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COST EFFECTIVE STRATEGIES FOR NITROGEN OXIDES REDUCTION: OZONE ATTAINMENT POLICY FOR NEW ENGLAND

by

Erin Tracy O'Neill

B.S., Mechanical Engineering, Cornell University, 1992

Submitted to the Department of Mechanical Engineering
in Partial Fulfillment of the Requirements for the Degree of

MASTER OF SCIENCE
in Technology and Policy
at the

Massachusetts Institute of Technology

June 1996

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ABSTRACT

Regulation of NO_x emissions, a pre-cursor to tropospheric ozone, is coordinated by the Ozone Transport Committee for the eastern seaboard. In 1994, a Memorandum of Understanding was issued detailing specific NO_x reduction goals for stationary sources in the Northeast. This analysis examines different compliance options available to the electric utilities in New England in order to determine the most cost-effective strategy.

Results show that a combination of a moderate numbers of Phase II (1999) retrofits and operational controls in southern New England during the ozone season meets the reduction targets at the least cost. This option also performed well in terms of costs and NO_x, CO_2 and SO_2 emissions, across other electric power system options and natural gas cost uncertainty. Additional options examined included choice of gas, coal, and wind generation technology and level of Demand Side Management. This NO_x strategy in combination with higher levels of DSM and new gas combined cycle generation meets the NO_x reduction target of 80% for southern New England, reduces cumulative CO_2 emissions by 6 percent and SO_2 emissions by 3 percent with a modest increase in total regional costs and lower costs than other compliance options examined.

The policy implementation of this combined strategy was also examined. A "Cap and Trade" system, while not without some problems, seems to be the policy instrument most consistent with the least cost NO_x strategy particularly with increasing competition in the electric sector. There are reasonable means to address all of the concerns surrounding a NO_x emission trading system.

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This thesis is part of a larger project at the Massachusetts Institute of Technology (MIT) Energy Laboratory called the New England Project. A team of researchers and graduate students called the Analysis Group for Regional Electricity Alternatives (AGREA) work on this project in order to inform the debate concerning electric power planning and policy in New England. This project also serves to facilitate the dialogue amongst the regions various stakeholders in the electric power industry including utilities, state regulators, environmental advocacy groups and electric consumers.

I thank all of the members of the AGREA team including Steve Connors, Mark Ellis, Richard Tabors, Mort Webster, and Scott Wright. Special thanks go to Steve and Mark; without their patience, knowledge and hard work, this thesis would not exist. In addition, the New England Project Advisory Group has provided needed expertise, feedback, and a much needed reality check. In particular, Kevin Mankouski of NEPLAN provided detailed knowledge of the New England electric power sector and the NO_x regulatory debate.

Thanks also to my friends and family for their infinite support and encouragement. To my sisters who have always had more confidence in me than I. To my mother, for her love, laughter and friendship. To my father who was the first to pique my curiosity about the way things work. To Elson Liu, my constant confidante and brother in Christ. To my soul mate, Edmond Toy. And finally, all praise and honor to the Lord my God. "May the words of mouth and the meditation of my heart be acceptable to you, O Lord, my rock and my redeemer." (Psalm 19:14)

> "Of making many books there is no end, and much study wearies the body. Now all has been heard; here is the conclusion of the matter. Fear God and keep his commandments, for this is the whole duty of man." (Ecc. 12:11-13)

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CHAPTER 1 - INTRODUCTION

A. THE GROUND LEVEL OZONE PROBLEM

New England (NE), along with many other regions of the country, is not yet in compliance with the National Ambient Air Quality Standard (NAAQS) for ozone defined in the Clean Air Act Amendments of 1990 (CAAA). Excessive concentrations of ground-level ozone have been shown to cause acute human respiratory problems, urban smog and damage to plants, animals, agriculture and other materials. At present, over half of the U.S. population lives in areas considered to have unhealthy ozone levels during part of the year. Ozone is considered to be "the most pervasive air pollution problem in the United States..." (Tietenberg, 1995).

Ozone (O_3) is a colorless, reactive gas produced naturally in trace amounts in the earth's atmosphere. Background concentrations are typically about 10 parts per billion (ppb). There is general consensus within the scientific community that ground level ozone concentrations have been steadily increasing over time. During the 1980s, an increase in ozone levels of about 10 percent occurred over Europe. The most critical aspect of the ground-level ozone problem is its formation in and downwind of large urban areas, where ozone concentrations can be as high as 200-400 ppb. The ozone NAAQS level, designed to protect human health and the environment, is 120 parts per billion (ppb) or 235 $\mu gm/m^3$ maximum average hourly concentration.

One of the main factors causing excessive ground-level ozone formation is emissions of nitrogen oxides (NO_x), mainly nitrogen dioxide (NO_2) and nitric oxide (NO). The negative consequences of these pollutants have led federal and state regulators to control ambient ozone levels through control of anthropogenic NO_x emissions, as well as other air pollutants. The most recent federal regulations were established by Congress in the Clean Air Act Amendments of 1990. Ground level ozone control remains one of the most difficult and urgent goals of this legislation. Under these regulations, the New England states must meet attainment standards by 1999. As of 1995, the New

England states had implemented the initial phase of controls intended to bring the region into compliance. However, these controls alone will not accomplish the attainment goal. Therefore, states are now attempting to agree on second and third phase control strategies to further reduce NO_x emissions. These control phases will include additional controls in the electric power sector, a major source of NO_x emissions.

The traditional means of reducing electric power plant NO_x emissions has been the installation of combustion modifications and flue gas treatment on large utility boilers. However, there are several other possible means of controlling emissions that do not involve large capital expenditures for plant retrofit equipment. These strategies include time specific operational controls, greater demand side management and a larger mix of low-NO_x emitting generation (i.e. renewables). It is unknown whether these methods can be as effective in reducing NO_x emissions as the more traditional retrofit approach. This thesis will analyze these four methods of reducing electric power plant NO_x emissions in order to determine whether individual reduction strategies or combinations thereof can be more cost-effective in controlling emissions for the New England region than technological retrofits alone. Effectiveness will be measured in terms of NO_x reduction capability, cost, impact on other emissions and performance over a range of future uncertainties.

This study seeks to compare the power sector impacts of alternative electric utility NO_x control strategies in New England over the next twenty years. It does not investigate the air quality effects of NO_x control strategies nor the impacts of NO_x controls in other sectors, such as transportation or manufacturing. The study is intended to inform policy makers and planners concerning the power sector impacts of utility NO_x control strategies and what policies could best encourage the most socially desirable strategy. Potential impacts of the current electric utility industry restructuring on nitrogen oxide control policies will also be addressed. The study supports the larger question of what society should do to address the ground level ozone problem.

B. Impacts of Nitrogen Oxides on Environmental Quality

Emissions of nitrogen oxides into the air contribute to two major environmental quality problems: ground-level ozone formation and acidic deposition (acid rain). Both of these are regional problems, stretching on the order of zero to one thousand miles in scope, rather than tens of thousands of miles like many other global environmental concerns. Nitrogen oxides react with oxygen and water in the atmosphere to form HNO_3 or nitric acid, which contributes to acid rain. Sulfur dioxide (SO_2) also reacts with oxygen and water in the atmosphere to produce sulfuric acid. Sulfuric acid (H_2SO_4), formed from sulfur oxides produced by burning fuels containing sulfur, contributes the lion's share to the acid rain problem. Thus, regulation of NO_x is currently driven by concern over ground-level ozone.

Excessive ground-level ozone has been shown to cause adverse human health effects. High, but brief, concentrations of ozone can impair the respiratory system causing shortness of breath, chest pain, coughing, and wheezing. Prolonged human exposure leads to diminished lung function and aggravates various pulmonary disorders. Ozone contributes to photochemical smog which is both an eye irritant and an eyesore. Long term exposure can cause chronic effect such as reduced pulmonary response and premature aging of the lungs. Ground level ozone also causes direct damage to plants and agricultural yield, as well as damage to certain minerals. It has been identified as the air pollutant with the most adverse affects on agricultural crop yield in the U.S., decreasing crop yields and crop quality and increasing susceptibility to biotic and antibiotic stresses. In 1991, over 140 million people in the U.S., more than half the population, lived in regions which were not in ozone attainment (Grace, 1993).

It is important to distinguish between ozone near the ground (the pollutant) and ozone in the upper atmosphere (which helps protect us from ultraviolet radiation). Tropospheric, or ground-level, ozone occurs between the earth's surface and about 10 kilometers altitude and is responsible for photochemical smog. Stratospheric ozone, occurring between 10 and 50 kilometers in altitude, absorbs ultraviolet wavelengths shielding humans, animals and plants from excessive exposure to radiation which can cause cancer and has other mutagenic effects. Stratospheric ozone is also a factor in determining earth's climate by absorbing infrared radiation. The high stability of the region which separates the troposphere and the stratosphere prevents mixing or exchange of ozone between these atmospheric layers.

Ozone is one of six criteria pollutants regulated by a National Ambient Air Quality Standard under the CAAA of 1990. The other five include sulfur oxides, particulate matter, carbon monoxide, nitrogen dioxide and lead. Criteria pollutants are relatively common substances, found in almost all parts of the country, and are currently presumed to be dangerous only in high concentrations . Unlike the other criteria pollutants, ozone itself is not emitted in large quantities by human activity. Rather, ground level ozone is formed through a complex set of chain reactions, with two main "pre-cursor" emissions playing critical roles. This reaction can be simplified as follows:

$$VOC + NO_x + \text{sunlight} \dashrightarrow O_3 + \text{other pollutants}$$

Volatile Organic Compounds (VOCs) react with nitrogen oxides (NO_x) in the presence of ultraviolet radiation (sunlight) to form ozone and other pollutants. Intermediate precursors include hydroxyl radicals (OH), molecular oxygen (O_2), oxygen atoms and carbon monoxide (CO), all naturally present in the atmosphere. Weather conditions have a very significant impact on ground-level ozone formation. Ozone formation is greatest at high temperatures and slow moving, high pressure system which allow increased mixing. A typical ozone episode occurs during hot summer days with clear skies and light winds. As a result, the summer months in New England, from May to September, are considered the ozone "season."

Ozone concentrations can be controlled through the reduction of NO_x and/or VOC emissions from industrial processes and mobile sources. Recently, it has become evident that controlling only VOCs is not a sufficient means of bringing ozone concentrations down to environmentally safe levels. Monitoring of VOC and NO_x concentrations in laboratory experiments revealed that the VOC/NO_x ratio is a useful parameter for predicting ozone formation. Because the New England states have relatively high background concentrations of VOCs and are downwind of other major polluting regions (the Midwest and the remainder of the northeast), it is believed that the New England ozone attainment problem is generally NO_x limited. Thus, NO_x only control strategies are necessary to successfully bring New England into attainment.

Many non-attainment regions in the U.S., including New England, exceed the ozone standard only a handful of days a year. In 1994, New England exceeded the ozone NAAQS only 21 days. However, the limit was exceeded by nearly 50%, or 1.87 ppm. Ozone formation, unlike most pollution concerns, is highly time and space specific, depending as it does on chemical and weather conditions. The states in the northeast region typically experience simultaneous ozone standards exceedances due to long-range transport of ozone and its precursors into and within the region. It is important to keep the meteorological variable in mind when developing a policy for ozone reduction. Control strategies may achieve greater benefits and lower costs by accounting for the temporal and geographic nature of the ozone problem.

Ozone exceedances in the Northeast are very time specific. The number of days in which any of the states in the Northeast transport region exceeds the standard varies from zero to forty per year. The forty day maximum represents only 25 percent of the ozone season from May to September. The exceedances occur predominantly during multi-day episodes. Thus controlling ozone precursors only around potential exceedance days, if detectable, could significantly reduce costs and increase benefits compared with other more permanent control measures.

C. Regulatory History of Ozone and Nitrogen Oxide Controls in New England

Due to its harmful effects, ozone was first regulated at the federal level under the Clean Air Act of 1977. The act, administered by the Environmental Protection Agency, defines ozone attainment according to a National Ambient Air Quality Standard. The ozone NAAQS level is 0.12 parts per million (ppm) or 235 $\mu gm/m^3$ maximum average hourly concentration. This level is not to be exceeded more than three times over a three year period. The northeast has some of the highest ozone levels in the country, and also contributes to problems elsewhere as a result of ozone transport. In the past, ozone abatement efforts have concentrated on reducing VOC emissions. However, recent evidence shows that a combined VOC and NO_x reduction strategy can be much more effective.

Therefore, the Clean Air Act Amendments of 1990 mandated Reasonably Available Control Technology (RACT) for both VOC and NO_x emissions for existing sources in non-attainment or transport regions. New sources are subject to Best Available Control Technology (BACT) standards, since these more stringent controls are more cost-effective when integrated into plant design before construction. As one of the primary sources of national NO_x emissions and as an easy sources to control, electric power plants are subject to RACT limits.

The CAAA requires states in non-attainment or within transport regions to incorporate plans for achieving compliance in their State Implementation Plans (SIPs). The act authorizes the EPA to approve the SIPs or to replace ones the EPA deem insufficient with Federal Implementation Plans (FIPs). Recognizing the regional nature of the northeast's ozone problem, Congress created an Ozone Transport Commission (OTC) under the CAAAs of 1990. The Northeast OTC is composed of representatives from twelve states from Maine to Virginia and the District of Columbia. The OTC develops recommendations for additional control measures beyond those mandated in the CAAAs for regions which do not meet attainment levels while complying with RACT and BACT standards. Individual states or the OTC may decide to institute more stringent NO_x emission controls for existing power plants in order to achieve attainment. They may also opt for other control strategies such as conservation, minimum-NO_x dispatch or non-fossil generation.

The first phase of electric utility NO_x control strategies focused on meeting the RACT standard by May 15, 1995. It now appears that, although New England has complied with the first phase of RACT retrofit controls, most of Southern New England is still not in attainment for ozone. The CAAA identify five classes of ozone non-attainment ranging from marginal to extreme. Most of northern NE (New Hampshire, Maine and Vermont) is now in attainment for ozone except for a narrow section along the Maine and New Hampshire coasts classified as marginal. Southern NE is classified from "Moderate" in Rhode Island, to

"Serious" in sections Connecticut and Massachusetts. Moderate non-attainment regions are to meet the NAAQS by the middle of 1999. Serious non-attainment regions are to meet these regulations by the middle of 2003.

D. SOURCES OF NITROGEN OXIDES IN NEW ENGLAND

The seven oxides of nitrogen that are known to occur are NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these seven nitrogen oxides, NO (nitric oxide) and NO_2 (nitrogen dioxide) are the two most important air pollutants because they are emitted in the largest quantities. About 95% of all NO_x from stationary combustion sources is emitted as NO. The term "NO_x" can refer to all of the oxides of nitrogen but, in air pollution work, generally refers only to NO and NO_2.

There are several sources of nitrogen oxides in the atmosphere. NO_x emissions result from the combustion of fossil fuels as well as from two natural phenomenon: lightning and chemical and microbial processes in the soil. Anthropogenic sources include the transportation sector, electric power plants and other industrial combustion processes. Relative contribution from all of these sources in the United States are shown in Figure 1-1. A more detailed break down of only the anthropogenic sources in the U.S. in 1990 is shown in Table 1-1. Table 1-2 shows magnitude of VOC and NO_x emissions for each of the New England states in 1990.

Figure 1-1: Breakdown of Total NO_x Emissions by Sources (NRC, 1991)

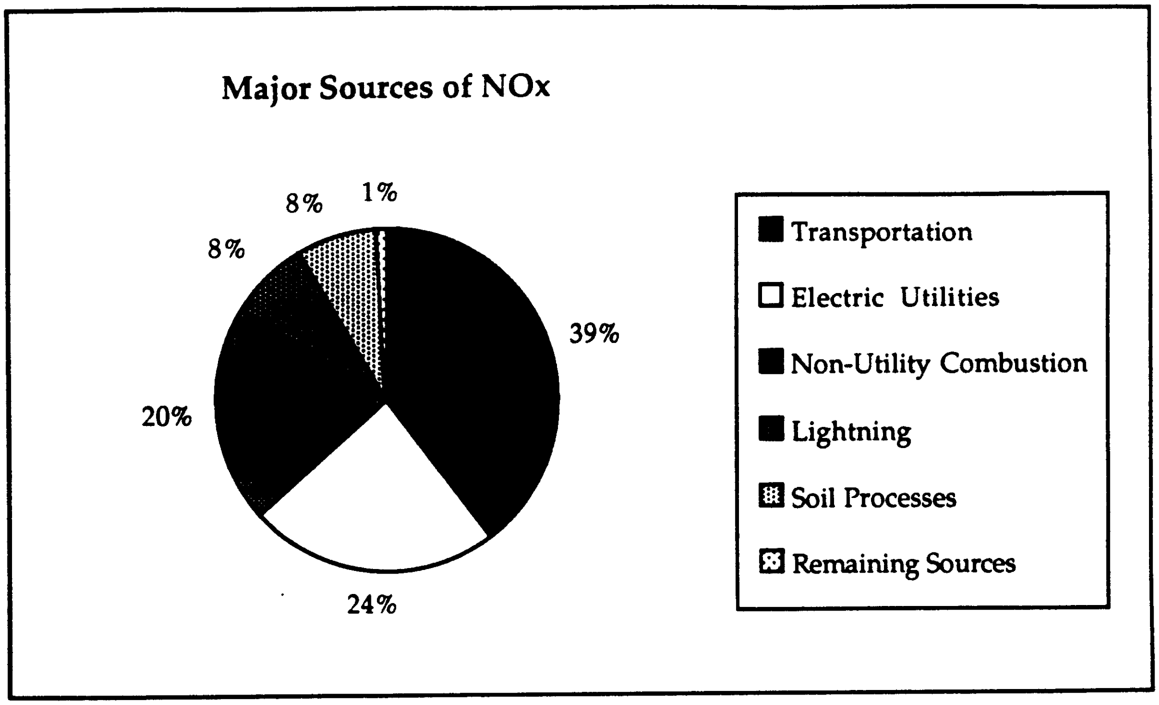
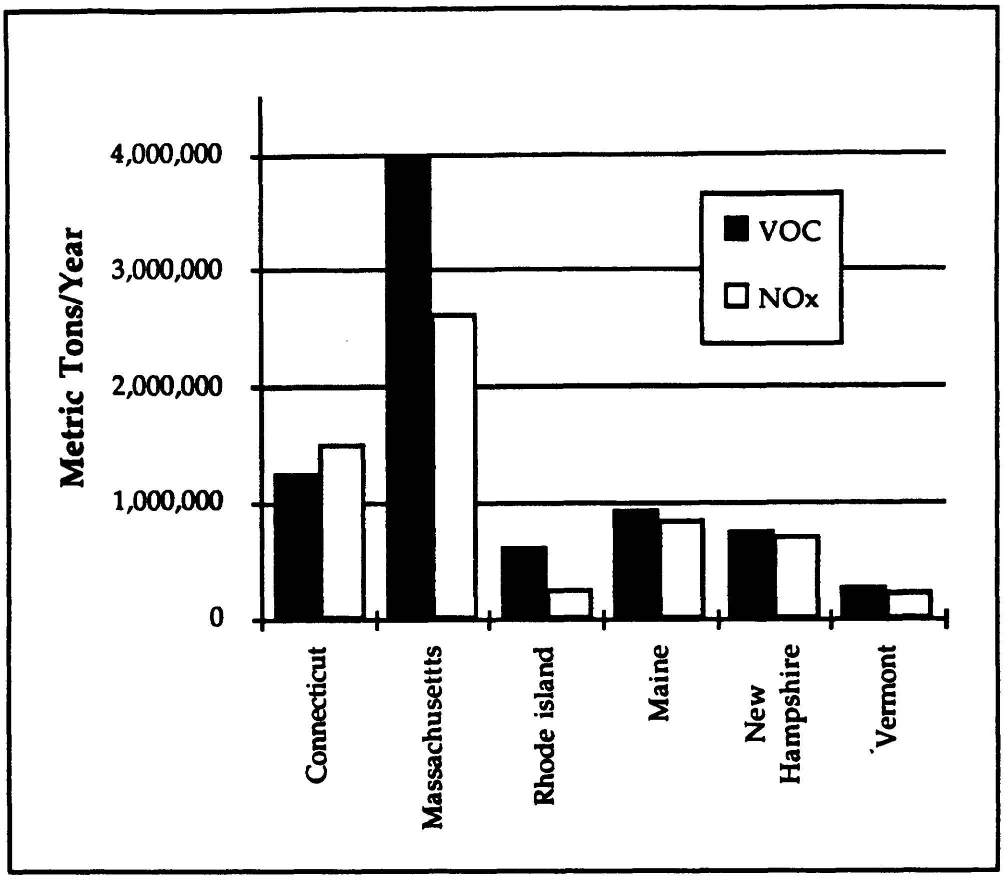


Table 1-1: Share of Total Anthropogenic NO_x Emissions by Source For the United States, 1990

Anthopogenic Sources	Percent	Magnitude (Metric Tons)
Cars & Light Duty Trucks	30.0%	1,836,000
Electric Utilities	28.5%	1,744,200
Highway Diesels	13.5%	826,200
Industry Fuel Combustion	8.2%	501,840
Non-road Diesels	8.0%	489,600
Fuel Combustion (Other)	7.7%	471,240
Railrods	3.1%	189,720
Other Industry Processes	0.5%	30,600
Remaining Sources	0.5%	30,600
Total	100.0%	6,120,000

Figure 1-2: State Emission Inventories of NO_x and VOCs, 1990



Nitrogen oxides are emitted in the United States at a rate of about 7 million metric tons per year, about 45 percent of which is emitted from mobile sources. Of the 3 million metric tons of nitrogen oxides that originate from stationary sources, about 35% are the result of fuel combustion in large industrial boilers and 65% is from electric utility boilers. Although mobile sources are the largest single source of nitrogen oxides, it is often easier to control emissions from large utility boilers. Utility controls are easier to implement due to the concentrated nature of the emissions, centralized ownership of plants, a tighter regulatory framework, and, at present, a regulated rate case structure allowing a return on capital investments.

Nitrogen oxides are formed by either or both of two mechanisms - thermal NO_x and fuel NO_x formation. Thermal NO_x is formed by a reaction between the nitrogen and oxygen in the air used for combustion. The rate of formation of thermal NO_x is extremely temperature sensitive, becoming rapid only at "flame" temperatures of 3000 - 3600° F. Fuel NO_x results from the combustion of fuels that contain organic nitrogen (primarily coal and heavy oil). Fuel NO_x formation is dependent on local combustion conditions (oxygen concentration and mixing patterns) and on the nitrogen content of the fuel (Glassman, 1987).

Volatile organic compound emissions differ greatly from NO_x emissions in that approximately half of all the VOCs emitted in the U.S. come from biogenic sources rather than anthropogenic sources. These natural sources include forests (45% of the total) and agricultural crops (5%). Anthropogenic sources of VOCs include incomplete combustion of fuel or fuel vaporization in the transportation sector (20%), industrial organic solvents (15%), industrial surface-coating evaporation (9%), and certain combustion sources (6%).

Historically, the main strategy for reducing ozone has to control VOCs. However, in recent years studies have shown that greater reductions can be achieved through reductions in both VOCs and NO_x. This is especially true in heavily forested areas because biogenic sources, at least half of total VOC emissions, cannot be controlled. A study by the National Academy of Science on ground level ozone completed in 1991 indicated that a combination of reduction in emissions of VOCs and NO_x would be necessary in order to bring the Ozone Transport Region (OTR) into attainment by the statutory attainment dates. This has resulted in widespread acceptance of NO_x emission reductions as a necessary part of the ozone attainment strategy in New England.

E. REGIONAL NO_x STRATEGY FOR STATIONARY SOURCES IN SUPPORT OF THE 1994 STATE IMPLMENTATION PLANS

Ozone Transport Commission Memorandum of Understanding

A Draft "Memorandum of Understanding Among the States of the Ozone Transport Commission on Development of a Regional Strategy Concerning the Control of Stationary Source Nitrogen Oxide Emissions" (OTC MOU) was published on September 27, 1994 (See Appendix A). This document detailed a compliance strategy requiring further reductions in NO_x emissions from large fossil fuel fired and indirect heat exchangers and smaller sources within the Ozone Transport Region in a two step process. According to this plan, there would be two phases of retrofit controls following the RACT requirements of 1995 as follows:

> Phase II (i.e. initial reduction beyond RACT) will require reductions by May 1, 1999 and a specific phase III reduction by May 1, 2003. Phase III would require further reductions as a default value unless determined by modeling and scientific evaluations that an alternative program is preferable to achieve attainment goals. The default will ensure that a reduction strategy is implemented in the event that the scientific efforts are inconclusive or that there is no consensus in the future on an alternative strategy.
>
> \- OTC MOU

The OTC recommended that regional emission targets be set by calculating, on a unit by unit basis, either a pre-determined uniform emission limit or a pre-determined percentage emission decrease as a rate. The least stringent of these two values would apply in each affected area. States may implement this program in an alternate manner as long as the emission reduction targets for the State are satisfied. The OTC concluded that current available technologies provide a feasible and cost-effective means for at least a 75 percent reduction in NO_x from the 1990 historic emission rate.

The MOU defines "Inner", "Outer" and "Northern" zones for the Ozone Transport Region. The "Inner" zone includes all of Southern New England (i.e. Massachusetts, Connecticut and Rhode Island), as well as sections of New York, Pennsylvania, New Jersey and Maryland. Since this study is primarily concerned with the New England region, the term "Southern" zone will refer specifically to the three southern NE states. All of the moderate and above non-attainment areas in New England are in the southern zone. The "Outer" zone refers to attainment regions outside of New England which are within the Ozone Transport Region. This region will not be dealt with explicitly in this study. The "Northern" zone refers to all of northern New England (i.e. New Hampshire, Maine and Vermont) and part of up-state New York. For this study "Northern Zone will refer to the three Northern NE states which include all of the attainment areas in New England.

Phase II controls are to be in effect by May 1, 1999. The objective of this phase is to reduce the rate of production of NO_x from electric power plants to 0.2 lb/MMBtu or to achieve a reduction of 60 to 75 percent from the 1990 historic NO_x emissions level of 159 thousand tons. A 65 percent reduction is recommended by the OTC. This target applies only to the Southern Zone. The Northern Zone is not subject to any additional controls beyond RACT for this phase. The target reductions are to be achieved through the installation of control technologies on fossil fuel fired indirect heat exchangers with heat output of 250 MMBtu/Hr or greater.

Phase III controls are to be in place by May 1, 2003. The objective of this phase is to reduce the rate of production of NO_x to between 0.1 and 0.15 lb/MMBtu or achieve a reduction of 75 percent below the 1990 NO_x emissions level in the Southern zone. These further reductions from phase II are to be achieved through the installation of control technologies on smaller combustion units, direct-fired process heaters and engines and smaller indirect heat exchangers if necessary (units of 150 MMBtu and greater). The Northern zone target for phase III is 0.2 lb/MMBtu or a 50-65 percent reduction from the 1990 level. A 55 percent reduction is recommended by the OTC. Table 1-2 summarizes the NO_x reduction targets detailed in the MOU.

Table 1-2: Summary of OTC MOU Targets

	Effective Date	*Emission Rate (lb/MMBtu)*	*Reduction (% fro m1990)*	*Boiler Size (MMBtu/Hr)*	*Region*
Phase II	May 1, 1999	0.2	60-75	250	Southern
Phase III	May 1, 2003	0.1 to 0.15	75	150	Southern
Phase III	May 1, 2003	0.2	50-65	250	Northern

Phase II and III limits are applicable only during the ozone season from May 1 to September 30. This is the most probable period for violating the ozone air quality standards in the OTR. The OTC MOU explicitly states that "year round reductions, while useful for acid rain mitigation, and other environmental issues, are not necessary to achieve the ozone standards, and are beyond the OTC regional NO_x strategy." (OTC MOU 1994)

Industry Restructuring

Subsequent to the passage of the CAAA of 1990, the electric utility industry has been undergoing an historic transformation to a more competitive structure. The industry is being "restructured" to allow wholesale, and eventually retail, customer access to different electricity suppliers. As the utilities' traditional customer-base gains access to alternative suppliers, utilities will need to price electricity competitively in order to retain their customer base. Capital investments will no longer be automatically recovered through a rate structure approved by the state utility commissions and imposed on a service territory.

