch and locational prices that reflect the prevailing $NO_X$ emissions permit exchange rates.

The effectiveness of the system that we envision rests on four necessary conditions. The first condition 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.[21] The second condition is that the

---

[21] The literature suggests that this may be 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

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 transparent weather and atmospheric chemistry indicators 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 each of these 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 short-term flexibility to reduce $NO_X$ emissions from generating units given realistic assumptions about the electricity markets and physical network in which they operate.

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 the use of emission control technologies. For example, observation of historical compliance with the seasonal cap-and-trade programs suggests that power plant operators

---

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).

can alter the $NO_X$ rates of some units – especially those employing combustion-altering technologies – on the time scale of a few weeks.[22] 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. We focus here on the potential magnitude of reductions in $NO_X$ emissions 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; that is, we set 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, certain 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; but winds can also 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, pages 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

[22] 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. As noted above, there is evidence that these systems are turned on and off not only with the imposition of a price on $NO_X$ emissions during the regulatory ozone season but also within the ozone season. This is the topic of an additional working paper in our research group.

the level of concentration (i.e. without a threshold below which exposure is safe).[23] 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).[24] Technically, ozone attainment status is determined by a three-year average of the 4$^{th}$ 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 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.[25]

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 policymakers will continue to seek to achieve. If indeed a time and location varying regulatory system is feasible and more effective than the currently available undifferentiated system, whether cap-and-trade or command-and-control, then it will be a relatively simple extension of our work to adjust ratios to reflect more accurately the marginal damages associated with given ozone concentrations in various locations.

## Section 3. Methodology

Generating units' marginal costs and emission rates vary with their physical characteristics (e.g. heat rates and boiler type), fuel, size, age, and emission control

---

[23] 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).

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

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

technologies employed. Setting issues of market power aside, a security-constrained, bid-based economic dispatch (in which it is assumed that all generators bid their marginal supply costs) results in the lowest-cost generation filling demand for electricity, given that all the network constraints are met.[26] During the summers when the existing $NO_X$ cap-and-trade programs are in effect, generators' bids may also reflect the costs associated with controlling their $NO_X$ emissions, the opportunity cost of emissions permits that have been allocated to them, or with buying additional emissions permits to cover them. Once we have shown that there is the physical potential for significant $NO_X$ reductions with redispatch, our next step will be to introduce generator cost functions into our models to simulate the levels of $NO_X$ permit prices required to induce various levels of economic redispatch through wholesale market mechanisms. This analysis will first proceed assuming that generating units engage in Bertrand competition since there is little evidence of significant market power in PJM today.[27] However the PowerWorld model integrates unit-specific cost functions with a refined characterization of the PJM network, including congestion and other network constraints. This will allow us to explore the implications of market power as well in future research.[28]

In general, any generating units that are operational and can start-up or ramp-up output quickly enough can be used to fill demand for electricity in an hour. It is the attention to minimizing cost, maintaining system security, start-up and ramp rates, and transmission network constraints that limit the ways in which generating units can be dispatched to fill demand. If, a price on $NO_X$ emissions changes the relative marginal costs of different generators, then the security constrained bid-based dispatch will also change as will the network constraints that are binding and the locational prices for electricity. We use two complementary methods to simulate the potential magnitude of

[26] PJM does not believe market power to be a significant problem, see PJM (2006) pages 59-69 and 83-93.

[27] See PJM 2006 pages 59-69 and 83-93.

[28] 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.

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 detailed unit-level emission rates and balance electricity supply and demand, but the first "zonal" method more accurately incorporates emission rates while the second method, that uses PowerWorld Simulator, an optimal power flow (OPF) model, more accurately simulates network constraints. The two methods yield reasonably consistent results.

***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 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, the redispatch of generating units that minimizes generating costs while taking into account any price placed on $NO_X$ emissions as well as standard marginal generating costs (primarily fuel costs), would be possible for the same levels of demand.

In reality, however, the lowest cost, unconstrained generator dispatch may not be feasible due to transmission network constraints. A security constrained bid-based dispatch as is now in operation in the ISO areas of the Northeastern and Midwestern states in the U.S. (Joskow 2006) would yield the least cost mix of generating capacity and a compatible set of locational prices for electricity given such transmission network constraints. Prices at different nodes will vary to account for the marginal cost of congestion (and the marginal cost of losses in those markets where the marginal cost of losses has been integrated with the security constrained bid-based dispatch). Similarly, transmission network constraints may also 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. That is, a theoretical redispatch aimed at minimizing $NO_X$ production that ignores physical constraints on the network could cause power to flow over congested lines, it could cause other transmission facilities that were previously unconstrained to become congested, or it could even relieve a constraint on a formerly congested line.

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. The units in these zones of the grid are considered in this analysis to be good physical substitutes for each other. In order to maintain levels of operating reserves and to avoid the added complexities of unit commitment, we do not assume that any units with high emission rates are turned off in the redispatch cases but rather that they can be turned down to 20% of their capacity.

There has been a debate in the academic literature over the relative merits of zonal and nodal pricing systems.[29] 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.[30] 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.

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

---

[29] See, for example, Stoft (1997) and Hogan (1999)

[30] Stoft (1997)

### *Constructing the zonal model*

Publicly available data on the PJM transmission system[31] – data on the name, type (e.g. transformer, generator, load), and voltage of each bus and the buses to which each connects – were used to create an abstract representation of the PJM system, or a network graph.[32] 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, and a switching station where voltage is stepped up and down.

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.[33] Hourly generating unit operation data, like heat input, gross 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 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).[34]

---

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

[32] 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).

[33] 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/.

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

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 between zones and not within the zones.

The second criterion used historical hourly locational marginal price (LMP) data to define zones. This is a more restrictive 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 their website and we matched them to the network graph.[35] The second criterion is that the standard deviation of the LMP's within each zone must be <$10/MWh in 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 but rather indicate other differences in marginal cost between nodes.[36] Additionally, for our purposes we only required the zonal model to capture the most frequent patters of congestion not every possible pattern that might occur. Many of the

---

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

[36] 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.

identified zones more than 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 gross generation data to the zones. This to 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 gross generation from the generators must be 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.[37]
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 fact that some generators have high start-up costs and are not often turned off. The fourth constraint is necessary because if the net generation from units on the high-LMP side of a constraint decreased, it would necessitate 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

[37] The summer rated capacities used in these simulations do not reflect forced outages. In PJM in 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 the 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.

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 (create counterflow), 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. 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. 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 forth 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.[38] 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.

The zonal analysis has two 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 for the flow over a congested line not to increase. The second method that makes use of an optimal power flow model,

---

[38] See infra note 37.

described below, addresses these issues by using a power flow model to simulate the PJM network.

### *Analysis of $NO_X$ reductions using PowerWorld Simulator®*

PowerWorld Simulator contains an optimal power flow (OPF) analysis package that can solve power flows for electricity systems with up to 100,000 buses and an unlimited number of lines.[39] It uses a full Newton-Raphson AC load flow algorithm or a DC approximation.[40] We use PowerWorld to simulate the power flows over the entire PJM network (about 13,700 busses). But, we only simulate the potential $NO_X$ emission reductions from redispatch in the area of Classic PJM, as done in the zonal method.

To perform detailed simulations of the PJM network, we use the information on network elements from the network model used for the PJM Financial Transmission Rights (FTR) auctions.[41] This model includes information for most of the buses and lines in the PJM network, including the voltages and impedances of lines. This information allows PowerWorld simulator to solve for the power flows across the lines in the PJM network given the injections of power at generation buses and the withdrawals of power at load buses. Although PowerWorld also has the capability to simulate the security-constrained *economic* dispatch of generators to fill demand, we are not yet utilizing this functionality as we are still developing sufficiently detailed cost functions for the generators in PJM. Instead, we simply compare the base-case power flows that resulted from PJM's historical dispatches (bid-based, security-constrained economic dispatch) with the power flows in cases that minimize the $NO_X$ emissions from the fossil fuel-fired generating units in Classic PJM.[42] Once we have completed the construction of the marginal generation cost functions we will be able to estimate the responsiveness of the market to variations in $NO_X$ emissions prices and the associated costs of any redispatch induced by time and locational $NO_X$ emissions price variations.

---

[39] PowerWorld, http://www.powerworld.com/.

[40] See, for example, Sun *et. al.* (1984).

[41] PJM, "FTR Model Information," see http://www.pjm.com/markets/ftr/model-info.html.

[42] 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.

As in the zonal model, we compare two cases: 1) an "unconstrained" case where the generation from units in Classic PJM is exchanged freely to minimize $NO_X$ emissions, and 2) the network-constrained case in which the redispatch reduces $NO_X$ emissions but does not increase the flows over congested lines nor cause power flows that exceed the limits of other lines. In this way, the PowerWorld analysis complements the zonal analysis, which does not insure that the redispatch creates no new congestion.

The shortcoming of the PowerWorld analysis is that it requires some additional assumptions about the emission rates and capacities of generating units. The network information provided by the FTR model base cases does not provided details on the generators in the network, only that the generators exist at certain buses and that some of them produce a given amount of power in the model hour. The generating unit identifiers in the PJM FTR model and the EPA and EIA data are not the same, so matching the EPA and EIA data with the correct buses in the FTR model is a challenge.