This new environment adds a higher degree of importance to cost. This concern over minimizing costs extends into the realm of environmental compliance. Utilities are very concerned about meeting ozone attainment at the lowest cost to the system. Capital costs which need to be recovered over an extended period of time are of particular concern. Some utilities are facing large "stranded" costs from investments that may be difficult to pay off in a competitive environment where prices are based on the marginal not the total cost of production.

The various NO_x strategies to be examined may or may not work well in a restructured environment. For instance, mandated retrofit controls, which may not impose equal costs on all the utilities in the region, may be problematic. The changing utilization of power plants may also effect the environmental reduction targets. When environmental costs were fully recoverable through the rate case, there was no inherent conflict. No such cost-recovery guarantee now exists. Operational controls which are functionally similar to an economic cap and trade system may be a more consistent and equitable way to achieve NO_x reductions in a competitive industry. This study will examine the potential impacts of electric utility industry restructuring and the robustness of the NO_x reduction strategies given the possible impacts.

F. RESEARCH GOALS AND APPROACH

This thesis will examine two different strategies for meeting the New England attainment goal identified in the CAAA and the MOU described above. The strategies for reducing NO_x emissions examined here are:

1. NO_x Control Retrofits
2. Operational Controls

The alternative control strategies and combinations of strategies are compared over a multiple of criteria. The most important of these criteria include:

System Costs (Total Regional and Electric Industry Direct)
Annual NO_x Emissions
Ozone Seasonal NO_x Emissions
Ozone Episodal NO_x Emissions
Annual and Cumulative CO_2 Emissions
Annual and Cumulative SO_2 Emissions
Robustness Across Fuel Cost Uncertainty
Impact of Demand Side Management Programs
Impact of New Generation Resource Mixes

No attempt will be made to reduce these multiple criteria to a single objective function, such as a monetary measure. This approach would require many assumptions regarding the societal value of human health effects and environmental impacts, the time value of money, the probabilities of fuel cost or load growth futures, and other factors. Instead, the study will identify strategies that successfully meet the legislated NO_x emissions at the least cost, considering many possible futures.

This policy analysis seeks to make recommendations by which the most desirable strategies may be encouraged while leaving substantial flexibility for future uncertainties. First, the degree to which each strategy may be pursued by the utilities is discussed. Second, the degree to which each of the strategies achieves the desired result are discussed. Third, the effectiveness of strategy combinations in achieving the desired goals are examined. Fourth, the performance of the strategies across other system demand and supply side alternatives are investigated. And fifth, the implications of NO_x strategy results for effective policy making, accounting for the current environment of electric utility industry restructuring, will be discussed.

The next chapter will describe the general model used in this analysis. Chapter 3 will describe the details behind the NO_x strategies examined and evaluate their performance based on NO_x reduction potential and cost impact. Chapter 4 will examine the performance of the viable NO_x strategies across other system emissions as well as alternate supply side and demand side options. Chapter 5 then examines the performance of these viable scenarios across natural gas cost uncertainty. The concluding chapter will examine possible policy implementation instruments in light of the strategy analysis in previous chapters and the current regulatory environment.

CHAPTER 2 - RESEARCH METHODOLOGY

The research in this thesis employs the methodology and tools of the MIT Energy Laboratory's Analysis Group for Regional Electricity Alternatives (AGREA). The AGREA New England Project, of which this study is a part, began in 1988 and has examined many different aspects of the New England electric generating system. Previous analyses have included the impact of an electric vehicles program in New England, the impacts of nuclear generation attrition, and the viability of renewable resource for the NE electric system, among others. This project is funded by most of the major utilities in New England. Results are presented to an Advisory Group (AG) consisting of electric utilities, state regulators, environmental organization and electricity consumers.

A. ANALYSIS TOOLS

The systematic approach employed in the New England Project centers around simulating New England's electric power system over a twenty year period starting in 1995. Each simulation tests a different scenario, or combination of planning strategy and future uncertainty. The simulation uses a combination of many different analysis tools including an industry standard production costing model called the Electric Generation Expansion Analysis System (EGEAS), an Attribute Processor (AttPro) as well as many support programs, routines and spreadsheet.

EGEAS

The main analysis tool, EGEAS, was developed by the Electric Power Research Institute (EPRI) in collaboration with Stone and Webster Management Consultants and the Massachusetts Institute of Technology. EGEAS is a FORTRAN program simulating the operation and planning of the New England electric power system. Model functions include dispatching units, building new supply, retiring existing generation, and meeting emission constraints. EGEAS crudely approximates transmission costs and maintenance but does not model the transmission and distribution system. As part of the AGREA New England

Project, both the input and output data are reality checked by an Advisory Group consisting of electric power stakeholders in the New England region, including utilities, regulators, environmentalists, industry, and consumer groups. More detailed information about EGEAS is contained in the EGEAS User's Manual, identified in the bibliography.

EGEAS takes as input data on all of the electric generating plants in New England including capacity, heat rates, fixed and variable costs, maintenance schedules, and emission rates. The system models over 350 plants, including "generic" new plants for future capacity additions. Trajectories for electric load, maintenance requirements, available technology, and fuel costs for the 20 year study period are also input. EGEAS then performs an economic (least cost) dispatch of the existing plants in order to meet the designated load, complies with emission limits, and retires old plants, and builds new plants as prescribed. Most of the input data is obtained from the New England Power Pool planning group (NEPLAN). The data is then modified to reflect the alternative strategies under consideration. Input and output data are benchmarked by NEPLAN and is also subject to frequent peer review by AGREA's Advisory Group members.

Emission rates for existing power plants are input into EGEAS for every power plant in New England. Because none of the units in New England have scrubbers, the emission rates for CO_2 and SO_2 are simply based on the carbon and sulfur content of the fuels used in each plant. The emission results are aggregated by EGEAS on a year-to-year basis, depending on the size, capacity and fuel type of each plant. Plant specific NO_x emission rates are provided by NEPLAN for existing units. These emission rates have been updated according to the NEPOOL 1995 environmental database which includes all modifications implemented to comply with RACT. This data provides the baseline for this study.

EGEAS output is quite comprehensive. Data is reported on electricity generated, total costs, capital recovery, fuel costs, and fixed and variable system O&M. Yearly and seasonal emissions on eight power plant pollutants including, SO_2, CO_2, NO_x, PM_{10} and ash are also reported by generation type (existing or new). The program also provides information on new capacity additions, system reliability, unmated energy demand, generation by fuel type and the cost of electrical service as well as various, more specific data.

AttPro

EGEAS output is loaded into a large spreadsheet called the "Attribute Processor" or AttPro. The AttPro collapses 20 year trajectories into hundreds of attributes which measure scenario performance. AttPro also does various costing and allocation procedures including DSM, electro-technologies and renewable generation calculations. Some of the most important attributes for this study include the calculation of costs based on Standard Financial, Inflation Adjusted and Risk Adjusted discounting for the Electric Industry and the Total Region. The AttPro also breaks down NO_x emissions by Annual, Seasonal and Episodal emissions for Southern, Northern and All of New England. The AttPro allows the user to evaluate year-to-year costs, emissions and other performance measures.

The resulting attribute database for the hundreds of scenarios under consideration are examined based on both their 20 year trajectories as well as the cumulative attribute value. This analysis focuses on the yearly trends because the ozone formation is very time dependent. NO_x reductions need to be concentrated during the ozone season and must be consistent on a year-to-year basis.

The NO_x strategies simulated here will be evaluated based on several criteria. Technical effectiveness in reducing NO_x emissions will be examined over a range of Demand Side Management programs, new supply resource options and fuel price uncertainties. Economic costs will be evaluated in a similar manner. Strategies will also be evaluated based on their impact on other emissions, mainly SO_2 and CO_2. Also, combinations of options will be analyzed to determine if positive synergistic affects between strategies might further increase overall performance.

B. SCENARIO FORMATION AND NAMING

Each EGEAS simulation yields output data for one "scenario." A scenario is a combination of a set of strategy options and a set of future uncertainties. Each strategy consists of multiple operating and planning decisions such as technology control retrofit level and new supply technology. And each set of futures consists of an uncertainty, such as load growth or fuel costs. The process of scenario formation is described below.

For comprehensive analysis of many power system alternatives, hundreds or more scenarios are simulated and compared. For this study, each scenario is a combination of one option from each of eight supply side strategy options, six demand side strategy options, and six uncertainties. This study examines the impact of three of the supply side options, three of the demand side option and one of the future uncertainties.

This research examined three supply side options, two demand side options and one future uncertainty. The supply side strategy options examined in this thesis are new supply technology mix, NO_x operational control policy, and level of NO_x retrofit control. In this study, the level and cost allocation of DSM are the only demand side strategies that will be examined. This thesis will examine only the impacts of natural gas fuel cost uncertainty.

Every alternative within each option set has a code letter abbreviation. The code letters allow cryptic, but pronounceable, scenario names. For instance, the base case scenario for this study is:

GUMINARU-ZEVONO-MOBESE

The first six scenario name letters represent the supply side strategies according to Table 2-1 below. The next eight scenario name letters represent the demand side options according to Table 2-2 below. And the last six scenario name letters represent the future uncertainties according to Table 2-3 below.

Table 2-1: Supply Side Strategy Options

Supply Side Strategies		
Options Set	*Option*	*Code*
New Supply	Gas Combined Cycle	G
	Gas Combined Cycle & Simple Cycle	S
	Gas CCs & Conventional Coal	H
	Gas CCs & Wind	W
	Gas CCs, Conv. Coal, & Wind	V
NIMBY	Unconstrained	U
Fossil Reliability	Maintained	M
Retire/Repower	Life Extension	I
NOx Operational	All New England/None	N
	All New England/NOx Season	S
	Coastal New England/NOx Season	L
	All New England/NOx Episode	P
	Coastal New England/NOx Episode	D
NOx Retrofit	RACT Only	A
	Strict Phase II (65%0	E
	Relaxed Phase II (50%)	I
	Strict Phase III (75%)	O
	Relaxed Phase III (65%)	U
	Old Source Review	Y

Table 2-2: Demand Side Strategy Options

Demand Side Strategies		
Options Set	*Option*	*Code*
DSM Level	None	N
	Reference DSM	R
	Double Ref. DSM	D
	Triple Ref. DSM	T
DSM Cost Alloc.	All Utility	U
Electric Vehicle	None	Z
EV Charging	Off-Peak Modified	O
EV Battery Eff.	Stuck	S
End-Use Fuel Swith	None	O
Adv. Electrotech	None	N
Emissions Offsets	None	O

Table 2-3: Future Uncertainties

Uncertainties		
Options Set	*Option*	*Code*
Load Growth	Medium	M
Fuel Tax	No Tax	O
Fuel Costs	Base Gas	B
	High Gas	G
EV Costs	Low	O
NUMB	Status Quo (Medium RM)	S
Nuclear Attrition	Decommion	E

C. LOAD GROWTH

The electric peak load and energy demand in New England from 1995 to 2010 are estimated based on the NEPLAN 1995 "Capacity, Energy, Loads and Transmission" report (CELT). The Reference DSM scenario peak load forecast is then extrapolated from NEPLAN's estimates for the remaining model years (2011-2014) as shown in Figure 2-1. This figure reflects an annual peak demand increase of 1.06 percent for the Reference Demand Side Management (DSM) scenario. Without utility sponsored DSM measures, peak load is projected to increase at 1.50 percent per year. The electricity demand forecast is estimated in a manner similar to the peak load forecast and results in a 1.26% annual increase with Reference DSM and 1.59% increase with no DSM. The demand forecast is shown in Figure 2-2.

Figure 2-1: New England Peak Load Forecast

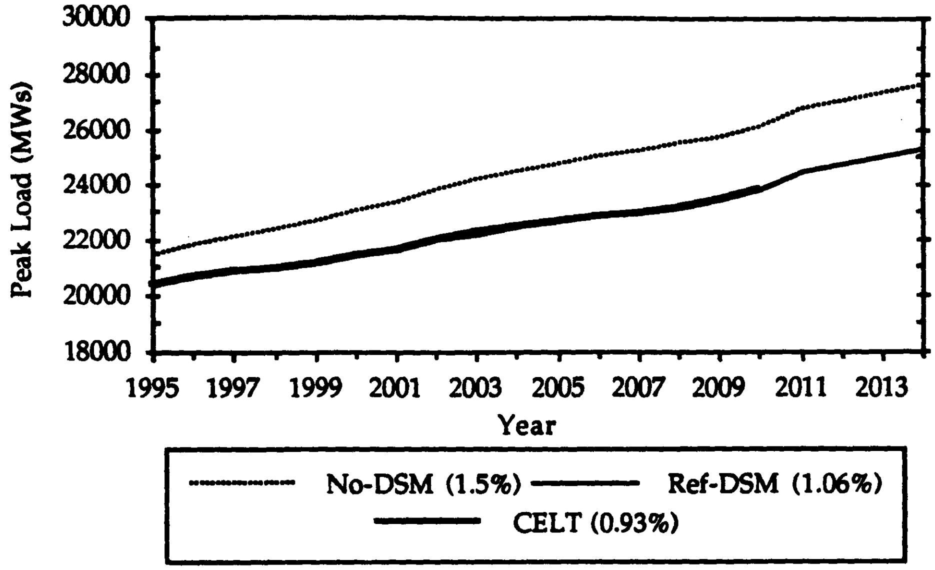
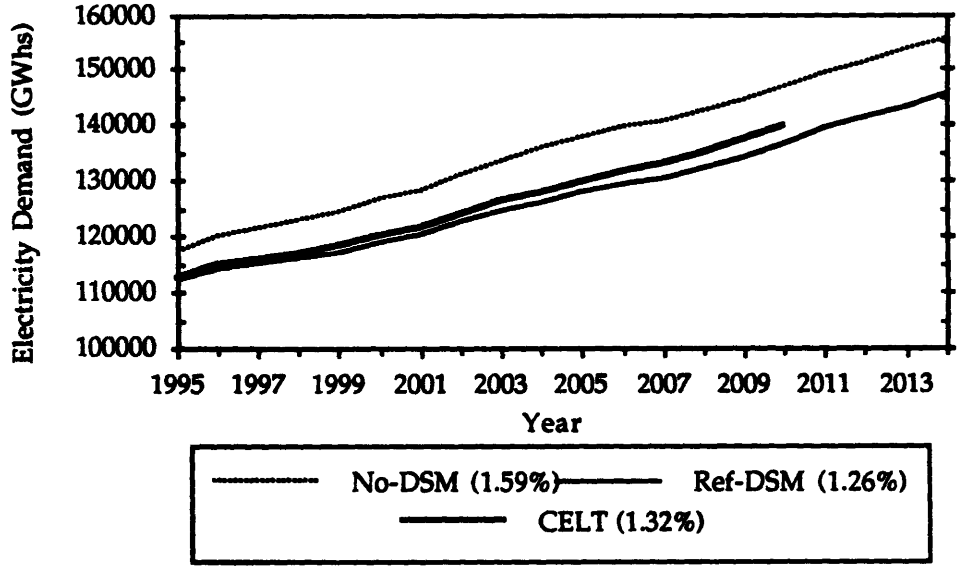


Figure 2-2: New England Electricity Demand Forecast

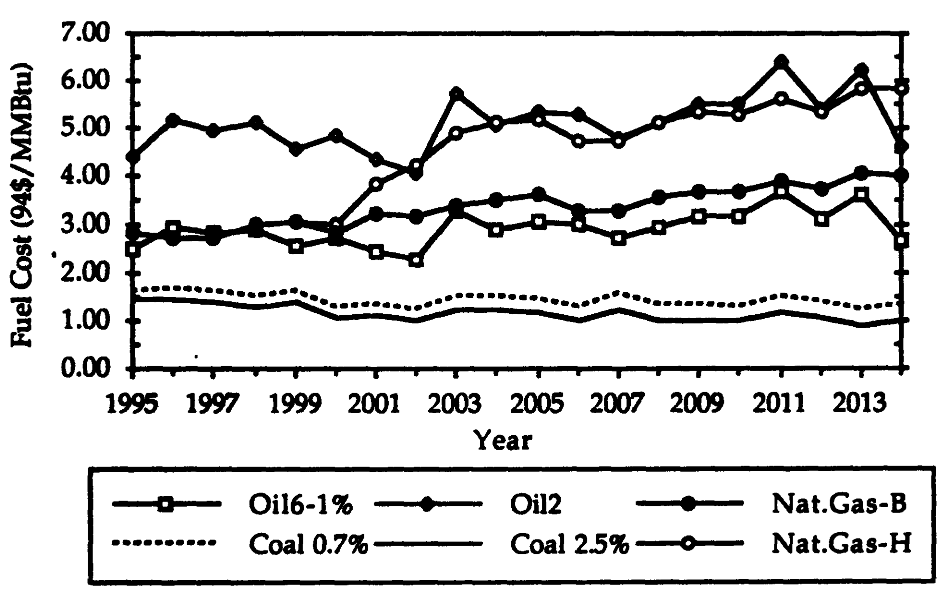


D. FUEL COSTS

An important determinant to the emissions of the electric power sector is the fuel cost trajectory used for future years. Fuel costs are a major constituent of total operating cost and, thus, figure heavily into the least cost economic dispatch. The fuel cost trajectory is modeled as an uncertainty and two trajectories are employed in this study: base fuel costs and high natural gas costs. The latter addresses the concern over New England's increasing dependence on natural gas and the potential vulnerability should prices increase substantially in the near or long term. The impact of natural gas fuel cost uncertainty will be examined in Chapter 5.

Fuel cost estimates for the years 1995 to 2010 are obtained from NEPOOL assumptions. The smooth cost projections obtained from NEPOOL are then modified to reflect short-term variations in the highly volatile fuel markets. Year to year variations in fuel costs are simulated by sampling within a narrowly constrained distribution of annual variations in historical fuel costs. The actual fuel cost projections used in the simulation are shown in Figure 2-3 above. The trajectory labeled "Nat. Gas - B" represents the base case assumption of future natural gas fuel cost. The "Nat. Gas - H" reflects the high natural gas cost future assumption. The percentages listed next to the fuel type specifies the sulfur content of the fuel.

<u>Figure 2-3</u>: Fuel Cost Uncertainties



E. SCENARIO COST CALCULATION

Electric Industry Direct and Total Regional Cost

Scenario costs are calculated in two ways: Electric Industry Direct Cost and Total Regional Cost.

The Electric Industry Direct cost includes the following:

- Supply Side Capital Recovery (existing, committed and generic units)
- Dispatch Cost (fuel and variable operating and maintenance)
- Miscellaneous Fixed Charges (Fixed O&M, Transmission and Distribution, and General and Administrative costs)
- DSM Costs/Earnings (DSM Cost Recovery and Incentives)

The Total Regional Cost includes the Electric Industry Direct Costs as well as:

- DSM Participant Direct Measured Costs
- Customer Offset Cost & Subsidies (includes renewable production tax credit)

Standard Financial, Inflation Adjusted, and Risk Adjusted Discounting

Each of the scenario costs (electric industry direct and total regional) are calculated in three ways: Standard Financial (SF), Inflation Adjusted (IA) and Risk Adjusted Discounting (RA). The SF cost calculation is a standard "Revenue Requirement" present value applied to all of the region's direct costs over the twenty year study period. This includes participant contributions to Demand Side Management for the Total Regional Cost. The utility cost of capital of 10 percent is utilized as the standards financial discount rate.

The Inflation Adjusted cost calculation is similar to the SF calculation except that the future dollar cost stream is not discounted. Instead, the cost stream is simply summed after conversion into 1994 base year dollars. Long-term average inflation in this study uses 3.2 percent.

Risk Adjusted discounting is similar to the SF discounting except that the future dollar cost stream is broken up into two cost components which are then discounted at different rates. Recurring costs are discounted at 3.6%/yr. plus inflation (net 6.8%/yr.). One-time costs are discounted at 6.8%/yr. plus inflation (net 10%/yr.). This reflects the relative "buy-in" to cost uncertainties such as fuel, variable operating and maintenance, and general and administrative costs, versus capital expenditures on equipment. These three cost attributes allow us to judge the sensitivity of cost results to "standard" economic analysis (corporate discount rates), "sustainable economics" (inter-generational discount rate), and "financial risk" (risk adjusted discount rates).

F. CHAPTER SUMMARY

This chapter examined the general modeling framework for this analysis. The next chapter examines two different methods for reducing NO_x emissions from New England power plants: control technology retrofits and operational controls. Chapter 3 is mainly concerned with identifying the most cost effective means of achieving the recommended NO_x target. This includes examining combinations of the two reduction strategies. Chapter 4 then identifies the impact of these reduction strategies on other system emissions such as CO_2 and SO_2 as well as the complimentary and conflicting impact of resource options such as DSM and new generation technology have on costs and emissions. Chapter 5 will then examine the specific policies to encourage the cost effective strategy as well as looking at potential implementation problems. This chapter will also discuss the difficulties that may arise under electric utility industry restructuring.

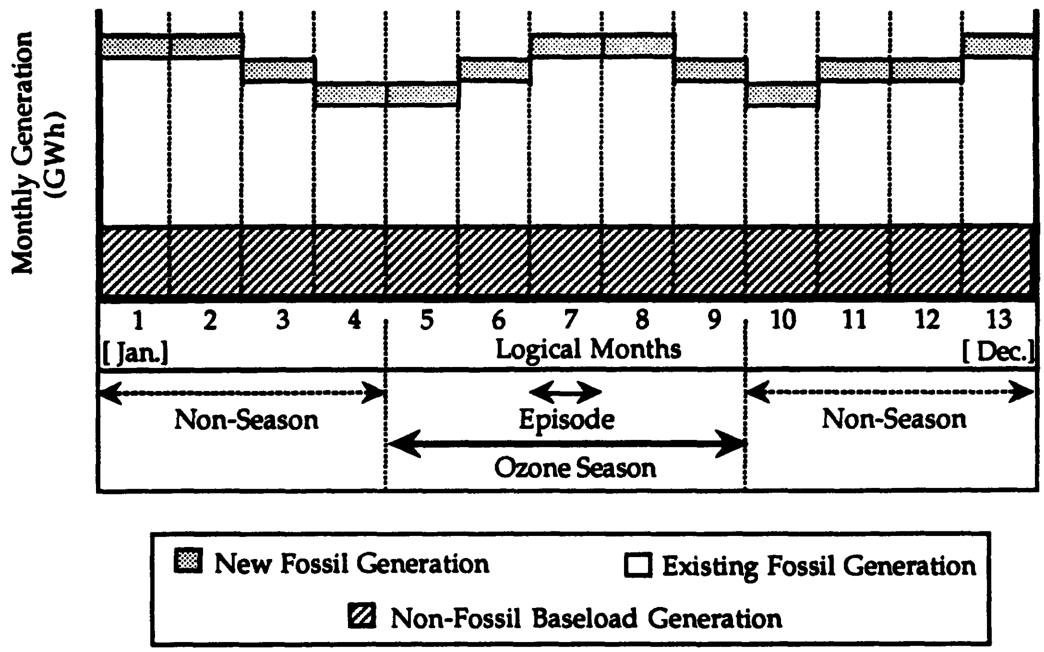
CHAPTER 3 - NO_X CONTROL OPTIONS AND THEIR RELATIVE PERFORMANCE

There are a wide variety of NO_x reduction options available to policy makers and electric utilities. Methods vary significantly in terms of capital and O&M costs, NO_x reduction capabilities, impact on other emissions, ease of implementation and consistency with industry restructuring. The two most promising reduction techniques, Retrofit Controls, and Operational Constraints, are analyzed in this chapter. These techniques, their modeling details, and their NO_x reduction performance are described below. These strategies will be examined in conjunction with the Gas/Combined Cycle new generation option and the current level of utility-sponsored DSM. The next chapter will look at their performance across other demand and supply-side options.

A. NO_x CAP CALCULATIONS

Since a seasonal and/or summer month NO_x cap (tons/month) has not been identified, AGREA calculated a hypothetical cap based upon MOU target reductions and historical emissions. In this approach 1990 annual NO_x emissions are allocated to each "logical month" (4-weeks each) based upon the proportion of fossil generation in that month. The limit is then "relaxed" to account for emissions from new generation sources, since stack emissions, not emissions less offsets, are constrained in the modeling (refer to Figure 3-1). These are then used as the baseline emissions to calculate an ozone season cap. Note that the "Seasonal" options actually constrains each logical month's NO_x emissions, not the season in its entirety.

Figure 3-1: NO_x Cap Derivation



A seasonal NO_x emission cap of 5,960 tons/logical month approximates a 65 percent reduction in emissions from the 1990 level for all of NE (not including emissions from new fossil generation). This cap was increased to compensate for NO_x emissions from new generation in later years. The actual NO_x Cap modeled included a 580 ton/logical month adder for new generation resulting in a 6,540 tons/logical month cap for the five month ozone season. The Southern region NO_x Cap was 2,790 tons/logical month during the ozone season (including the new generation adder). This corresponds to an 80 percent reduction from 1990 levels in the Southern Zone. The analytic derivation of these caps is detailed below.

All New England NO_x Cap Derivation

NO_x emission targets detailed in the OTC MOU are based on reductions from the 1990 historic annual NO_x emissions of 159 thousand tons. The 1990 NO_x emission rate is based on the total NO_x emissions, the average fossil heat rate and the annual fossil energy produced. The target emission rate is then calculated as a percentage of the 1990 rate. The ozone monthly seasonal limit is based on the ozone season monthly energy production, fossil heat rate and emissions rate limit. The new generation monthly limit is based on the NO_x emissions from new generating units in the year 2005, approximately the middle of the period modeled. The ozone seasonal adjusted NO_x limit is then calculated as the sum of the seasonal monthly limit plus the new generation limit. Table 3-1 gives an example of the All New England seasonal NO_x cap calculation is given below. This calculation targets 65% reduction from the 1990 emissions level for Phase II as required by the MOU.

Table 3-1: All NE Seasonal Constraint for 65% Emission Reduction

• 1990 NO_x Rate	= 1990 NO_x emission/ (Fossil Heat Rate * Annual Fossil Energy) = (160,000 tons) * (2,000 lbs/ton) / [(10,151 MMBTU/GWh) * (51,085 GWh)] = 0.617 lbs/MMBTU
• MOU Phase I Emission Rate Limit	= 1990 NO_x Rate * (1 - 0.65) = 0.617 lbs/MMBTU * (1 - 0.65) = 0.216 lbs/MMBTU
• Ozone Season Limit	= Ozone Season Monthly Energy * Fossil Heat Rate * Emission Rate Limit = (5,438 GWh/mo.) * (10,151 MMBTU/GWh) * (0.216 lbs/MMBTU) * (ton/2,000 lbs) = 5,961 tons/mo.
• New Generation Limit	= monthly emissions from new units in 2005 = 7,500 annual tons / 13 months = 577 tons/mo.
• O_3 Season Adjusted Limit	= Seasonal Limit + New Generation Limit = 5,961 tons/mo. + 577 tons/mo. = 6,538 tons/mo.