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 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. We were not able to match about 3 GW of the fossil capacity (about 46 GW) in Classic PJM to the FTR model. As a result, the PowerWorld simulations were performed with slightly fewer generating units than the zonal simulations.

To perform the simulations of potential emission reductions using PowerWorld we used the following steps:

1. Solve the power flow for the base-case.
2. Calculate the base-case emissions from units in Classic PJM using unit-level emission rates. This provides the $NO_X$ emissions for the "base case".
3. "Redispatch" the generating units in Classic PJM to minimize $NO_X$ emissions, while holding total generation constant. This provides the $NO_X$ emissions for the "$NO_X$-minimizing" or "unconstrained" case.
4. Import the generation data from Step 3 into PowerWorld and resolve the power flow. Alter the generation from units located Classic PJM so that
    a. Flows on lines initially loaded over 90% in the base case do not increase by more than 3%.
    b. Flows on lines initially loaded over 80% in the base case do not increase by more than 13%.
    c. Flows on all lines initially loaded under 100% do not increase to over 100% of the lines' capacities.
5. Calculate the total $NO_X$ emissions from the generation in Classic PJM in Step 4. This provides the $NO_X$ reduction estimates for the "network-constrained" case.

The PowerWorld simulations may overestimate the impact of network constraints on the potential $NO_X$ reductions because Step 4 alters the generation from units in Classic PJM according to their impact on the congested lines and does not try to find the lowest-$NO_X$ redispatch that satisfies the transmission constraints. That is, the units with power transfer distribution factors (PTDF) indicating that a large portion (e.g. 30%) of their generation is flowing over a congested line are "turned down" and those with PTDFs that indicate that a portion of their generation causes counter-flow on the congested line are "turned up". This process does not consider any alternative dispatch combinations that might satisfy the constraints with lower $NO_X$ emissions.

The FTR base cases simulate hours when the total electricity demand was relatively low, around 80 GW in all of PJM while peak demand in PJM in 2005 was around 130 GW. Ozone pollution is a summertime phenomenon and occurs on warm, sunny days. Hot weather increases electricity demand for air conditioning so it is important to simulate the potential $NO_X$ reductions when electricity demand is high, when the network is more likely to be congested. In order to simulate these days using the PowerWorld model, we scaled the PJM FTR model base-case for July to approximate the higher demand hours studied with the zonal model. We did this using historical hourly demand data for PJM and the historical CEMS data, which provides hourly gross generation data for individual generating units. We scaled the generation of individual units to match that of a given historical, high-demand hour. We scaled the nodal load data by factors proportional to the increase in the corresponding zonal load for the same hour.[43] This new, scaled case was then used as the base-case in the five-step process described above.

***Preliminary order-of-magnitude estimates of $NO_X$ prices needed to cause redispatch***

After examining the physical opportunities to use generator redispatch to reduce $NO_x$ emissions we report the results of a simple preliminary analysis of the magnitude of the $NO_x$ prices required to induce various levels of $NO_x$ reduction through an economic redispatch that reflects these $NO_x$ prices. As we noted above, a more detailed analysis of these economic issues are the subject of future work. Here, we used linear cost curves for the generators in Classic PJM to estimate of the magnitudes of $NO_X$ prices needed to achieve a range of $NO_X$ reductions up to the maximum level estimated in the unconstrained simulations discussed above. We created simple, linear cost curves for the units in Classic PJM using their 2005 ozone-season heat rates and $NO_X$ rates from the EPA and August 2005 fuel costs and variable operation and maintenance (O&M) costs from the EIA. The fuel cost data used were the average delivered cost of fuel for natural gas, coal, petroleum products, and petroleum coke to the electricity sector by state and month from the EIA's Electric Power Monthly.[44] We matched these data to the generating units by state and fuel. The variable O&M data was from the Annual Energy Outlook for 2006 matched roughly by technology type and fuel, including rough costs for nuclear and hydro-powered units.[45] The linear cost curves are defined simply by:

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

---

[43] Hourly load data are only available at the zonal level: PJM, "Hourly Load Data", available at http://www.pjm.com/markets/jsp/loadhryr.jsp.

[44] 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.

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

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 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 up to 90% of capacity (to roughly account for spinning reserve and outages). The $NO_X$ price was applied uniformly to all units in PJM and was varied between $0/ton and $200,000/ton. The $NO_X$ emission reductions were calculated at each level of $NO_X$ price, without regard to transmission constraints.

## Section 4. Results and Discussion

This section discusses the results of our estimates of the physical potential for $NO_X$ reductions from redispatch in PJM and of our simple preliminary examination of the magnitude of the $NO_X$ prices that would be needed to achieve various levels of $NO_X$ reduction up to the physical maximum through economic redispatch mediated through PJM's wholesale market mechanisms. As described in Section 3, these estimates come from simulations that balance supply and demand in environments with and without transmission network constraints, utilizing the two basic methods for taking transmission network constraints into account. We first discuss the general background characteristics of capacity and generation 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.

***Background***

Both the demand and fossil fuel-fired generation in PJM and in Classic PJM are at their highest during the ozone season (May through September). Table 1 shows the average and maximum 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 gross generation from the fossil-fired generating units in Classic PJM that we used in our simulations (371 units).[46] The maximum-demand hour for all of PJM in 2005 occurred on August 3rd at 5 pm. The demand of about 12 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 4pm with demand of about 1.7 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

The summertime peak $NO_X$ emissions were about 45 tons, compared to the 46 tons at the winter peak. But, the total generation in the summer peak hour was about 10 GW higher than at the winter peak: the average $NO_X$ rate during the summer peak hour was about 2.5 lbs/MWh, compared to 3.5 lbs/MWh during the winter.

Even during the hours of the highest peaks in demand, there was generating capacity in Classic PJM that did not generate electricity. Table 2 shows the capacity of

[46] 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.

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 43 GW of unforced capacity (capacity de-rated by the annual forced outage rate for PJM in 2005).[47] The maximum hourly generation from these units during 2005 was about 36 GW, leaving about 7 to 10 GW of capacity that was not generating electricity. Some of this remaining capacity, however, was providing spinning, non-spinning, and supplemental reserve margins for reliability purposes. We assumed that these reserves could have been provided, at least for short periods of time, by other units that generated power in the peak hours – namely those with the highest $NO_X$ emission rates. Natural gas-fired capacity represented the largest portion of the unutilized capacity (for both peak and average hours). This is expected because natural gas-fired units tend to have the highest marginal costs given natural gas prices in 2005 and the bid-based, security constrained economic dispatch will utilize them last as a result.

**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 the generation from oil-fired capacity had the highest average $NO_X$ rate, at over 3 lbs/MWh (or about 0.3 lbs/mmBTU assuming a heat rate of 10 mmBTU/MWh). Natural gas generation had the lowest average $NO_X$ rate of less than

[47] As noted earlier (infra note 37), the annual forced outage rate may be too restrictive so the range is presented.

1 lb/MWh. For all fuel-types, the generation dispatched to fill peak demand appears to have had a slightly higher $NO_X$ rate than that dispatched to fill average levels of demand.

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 the summer of 2005). The left graph shows that about 42% of the remaining fossil fuel-fired capacity had a lower $NO_X$ rate than the median $NO_X$ rate of the units used to fill demand in that hour. About 34% of the remaining coal-fired capacity had a lower $NO_X$ rate than the median $NO_X$ rate of the coal-fired units that generated electricity in that hour.

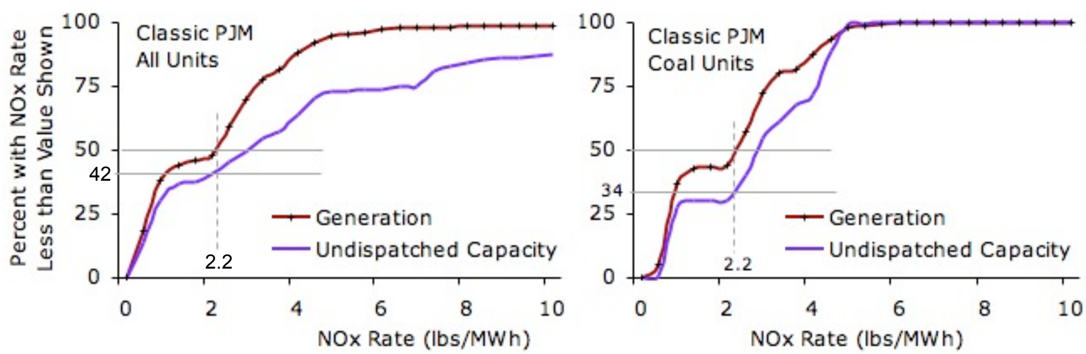


**Figure 2** Cumulative Distributions of Generation and Undispatched Capacity over NOx Rate in Classic PJM on August 4th, 2005 at 2pm. Graph on the left is for all fossil fuel-fired generating units in Classic PJM and the graph on the right is for coal-fired units only.

This result was fairly consistent across other hours and levels of demand. In hours with significantly 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. That relatively low-$NO_X$ capacity was available, 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 lower-$NO_X$ rate generation from being utilized.

### *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.[48] As discussed above, this is important for our purposes because of the time lags between $NO_X$ emissions and their impact on the downwind formation of ozone and also because the impact of $NO_X$ emissions on ozone formation can vary locally with meteorological conditions. Table 3 shows the simulation results for both the zonal and power flow models. It shows the original (base case) generation and $NO_X$ emissions for the simulated hours.