Note: All limits are expressed per logical, seasonal month (28 days)

Southern Seasonal NO_x Cap Derivation

The Southern Seasonal NO_x Cap is derived in a manner similar to the process for the All New England Cap described above. Southern NO_x emissions are assumed to be approximately 70 percent of total New England emissions (based on EGEAS modeling output). The target reduction for the Southern region for Phase III modeled here is 80% percent. The Southern cap derivation for Phase III is shown in Table 3-2 below:

Table 3-2: Southern NE Seasonal Constraint for 80% Emission Reduction

• 1990 NO_x Rate	= 1990 NO_x emission/ (Fossil Heat Rate * Annual Fossil Energy) = (160,000 tons) * (2,000 lbs/ton) / [(10151 MMBTU/GWh) * (51,085 GWh)] = 0.617 lbs/MMBTU
• Emission Rate Limit	= 1990 NO_x Rate * (1 - 0.80) = 0.617 lbs/MMBTU * (1 - 0.80) = 0.1235 lbs/MMBTU
• Southern Ozone Season Limit	= 0.7 * Ozone Season Monthly Energy * Fossil Heat Rate * Emission Rate Limit = 0.7 * (5,438 GWh/mo.) * (10,151 MMBTU/GWh) * (0.1235 lbs/MMBTU) * (ton/2,000 lbs) = 2,386 tons/mo.
• New Generation Limit	= monthly emissions from new units in 2005 = 5,250 annual tons / 13 months = 404 tons/mo.
• Southern O_3 Season Adjusted Limit	= Seasonal Limit + New Generation Limit = 2,386 tons/mo. + 404 tons/mo. = 2,790 tons/mo.

Note: All limits are expressed per logical, seasonal month (28 days)

Table 3-3 summarizes the seasonal NO_x operational constraints for All and Southern NE strategies.

Table 3-3: Monthly Cap Constraint Summary for Operational Controls

	Effective Date	Reduction Target (% from 1990)	Monthly Cap (tons/month)	Total Seasonal Emissions (tons)
Seasonal/All NE	May 1, 1999	65	6,538	32,690
Seasonal/Southern	May 1, 1999	80	2,790	13,950

Now that specific NO_x seasonal and episodal targets have been identified, the means to achieve these reductions must be examined. The rest of this chapter will examine the performance of the two reduction strategies, retrofit controls and operational controls, in order to determine if the targets identified above are attainable.

B. NO_x CONTROL RETROFIT OPTIONS

The Clean Air Act Amendments of 1990 requires regions not in attainment for NO_x ambient air quality standards to install Reasonably Available Control Technology (RACT) on existing plants by May 15, 1995. RACT controls were aimed to reduce NO_x emissions by 30-40 percent from 1990 emission levels. New England utilities implemented combustion modifications such as Low NO_x Burners (LNB), Flue Gas Recycling (FGR), Reburning (REB), Overfired Air (OFA) and Two Stage Combustion (TSC) in order to meet the State Implementation Plan (SIP) reduction targets.

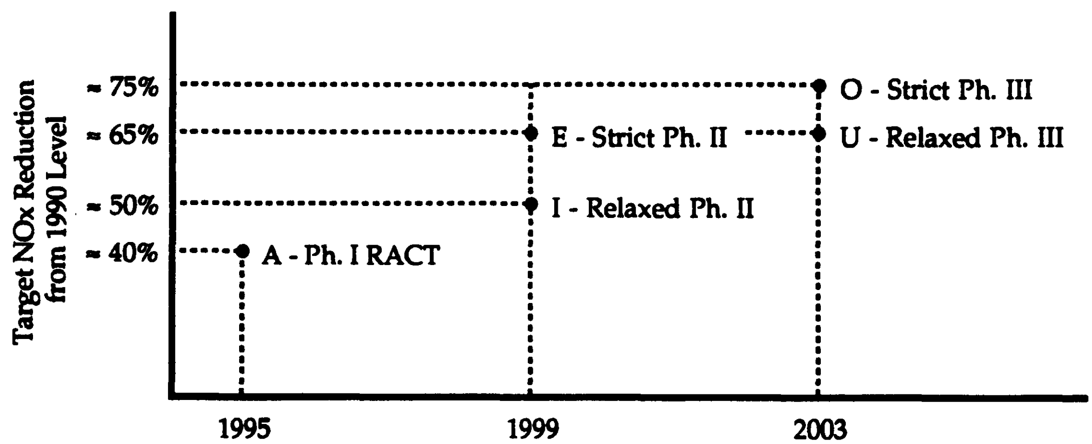
Because NE still does not comply with ozone ambient standards, even after satisfying the RACT requirements of the CAAA, additional actions are required. The strategy for making additional reductions is under the control of environmental regulators in the form of operating permits and SIPs. The ozone strategy detailed in the 1994 draft MOU describes these further possible reductions in NO_x emissions from large fossil fuel fired boilers and smaller sources within the Ozone Transport Region in a two step process. The OTC MOU was described in detail in Chapter 1. The state could pursue a strategy of installing more control retrofits on smaller generation units and/or installing more advanced controls (like SCRs) to meet these target reductions. Combustion retrofits are the traditional command and control means for achieving the remaining necessary reductions. To reflect the relative cost and performance of the "command and control" approach six levels of NO_x retrofits are modeled in this study:

- RACT Only (Reference)
- Strict Phase II
- Relaxed Phase II
- Strict Phase III
- Relaxed Phase III
- Old Source Review

Both Phase II and Phase III are modeled at two different levels, a "strict" and a "relaxed" level of retrofit. The relaxed strategies are designed to work in conjunction with operational controls to achieve the NO_x reduction targets. Operational controls will be discussed below. The strict strategies are designed to achieve the NO_x targets without implementing any other reduction strategies.

Figure 3-2 below summarizes the target reductions and time frame for 5 of the NO_x retrofit levels modeled in this study. The Old Source Review strategy was proposed by the Conservation Law Foundation (CLF) and the New England Electric System (NEES) without a specific stated NO_x reduction target. Old Source Review retrofits begin in 1999 and falls somewhere between Phase I RACT and Relaxed Phase II in Figure 3-2.

Figure 3-2: NO_x Retrofit Reduction Targets



Control Technologies

There are several more technologies, other than those mentioned above, available for reducing NO_x emissions from fossil plants. The most effective control technologies require flue gas treatment and include Selective and Non-Selective Catalytic Reactors (SCRs and SNCRs). Steam Injection (SSIs) is another possible cost-effective control technology. These controls are very effective in reducing NO_x emissions, however, they require significant capital and operational costs. The economic and technical performance of these control technologies is described below.

Steam Injection Units

Steam injection (SSI) can be an effective means of reducing the flame temperature in gas turbine combustion chambers. This significantly reduces the formation of thermal NO_x. This makes steam injection an effective option for combustion turbines, with NO_x reduction capability of about 80 percent for new installations. For this analysis, NO_x reduction for existing installations with SSI retrofits was assumed to be 40 percent. SSIs have relatively low capital costs but high operational costs. Therefore, an SSI is a good candidate technology for a unit with a low capacity factor but high NO_x formation rate.

Selective Catalytic Reactors

The most advanced flue gas treatment method is selective catalytic reduction (SCR). In selective catalytic reduction, only the NO_x species are reduced, ultimately to N_2 gas. With a suitable catalyst, NH_3, H_2, CO, or even H_2S could be used as the reducing gas, but the most commonly used material is NH_3 (ammonia). The most common catalyst is a mixture of titanium and vanadium oxides and is formulated in pellets (for gas-fired units) or honeycomb shapes (for oil or coal fired units which have particulates in the flue gas).

The best temperature range for SCR catalyst activity and selectivity is from 300 to 400° C (600 to 800° F). Ammonia is vaporized and injected downstream from the economizer (boiler feedwater preheater). SCR units typically achieve about 80 percent NO_x reduction when installed on new units. For this analysis, NO_x reduction for existing installations with SCR retrofits was assumed to be 65 percent.

Selective Non-Catalytic Reactors

At temperatures of 900-1,000° C (1,650 - 1,800° F), ammonia (NH_3) will reduce NO_x to di-nitrogen (N_2) without a catalyst. Non-catalytic reduction can decrease NO_x emissions by 40-60 percent for new installations. SNCRs are sometimes preferable over SCRs due to their operating simplicity and lower capital cost. For this analysis, the NO_x reduction capability of SNCR retrofits on existing installations was assumed to be 40 percent. SNCRs have high capital costs relative to SSIs but low operational costs. Therefore, an SNCR is a good candidate technology for a unit with a high capacity factor.

Control Technology Summary

Table 3-4 summarizes the three NO_x control technologies discussed above and used in this model. SCRs have the highest costs but also the highest reduction capability. SNCRs and SSIs have different cost characteristics, and similar NO_x reduction capabilities. SNCRs are significantly more expensive than SSIs but SSIs have very high operating costs and are only applicable for gas turbine units.

In this analysis, SCRs and SNCRs were chosen for most retrofits since they have the highest NO_x reduction potential.

Table 3-4: Control Technology Summary

Technology	*Capital Cost* ($/KW)	*Variable O&M* ($/MWh)	*Fixed O&M* ($/KW-yr)	*Reduction* (%)
Selective Catalytic Reactor (SCR)	45.0	4.000	1.000	65.0
Selective Non-Catalytic Reactor (SNCR)	25.0	0.756	0.191	40.0
Steam Injection (SSI)	7.0	0.700	2.400	40.0

NO_x Retrofit Options

An iterative process was used to determine which units within New England should be retrofit. This process is described as follows:

1. Only fossil units were eligible for control retrofits.
2. No plants below 100 MW were retrofit (NO_x reduction potential too low to justify the cost).
3. Units that had SNCRs as a RACT requirement were not retrofit further.
4. Above assumptions for technology cost and performance were assumed (these costs would be significantly lower for installation of on new units).
5. NO_x reduction potential was determined for each unit based on:
   NO_x Reduction Potential = Rated Capacity * NO_x emission Rate * Availability
6. Use SNCR and SCR retrofits on units with highest emission potential.
7. Iterate using EGEAS to determine exact Phase II & Phase III retrofits necessary to achieve 65% reduction by 1999 and 80% reduction by 2003.

Note that actual NO_x emissions depend on the capacity factor of the generating units. This can only be determined through dispatching the system, necessitating an iterative process to determine the retrofit requirements.

Table 3-5 summarizes the retrofits implemented in the strict Phase II and strict Phase III retrofit strategies. Strict Phase II targets a 65 percent reduction from 1990 emission levels. This is modeled as installing SCRs on over 7,100 MWs of generating capacity and SNCRs on almost 2,000 MWs of capacity. Strict Phase III targets a 80 percent reduction from 1990 emissions levels. This is modeled as installing SCRs on over 7,600 MWs of capacity and SNCRs on almost 2,000 MWs of capacity.

Table 3-5: Summary of Strict Retrofit Strategies

NOx Control Technology	(A) Phase I RACT (1995) Units	MWs	(E) Strict Phase II (1999) Units	MWs	(O) Strict Phase III (2003) Units	MWs
Low NOx Burners	10	1,400	7	675	3	739
Overfired Air	1	460				
Flue Gas Recycling	2	19	2	19	2	19
Combustion Mods.	20	5,066	4	568	2	490
OFA & LNB & FGR	3	1,260	2	718	2	718
LNB & OFA	4	1,143	1	19	1	19
Reburning	1	239				
Steam Injection					2	117
SCR			23	7,166	35	7,647
SNCR	7	963	11	1,980	11	1,980
Total Units Effected	48	10,550	50	11,145	58	11,729

Table 3-6 summarizes the retrofit levels implemented in the relaxed Phase II and relaxed Phase III strategies. Relaxed Phase II controls target a reduction of 50 percent from 1990 emission levels. This is modeled as installing SCRs on over 5,300 MWs of capacity and SNCRs on almost 2,000 MWs of capacity. Relaxed Phase III controls target a reduction of 65% from 1990 emission levels. This is modeled as installing SCRs on over 7,100 MWs of capacity and SNCRs on almost 2,000 MWs of capacity.

Table 3-6: Summary of Relaxed Retrofit Strategies

NOx Control Technology	(A) Phase I RACT (1995) Units	MWs	(I) Relaxed Phase II (1999) Units	MWs	(U) Relaxed Phase III (2003) Units	MWs
Low NOx Burners	10	1,400	8	789	7	675
Overfired Air	1	460				
Flue Gas Recycling	2	19	2	19	2	19
Combustion Mods.	20	5,066	13	1,961	4	568
OFA & LNB & FGR	3	1,260	2	718	2	718
LNB & OFA	4	1,143	1	19	1	19
Reburning	1	239	1	239		
Steam Injection						
SCR			12	5,377	23	7,166
SNCR	7	963	11	1,980	11	1,980
Total Units Effected	48	10,550	50	11,102	50	11,145

In addition to the targets specified in the OTC MOU, a retrofit strategy focused on upgrading old plants has been proposed by CLF and others. Under this program, the twelve oldest and most polluting plants in New England would be retrofit to meet the strict requirements in place for new generating units. This "Old Source Review" strategy is modeled here as the installation of SCRs on the twelve dirtiest plants in New England (as identified by the Conservation Law Foundation in conjunction with the New England Electric System). Table 3-7 below lists these "dirty dozen" units. This retrofit strategy is intended to work in conjunction with the operational controls described below. It should also be noted that the Old Source Review strategy proposed by CLF is intended to be a multi-emission reduction strategy. This thesis focuses on the NO_x reduction capability of this program in order to determine its viability as an OTC compliance strategy. However, impacts on alternative emissions are also considered in Chapter 4.

Table 3-7: Old Source Review Retrofit Units

"Old Source Review" Unit	*Capacity (MW)*	*"Old Source Review" Unit*	*Capacity (MW)*
Mystic 7	617	Brayton Point 3	643
New Boston 1	359	Brayton Point 4	476
New Boston 2	359	Salem Harbor 4	476
WF Wyman 4	632	Merrimack 2	346
Canal 1	543	Bridgeport Harbor 3	400
Canal 2	530	New Haven Harbor	460
		Total MW Effected:	5,838

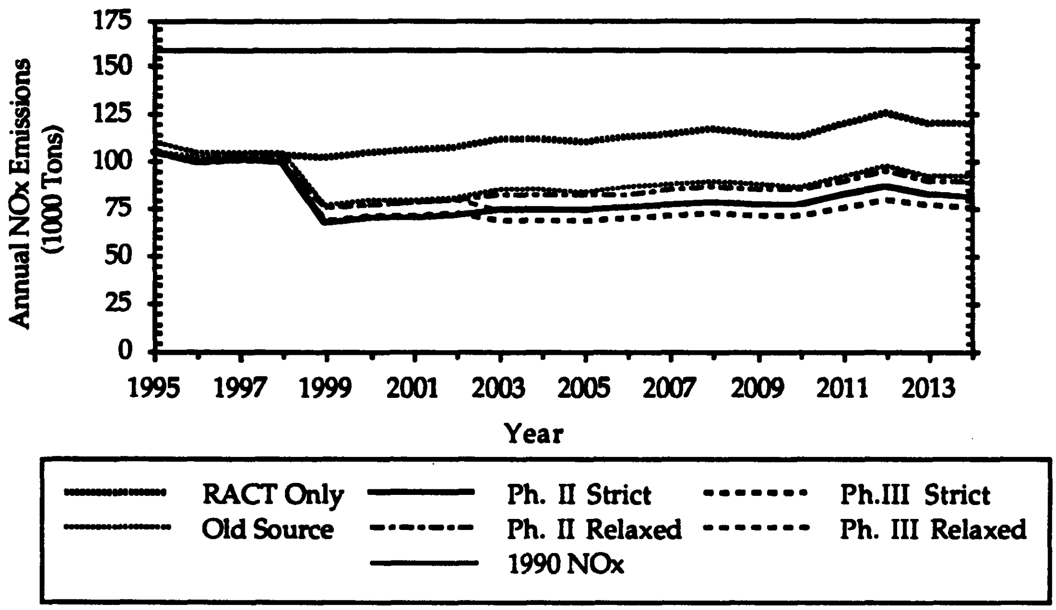
C. NO_x CONTROL RETROFIT PERFORMANCE

Six levels of technological retrofit controls were modeled as described above. These strategies are evaluated in terms of their ability to meet the Southern Seasonal NO_x emission "Cap" and the corresponding Southern Episodal "Month". The seasonal "Cap", as calculated in section A above, is 13,950 tons and the "Month" is 2,790 tons. The cost-effectiveness of these options is also examined based on their impact on the Total Regional and Electric Industry Direct Costs.

NO_x Performance

Figure 3-3 below shows the annual NO_x emission trajectory for the 6 retrofit options and identifies the 1990 historic NO_x emission level. Phase I RACT has already reduced NO_x emissions significantly. Phase II and Phase III retrofit controls are successful in further reducing NO_x emissions. However, NO_x is fundamentally not an annual problem due to the chemistry of ozone formation in the presence of sunlight. Therefore, it is more important to examine NO_x reduction during the ozone season in southern NE.

Figure 3-3: Annual NO_x Emissions



Examining Figure 3-4, it is evident that additional NO_x retrofit controls beyond RACT are very effective in reducing the amount of NO_x emitted during the ozone season in Southern New England. Both Strict and Relaxed Phase III controls, as well as Strict Phase II controls, reduce NO_x emissions below the Southern Seasonal Cap. Relaxed Phase II controls also come close to meeting the seasonal NO_x target. The Old Source Review strategy, while significantly reducing NO_x emissions, does not come close to meeting the Cap. The NO_x reduction capability of these strategies remains consistently effective throughout the 20 year period modeled.

Figure 3-4: Southern NE Seasonal NO_x Emissions

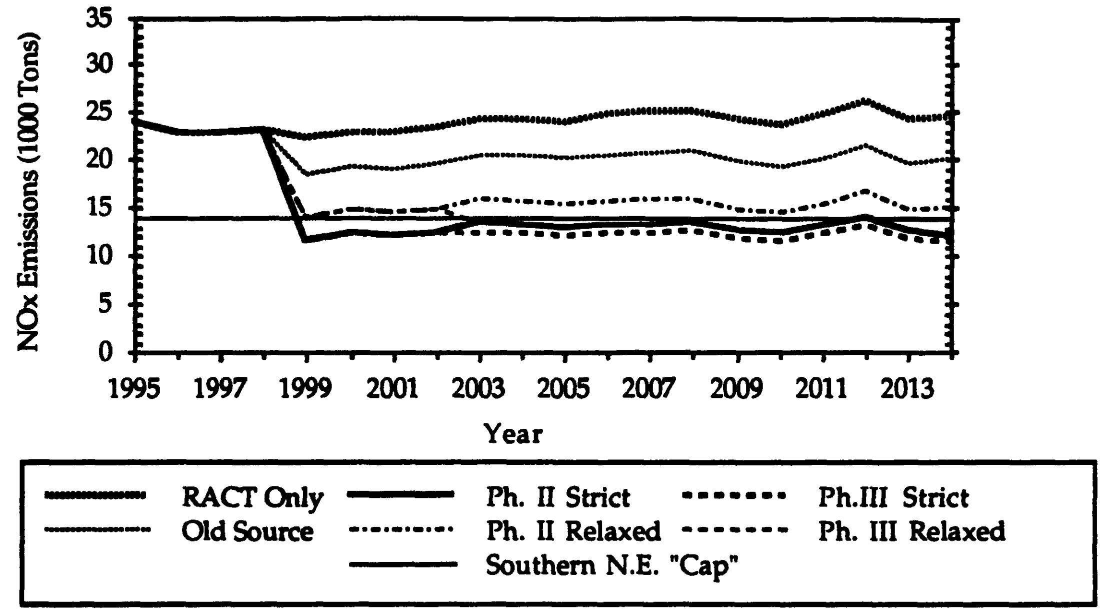
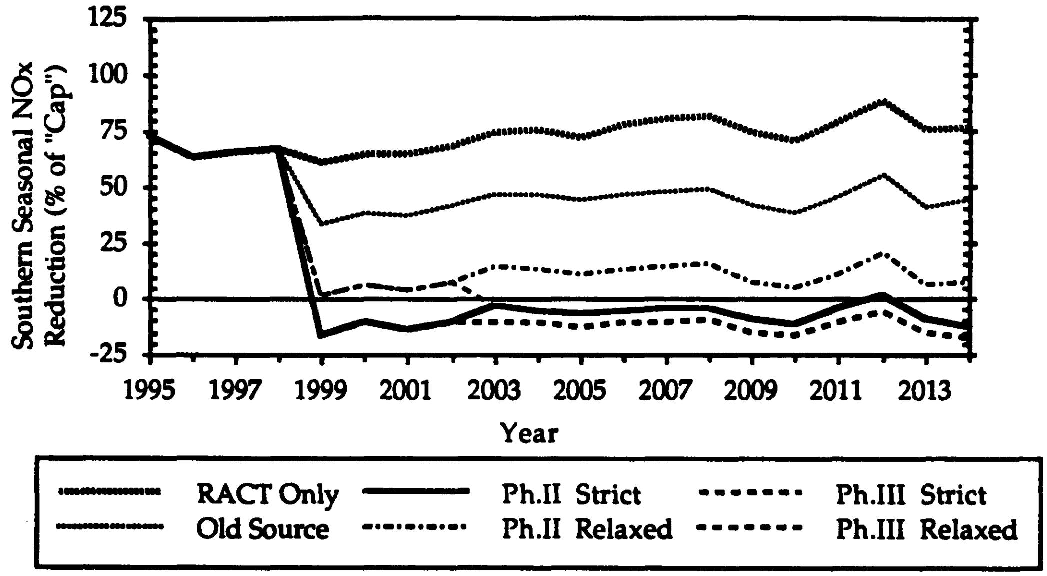


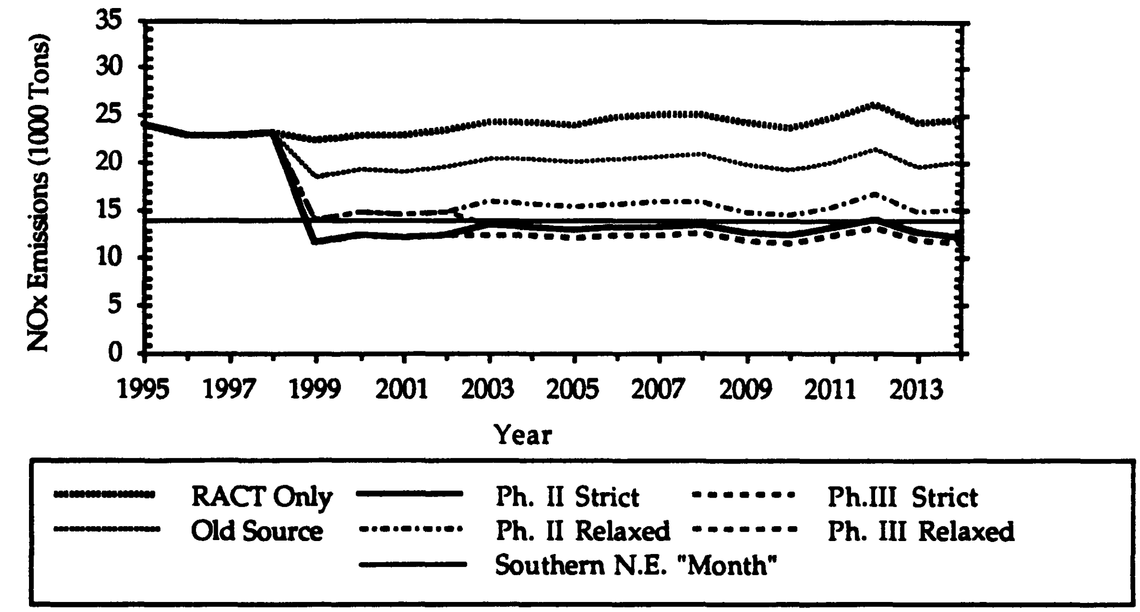
Figure 3-5 shows the retrofit control scenario performance as a percentage of the Southern Seasonal Cap. The Strict Phase III emissions are generally 5 to 10 percent below the Cap. Although this may seem desirable at first, it should be noted that the Cap is defined to be the level of emissions which regulators feel is sufficient to address the seasonal ozone non-attainment problem. Therefore, over-compliance may not add significantly to the positive benefits of NO_x reduction, although this may change as the science associated with ozone formation advances. This is another way in which retrofit controls over-comply with current proposed regulations. The Relaxed Phase II scenario is generally within 10 to 15 percent above the seasonal cap while the Old Source Review strategy is generally between 40 to 45 percent above the Cap.

Figure 3-5: Southern NE Seasonal NO_x as Percent of Seasonal NO_x Cap



Retrofit control NO_x reduction also performs well in reducing episodal NO_x emissions. Figure 3-6 shows that the for Southern Episodal "Month" both of the Phase III scenarios and the Relaxed Phase II strategies meet the target. The Relaxed Phase II strategy comes close (within 20 percent) to compliance without operational controls. Old Source Review remains 40 to 50 percent above the cap. This should be expected since the retrofit control technologies do not have a seasonal component and Old Source review targets units outside of the Southern Zone. Once a unit is retrofit, the controls are in place for the entire year. Therefore, NO_x reduction results are similar for any time period examined, including annual impacts. This is another way in which retrofit controls over-comply with NO_x reduction targets since only seasonal NO_x reductions are required by currently proposed regulations.

Figure 3-6: Southern NE Episodal NO_x Emissions



Cost Performance
Retrofit controls have a fairly large impact on total regional costs, as shown in Figure 3-7 below. The largest cost difference between Strict Phase III controls and RACT Only amounts to almost $400 million in 1999 and $800 million by 2014 in future year dollars (or $300-400 million in base year 1994 dollars). The percent differences between all the retrofit levels and RACT Only remains constant over time because the total cost increases at the same rate as the cost difference (approximately the inflation rate). This difference makes Strict Phase II controls approximately 2.6 percent more expensive than RACT Only.

All of the control retrofit levels beyond RACT vary little in terms of cost impacts. Relaxed Phase II is the least expensive retrofit option beyond RACT Only. The Total Regional Cost difference between Phase II Relaxed and Strict Phase III controls is approximately $200 million annually (or $120 million in base year dollars). This is a 0.6 percent difference in total cost. The Old Source Review strategy has approximately the same cost impact as the Strict Phase II controls.

Figure 3-7: Total Regional Cost Difference from RACT Only in Future Year Dollars

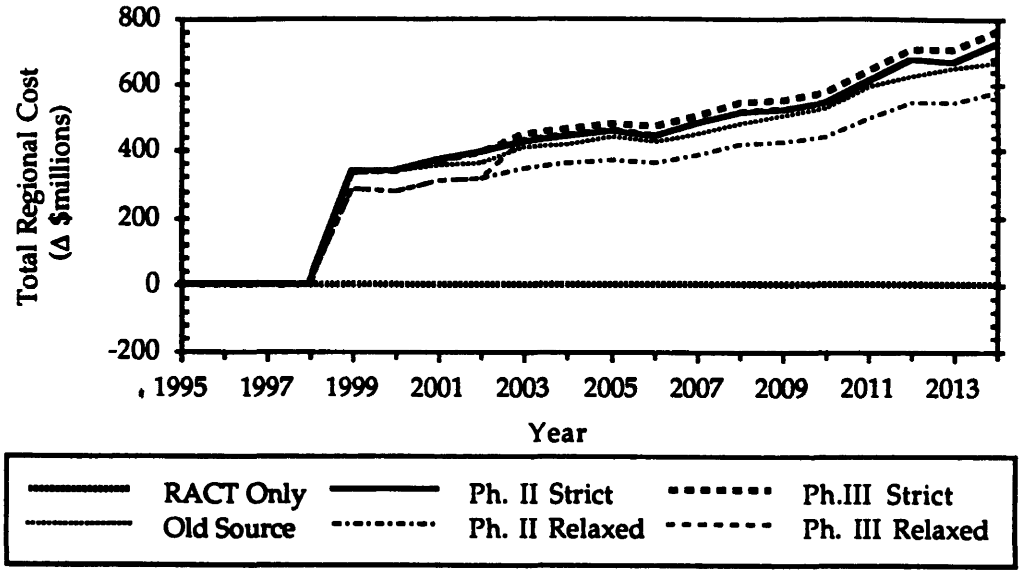


Figure 3-8 shows the breakdown and trajectory of the cost difference between the RACT Only and two other retrofit levels. The Relaxed Phase II diagram shows that the capital cost of retrofit controls is approximately 30 percent of the total cost when they are first installed. This portion of the cost difference declines as the equipment depreciates. Variable O&M cost, which starts at 50 percent, increases over time to make up 70 percent of the cost impact at the end of the model period because of the capital depreciation. Fuel costs consistently amount to about 20 percent of the difference and fixed O&M costs are a very small 2 percent. The Strict Phase III diagram reflects percentages similar to the Relaxed Phase II diagram. Fuel costs are a slightly smaller portion and variable O&M a slightly larger portion. The magnitude of the cost impact is larger for the Strict Phase III strategy.