**Table 3** Results of Simulation of Potential Reductions in $NO_X$ Emissions from Redispatch in Classic PJM using both Zonal and PowerWorld Models.

| | Base Case | | Unconstrained Case | | Transmission Constraints Case | | Unforced Capacity^ with Trans. Const.* | | Only "ON" Units with Trans. Const.* | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Date** | **Generation** | **NOx** | **NOx Reduction** | **%** | **NOx Reduction** | **%** | **NOx Reduction** | **%** | **NOx Reduction** | **%** |
| ***Zonal Results*** | | | | | | | | | | |
| 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 | 4.5 | 16 |
| 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 |
| ***PowerWorld Results***** | | | | | | | | | | |
| 8/3/05 18:00 | 32 | 34 | 8.6 | 25 | 8.3 | 24 | -- | - | -- | - |
| 8/4/05 2:00 | 18 | 17 | 9.5 | 56 | 8.5 | 50 | -- | - | -- | - |
| 8/4/05 8:00 | 26 | 24 | 8.5 | 35 | 8.1 | 34 | -- | - | -- | - |
| 8/4/05 14:00 | 33 | 37 | 8.6 | 23 | 8.3 | 22 | -- | - | -- | - |
| | *(GW)* | *(Tons)* | *(Tons)* | *(%)* | *(Tons)* | *(%)* | *(Tons)* | *(%)* | *(Tons)* | *(%)* |

* These simulations were only performed for every four hours and have not been completed in PowerWorld.
** The emissions data were not completely matched to the PowerWorld data. The simulations of NOx reductions were therefore performed with fewer units. The lower initial levels of generation and NOx in the base case compared to the zonal simulations for the same hours reflect this.
^ Capacities were derated by the 2005 demand equivalent forced outage rate for PJM of 7.3% (PJM 2006).

[48] 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.

The range of total hourly generation for the units we considered in Classic PJM was from about 18 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. Table 3 reports the results of the simulations as "$NO_X$ Reductions" from the initial level of hourly $NO_X$ emissions. The reductions ranged from about 7 tons (20 to 25%) to nearly 11 tons (about 50%).[49] The largest reductions occurred in early morning and late night hours. This result is expected both because the network is typically more constrained during higher demand, daytime hours and because less capacity is utilized during the lower demand hours so more is available for exchange.

In the simulation in the columns of Table 3 labeled "unforced capacity" 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 fact that all capacity will not be available at a level of 100% in all hours.[50] As one might expect, this reduced the estimated magnitude of the potential $NO_X$ reductions.

The simulation in the columns of Table 3 labeled "only 'ON' units" represents the case where $NO_X$ emissions were reduced by essentially exchanging which units were providing spinning reserve services. During the higher-demand hours, the majority of the $NO_X$ reductions came from the exchange of high-$NO_X$ generation for the unutilized capacity of other units that were already generating, but at lower than their maximum capacity. The requirement that only operating units could exchange generation caused the estimates of potential $NO_X$ reductions to decrease in all hours examined, and to decrease further than the "unforced capacity estimates".

A comparison of the "unconstrained" reductions – from the simulation of redispatch without the enforcement of network constraints – to the "transmission

---

[49] Natural gas prices were high during the summer of 2005. This could have affected the base-case emissions, and therefore the potential reductions, in 2005 because natural gas units tend to have lower $NO_X$ emission rates than coal and oil units. For comparison, in a peak demand hour of 2001 there were about 31 GW of fossil generation in Classic PJM and 51 tons of $NO_X$ emissions. The potential unconstrained $NO_X$ reductions were about 16 tons or 32%. Both the initial emissions and $NO_X$ reductions were higher in 2001 than in 2005 for the same level of fossil generation (e.g. 8/3/05 20:00) but the percent reductions in the unconstrained case were about the same.

[50] 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 0.923.

constraints" case shows that the network constraints had a relatively small impact on the magnitude of potential reductions on the classical PJM network. Even in the optimal power flow model simulations, the network constraints only lessened the potential $NO_X$ reductions by between 5 and 10%. In PJM, transmission network constraints were more significant during off-peak hours than during peak demand hours.[51]

***The Impact of Network Constraints on Potential $NO_X$ Reductions***

There are three primary reasons that network constraints did not drastically reduce the potential $NO_X$ reductions from redispatch in Classic PJM. First, starting from the $NO_X$-minimizing case, the network constraints were satisfied by a small change in generation. For example, compare 2 pm with 4 am on August 4th. There were four congested lines in Classic PJM at 2pm on August 4th and two congested lines at 4 am. At 2 pm, the unconstrained and network-constrained estimates of $NO_X$ reductions only differed by about 200 lbs in the zonal simulation. In this hour, the original generation was about 35 GW, the amount of generation that was "turned up and down" to minimize $NO_X$ in the zonal simulation was about 9 GW, and the amount changed from the unconstrained case to satisfy network constraints was about 1.2 GW (about 3.5% of the total generation). At 4 am on August 4th, the unconstrained case yielded 1.5 tons more $NO_X$ reduction than the case with network constraints. In this hour, the original generation was about 20 GW, about 17 GW was changed to minimize $NO_X$, and about 3.5 GW of this had to be changed again to satisfy network constrains (about 18% of the total generation in the hour).

In the low-demand hour (4 am) much more generation had to be changed from the unconstrained case to satisfy the constraints. The major difference between these two hours was the initial level of generation (driven by demand). The lower level of generation at 4 am meant that more generation could be exchanged in the unconstrained, $NO_X$-minimizing case. This also means that the network constraints were unlikely to be

[51] This should not be too surprising. As demand rises throughout the system "local demand" absorbs generation in areas with relatively low marginal cost "local generating capacity" and there is less relatively inexpensive capacity available to "export" to locations where there is relatively high marginal cost generating capacity, reducing the transfers from low marginal cost to high marginal cost nodes on the network.

satisfied after the exchange, so more adjustments had to be made to satisfy the constraints. The large amount of generation needed at 2 pm prevented a similarly large exchange to minimize $NO_X$ in the unconstrained case. This meant that less additional adjustment was needed to satisfy the constraints.

The second reason that the transmission constraints do not greatly impact the emissions reductions is that the low-$NO_X$ generation tends to be located on the high-LMP side of network constraints. For example, the capacity on the low-LMP side of the frequently constrained 10THST to OST line has an average $NO_X$ rate of 3.1 lbs/MWh while that on the high-LMP side has an average $NO_X$ rate of 1.8 lbs/MWh. The tendency of generators with lower $NO_X$ rates to be on the high-LMP side of congested lines means both that low-$NO_X$ generation typically has higher marginal costs and also that the redispatch of generation to reduce $NO_X$ will tend to relieve transmission constraints.

The third reason for the small impact of network constraints on the $NO_X$ reductions is related to the large heterogeneity in $NO_X$ emission rates of the generating units in PJM. Even when transmission constraints limited some exchanges between generators, other exchanges were still possible that resulted in almost the same magnitude of $NO_X$ reductions. Figure 3 shows distributions of generation over $NO_X$ rate for three sets of units (for both the original and the redispatched cases). The top graph shows that the much of the original generation in Classic PJM had a $NO_X$ rate between about 0.5 lbs/MWh and 1.5 lbs/MWh. But, a large portion also had a higher $NO_X$ rate. The simulations of redispatch are able to replace

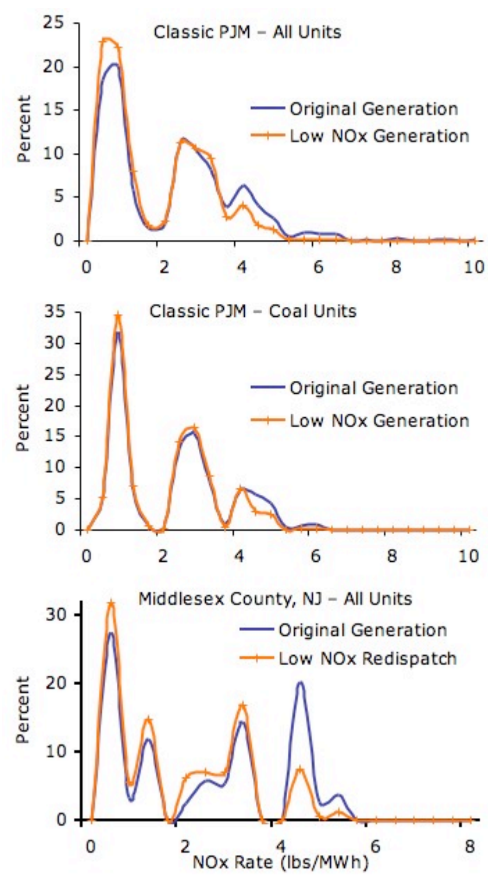


**Figure 3** Distributions of capacity over $NO_X$ rate for all units in Classic PJM, for coal units in Classic PJM, and for all units in Middlesex County, NJ.

some of the generation with high $NO_X$ rates for that with lower $NO_X$ rates. Additionally, substitution was also possible on a smaller geographic scale than PJM alone. The bottom graph in Figure 3 shows the distributions over $NO_X$ rate for generation located in Middlesex County, NJ. Transmission constraints may effectively isolate smaller groups of generators, but $NO_X$ reductions are still possible within these as long as each zone is characterized by $NO_X$ rate heterogeneity and unutilized, low-$NO_X$ capacity.