This diagram is counter-intuitive in several ways. Retrofit controls are not designed to change the operation of the electric power system. However, changing the variable O&M cost of the retrofit units, does change the system dispatch order. This explains the fuel cost difference reflected in the diagrams. More importantly, the variable O&M cost predominates over the capital costs. O&M costs are recurring and, by design, have been applied to units with high capacity factors in order to attain the maximum NO_x reduction. The capital costs are single expenditures depreciated over time. These two factors result in a variable O&M cost impact significantly larger than the capital charge impact. The implication of this cost impact is that SCRs and SNCRs should be installed but only run during the ozone season to save on operational expenses.

Figure 3-8: Breakdown of Cost Impact by Type for Relaxed Phase II and Strict Phase III Retrofit Controls in Base Year 1994 Dollars

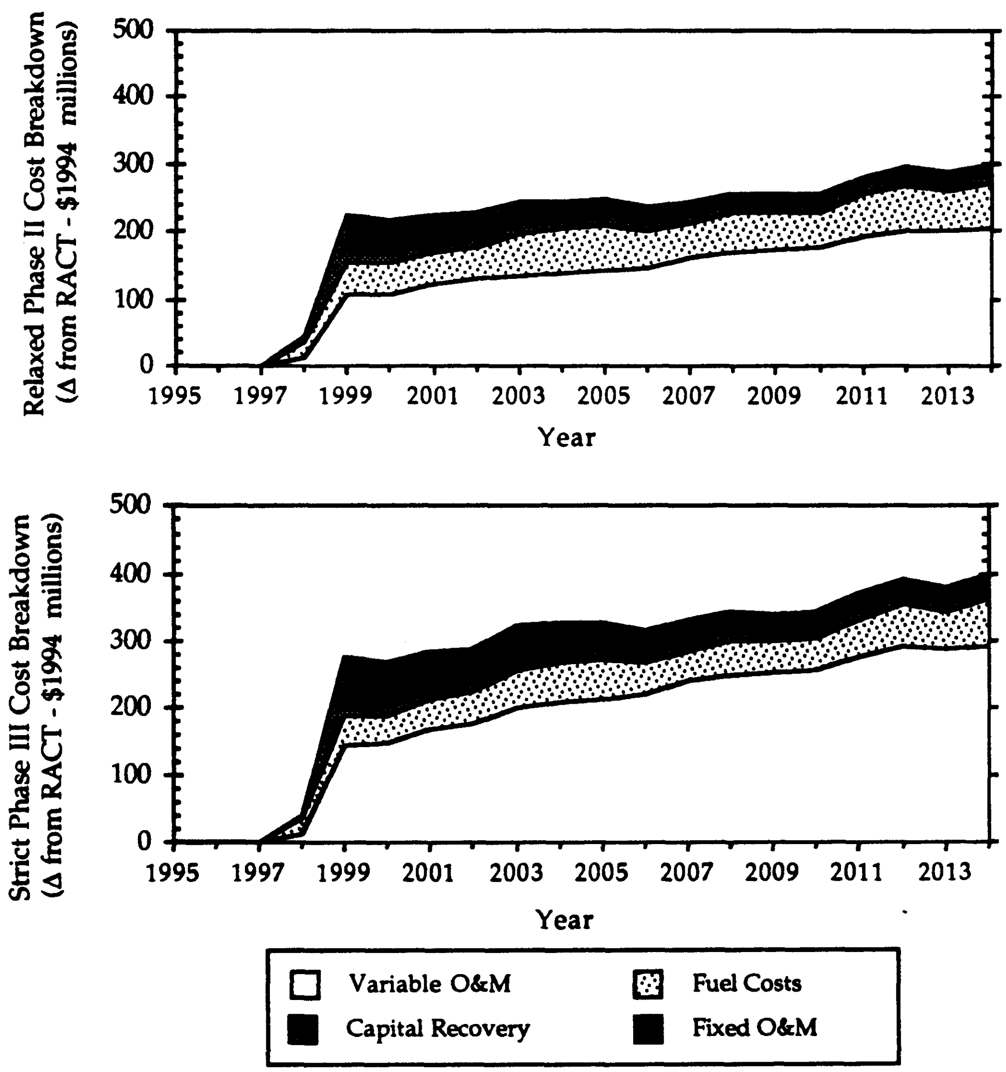


Table 3-6 summarizes the cumulative impact of retrofit controls on Total Regional Direct and Electric Industry Costs. Retrofit controls do have a significant impact on costs, resulting in a maximum total cost increase of $5.5 billion. Retrofits do not impact the regional costs more than the electric industry directly since the costs are recovered through rates. However, the method of cost calculation does significantly impact the potential cost impact. In all cases, Strict Phase III controls are the most expensive while Relaxed Phase II controls are the least expensive at a maximum $4.2 billion. The Risk Adjusted discounting makes the capital intense retrofit controls appear less costly by discounting more rapidly the non-recurring, and therefore less risky, expenses.

Table 3-8: Cost Impacts of Retrofit Controls on Industry Costs

NOx Retroft Strategy	NPV Direct Costs Regional Direct	Elec. Ind. Direct	Inflation Adj. Direct Regional Direct	Elec. Ind. Direct	Risk Adj. Discounting Total Direct	Elec. Ind. Direct
RACT Only	133.6	132.4	254.1	252.1	150.8	149.5
Ph. II Strict	136.0	134.8	259.3	257.3	154.0	152.8
Ph. II Relaxed	135.5	134.3	258.3	256.3	153.4	152.2
Ph. III Strict	136.0	134.9	259.5	257.6	154.1	152.9
Ph. III Relaxed	135.8	134.6	259.1	257.1	153.8	152.6
Old Source	136.0	134.8	259.2	257.2	154.0	152.8
	(PV-1994$B, r=10$)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ from RACT Only						
Ph. II Strict	2.3	2.3	5.2	5.2	3.2	3.2
Ph. II Relaxed	1.9	1.9	4.2	4.2	2.6	2.6
Ph. III Strict	2.4	2.4	5.5	5.5	3.3	3.3
Ph. III Relaxed	2.2	2.2	5.0	5.1	3.1	3.1
Old Source	2.4	2.4	5.1	5.1	3.2	3.2
	(PV-1994$B, r=10$)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ% from RACT Only						
Ph. II Strict	1.7	1.8	2.1	2.1	2.1	2.1
Ph. II Relaxed	1.4	1.4	1.7	1.7	1.7	1.7
Ph. III Strict	1.8	1.8	2.1	2.2	2.2	2.2
Ph. III Relaxed	1.7	1.7	2.0	2.0	2.0	2.0
Old Source	1.8	1.8	2.0	2.0	2.1	2.2
	(Δ%)		(Δ%)		(Δ%)	

Summary

Table 3-7 summarizes the cumulative impacts of retrofit controls on the New England electric system NO_x emissions without any operational constraints. The percent reductions are basically the same for the three All New England time periods modeled (annual, seasonal and episodal) because these retrofit controls do not have a time component. Retrofit controls are effective in reducing Southern NE NO_x because, by design, most of the generating units selected for control technologies are in the South. Looking only at Southern NE, retrofit controls can achieve a cumulative reduction in NO_x of 40 percent.

Table 3-9: Emissions Impact Summary for Retrofit Controls

NOx Retrofit Strategy	Total Seasonal Geographic NOx Emissions: NOx Emissions	All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
RACT Only	2.32	0.84	0.50	0.17	0.10
Ph. II Strict	1.70	0.62	0.31	0.13	0.06
Ph. II Relaxed	1.83	0.67	0.36	0.14	0.07
Ph. III Strict	1.62	0.59	0.30	0.12	0.06
Ph. III Relaxed	1.73	0.63	0.32	0.13	0.07
Old Source	1.90	0.68	0.44	0.14	0.09
	(MTons, 1995-2014)				
Δ from RACT Only					
Ph. II Strict	-0.62	-0.22	-0.19	-0.04	-0.04
Ph. II Relaxed	-0.49	-0.17	-0.15	-0.03	-0.03
Ph. III Strict	-0.69	-0.25	-0.20	-0.05	-0.04
Ph. III Relaxed	-0.59	-0.21	-0.18	-0.04	-0.04
Old Source	-0.42	-0.16	-0.06	-0.03	-0.01
	(ΔMTons, 1995-2014)				
Δ% from RACT Only					
Ph. II Strict	-26.89	-26.20	-37.80	-25.91	-37.10
Ph. II Relaxed	-21.07	-20.61	-28.94	-20.32	-28.31
Ph. III Strict	-29.94	-29.98	-40.13	-29.72	-39.51
Ph. III Relaxed	-25.52	-24.90	-35.73	-24.58	-34.98
Old Source	-18.21	-18.81	-12.24	-18.48	-12.00
	(Δ%)				

The performance of retrofit controls for reducing NO_x emissions is very strong. They achieve sufficient reductions to meet the OTC MOU target cap. However, there are several drawbacks to retrofit controls. Although they do have a geographic component, as modeled here, retrofit controls are implemented all 12 months of the year for an inherently 5 month problem. It is also possible to over-comply by installing control technologies on too many generating units. This is reflected by the Strict Phase III option which resulted in NO_x emissions below the OTC MOU target. This is costly and not currently deemed necessary to protect human health and the environment. This may change in the future, as NO_x is becoming more important as an acid rain emission due to some recent environmental reports and the successful reduction of SO_2 emissions. Control technologies achieve large NO_x reductions but are expensive, so they should be used sparingly. This suggests that retrofit controls may work best in combination with other reduction strategies which cost less and/or have a seasonal component.

D. NO_X OPERATIONAL CONTROL OPTIONS

The nature of the urban photochemical smog problem is intermittent and depends heavily on the sun and temperature. Due to the seasonal nature of ozone formation, New England experiences "ozone episodes" during the summer months. While there may be benefits to reducing ozone concentrations during non-episode times, the focus of policy since the first Federal Clean Air Act in the early 1970s has been to reduce the number and duration of exceedances of air quality standards, both federal and state. While the cost of physical NO_x control, in terms of dollars per avoided ton NO_x emitted, may be low, it might be expensive in terms of dollars per avoided episode day ton.

Operational controls modify the dispatch order of generating plants based on a NO_x constraint rather than strictly minimum cost criteria during potential ozone periods. The advantage of this approach is that it concentrates the NO_x reduction effort only on the specific problem window. In this study, operational controls have been modeled in two ways: a seasonal and an episodic NO_x constraint. "Seasonal Controls" set a "Cap" on NO_x emissions during the summer months (May to September) according to the Ozone Transport Commission's Memorandum of Understanding described in Chapter 1. However, New England is only at risk of exceeding ozone limits between 20 and 30 days each year. "Episodal Controls" model this as one summer "Month" (roughly July) when generation is dispatched to minimize NO_x irrespective of cost.

Operational Controls are an attractive alternative for achieving NO_x reductions since they require little or no additional capital equipment. However, the NO_x reduction capability of this strategy is questionable. One additional aspect to be considered is that operational controls shift all effected power plants' emissions, while NO_x retrofit approaches only reduce NO_x emissions. Impacts on these other emissions will be examined in the next chapter. Five levels of operational controls were modeled:

- No Operational Controls (reference)
- Seasonal Constraint for All New England
- Seasonal Constraint for Southern New England only
- Episodal Minimum NO_x Dispatch for All New England
- Episodal Minimum NO_x Dispatch for Southern New England only

E. NO_x OPERATIONAL CONTROL PERFORMANCE

There are five different operational control scenarios as described above. These options are evaluated based on the same criteria that were applied to the retrofit control options. First the technical NO_x reduction performance of operational controls will be examined and then their impact on costs will be analyzed.

NO_x Performance[1]

Operational Controls in conjunction with NO_x RACT alone are not effective in reducing NO_x emissions to the seasonal cap of 13.95 thousand tons. Figure 3-9 shows that Southern Seasonal controls, which reduce Southern Seasonal NO_x to about 16 thousand tons, within 10 percent of the Cap, comes the closest to compliance with the RACT only level of retrofits. The Southern Seasonal strategy reduces NO_x the most because it is focuses on Southern NE during the ozone season. Episodal controls, by definition, do not perform well in reducing seasonal NO_x since they are applied during only one of the five seasonal months. The All NE strategies disperse the NO_x reductions throughout NE rather than concentrating them in the non-attainment area of Southern NE. Therefore, these strategies do not perform well when evaluating Southern Seasonal NO_x. All NE Southern and Episodal controls reduce NO_x emission to approximately

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[1]NO_x dispatch targets for operational controls with RACT caused some unintended results. When the system dispatches for an unattainable NO_x target, it dispatches virtual "emergency" procedure units (OP-4 units). These database units model unmet energy hours. They have very high dispatch cost modifiers to ensure they are only dispatched after real units. When NO_x targets are extremely low, these virtual units with no NO_x emissions are ultimately dispatched to meet the NO_x target. In the modeling, the resulting "virtual" brown-out do not actually cost the utility anything or result in any emissions. Therefore, operational control strategies with NO_x targets low enough to cause the system to dispatch these emergency units give misleading results. These scenarios suggest lower costs and emissions than would actually result under operational controls.

In order to obtain more reliable results for these operational control strategies, the emergency units were disabled for the RACT Only scenarios presented in this section. This allows accurate modeling of system emissions and costs. When operational controls are used in combination with retrofit controls beyond RACT, there is no longer a problem with virtual emergency units. Retrofit controls reduce NO_x emissions close to or below the NO_x target. This makes the NO_x dispatch constraint easier to achieve through dispatching and avoids the need to dispatch OP-4 units. Even with the modeling "artifact" of disabling the OP-4 units strategies with only operational controls still do not achieve the required reduction in NO_x and are therefore unviable "solutions." This chapter discusses the results of operational and retrofit controls in combination with the emergency units enabled.

20 thousand tons, or 40 percent above the Cap and 24 thousand tons, or 60 percent above the Cap, respectively.

Unlike the other NO_x options examined in this thesis, operational controls do have a seasonal and geographic component. Therefore, NO_x emission reductions during the ozone season and episodes are significantly greater than the annual NO_x reductions. And reductions for Southern NE are greater when Southern controls are instituted. However, Figure 3-10 shows that the strictly episodal strategies do not achieve significantly greater reductions during the ozone episodal "Month" than the seasonal controls achieved. This is explained by the fact that, without using any other reduction strategies, the NO_x Cap is already so low that there is effectively no difference between dispatching for a NO_x Cap and a minimum NO_x dispatch with only RACT retrofits.

Figure 3-9: Seasonal NO_x Emissions in Southern NE with RACT Only Retrofit Control

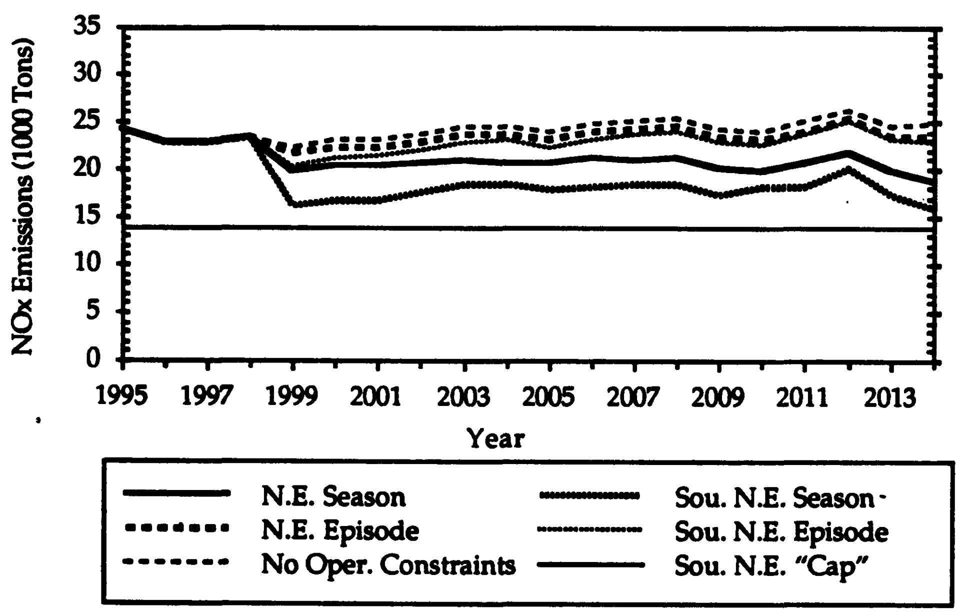
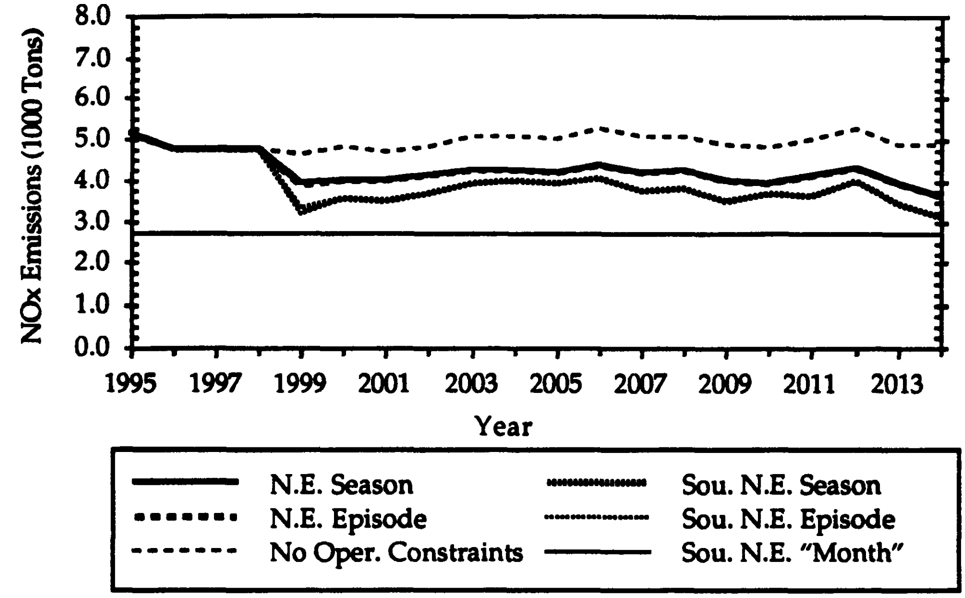


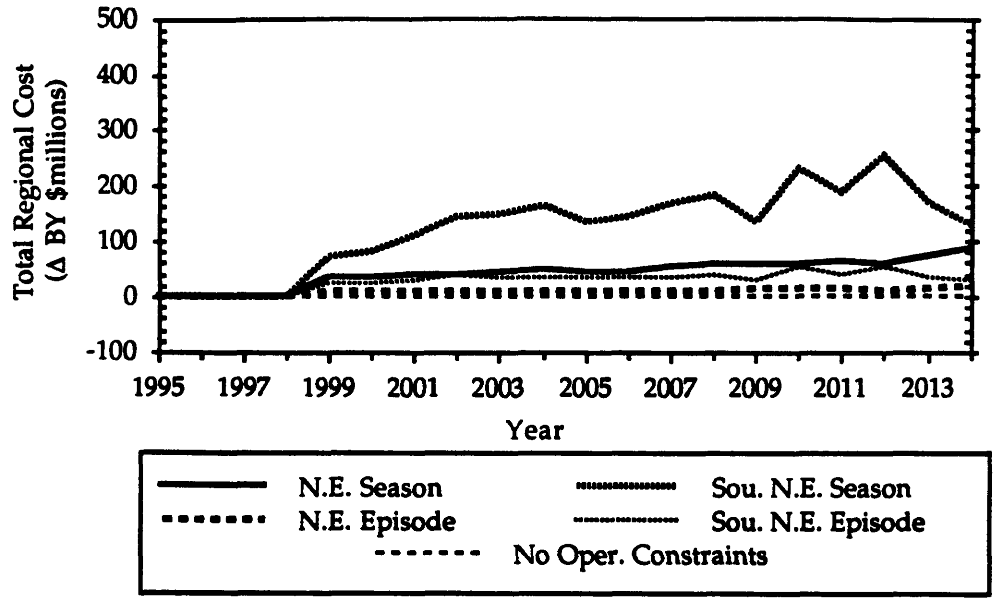
Figure 3-10: Episodal NO_x Emissions in Southern NE with RACT Only Retrofit Controls



Cost Performance

Figure 3-11 shows that operational controls have a moderate impact on total regional costs. The most expensive option, Southern Seasonal controls, increases cost above No Operational by about $175 million in 1999 and $400 million by 2012. In base year 1994 dollars, this cost impact is consistently around $160 million. This difference makes Southern Seasonal controls approximately 1.2 percent more expensive than no controls. The impact of operational controls varies significantly depending on fuel cost variations and the retirement of nuclear units. The price of oil spikes in 2010 and 2012 corresponding to the observed spikes in the cost impact of operational controls. Unlike the retrofit control strategies, the cost of difference of operational controls varies significantly. All NE seasonal controls have a significantly smaller impact than Southern Seasonal controls reaching a maximum of $165 million in 2014. The Regional Cost difference between these two operational control options is approximately $250 million in 2012 representing a 1.4 percent difference. This difference is due to the stricter nature of the Southern Seasonal Cap. The electric generating system is trying to dispatch for a constraint that is unattainable with the existing capital stock. Not surprisingly, the impact of episodal controls are roughly one fifth those of their seasonal counterparts.

Figure 3-11: Total Regional Cost Difference from No Operational Controls with RACT Only Retrofit Controls



Summary

Southern Seasonal controls are somewhat effective in reducing Southern Seasonal NO_x, but do not provide sufficient reduction to meet the NO_x target Cap without additional retrofits. Both of the southern control strategies are effective in reducing southern episodal NO_x emissions, but again, neither meets the actual MOU targets. The cumulative costs of operational controls are below those of the retrofit control options but still pose a significant cost impact. A detailed analysis of the operational control cost impact is not provided here since this strategy alone is not sufficient to meet the OTC MOU NO_x target.

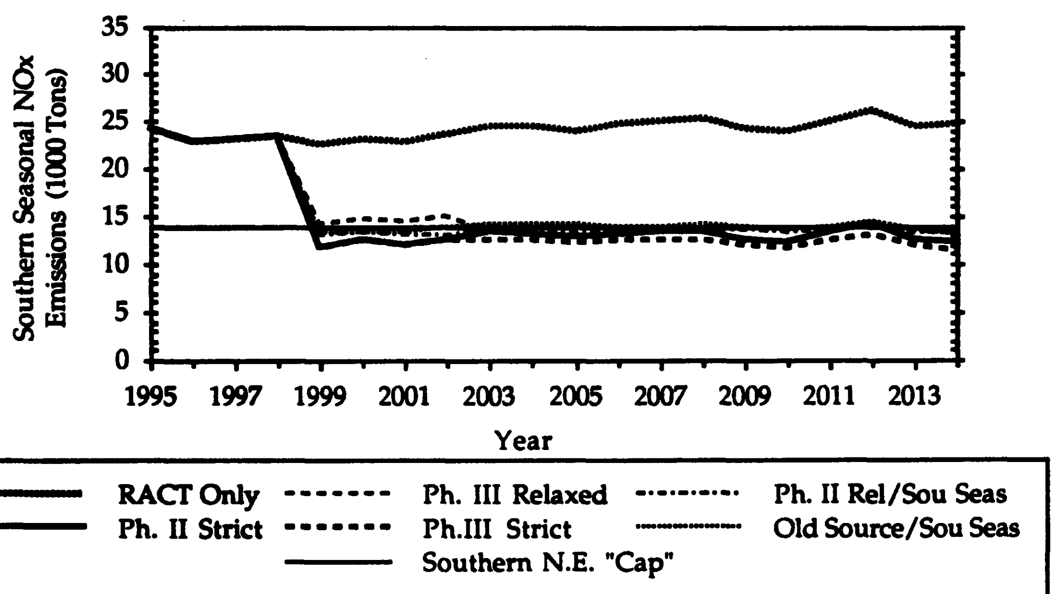
F. COMBINED NO_x RETROFIT AND OPERATIONAL CONTROL OPTIONS

Figure 3-12 below shows the NO_x emissions trajectory for "candidate" NO_x strategies and the reference scenario. These candidate strategies consistently achieve the desired reduction for Southern Seasonal NO_x. The candidate scenarios are:

- Strict Phase II Retrofit Controls with No Operational Controls
- Relaxed Phase III Retrofit Controls with No Operational Controls
- Strict Phase III Retrofit Controls with No Operational Controls
- Relaxed Phase II Retrofit Controls with Southern Seasonal Controls
- Old Source Review Retrofit Controls with Southern Seasonal Controls

Strict Phase II and III and Relaxed Phase III retrofit controls with operational controls are not considered because these retrofit strategies alone meet the NO_x Seasonal Cap. Figure 3-12 shows that Relaxed Phase II and Old Source Review retrofit levels, in combination with Southern Seasonal controls, meet the NO_x target.

Figure 3-12: NO_x Emission Trajectory for Candidate Scenarios



Total Regional Costs for the candidate NO_x scenarios are shown in Figure 3-13. There is a significant difference in the cost impact of these strategies. The

Relaxed Phase II with Southern Seasonal controls scenario has the lowest cost while the Strict Phase III control scenario has the largest cost impact. Relaxed Phase II with Southern Seasonal controls is consistently 0.5 percent or around \$175 million less than the other candidate scenarios (or \$125 million in base year dollars).

Figure 3-13: Total Regional Cost Impact of Candidate Scenarios

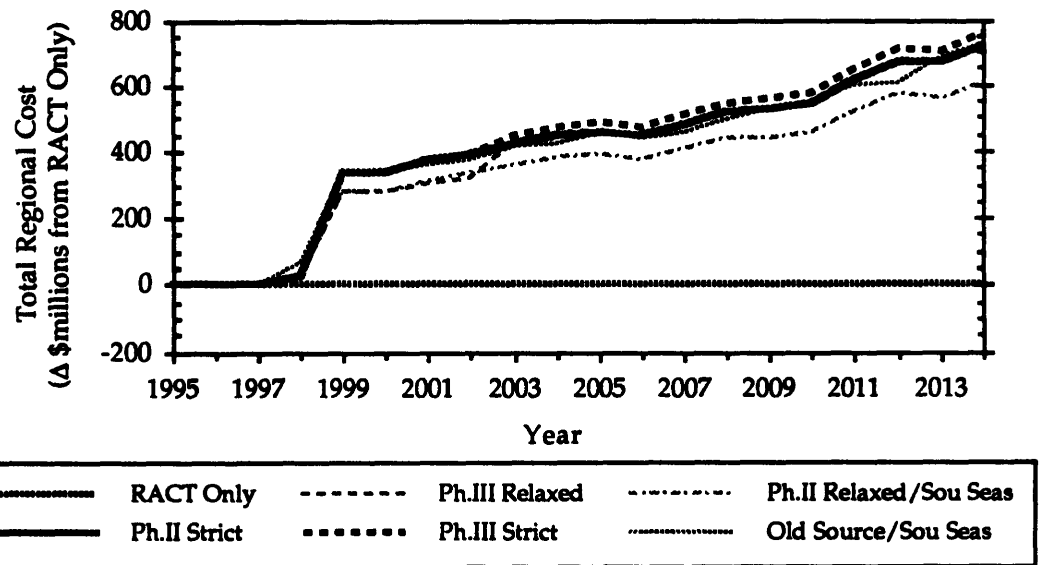


Table 3-10 summarizes the cumulative cost impacts of the candidate scenarios identified above. The Relaxed Phase II with Southern Seasonal control scenario is consistently the least expensive, regardless of cost calculation technique. Old Source Review with Southern Seasonal Controls and the Strict Phase III retrofit control are the most expensive. The cumulative cost difference between Relaxed Phase II with Southern Seasonal controls is \$300 to \$800 million over the next least expensive, viable option of Strict Phase II. Operational controls are generally less expensive than retrofit controls because they can be implemented during only the ozone season. As discussed above, retrofit controls over-comply with NO_x targets by reducing emissions during non-ozone season months as well as in Northern NE.