***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 be areas in which emission reductions do not occur because sources in an area chose to buy permits for their pollution, rather than taking actions that resulted in abatement.[52] This motivates the question of whether the redispatch of units to reduce $NO_X$ results in areas with substantial increases in $NO_X$ emissions.

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 4 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

[52] 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 4** 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. 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.

| STATE | COUNTY | Nox | Delta Nox | Generation | Delta Gen |
|---|---|---|---|---|---|
| NJ | Hudson | 4581 | -3153 | 906 | -457 |
| NJ | Middlesex | 4651 | -1716 | 1721 | -56 |
| PA | Northampton* | 6481 | -1716 (-692) | 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 |
| MD | Dorchester | 744 | -595 | 160 | -128 |
| MD | Anne Arundel | 2398 | -588 | 1873 | -55 |
| NJ | Salem | 1175 | -492 | 269 | -101 |
| NJ | Hunterdon | 1358 | -382 | 539 | -83 |
| NJ | Essex | 733 | -332 | 311 | 45 |
| 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 (9) | 271 | 279 |
| | | *(lbs)* | *(lbs)* | *(MWh)* | *(MWh)* |

* Exchanging the 279 extra generation in DC for generation in Northampton County yields the results in parentheses (to remedy the large increase in NOx in DC if needed).

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 exception is Washington DC. An increase in generation of about 275 MW caused the increase in $NO_X$ emissions 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 $NO_X$. For example if units in New Jersey did not decrease their generation as a result of redispatch in order to avoid the increase in generation in DC, then emissions would decrease by 1002 lbs in DC and increase by 1024 lbs in Northampton County, leaving a net decrease of about 600 lbs of $NO_X$ in the latter.

Alternatively, if DC were combined with the surrounding counties in Maryland, the total reduction from the four counties would be about 640 lbs of $NO_X$.[53]

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 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 suggest 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.

***Simple preliminary estimates of the effect of varying $NO_X$ permit prices***

As discussed in Section 3, we used linear cost curves to estimate the order-of-magnitude impact of varying $NO_X$ permit prices on redispatch in the unconstrained case. Future analysis will extend these estimates using cubic cost curves estimated for each generating unit as well as by using the PowerWorld model to simulate bid-based, security-constrained economic dispatch with varying $NO_X$ permit prices. Table 5 summarizes the estimates. It shows the total $NO_X$ reductions over two 24-hour periods (August 3rd and 4th 2005) for Classic PJM. $NO_X$ permit prices of $20,000/Ton produced reductions of about 120 tons daily, or about 15% from base case levels.[54]

---

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

[54] If the $NO_X$ emission rate of the marginal generating unit were 3 pounds/MWh then a $20,000/ton $NO_X$ price would add (roughly) $30/MWh to the locational price for electricity. This is the case in the above example when the $NO_X$ price is $20,000/ton and the demand is about 30 GW. The marginal generating unit, in the simple example above, when $NO_X$ prices are $20,000/ton and demand is 50 GW has a $NO_X$ rate of 0.5 pounds/MWh. In this case, the $NO_X$ price would only add about $5/MWh to the locational price for electricity.

**Table 5** Total $NO_X$ reductions over two 24-hour periods in 2005 in Classic PJM for a range of $NO_X$ permit prices applied uniformly to all generating units in Classic PJM. The percent reductions from the base case (observed emission rates and dispatch given historical $NO_X$ permit and fuel prices) are also presented.

| 2005 Classic PJM | NOx Permit Price | August 3rd Redutions | August 4th Reductions |
|---|---|---|---|
| | **Base Emissions** | 843 | 868 |
| Daily NOx Reductions (Tons) | **$10,000/Ton** | 53 | 46 |
| | **%** | *6* | *5* |
| | **$20,000/Ton** | 121 | 119 |
| | **%** | *14* | *14* |
| | **$50,000/Ton** | 216 | 215 |
| | **%** | *26* | *25* |
| | **$100,000/Ton** | 326 | 328 |
| | **%** | *39* | *38* |
| | **$200,000/Ton** | 367 | 365 |
| | **%** | *44* | *42* |

Figure 4 shows that the effect of a high $NO_X$ price on redispatch varies according to the level of demand. The graph shows the $NO_X$ emissions of the units in Classic PJM (were they dispatched at 90% of their rated capacities) versus cumulative capacity.