Table 3-10: Summary of Cost Impacts of Candidate Scenarios

NOx Retroft Strategy	NPV Direct Costs Regional Direct	Elec. Ind. Direct	Inflation Adj. Direct Regional Direct	Elec. Ind. Direct	Risk Adj. Discounting Total Direct	Elec. Ind. Direct
RACT Only/No Oper	133.6	132.4	254.1	252.1	150.8	149.5
Ph. II Strict/No Oper	136.0	134.8	259.3	257.3	154.0	152.8
Ph. II Rel/Sou Seas	135.6	134.4	258.5	256.5	153.5	152.3
Ph. III Strict/No Oper	136.0	134.9	259.5	257.6	154.1	152.9
Ph. III Rel/No Oper	135.8	134.6	259.1	257.1	153.8	152.6
Old Source/Sou Seas	136.0	134.8	259.3	257.4	154.1	152.9
	(PV-1994$B, r=10$)		(1994$B, r=3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ from RACT Only/No Oper						
Ph. II Strict/No Oper	2.3	2.3	5.2	5.2	3.2	3.2
Ph. II Rel/Sou Seas	2.0	2.0	4.4	4.4	2.7	2.7
Ph. III Strict/No Oper	2.4	2.4	5.5	5.5	3.3	3.3
Ph. III Rel/No Oper	2.2	2.2	5.0	5.1	3.1	3.1
Old Source/Sou Seas	2.4	2.4	5.3	5.3	3.3	3.3
	(PV-1994$B, r=10$)		(1994$B, r=3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ% from RACT Only/No Oper						
Ph. II Strict/No Oper	1.7	1.8	2.1	2.1	2.1	2.1
Ph. II Rel/Sou Seas	1.5	1.5	1.7	1.7	1.8	1.8
Ph. III Strict/No Oper	1.8	1.8	2.1	2.2	2.2	2.2
Ph. III Rel/No Oper	1.7	1.7	2.0	2.0	2.0	2.0
Old Source/Sou Seas	1.8	1.8	2.1	2.1	2.2	2.2
	(Δ%)		(Δ%)		(Δ%)	

The risk adjusted discounting cost calculation technique does narrow the gap between the Relaxed Phase II with Southern Seasonal controls and the Strict Phase III retrofit control scenarios. This is due to the fact that adjusting for risk places a premium on the recurring costs associated with operational controls. However, even accounting for this risk, Relaxed Phase II with Southern Seasonal controls remains the dominant scenario.

Table 3-11 summarizes the cumulative emissions of the candidate scenarios. There is very little difference between the scenarios in terms of their seasonal and episodal NO_x emissions. The scenarios without southern seasonal operational controls, have lower annual and All NE emissions. However, annual NO_x emissions are not the primary concern in ozone regulation. All of these scenarios have been shown to meet the target NO_x cap, any reductions below the cap or in Northern NE are not strictly required.

Table 3-11: Summary of NO_x Emission Impacts of Candidate Scenarios

NOx Retrofit Strategy	Total Seasonal Geographic NOx Emissions				
	NOx Emissions	All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
RACT Only/No Oper	2.22	0.81	0.48	0.16	0.10
Ph. II Strict/No Oper	1.62	0.60	0.30	0.12	0.06
Ph. II Rel/Sou Seas	1.73	0.62	0.30	0.12	0.06
Ph. III Strict/No Oper	1.56	0.57	0.29	0.12	0.06
Ph. III Rel/No Oper	1.65	0.61	0.31	0.12	0.06
Old Source/Sou Seas	1.74	0.59	0.32	0.12	0.06
	(MTons, 1995-2014)				
Δ from RACT Only/No Oper					
Ph. II Strict/No Oper	-0.60	-0.21	-0.19	-0.04	-0.04
Ph. II Rel/Sou Seas	-0.49	-0.19	-0.18	-0.04	-0.04
Ph. III Strict/No Oper	-0.67	-0.24	-0.19	-0.05	-0.04
Ph. III Rel/No Oper	-0.57	-0.20	-0.18	-0.04	-0.04
Old Source/Sou Seas	-0.49	-0.22	-0.16	-0.04	-0.03
	(ΔMTons, 1995-2014)				
Δ% from RACT Only/No Oper					
Ph. II Strict/No Oper	-27.15	-26.00	-38.56	-25.86	-37.96
Ph. II Rel/Sou Seas	-22.06	-23.75	-36.69	-24.27	-36.79
Ph. III Strict/No Oper	-29.95	-29.65	-40.52	-29.53	-40.02
Ph. III Rel/No Oper	-25.78	-24.74	-36.54	-24.53	-35.86
Old Source/Sou Seas	-21.86	-26.84	-33.69	-26.91	-35.11
	(Δ%)				

All of the strategies examined in this section attain the NO_x reduction goal. However, the Relaxed Phase II level of retrofit controls combined with Southern Seasonal operational controls, achieves the reduction at significantly lower cost. Installing NO_x control technology provides enough low NO_x emitting units that operational controls can be very effective.

G. CHAPTER SUMMARY

Several important results are evident from the information presented here. Most importantly, it is possible, with the current generation mix, to meet the NO_x reduction goals set by the Ozone Transport Committee. Retrofits controls tend to over-comply with the regulation because and thus it is possible to install too much retrofit technology. The cost of retrofit controls is more operational than capital. The least cost strategy is a combination of Relaxed Phase II retrofit controls and Southern Seasonal Operational controls.

Section E examined the scenarios which attain the NO_x reduction target. Of these viable solutions, the Relaxed Phase II with Southern Seasonal controls was the least expensive by a significant amount. Now that a least cost NO_x reduction scenario has been identified, several other factors need to be considered. The impact of the NO_x strategies on other emissions needs to be addressed. Modifying the dispatch order of generating units impacts the amount of SO_2 and CO_2 emitted. The NO_x strategies are not designed to reduce these emissions but they may have significant, and sometimes negative, impacts.

The level of Demand Side Management sponsored by utilities in NE or achieved by energy service companies, may significantly impact on NO_x emissions through lower electricity demand as well as by decreasing the need to build new, clean generation. The choice of technology and fuel type for new generation will also impact NO_x emissions. The impact of these future demand and supply side resource options will be examined in the next chapter.

Lastly, future natural gas cost uncertainty will be examined. A NO_x reduction strategy should be robust across variations in fuel price. Along with examining the impact of future uncertainty on NO_x emissions, its impact on cost will also be investigated. The next chapter will also address this larger electric power system concern.

CHAPTER 4 - OVERALL NO_X STRATEGY PERFORMANCE

In the previous chapter, the two NO_x control strategies of technology retrofit and operational controls were examined. It was shown that there are several strategy option combinations that are successful in meeting the OTC MOU target NO_x reductions. It was also shown that one strategy, Relaxed Phase II retrofits with Southern Seasonal operational controls, is significantly less expensive than the other viable scenarios. However, there are other factors that must be considered. These factors include the impact of DSM and future generation, the impact on CO_2 and SO_2 emissions. These factors will be examined in this chapter in relation to the five viable scenarios identified in Chapter 3 with a focus on the Relaxed Phase II with Southern Seasonal Operational Controls scenario. Scenario performance across natural gas cost uncertainty will be examined in the next chapter.

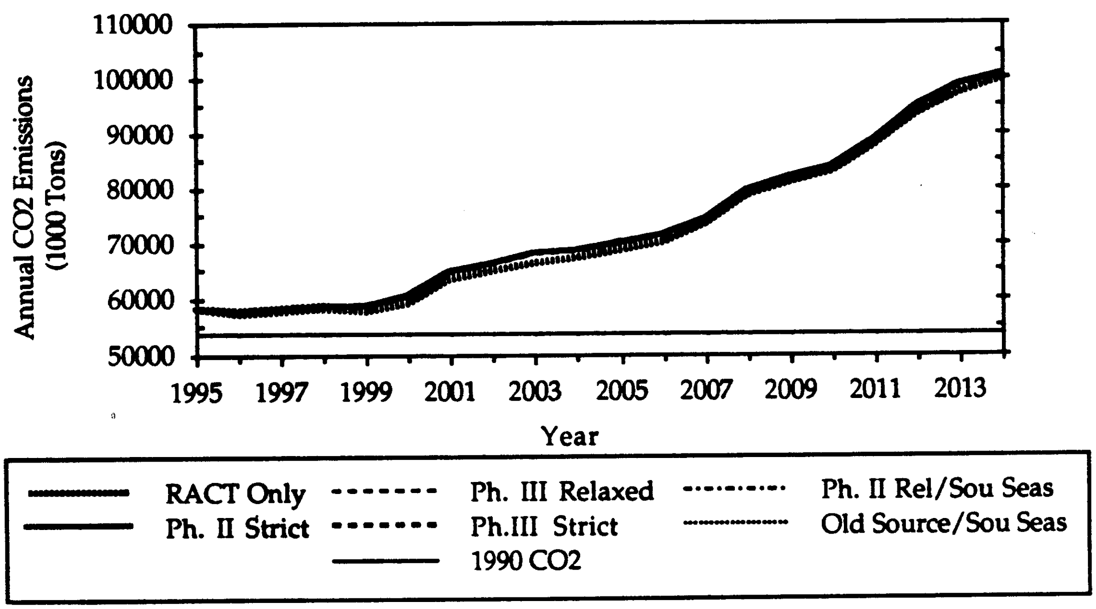
A. IMPACT OF NO_X STRATEGIES ON ALTERNATE EMISSIONS

Although the NO_x strategies are not intended to impact other emissions, they do affect these emissions through several mechanisms. Retrofit controls change the O&M cost of retrofit units, thereby changing the units position in the dispatch order. This shift in generation and fuel impacts CO_2 and SO_2 emissions. The operational controls strategies directly change the dispatch order by imposing the NO_x constraint. Again, this impacts CO_2 and SO_2 emissions. An optimal NO_x strategy should have a small impact on these emissions, or result in reduced emissions. This section will examine the impact of the candidate scenarios identified in the last chapter on CO_2 and SO_2 emissions. Then other electric system options will examined in order to identify means by which factors such as level of Demand Side Management and new generation technology choice can be leveraged to gain multiple emission reductions.

Impact on CO_2 Emissions

Figure 4-1 shows the annual CO_2 emissions trajectory for the candidate scenarios, the RACT Only base case scenario, and 1990 Historic CO_2 emissions. Figure 4-2 shows this trajectory as a percentage change from the 1990 historic emissions. All of the candidate scenarios, with the exception of the Old Source Review with Southern Seasonal controls, have approximately the same impact on CO_2. The impact difference among the scenarios modeled amounts to a maximum 1.75 million ton increase above RACT Only CO_2 emissions in 2001 for the Strict Phase III option. However, CO_2 emissions for all of the candidate scenarios increases drastically over time. By 2014, emissions are generally 50 million tons above the 1990 historic emissions which is the target for the United Nations' Climate Change Action Plan's Climate Challenge. The Old Source Review scenario has a somewhat smaller impact than the other scenarios, increasing emissions by only 80 percent above the 1990 level, as opposed to 85 percent for the other options. Even though the Old Source Review scenario causes a smaller increase in CO_2 emissions, the impact of the other is also not large compared to the overwhelming trend towards higher emissions.

<u>Figure 4-1</u>: Impact of Candidate Scenarios on Annual CO_2 Emissions



There are several mechanisms at work which lead to the observed increase in CO_2 emissions. The demand in New England continues to increase, albeit at a relatively slow rate. This growth accounts for most of the increase in CO_2 emissions. Also, several nuclear units are currently scheduled for re-licensing during this model period. This analysis assumed that these units will be retiring at the end of their license period. These retirements correspond to the sharp CO_2 emission increases seen in 2007, 2008, 2011 and 2012. This will be discussed in more detail later in this chapter. These two factors combine to cause the huge CO_2 emissions increase reflected in Figures 4-2 and 4-3.

Figure 4-2: Percentage Increase in CO_2 Emissions from 1990 Historic for Candidate Scenarios

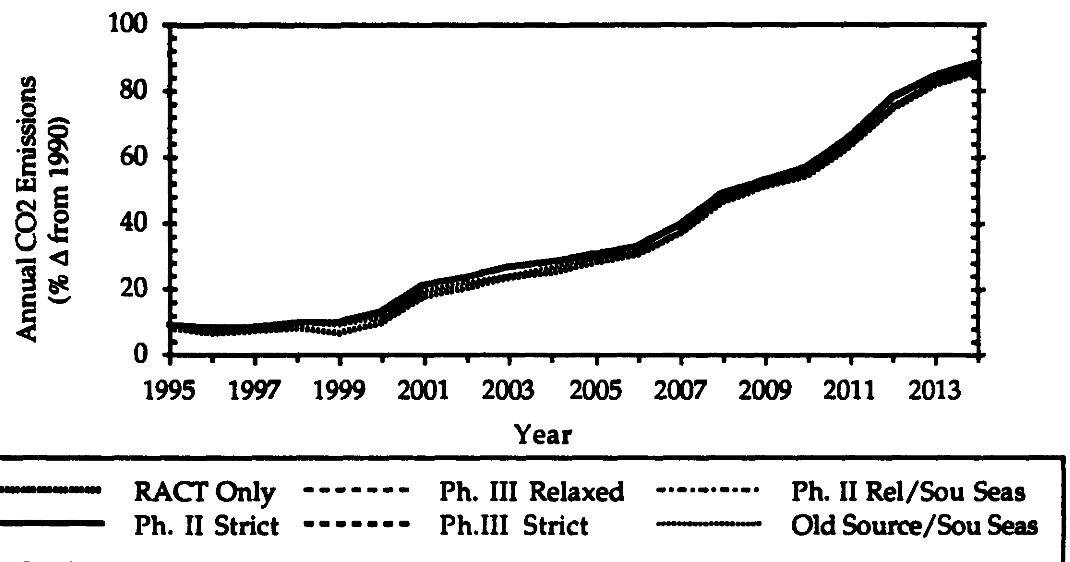
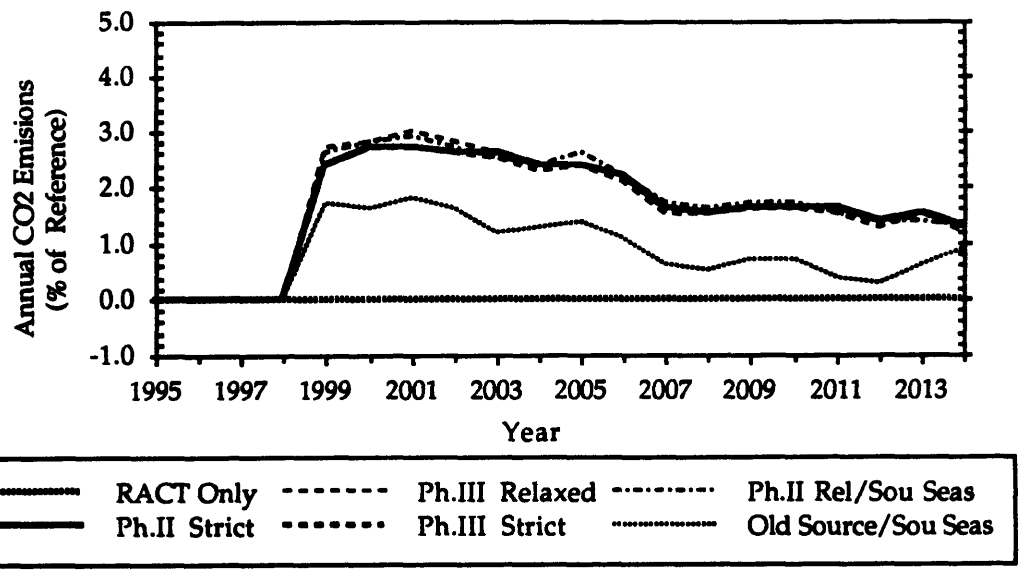


Figure 4-3 isolates the CO_2 emission impact of the candidate scenarios. As stated above all of the candidate scenarios have roughly the same impact on CO_2 emissions except for the Old Source strategy which has somewhat lower emissions. Most of the generation retrofit with NO_x controls is either coal or oil-fired. This results in a switch to existing, lower efficiency gas units. Also, when a NO_x constraint is imposed on Southern New England, generation shifts northward. As a result, there are several large, old and inefficient coal units in New Hampshire such as Merrimack units 1 and 2 which are run more frequently. Therefore, even though the total amount of coal generation decreases and the total amount of gas increases, CO_2 emissions increase. As new, high efficiency gas units come on line in later years, this increase in CO_2 emissions decreases. The Old Source Review causes a smaller increase in CO_2 emission because it targets old coal units including the ones in Northern NE. These units are therefore not run as much, and CO_2 emissions are not increased.

It should be noted that the moderate increase of the candidate scenarios is very small in comparison to the overall system wide increase in CO_2 emissions.

Figure 4-3: Percentage Impact of Candidate Scenarios on Annual CO_2 Emissions



Impact on SO_2 Emissions

Figures 4-4 and 4-5 show the impact of the candidate NO_x scenarios on SO_2 emissions. All of the candidate scenarios, with the exception of the Old source Review with Southern Seasonal controls, have approximately the same impact. The impact amounts to a 7 thousand ton decrease in SO_2 emissions in 2001 which declines over time to a 14 thousand ton reduction in 2014. This represent a 3 percent decrease in 2001 increasing to a 6.0 percent decrease in 2014. The Old Source Review scenario has a much larger impact, decreasing emissions by 19 thousand tons or 8.0 percent in 2001. This impact increases to a 34 thousand ton or 12.0 percent decrease by 2012. All of the candidate solutions move SO_2 emissions in the right direction.

The reductions in SO_2 emissions are explained by the same factors that caused the increase in CO_2 emissions. Reducing oil and coal generation reduces SO_2 emissions because these fuels have higher SO_2 production rates than the gas that is replacing them. The Old Source Review strategy reduces SO_2 emissions even further by targeting the units with the highest SO_2 emissions. As was noted earlier, Old Source Review was designed to reduce multiple emissions. And although it is successful at reducing all three emissions of primary concern in NE, as a NO_x strategy, it does not perform as well as other alternatives.

Figure 4-4: Impact of Candidate Scenarios on Annual SO_2 Emissions

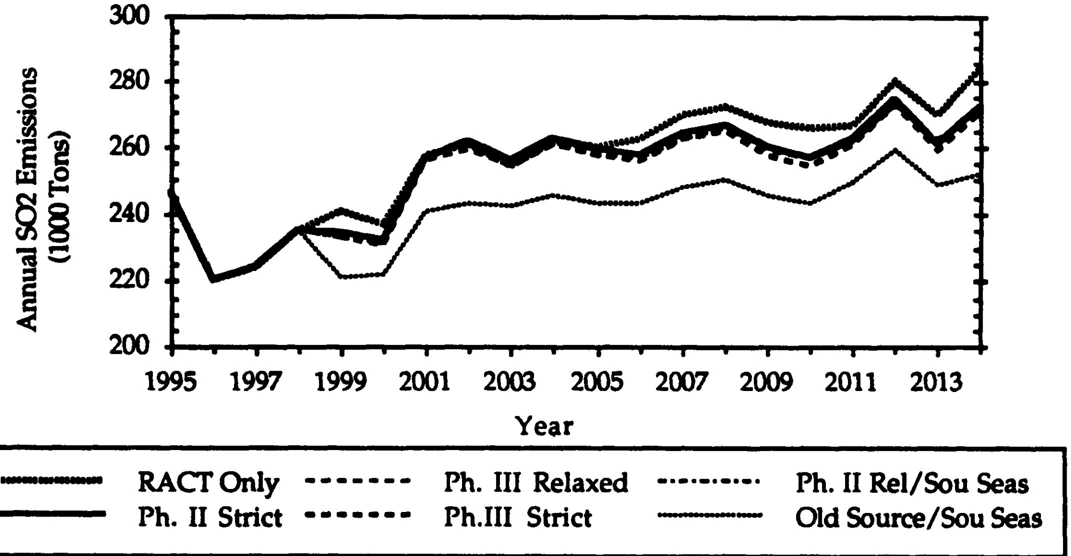
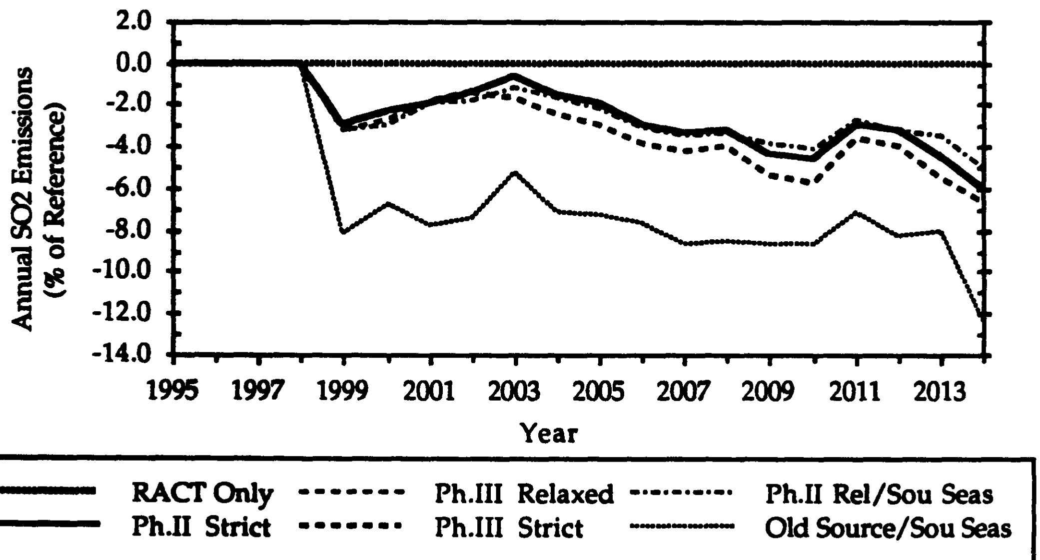


Figure 4-5: Percentage Impact of Candidate Scenarios on Annual SO_2 Emissions



Summary

Table 4-1 summarizes the impacts of the candidate scenarios on NO_x, CO_2 and SO_2 emissions. These NO_x control strategies are very effective in reducing NO_x emissions; cumulative reductions vary between 22 and 30 percent and reductions are larger for southern seasonal and episodal NO_x emission. They also reduce SO_2 emission between 3 and 7 percent and only increase CO_2 by at most 2 percent. Basically, these scenarios are successful in achieving their specific goal while resulting in a fairly neutral impact on other emissions. However, both the CO_2 and SO_2 annual emission trajectories reflect an overall upward trend for these emissions. CO_2 especially is a significant problem as the nuclear units in New England age and retire.

Table 4-1: Cumulative Electric System Emissions for Candidate Scenarios

	Cumulative Sys. Emisisons			Total Seas. Geographic NOx Emissions			
NOx Retrofit Strategy	NOx Emissions	CO2 Emissions	SO2 Emissions	All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
RACT Only/No Oper	2.22	1401.8	5.13	0.81	0.48	0.16	0.10
Ph. II Strict/No Oper	1.62	1429.4	5.03	0.60	0.30	0.12	0.06
Ph. II Rel/Sou Seas	1.73	1430.0	5.02	0.62	0.30	0.12	0.06
Ph. III Strict/No Oper	1.56	1429.1	5.01	0.57	0.29	0.12	0.06
Ph. III Rel/No Oper	1.65	1429.9	5.03	0.61	0.31	0.12	0.06
Old Source/Sou Seas	1.74	1416.5	4.79	0.59	0.32	0.12	0.06
	(MTons, 1995-2014)						
Δ from RACT Only/No Oper							
Ph. II Strict/No Oper	-0.60	27.7	-0.10	-0.21	-0.19	-0.04	-0.04
Ph. II Rel/Sou Seas	-0.49	28.3	-0.12	-0.19	-0.18	-0.04	-0.04
Ph. III Strict/No Oper	-0.67	27.4	-0.12	-0.24	-0.19	-0.05	-0.04
Ph. III Rel/No Oper	-0.57	28.1	-0.11	-0.20	-0.18	-0.04	-0.04
Old Source/Sou Seas	-0.49	14.7	-0.35	-0.22	-0.16	-0.04	-0.03
	(ΔMTons, 1995-2014)						
Δ% from RACT Only/No Oper							
Ph. II Strict/No Oper	-27.15	1.97	-2.02	-26.00	-38.56	-25.86	-37.96
Ph. II Rel/Sou Seas	-22.06	2.02	-2.30	-23.75	-36.69	-24.27	-36.79
Ph. III Strict/No Oper	-29.95	1.95	-2.40	-29.65	-40.52	-29.53	-40.02
Ph. III Rel/No Oper	-25.78	2.01	-2.05	-24.74	-36.54	-24.53	-35.86
Old Source/Sou Seas	-21.86	1.05	-6.74	-26.84	-33.69	-26.91	-35.11
	(Δ%)						

Other electric system options, such as Demand Side Management level and new generation technology choice, impact CO_2 and SO_2 emissions as well. The rest of this chapter will examine the impact of these two factors in conjunction with the

Relaxed Phase II with Southern Seasonal Operational controls scenario and the Strict Phase II with no Operational controls scenario. These two NO_x strategies are the most promising based on their ability to meet the NO_x southern seasonal Cap at a relatively low cost.

B. DEMAND SIDE MANAGEMENT OPTIONS

On the demand side of the electricity industry, Demand Side Management (DSM) programs are the main lever available to utilities and regulators. System emissions from the electric power sector can be reduced by decreasing the amount of electricity consumed. This is accomplished through the implementation of utility-sponsored DSM programs. These programs are predominantly aimed at energy conservation and efficiency. Figures 4-6 and 4-7 below show the very large impact of hypothetical DSM levels on total energy demand and on peak electricity demand.

Figure 4-6: Electricity Impacts of Hypothetical Demand Side Management Options

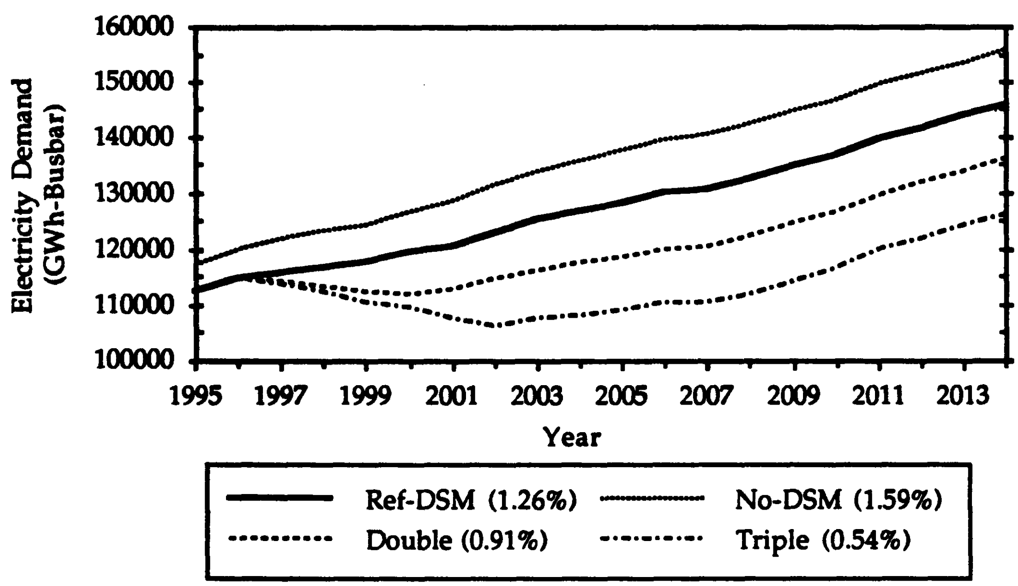
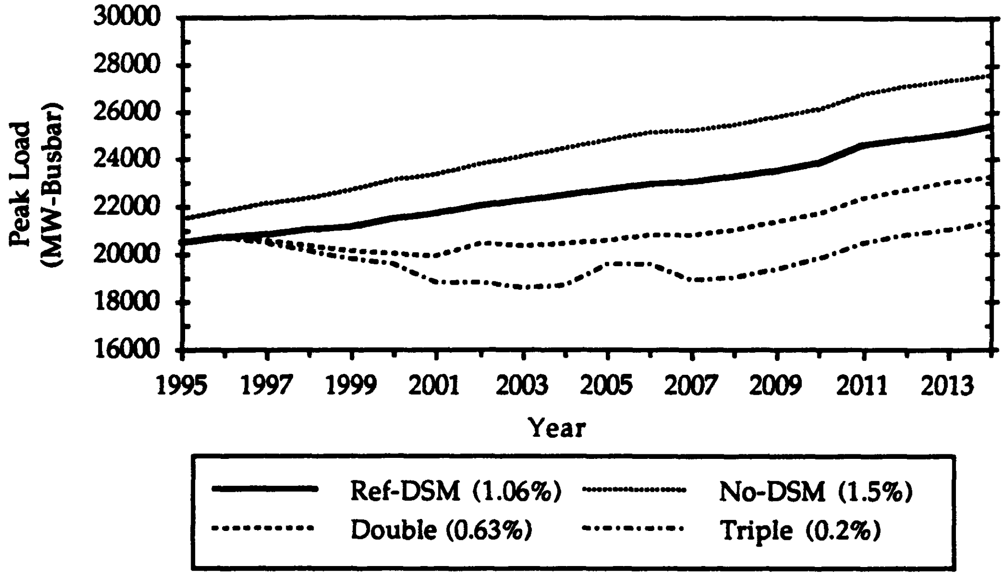


Figure 4-7: Peak Load Impacts of Hypothetical Demand Side Management Options



DSM measures are most effective at reducing NO_x when they target loads occurring during the ozone season. Such measures include efficient air conditioners, chillers, etc. This is a problematic approach from an emissions standpoint because it leads to a reduction in the number of new, cleaner plants built by reducing overall peak demand. Since new plants have stricter emission requirements or may be renewable plants with zero air emissions, DSM may or may not translate into an effective emissions reduction strategy. However, reducing demand could have a positive impact on the effectiveness of operational controls since it opens up the amount of excess capacity for unit "juggling" when dispatching for minimum NO_x. Also, DSM programs translate to multiple emission reductions, especially CO_2. This may make DSM a valuable addition to an electric power system strategy. This section describes the way in which DSM programs are modeled by AGREA and the following section will examine the performance impact of these DSM programs.

DSM Modeling

The DSM scenarios modeled by AGREA use current NEPLAN forecasts of utility-sponsored DSM programs as a baseline for developing potential future savings options from DSM and end-use standards together. Different hypothetical levels of savings are targeted and then the source, and therefore the bearer of the costs, is determined based on projections of the ability of standards to achieve those savings. Utility-sponsored DSM achieves the remainder of the savings that cannot be achieved through standards.

Although scenarios are based on forecasts of current utility-sponsored DSM programs, they are not meant to reflect any proposed or suggested utility DSM plans. Rather, the scenarios are analyzed in order to better understand the relative potential impacts of DSM programs and standards on the dynamics of the New England regional power system, with the goal of providing guidance to utility regulators and planners in the development of regulations and strategies for NO_x reduction. Utilities and others may determine that standards are a more cost-effective means of achieving electricity savings than direct investment in conventional DSM programs.

DSM Option Development

The first of the DSM parameters altered in scenario development is the amount of GigaWatt-hour (GWh) savings achieved by standards and DSM programs. Four different levels of savings were modeled, based on two NEPLAN hourly load forecasts (CELT, 1995). The "Reference" DSM option models loads reflecting utilities' current forecast of future DSM programs and the "No-DSM" option models loads without the utilities' DSM programs. The No DSM case does include savings from the standards program, but no utility-sponsored conservation. These forecasts provided two of the four DSM savings levels.

Two additional DSM levels were developed. By subtracting, on an hourly basis, the difference between the Reference and the No DSM options the utility-sponsored portion of the DSM impact was isolated. The standards portion is a constant component in all four DSM levels and the Double and Triple DSM levels are simply multiples of the utility-sponsored portion plus the standards component. This approach was implemented because utility-sponsored conservation faces the most uncertain fate in a more competitive electricity market, so the potential role of standards alone in achieving the same ends was deemed worthy of analysis. Conservation also accounts for the bulk (over 90%) of total GWh savings. These hypothetical programs result in the energy and peak demand forecasts shown in the figures above.

Allocation and Costs
AGREA is also set up to analyze two different allocation options for GWh savings between utility-sponsored DSM and standards. As mentioned above, the approach taken was to develop projections of the percentage of total conservation savings that could be attributed to standards, and then to assume that utility-sponsored DSM achieved the remainder. For a detailed discussion of the alternative cost allocation of "Utility/Standards" see Appendix 2.

The overall cost (revenue requirement) of the DSM level is determined by multiplying the levelized direct cost of conservation (cents per kilowatt-hour) by the total number of kWh saved (by customer class). This total cost is then allocated to installation years based upon the distribution of the conservation impacts, and then "collected" via "rates" and direct participant contributions.

These contributions are based upon assumptions of percentage participant contribution and utility amortization/expense accounting assumptions. The "cost" of meeting stricter standards based on the Energy Policy Act of 1992 (EPACT'92) standards are not included in any of the cost calculations. Levelized cost assumptions used in the analysis are 2.5¢/kWh for Commercial/Industrial savings, 5¢/kWh for Residential/Miscellaneous savings, and $40/kW-yr for peak management programs. Since conservation initiatives in the future are likely to focus predominantly on "lost opportunity" conservation, diminishing return multipliers were not added to these levelized cost factors in the higher conservation level options.

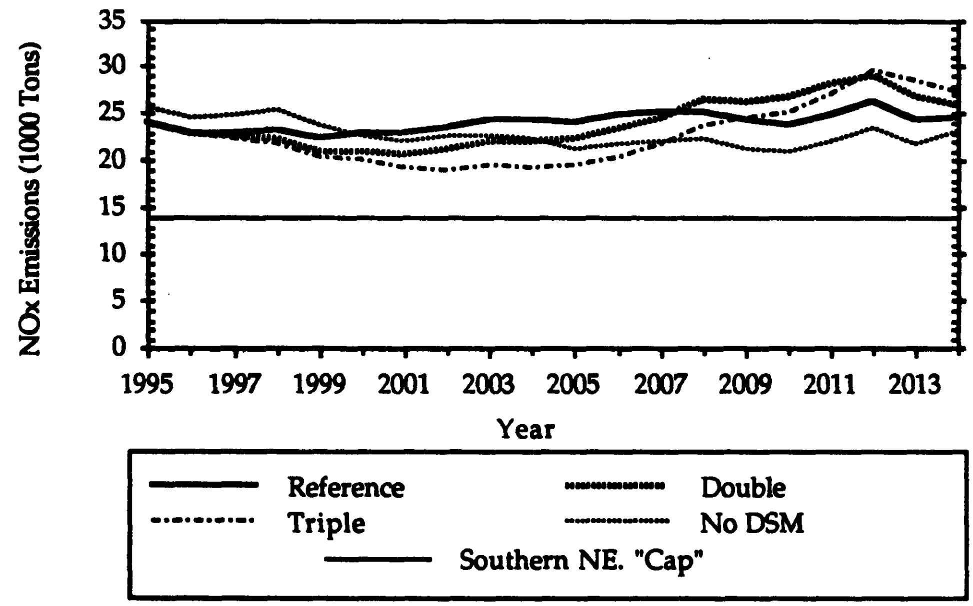
C. DEMAND SIDE MANAGEMENT PERFORMANCE

The impact of the four levels of Demand Side Management programs modeled are examined in this section. These strategies are examined in conjunction with Gas Combined Cycle new generation.

NO_x Performance
Figure 4-8 details the NO_x emission trajectories for the reference scenario of RACT Only retrofit controls and no operational controls across DSM level. This graph shows that Demand Side Management programs have a somewhat

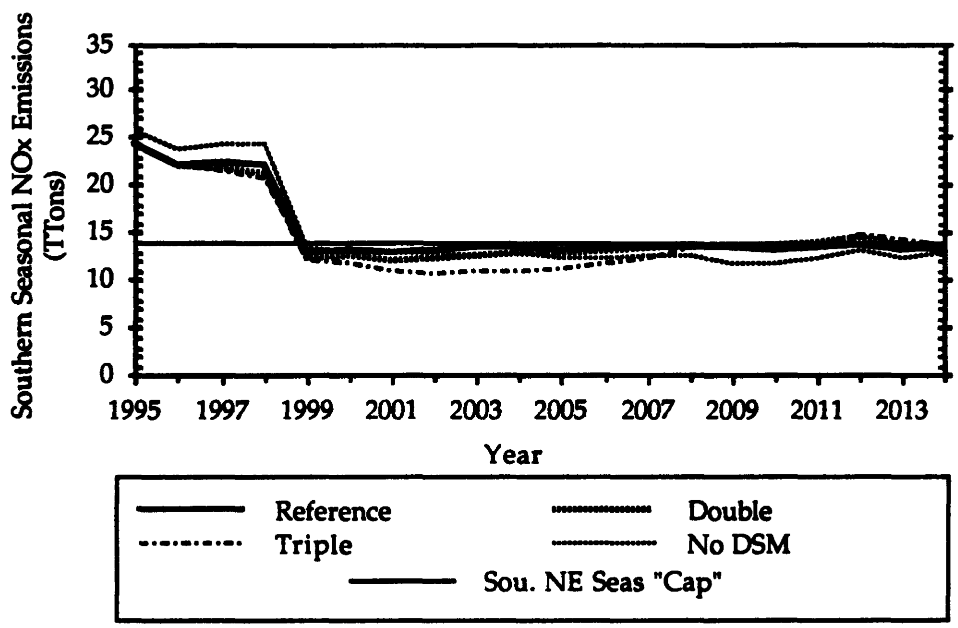
counter-intuitive impact on NO_x emissions. In the early years from 1995 to 2003, greater levels of DSM significantly reduce Southern Seasonal NO_x emissions. In 2002, the Triple DSM scenario reduces NO_x emissions to 19 thousand tons per year or within 35 percent above the Seasonal NO_x Cap from an initial 24 thousand tons or 75 percent above the Cap in 1995. Although this is a sizable reduction, it is still 5 thousand tons above the seasonal Cap of 13.95 thousand tons. In the later years from 2003 to 2014, higher levels of DSM result in a relative increase in NO_x emissions. By the end of the twenty years, the No DSM scenario reflects the lowest NO_x emissions level of 23.3 thousand tons (67 percent of the Cap) while the Triple DSM scenario reflects the highest emissions level of 27.4 thousand tons (97 percent of the Cap).

Figure 4-8: Coastal NE Seasonal NO_x Emissions for RACT Only



There are two main mechanisms by which DSM programs impact the electric generating system. Conservation and efficiency programs reduce the overall energy consumption reducing the total amount of NO_x produced. At the same time, DSM reduces the peak load thereby decreasing the need for additional generating capacity. However, new generating units have much lower emission production rates than old generating units. Therefore, reducing the amount of new generation built, eventually results in greater system-wide NO_x emissions. The opposing trends of these two mechanisms is obvious when looking at the 20 year projection in Figures 4-8 below. It takes longer for the NO_x increasing effect of less new generation to overcome the NO_x decreasing effect of DSM depending on the amount of conservation implemented.

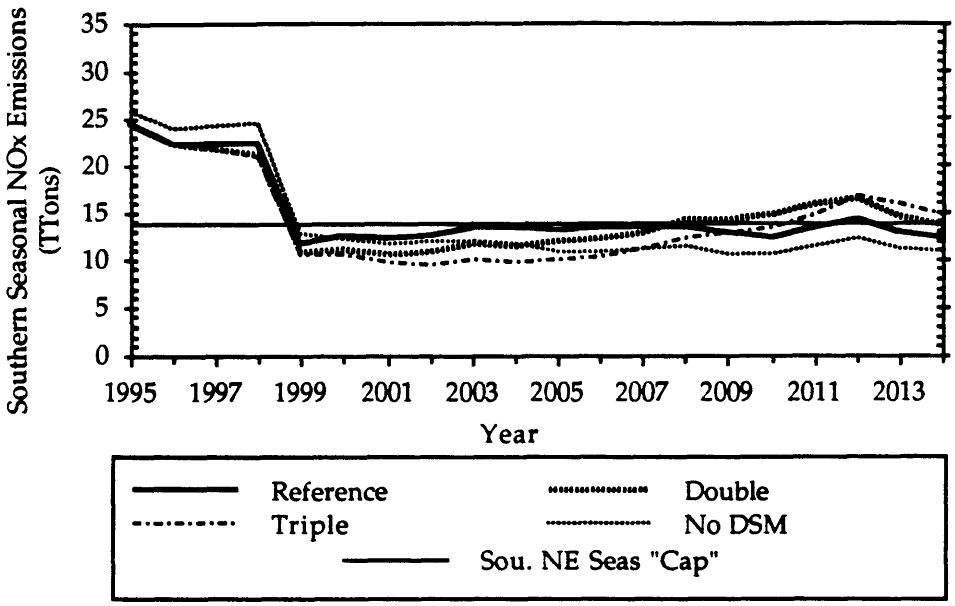
Figure 4-9: Southern NE Seasonal NO_x for Relaxed Phase II Retrofit Controls with Southern Seasonal Operational Controls



The counter-intuitive impact of DSM is also apparent for the candidate strategy of Relaxed Phase II with Southern Seasonal operational controls. However, as is evident from Figure 4-9 above, the impact of DSM on NO_x emissions is almost completely damped by the impact of the NO_x reduction measures. Seasonal NO_x emissions are still consistently below the Southern Seasonal Cap for all DSM level modeled throughout the model period.

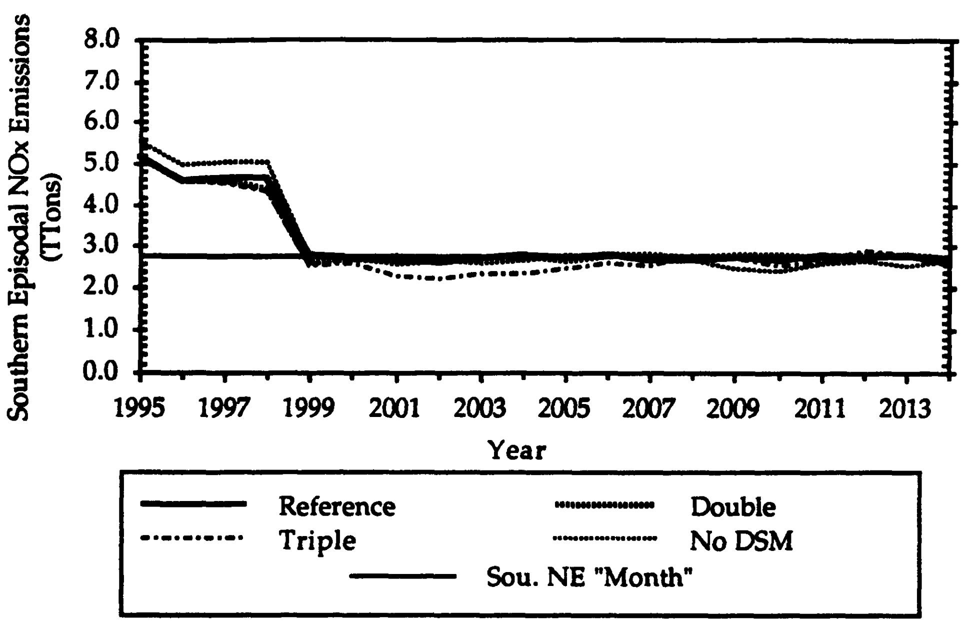
Figure 4-10 below, reflecting Southern Seasonal NO_x for the Strict Phase II strategy with no operational controls, also shows this same DSM tradeoff. However, the impact of DSM measures is more pronounced in this strategy. By 2010, the Double and Triple DSM options are no longer in attainment for the seasonal NO_x targets. By design, the scenario with operational controls dispatches to meet, not exceed, the NO_x target. The Strict Phase II strategy does not have this operational flexibility. Therefore, it tends to over-comply in the early and not comply in later years.

Figure 4-10: Southern NE Seasonal NO_x for Strict Phase II Retrofit Controls with No Operational Controls (LI)



As modeled, DSM programs do have a specific seasonal component. Conservation and efficiency programs target reductions at peak hours and during the peak season. Because the New England system peaks during the summer, reductions in peak load may have a relatively larger impact during the seasonal time period. Also, because most of the generation in New England is in the South, a reduction in generation due to conservation, will tend to reduce NO_x more in Southern NE than Northern NE. Figure 4-11 shows that there is no significant difference between the seasonal and episodal impacts of DSM for the Relaxed Phase II with Southern Seasonal controls. The same trend can be seen for Episodal NO_x emissions and the Seasonal NO_x emissions discussed above. The episodal NO_x trajectory for Strict Phase II also looks similar to the option's Seasonal trajectory.

Figure 4-11: Southern NE Episodal NO_x Emissions with Relaxed Phase II and Southern Seasonal Operational Controls (NE)

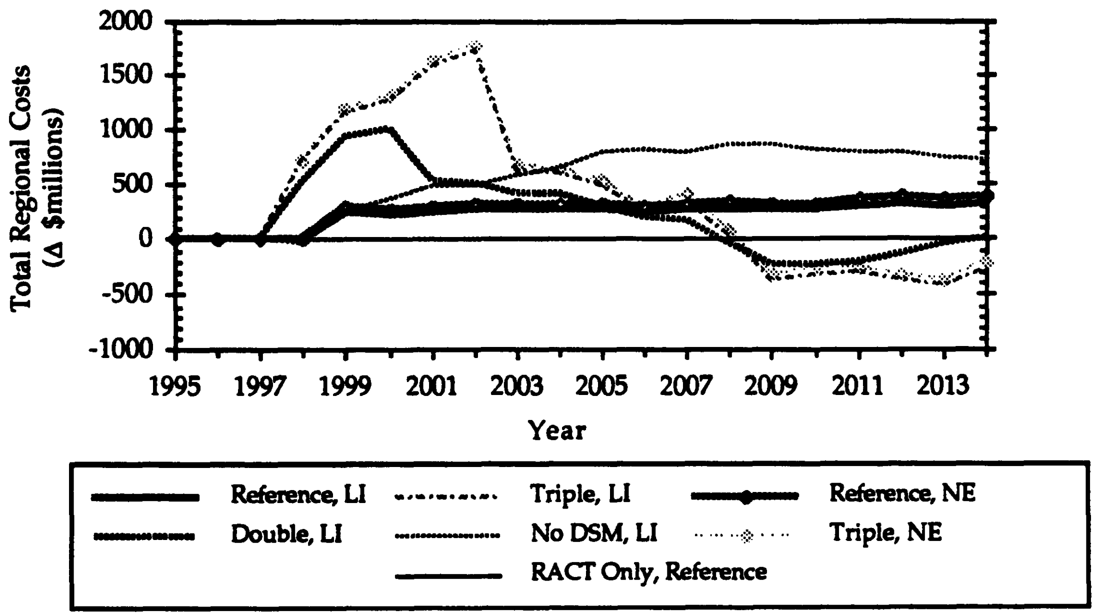


Cost Performance

Figure 4-12 shows the impact of DSM programs on the Total Regional Cost as a difference from the Reference DSM scenario cost for the Relaxed Phase II retrofit with Southern Seasonal Operational control and the Strict Phase II with No Operational control scenarios. It is evident that DSM programs have a relatively large impact on Total Regional direct cost. The impact of Triple DSM programs reaches \$1.8 billion above the Reference scenario costs in 2002, representing a 12 percent increase. However, by 2013, the Triple DSM program reduces regional industry direct costs by almost \$1.5 billion below the Reference scenario costs. Due to the overall increase in costs, this represents only a 5 percent reduction below Reference costs in 2013. The No DSM option initially costs \$0.1 billion less than the Reference DSM scenario but increases costs by over \$1 billion or almost 5 percent by 2009.

The trends in the cost impact of DSM programs reflect the same trade-off that was evident in the NO_x emissions trajectory. In early years, the program cost of implementing DSM, increases the total regional costs. In later years, when DSM programs result in a reduction in the need for large capital investments in new generation, the total regional cost decreases. DSM programs are paid for through their long term benefits to both utilities and electricity consumers.

Figure 4-12: Total Regional Cost Difference from RACT Only for Relaxed Phase II with Southern Seasonal Controls (LI) and Strict Phase II (NE)



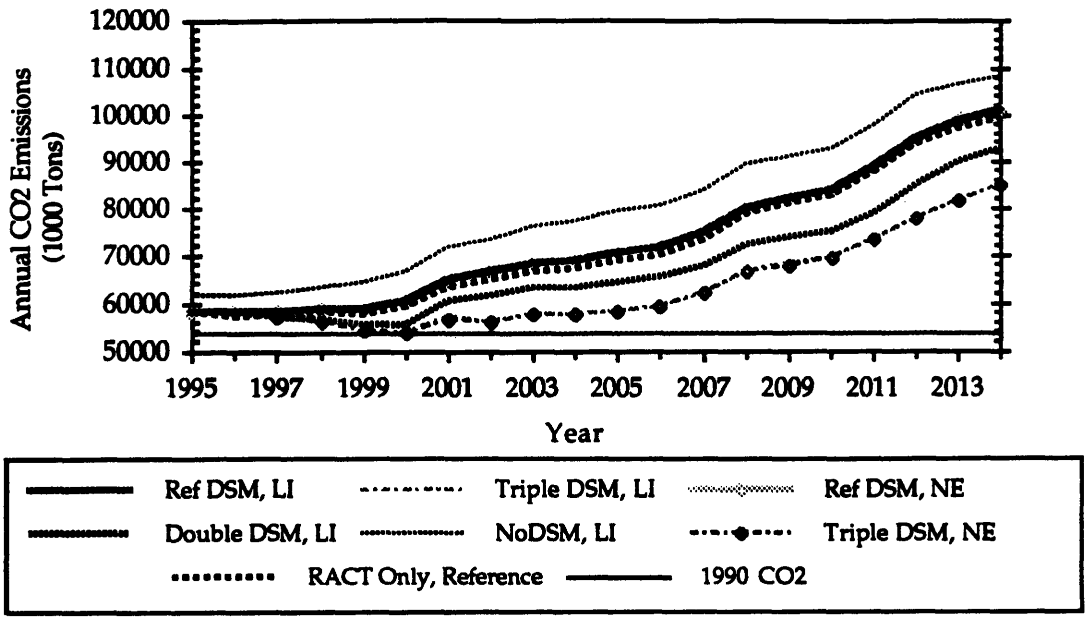
There is a small but consistent difference between the cost impact of the two NO_x scenarios. As was seen in the last chapter, the Relaxed Phase II with Southern Seasonal controls is less expensive than the Strict Phase II with no operational controls scenario. Figure 4-12 shows that this cost difference is independent of the level of DSM pursued. The trajectories for Strict Phase II with No DSM and Double DSM are not shown for clarity but show the same trend exhibited for the Reference and Triple DSM cases.

Impact on Alternate Emissions

Impact on CO_2 Emissions

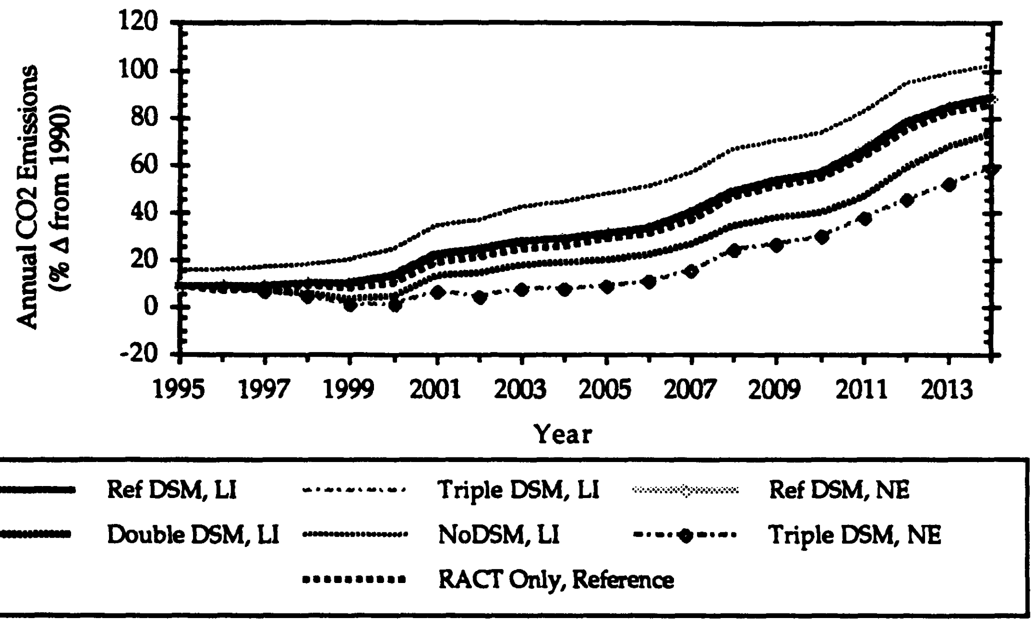
Figure 4-13 shows the CO_2 emissions trajectory for the two candidate NO_x strategies across DSM level. There is very little difference in CO_2 emissions between the two candidate NO_x options. CO_2 emissions are comparatively about 1 percent lower for the Relaxed Phase II with operational controls option in conjunction with all of the DSM levels. However, the impact of the NO_x strategy is negligible compared to the impact of DSM programs.

Figure 4-13: Annual CO_2 Emission for Relaxed Phase II with Southern Seasonal Controls (LI) and Strict Phase II (NE)



More important than the relative CO_2 performance of the two NO_x strategies, it should be noted that DSM is very successful in reducing CO_2 emissions. Figure 4-14 shows the percentage impacts on CO_2 from the different DSM levels compared to 1990 Historic CO_2 emissions. Double DSM increase CO_2 emissions by about 70 percent and Triple DSM by only 60 percent from the 1990 level which corresponds to 10 and 20 percent decreases from RACT Only respectively. This is important for several reasons. As discussed at the beginning of this chapter and shown below in Figure 4-14, the candidate NO_x strategies increase CO_2 emissions by about 3 percent over RACT Only. Also, CO_2 emissions in New England are increasing very rapidly as nuclear units begin to age and retire. Therefore, DSM Programs which reduce CO_2 emissions without affecting the system's ability to meet the NO_x target are very valuable.

Figure 4-14: Percentage Change in CO_2 Emission from 1990 Historic for Relaxed Phase II with Southern Seasonal Controls (LI) and Strict Phase II (NE)



Impact on SO_2 Emissions

Annual SO_2 emissions for the candidate NO_x strategy of Relaxed Phase II with Southern Seasonal controls across DSM level are shown in Figures 4-15 and 4-16. The trajectories for the Strict Phase II strategy are not shown here but have roughly the same impact on SO_2 emissions. Table 4-1 and Figure 4-4 above showed that these two candidate scenarios have almost identical impact on SO_2 emissions. The trend in SO_2 emissions, like NO_x emissions and total regional cost, reflect the DSM tradeoff between avoided electricity consumption in the beginning years and avoided new plant construction in later years. Triple DSM reduces SO_2 emission significantly from 1998 to 2007 after which No utility-sponsored DSM results in the lowest SO_2 emissions.

These figures also show that the Relaxed Phase II with Southern Seasonal control strategy SO_2 emissions are consistently below the reference RACT Only emissions. SO_2 emissions also do not reveal the same strong upward trend that was evident in the CO_2 emissions trajectory. Therefore, SO_2 reductions are not as much of a concern as CO_2 reductions.