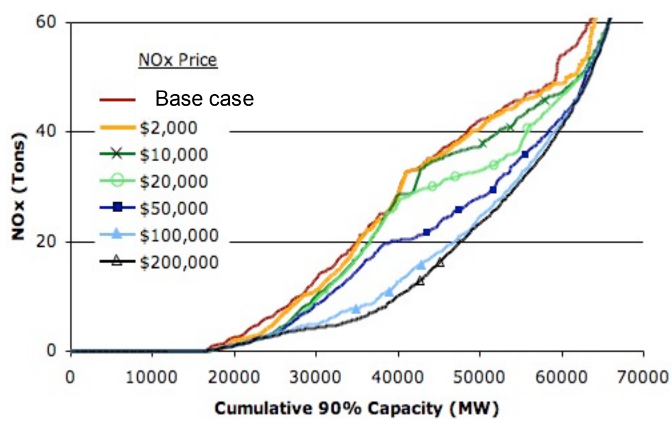


**Figure 4** $NO_X$ emissions from cumulative capacity (90% of each unit's rated capacity) of units in Classic PJM for a range of $NO_X$ permit prices from the base case to $200,000/Ton. $NO_X$ permit prices over about $20,000/Ton start to cause significant redispatch between coal- and oil-fired unit and natural gas-fired units.

The peak load in Classic PJM in 2005 was around 55 GW and the $NO_X$ emissions around 45 tons. This graph suggests that significant $NO_X$ reductions may begin to occur for $NO_X$ permit prices around $20,000 for load levels above about 40 GW. But, for load levels below this, permit prices would have to be much higher to induce redispatch from the less expensive coal units to natural gas-fired units. The over-night load levels on peak days in

Classic PJM in August of 2005 were around 32 to 35 GW. Natural gas prices were high in 2005 but similar calculations with 2003 fuel prices suggest that lower natural case prices would only increase the $NO_X$ reductions from a given level of $NO_X$ permit price by a few percent.

These rough estimates of the level of $NO_X$ permit prices that would be needed to cause daily $NO_X$ reductions of between 50 and over 300 tons in Classic PJM can be compared to the costs of some alternative $NO_X$ control measures in which the owners of generators might consider investing in response to “price spikes” of this magnitude realized during high ozone episodes. For example, some peaking units only generate electricity on the highest demand days and these days are often correlated with high ozone episodes (although further modeling would be needed to determine the contribution of the emissions from these units on ozone levels). The EPA calculates that the cost effectiveness of installing water injection $NO_X$ control technology on these peaking units in the Northeastern States would be about $158,000/ton to reduce $NO_X$ by about 0.23 tons/day for each unit that installed controls over a targeted 12-day, high-demand period.[55] Similarly, the EPA estimates that if uncontrolled coal units utilized selective non-catalytic reduction (SNCR) technology, the cost-effectiveness would be about $18,000/ton of $NO_X$ removed over the same, targeted 12-day period.[56] These controls would reduce $NO_X$ by about 196 tons per day if they were installed on the 89 uncontrolled coal plants the EPA analyzed – some of which were not in the Classic PJM region. Redispatch appears to be less costly than water injection, but the installation of SNCRs on uncontrolled coal-fired plants would be economic at lower $NO_X$ permit prices than those that would cause daily $NO_X$ reductions of about 200 tons (permit prices of about $50,000/ton). One of the benefits of time varying $NO_X$ prices is that these control decisions could be made through decentralized market incentives rather than by regulatory fiat.

---

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

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

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 potential economical 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) estimate 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

---

[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.

very costly in the most important subregions of PJM and other regions of the Eastern United States.

## 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 7 and 11 tons (or from 20% 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 optimal power flow modeling with the use of cost functions for the generating units that include the costs associated with $NO_X$ emissions. This will allow us to simulate the impacts of different patterns of $NO_X$ prices on generator dispatch decisions, locational prices, and ozone formation within the context of a competitive LMP-based wholesale electricity market.[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.

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.

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)

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 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 5 shows an example of this phenomenon for a coal-fired power plant in New Jersey.

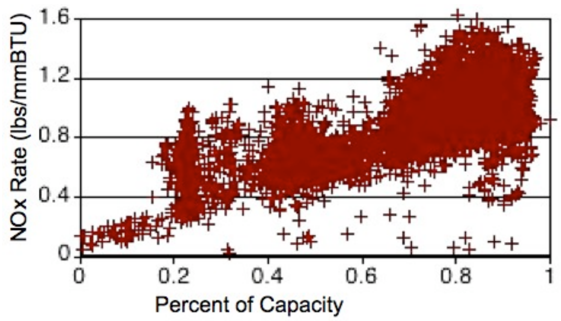


**Figure 5** Plot of $NO_X$ rate versus percent of capacity for a coal-fired power plant in PJM.

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.