Figure 4-15: Annual SO_2 Emission for Relaxed Phase II with Southern Seasonal Operational Controls (LI) Across DSM Level

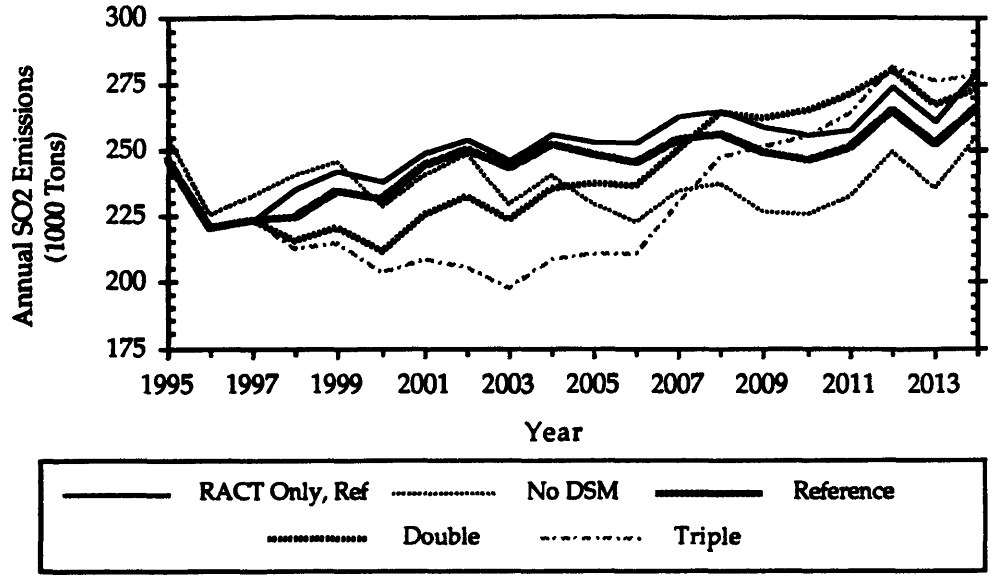
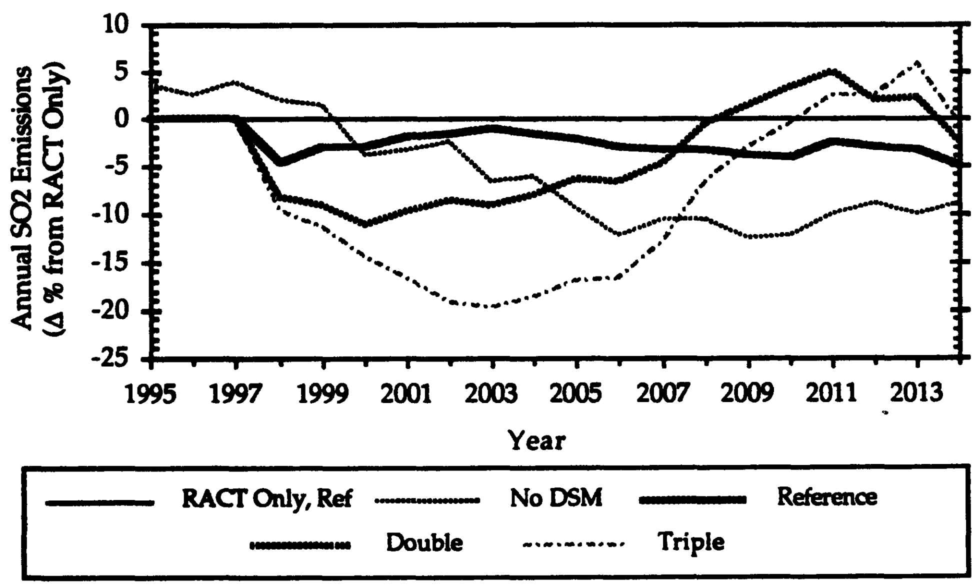


Figure 4-16: Percentage Change SO_2 Emissions from RACT Only for Relaxed Phase II with Southern Seasonal Operational Controls (LI) Across DSM Level



Cumulative System Impacts

Emissions

Table 4-2 summarizes the cumulative NO_x emission impacts of DSM Programs on the electric generation system over the twenty year modeling period. This table shows data for the Relaxed Phase II with Southern Seasonal controls and the Strict Phase II strategies across DSM levels. This data reveals very little cumulative difference in total annual emissions of NO_x across different DSM levels. Higher levels of DSM do result in reducing cumulative NO_x emissions slightly. However, unlike CO_2, NO_x is not a global environmental problem where accumulation in the atmosphere is the largest concern. NO_x is a geographic and seasonal problem which does not accumulate. Therefore, it is much more important that all levels of DSM allowed the combination NO_x strategy examined to consistently attain the NO_x seasonal Cap.

Differences in NO_x emissions are also extremely small for seasonal and episodal NO_x across DSM level in both Coastal New England and All of New England. From the perspective of cumulative emissions over the 20 year period, the No DSM, Reference DSM, and Double DSM scenarios are roughly equivalent, while the Triple DSM scenario is slightly superior (i.e. emissions are lower). Due to the seasonal and geographic component of DSM programs, NO_x reductions are highest during the Episodal time period. Seasonal reductions are also slightly higher than the annual reduction from the Reference scenario.

There are several other important results evident from examining Table 4-2. The most important impact of the DSM programs is their impact on CO_2 emissions. The Double DSM program reduced CO_2 emissions by over 6 percent while the No utility-sponsored DSM program increased emissions by over 12 percent. This suggests that a Double or even Triple DSM program would be highly beneficial for the NE system. The NO_x strategies proposed reduce SO_2 emissions, therefore all of the scenarios listed above also reduce cumulative SO_2 emissions. Both of the NO_x strategies result in almost exactly the same emissions for CO_2, SO_2 and Southern Seasonal NO_x while the Strict Phase II strategy has lower annual NO_x.

Table 4-2: Summary of DSM Program Emissions Impacts

NOx Retrofit Strategy	Total Elec. Sector Emissions: NOx Emissions	CO2 Emissions	SO2 Emissions	Total Seas. Geographic NOx Emissions: All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
RACT Only, No Oper.	2.22	1401.8	5.13	0.807	0.481	0.165	0.099
Reference DSM, LI	1.73	1430.0	5.02	0.615	0.304	0.125	0.062
Reference DSM, NE	1.62	1429.4	5.03	0.597	0.295	0.122	0.061
Double DSM, LI	1.71	1315.7	4.97	0.608	0.301	0.124	0.062
Double DSM, NE	1.59	1315.1	4.99	0.589	0.295	0.120	0.061
Triple DSM,LI	1.63	1228.6	4.81	0.586	0.289	0.119	0.059
Triple DSMl, NE	1.52	1228.0	4.83	0.565	0.279	0.115	0.057
	(MTons, 1995-2014)			(MTons, 1995-2014)			
Δ from RACT Only, No Oper.							
Reference DSM, LI	-0.49	28.26	-0.12	-0.19	-0.18	-0.04	-0.04
Reference DSM, NE	-0.60	27.66	-0.10	-0.21	-0.19	-0.04	-0.04
Double DSM, LI	-0.51	-86.10	-0.16	-0.20	-0.18	-0.04	-0.04
Double DSM, NE	-0.63	-86.70	-0.15	-0.22	-0.19	-0.04	-0.04
Triple DSM,LI	-0.59	-173.14	-0.32	-0.22	-0.19	-0.05	-0.04
Triple DSMl, NE	-0.70	-173.74	-0.30	-0.24	-0.20	-0.05	-0.04
	(ΔMTons, 1995-2014)			(ΔMTons, 1995-2014)			
Δ% from RACT Only, No Oper.							
Reference DSM, LI	-22.06	2.02	-2.30	-23.75	-36.69	-24.27	-36.79
Reference DSM, NE	-27.15	1.97	-2.02	-26.00	-38.56	-25.86	-37.96
Double DSM, LI	-23.14	-6.14	-3.12	-24.69	-37.45	-24.84	-37.10
Double DSM, NE	-28.27	-6.18	-2.84	-27.04	-38.66	-27.18	-38.45
Triple DSM,LI	-26.42	-12.35	-6.22	-27.37	-39.93	-27.60	-39.75
Triple DSMl, NE	-31.36	-12.39	-5.94	-29.98	-41.96	-30.38	-42.01
	(Δ%)			(Δ%)			

Costs

The cumulative impacts of DSM programs on the Total Regional and Electric Industry Direct Costs are summarized in Table 4-3 for the two candidate NO_x scenarios. Table 4-3 shows that DSM has a relatively large impact on system costs. It also shows that the Relaxed Phase II with Southern Seasonal operational controls has consistently lower costs across all present value cost calculations and across total regional and electric industry direct costs. Therefore, since both NO_x strategies are technically acceptable, this discussion will focus on this retrofit and operational controls strategy.

Higher levels of DSM result in lower costs for the electric utilities and higher total regional costs. The Triple DSM scenario decreases the Electric Industry Direct Costs by 1.2 to 2.3 percent depending on the method of cost calculation.

This could amount to a savings of as much as $6.0 billion over the Reference DSM scenario. Generally speaking, the decreased need for new generating capacity associated with higher levels of DSM tends to decrease the costs of the electricity sector. However, this same characteristic makes DSM less effective in reducing NO_x emissions. And, as was stated earlier, DSM programs are paid for through their long term benefits to both utilities and electricity consumers.

Table 4-3: Summary of DSM Program Cost Impacts

	Sandard Direct Costs		Inflation Adj. Direct		Risk Adj. Discounting	
NOx Retroft Strategy	Regional Direct	Elec. Ind. Direct	Regional Direct	Elec. Ind. Direct	Regional Direct	Elec. Ind. Direct
Reference DSM, LI	135.5	134.3	258.3	256.3	153.4	152.2
Reference DSM, NE	135.9	134.7	259.2	257.2	153.9	152.7
Double DSM, LI	136.1	133.0	257.5	252.1	153.0	149.9
Double DSM, NE	136.4	133.3	258.4	252.9	153.5	150.4
Triple DSM, LI	137.8	132.7	259.7	250.4	153.8	148.7
Triple DSM, NE	138.1	133.1	260.5	251.2	154.3	149.2
	(PV-1994$B, r=10%)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ from Reference DSM, LI						
Reference DSM, NE	0.4	0.4	0.9	0.9	0.5	0.5
Double DSM, LI	0.5	-1.4	-0.8	-4.3	-0.4	-2.3
Double DSM, NE	0.9	-1.0	0.1	-3.4	0.1	-1.8
Triple DSM, LI	2.3	-1.6	1.4	-6.0	0.4	-3.4
Triple DSM, NE	2.6	-1.3	2.2	-5.2	0.9	-3.0
	(PV-1994$B, r=10%)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ% from Reference DSM, LI						
Reference DSM, NE	0.3	0.3	0.3	0.3	0.3	0.3
Double DSM, LI	0.4	-1.0	-0.3	-1.7	-0.2	-1.5
Double DSM, NE	0.7	-0.7	0.0	-1.3	0.1	-1.2
Triple DSM, LI	1.7	-1.2	0.5	-2.3	0.3	-2.3
Triple DSM, NE	1.9	-0.9	0.8	-2.0	0.6	-1.9
	(Δ%)		(Δ%)		(Δ%)	

Higher levels of DSM tend to increase the Total Regional Direct Cost. The Triple DSM scenario could increase regional costs by as much as $2.3 billion depending on cost calculation method. This cost increase can be attributed to the increase in DSM participant measured direct costs. The No DSM scenario is the most costly in terms of Total Regional Cost because the increased cost to the electric sector overwhelms the lower participants costs in the non-utility sector. The No DSM option could cost up to $6.7 billion for the region.

Although the different methods for calculating costs significantly change the magnitude of the cost impact, they do not generally change the direction of the difference. The Triple DSM program has the lowest electric industry cost for all three cost calculations while the No DSM scenario has the highest. The No DSM scenario also has the highest cost for the Total Regional Cost across all calculation methods. The one instance where the method of cost calculation changes the cost preference is in favoring Double DSM over the Reference DSM from the perspective of the Total Regional Cost. Both the Inflation and Risk Adjusted Discounting favor the Double DSM while the SF favors the Reference DSM.

Summary

DSM programs have very little impact on NO_x emissions, especially when used in conjunction with a NO_x reduction strategy such as Relaxed Phase II retrofits with Southern Seasonal operational controls. However, they have a disproportionately large impact on cost. DSM is not primarily a NO_x reduction strategy, it is intended to be cost effective from a utility and a social perspective. The primary benefit of increased DSM in NE being the resulting decrease in CO_2 emissions. Although CO_2 is not the main topic of discussion in this thesis, it is a significant concern that will become more acute as the nuclear generation in NE begins to retire. Higher levels of DSM tend to be either neutral or to decrease the Electric Industry Cost. DSM can help to offset the higher cost and CO_2 emissions of the NO_x reduction strategies.

Two significant recommendation come out of the above discussion on DSM. First, a higher level of DSM has significant benefits and small, if any, costs. Therefore, a strategy of Double DSM is recommended. Also, the two NO_x candidate scenarios examined have very similar technical performance in terms of their emission impacts. However, one of the strategies is consistently less costly. Therefore, a NO_x reduction strategy consisting of Relaxed Phase II retrofit controls and Southern Seasonal Operational controls should be pursued.

D. NEW SUPPLY RESOURCE OPTIONS

EGEAS modeling is based on several databases which describe the existing and planned electric generating system in New England. This includes electric utility generators, Non-Utility Generators (NUGs) and power purchase agreements with New York and Canada. Figure 4-17 shows the capacity trajectory for existing generation, reflecting the retirement of existing plants. Figure 4-18 shows the breakdown of the existing capacity trajectory by fuel type. Three fairly large oil units, Middletown Units 2, 3 and 4, are scheduled to retire in 1998. These units have a total capacity amounting to 760 megawatts (MWs), representing a significant amount of oil capacity. Several nuclear units are scheduled for re-licensing in the 2010s. Connecticut Yankee and Maine Yankee are scheduled to retire in 2007 and 2008 respectively. These units amount to 1,490 MWs. Millstone 1, 660 MW, is scheduled to retire in 2011. And finally, Pilgrim 1 and Vermont Yankee, totaling 1,240 MWs, are scheduled to retire in 2012. This study assumes that all of these nuclear units will be retired, not re-licensed

Figure 4-17: Total Existing Capacity Trajectory

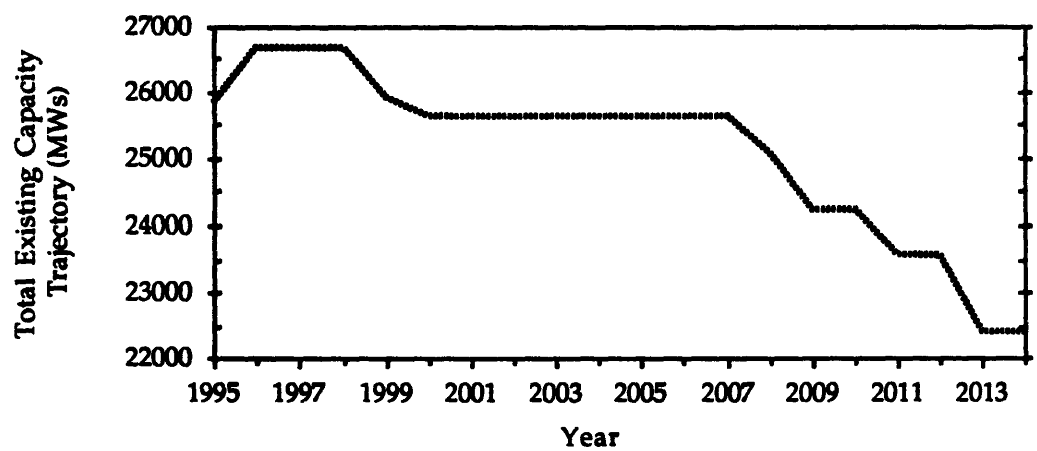
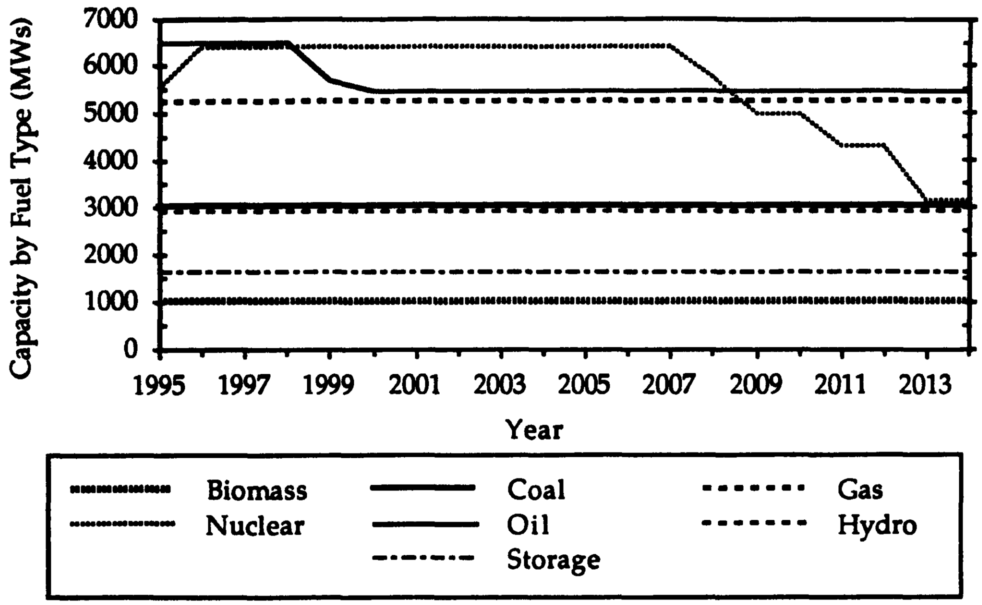


Figure 4-18: Existing Capacity Trajectory by Fuel Type



As the annual peak demand for electricity exceeds the installed generating capacity, new generation must be built. The new supply technology mix option determines the quantity and type of new generation to be built in each year over the twenty year simulation period. These options consist of fixed and variable capacity installation schedules. Fixed capacity refers to plants that are built according to a pre-determined schedule, regardless of any other factors. Variable capacity refers to those plants which are built as needed by the simulation, so the year and size of their installation varies between scenarios.

Different resource mixes result in different amounts of NO_x emissions. In general, all new fossil units must offset their NO_x emissions somewhere else in New England by financing the installation of NO_x reduction equipment on older units. However, the existence of new clean generation for base load operation, should still decrease both the rate of NO_x production and the total magnitude of NO_x emitted. Also, the addition of new, clean capacity to the system allows significantly more flexibility in dispatching for lower NO_x emissions. This makes operational controls more technically and financially efficient.

New renewable energy plants, such as wind generation, are also very effective in reducing the total amount of NO_x and other pollutants emitted. However, their non-dispatchable characteristics may limit their effectiveness during ozone episodes. Also due to their non-dispatchability, renewable plants cannot be relied upon to make up peak load. Therefore, sufficient fossil and nuclear capacity will always be necessary to satisfy peak load demand.

Four different resource mixes for future generation are examined here. These resource option include a mix of gas combined cycle (CC), gas simple cycle (SC), and conventional coal generation as the non-renewable resources. Wind turbines are included as the renewable resource option since wind is the most feasible renewable energy source in New England at this time. The technical performance and cost characteristics of these future generation options are detailed in Table 4-4 below. Table 4-5 details the exact resource mix for each of the four new resource strategies modeled.

Table 4-4: New Generation Resource Characteristics

Unit Type	*Nom. Rating*	*First Fuel*	*Second Fuel*	*Heat Rate*	*Effi- ciency*	*Install. Cost-Tot.*	*Lead Time*	*Fixed O&M*	*Variable O&M*
Advanced Combustion Turbines									
Tiny	23	Nat.Gas	Oil2	11337	30.1	826.0	2	0.60	12.100
Small	40	Nat.Gas	Oil2	9689	35.2	678.9	2	0.36	9.400
Medium	80	Nat.Gas	Oil2	9035	37.8	374.0	3	0.14	3.500
Advanced Combined Cycle Turbines									
Medium	250	Nat.Gas	Oil2	7520	45.4	736.4	5	12.06	0.677
Large	500	Nat.Gas	Oil2	7520	45.4	657.0	5	9.52	0.677
Very Large	750	Nat.Gas	Oil2	7520	45.4	633.7	5	8.51	0.677
Pulverized Coal with SCR									
Small	200	Coal 2.5%S		9840	34.7	2389.3	6	65.68	11.774
Medium	300	Coal 2.5%S		9910	34.4	1982.0	7	54.93	11.829
Large	440	Coal 2.5%S		9860	34.6	1672.6	7	43.78	11.789
Advanced Wind Turbines									
Kenetech	0.40	Wind		NA	NA	1000.0	2	10.00	0.00
Zond	0.55	Wind		NA	NA	1000.0	2	10.00	0.00
	(MW)	(10 mo.)	(2 mo.)	(Btu/kWh)		(94$/kW)	(yrs.)	('95$/kW-yr)	('95/MWh)

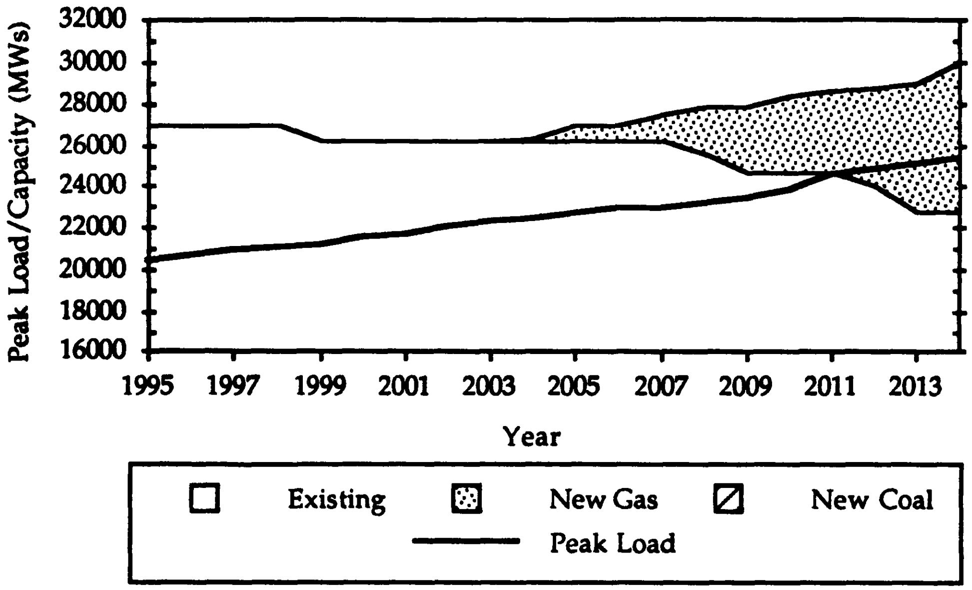
Table 4-5: New Resource Option Break Down

Unit Type	Nominal Rating	New Supply-Side Generation Mix (G) - Gas/Oil Combined-Cycle	(S) - Gas/Oil Simple-Cycle	(H) - Gas/Oil & Mature Coal	(W)-Gas/Oil & Wind
Advanced Combustion Turbines					
Small	40	20%	50%	20%	16%
Medium	87	''	''	''	''
Advanced Combined Cycle Turbines					
Medium	250	80%	50%	30%	66%
Large	500	''	''	''	''
Very Large	750	''	''	''	''
Pulverized Coal with SCR					
Small	200			10%	
Medium	300			''	
Large	440			40%	
Wind Turbines					
KVS-33	0.40				10%
Z-40FS	0.55				8%
	(MW)	(MW Ratio of New Generation Technology)			

The figures below detail the quantity of new generation that is built for each resource option. The existing capacity trajectory, new capacity trajectory for each technology type and peak load trajectory are shown. The figures reflect Reference and Double DSM levels. Similar graphs can be used to show trends in generating capacity for No and Triple DSM levels.

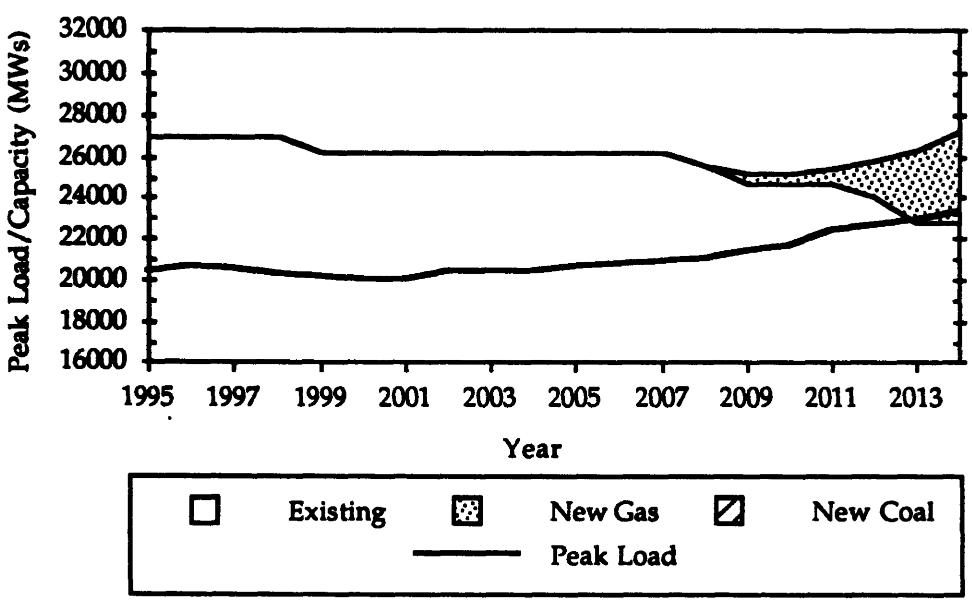
The gas combined cycle strategy consists of 20 percent advanced simple-cycle combustion turbines and 80 percent advanced combined-cycle combustion turbines. This resource strategy, in combination with reference levels of DSM, results in building 7,140 MW of gas fired generation by 2014. The first 160 MWs of "new" generation is installed in 2003. Figure 4-19 below tracks the quantity of new gas generating capacity, total generating capacity and peak load for this strategy.

Figure 4-19: Gas Combined Cycle and Reference DSM Scenario:
New Capacity Introduction (GR)



The gas combined cycle strategy, in conjunction with double levels of DSM, results in building 4,410 MW of gas fired generation by 2014. The first 500 MW of "new" generating capacity is installed in 2009. Figure 4-20 below reflects this strategy.

Figure 4-20: Gas Combined Cycle and Double DSM Scenario:
New Capacity Introduction (GD)



The gas simple cycle and combined cycle strategy consists of 50 percent advanced, simple cycle, combustion turbines and 50 percent advanced, combined cycle, combustion turbines. This strategy, in combination with reference levels of DSM, results in building 7,170 MWs of gas-fired generation by 2014. The first 250 MWs of "new" generation is installed in 2000. Figure 4-21 below tracks the quantity of new gas generating capacity, total generating capacity and peak load for the SR scenario.

The gas combined and simple cycle strategy, in conjunction with double levels of DSM, results in building 4,420 MW of gas fired generation by 2014. The first 250 MW of "new" generating capacity is installed in 2000. Figure 4-22 below reflects the SD strategy.

Figure 4-21: Gas Combined and Simple Cycle and Reference DSM Scenario: New Capacity Introduction (SR)

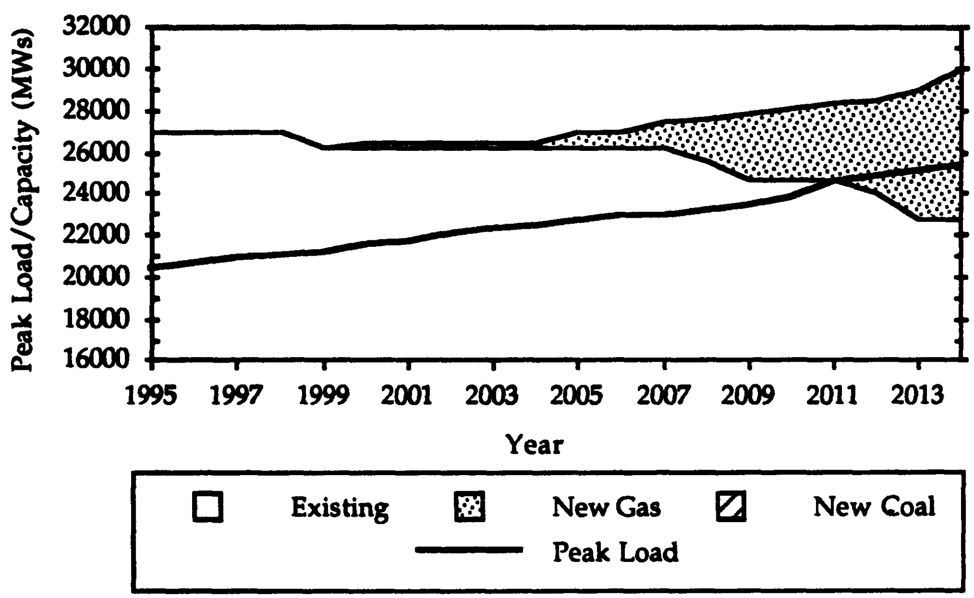
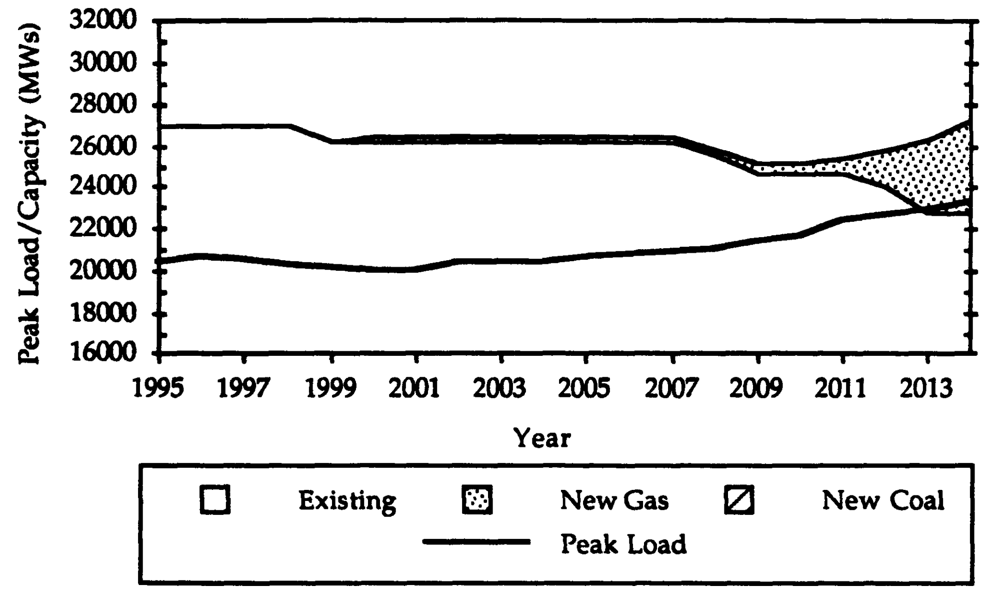


Figure 4-22: Gas Combined and Simple Cycle and Double DSM Scenario: New Capacity Introduction (SD)



The gas combined cycle and conventional coal strategy consists of 20% advanced, simple cycle, combustion turbines, 30% advanced, combined cycle, combustion turbines, 10% small pulverized coal units and 40% large pulverized coal units. This strategy, in combination with reference levels of DSM, results in building 2,390 MW of gas fired generation and 4,760 MW of coal fired generation by 2014 (total of 7,150 MW). The first 250 MWs of "new" generation is installed in 2000. Figure 4-23 below tracks the quantity of new gas generating capacity, total generating capacity and peak load.

The gas combined and simple cycle and conventional coal strategy, in conjunction with double levels of DSM, results in building 4,440 MW of gas fired generation by 2014. This consists of 1,840 MW of gas generation and 2,600 MW of coal generation. The first 250 MW of "new" generating capacity is installed in 2000. Figure 4-24 below reflects this HD strategy.

Figure 4-23: Gas Combined Cycle and Conventional Coal and Reference DSM Scenario: New Capacity Introduction (HR)

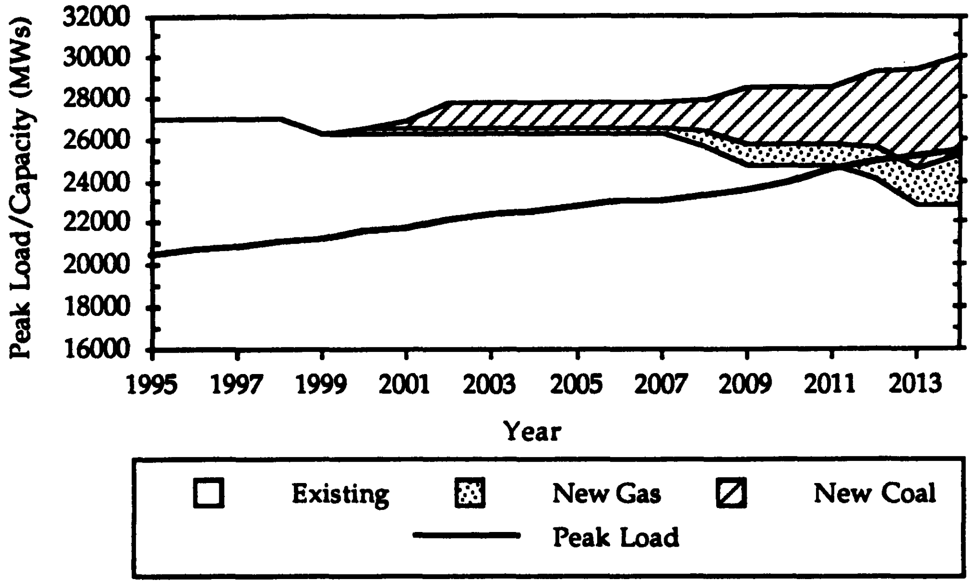
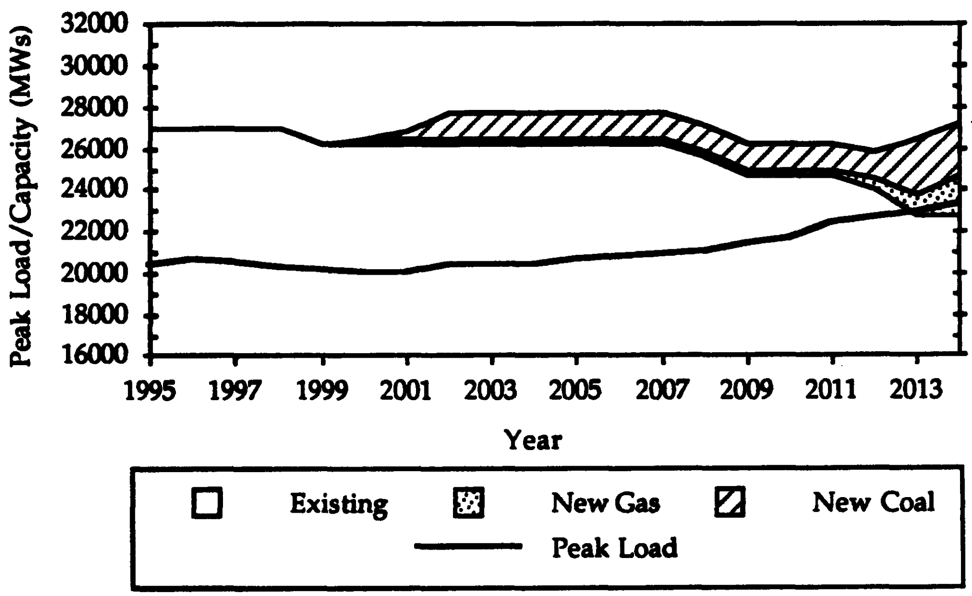


Figure 4-24: Gas Combined Cycle and Conventional Coal and Double DSM Scenario: New Capacity Introduction (HD)



The gas combined cycle and wind strategy consists of 16 percent advanced, simple cycle, combustion turbines, 66 percent advanced, combined cycle, combustion turbines, and 18 percent wind turbine generators. This strategy, in combination with reference levels of DSM, results in building 7,140 MWs of gas fired generation and 1,417 MWs of wind powered generation by 2014 (total of 8,557 MW). All of the wind strategies follow a fixed capacity installation schedule starting with 8 MWs in 1997 with incremental additions of wind power until 2010. The first 140 MWs of gas generation is installed in 2004. Figure 4-25 below tracks the quantity of new gas and wind generating capacity, total generating capacity and peak load. Significantly more generating capacity is built for the wind resource scenarios than for the other three resource options. Wind is a non-dispatchable resource, and therefore cannot be relied upon to meet peak load (i.e. capacity credit is zero). Therefore, sufficient gas generation must be built to cover increases in peak load. The installed wind capacity is intended to reduce CO_2 emissions by 2 percent by 2010.

The gas combined cycle and wind strategy, in conjunction with double levels of DSM, results in building a total of 5,827 MW of new generation by 2014. This consists of 4,410 MWs of gas generation and 1,417 MWs of wind generation. The first 500 MW of gas generating capacity is installed in 2009. Figure 4-26 below reflects this WD strategy. Wind capacity installation follows the same schedule as described above for the Reference DSM scenario.

Figure 4-25: Gas Combined Cycle and Wind and Reference DSM Scenario: New Capacity Introduction (WR)

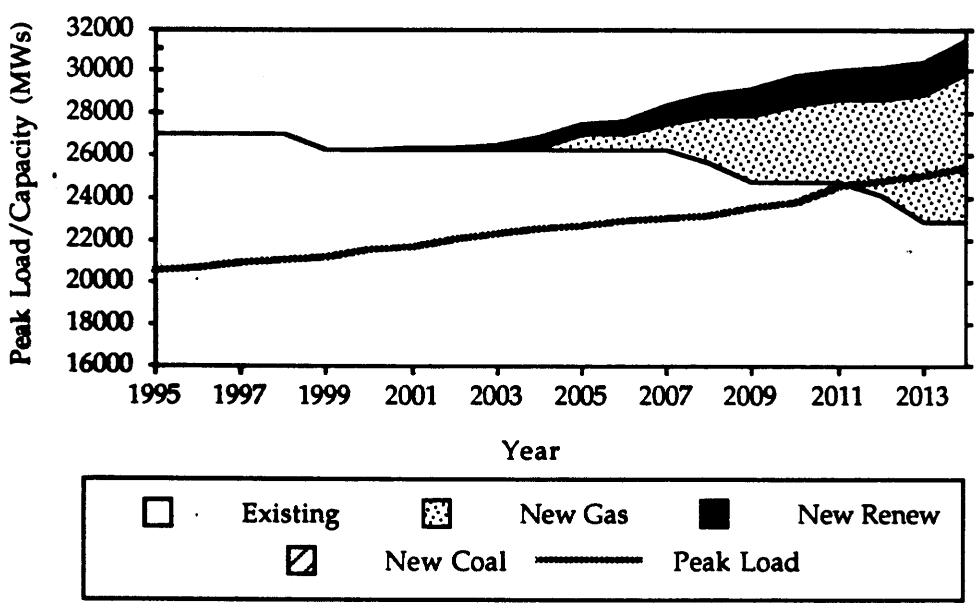
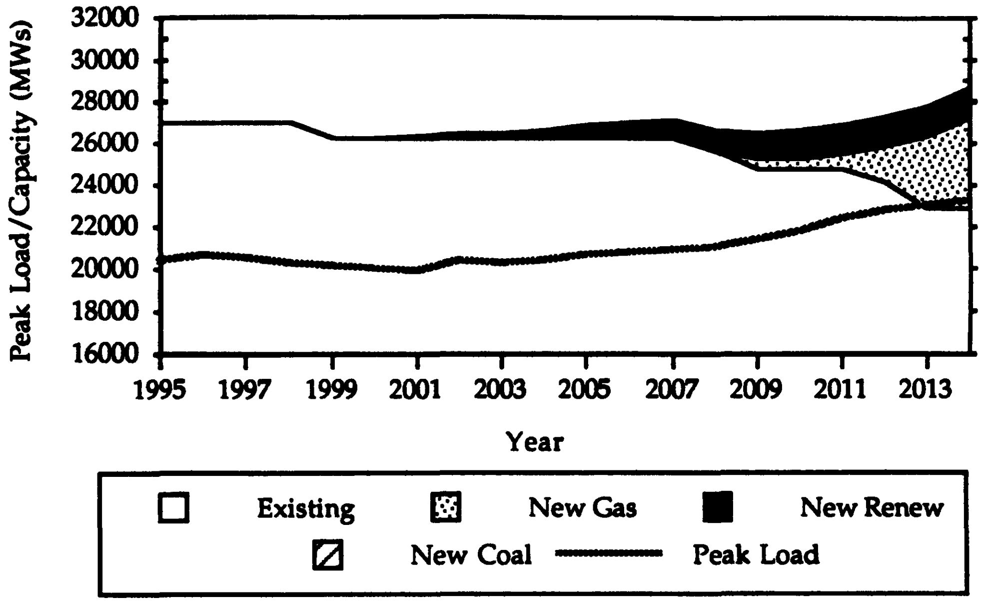


Figure 4-26: Gas Combined Cycle and Wind and Double DSM Scenario: New Capacity Introduction (WD)



E. NEW SUPPLY RESOURCE PERFORMANCE

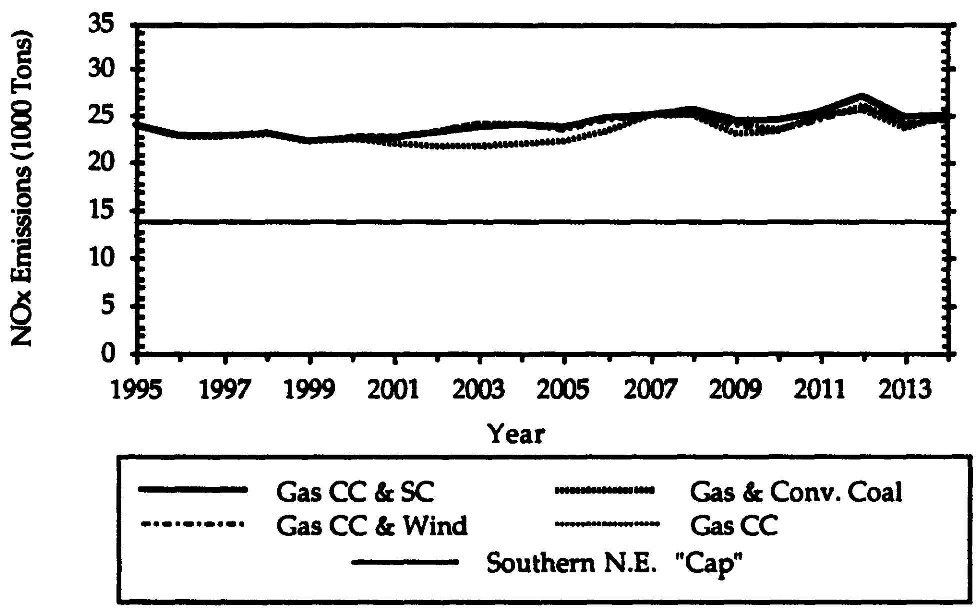
Four different new resource mixes were modeled. All of the future resource mixes contain a significant amount of combined cycle gas-fired generation. The base case scenario consists of all gas combined cycle for new generation. The other three strategies vary in terms of the amount of CC gas built and the type of generation technology that makes up the remainder of the new capacity requirement. The remainder is either gas simple cycle, conventional coal or wind power.

NO_x Performance

As can be seen from Figure 4-27, new generation mix has very little impact on the amount of NO_x emitted. Monthly emissions are generally around 10 thousand tons above the seasonal cap. The Gas and Conventional Coal resource option is the only one which has a non-negligible impact on NO_x emissions compared to the base case. Coal generation generally has a lower NO_x formation rate than gas generation because combustion temperatures tend to be lower. However, this difference only amounts to a 2.5 thousand ton maximum in 2003.

Contrary to intuition, the renewable wind resource option does not significantly change NO_x emissions from the natural gas strategy. This can be explained by the fact that most of the wind generation does not occur during the summer or during the peak hours of the day. As such, wind plants have little or no capacity credit, meaning that they do not decrease the amount of fossil generation that needs to be built. For these reasons, the wind capacity is not displacing Seasonal NO_x emissions. On an annual basis, the wind option does result in the lowest NO_x emissions.

Figure 4-27: Coastal NE Seasonal NO_x Emissions for the Reference Scenario of RACT Only



The impact of new resource options on NO_x emission with Relaxed Phase II retrofit controls and Southern Seasonal operational controls is shown in Figure 4-28. It is evident that choice of new generation technology has almost no impact on NO_x emissions. The chosen scenario, is effective in meeting the NO_x target, regardless of new generation technology choice.

New resource option scenarios do not vary significantly over the annual, seasonal and episodal time periods. The non-dispatchability of wind generation does cause some seasonal variation. Unfortunately, this seasonal variation does not work in favor of reducing NO_x emissions. Therefore, the episodal NO_x

trajectory for Coastal NE shown in Figure 4-29 reveals the same trends as the Seasonal graph shown above.

Figure 4-28: Coastal NE Seasonal NO_x for Relaxed Phase II Retrofit Controls with Southern Seasonal Operational Controls (LI)

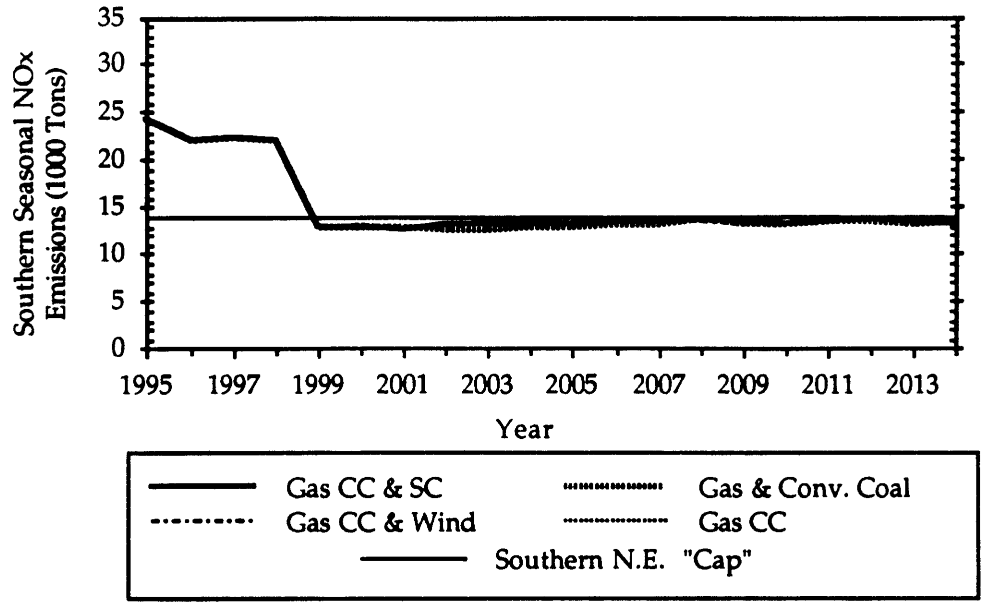
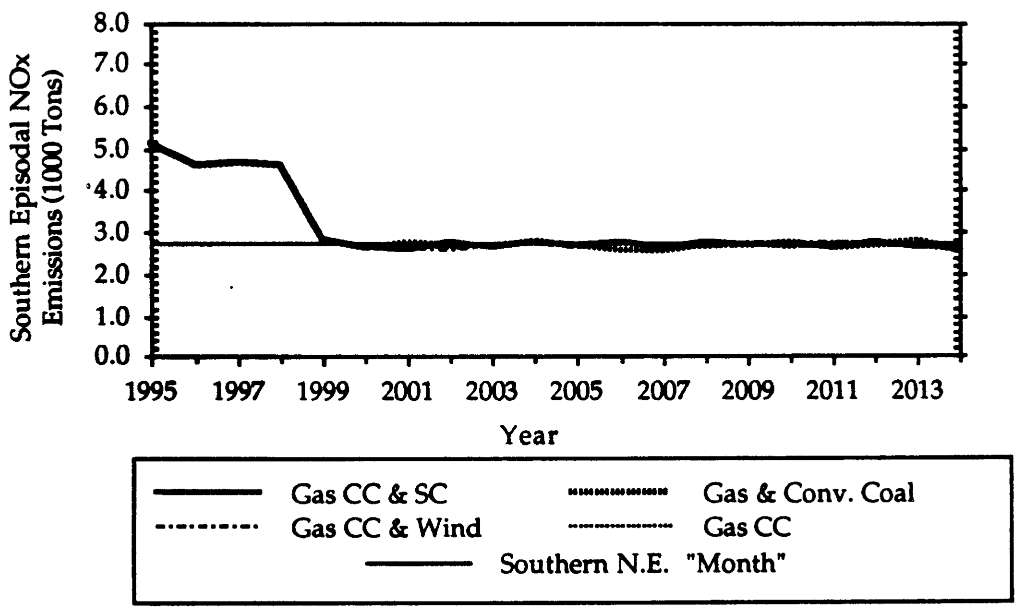


Figure 4-29: Coastal NE Episodal NO_x Emissions with Relaxed Phase II and Southern Seasonal Operational Controls (LI)



Impact on Alternate Emissions

Impact on CO_2 Emissions

Figures 4-30 and 4-31 show the impact of alternative new generation resources on annual CO_2 emissions for the two candidate NO_x scenarios controls compared to 1990 historic CO_2 emissions. There is very little difference between three of the resource options: Gas CC, Gas CC and SC and Gas CC with Wind. The two gas options increase CO_2 emissions by approximately 2.5 percent over RACT emissions. Only the wind option has CO_2 emissions below the RACT Only base case, and then only in later years (starting in 2008) as more wind generation is installed. The wind option decreases CO_2 emission by about 1 percent by 2010. The coal option significantly increases the system CO2 emissions to approximately 8 percent above RACT Only and increases over time. This is no surprise since coal has a higher carbon content than either oil or gas. The Gas CC option has lower CO_2 emissions than the Gas CC and SC due to the higher efficiency of the combined cycle units. In general, the impact of new resource options on CO_2 emissions is small compared to the system trend towards higher emissions.

Figure 4-30: Annual CO_2 Emissions with Relaxed Phase II and Southern Seasonal Controls (LI) and Strict Phase II (NE)

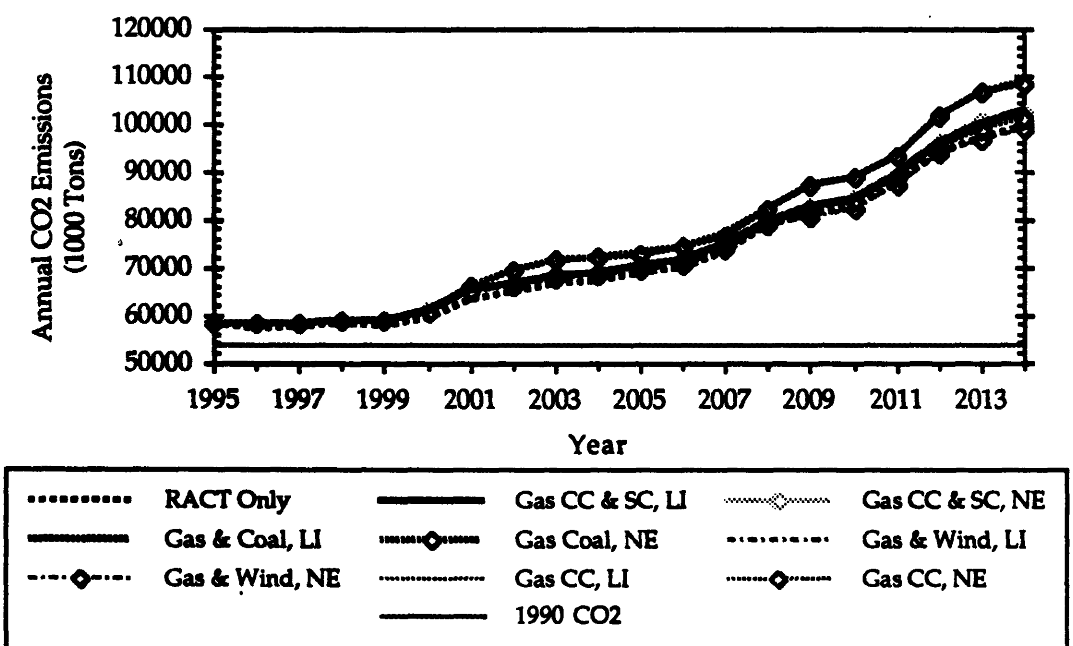
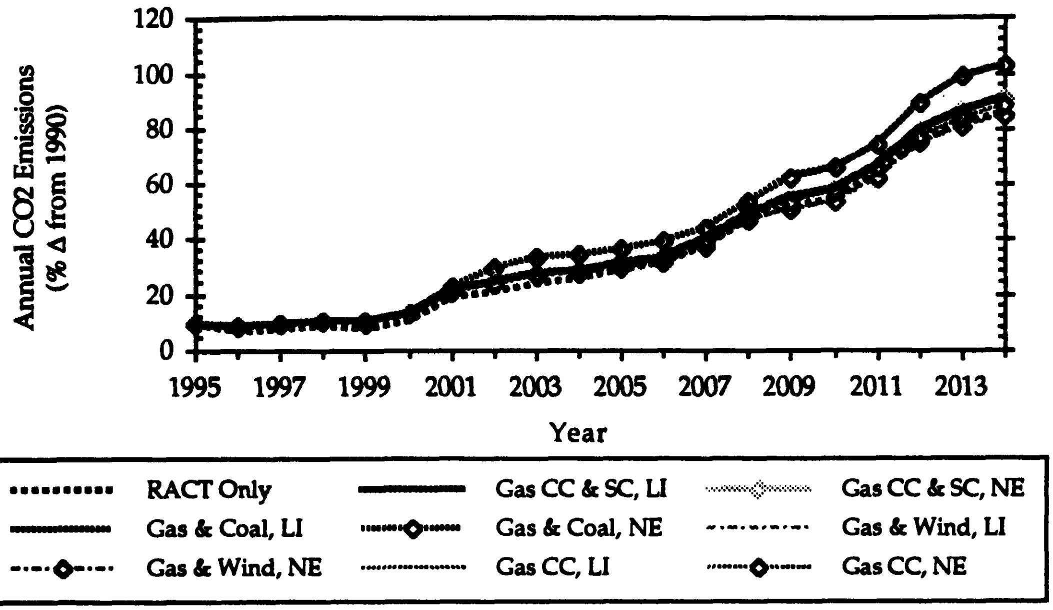


Figure 4-31: Percentage Change from 1990 Historic CO_2 Emissions for Relaxed Phase II with Southern Seasonal Controls (LI) and Strict Phase II (NE)



Impact on SO_2 Emissions

Figures 4-32 and 4-33 show the impact of the different new resource options on annual SO_2 emissions for the Relaxed Phase II with Southern Seasonal controls scenario compared to the RACT Only base case. SO_2 emissions trajectories for the Strict Phase II option is not shown here but has approximately the same impact as the Relaxed Phase II with Southern Seasonal controls. The coal resource option tends to increase SO_2 emissions, since there is a higher sulfur content in coal than in the other fossil fuels. The coal option increases SO_2 emissions by about 10 percent by 2011 and continues to increase. The Gas plus Wind option tends to decrease SO_2 emissions, due to the resulting decrease in fossil generation. The Gas with Wind option decreases SO_2 emission by about 7 percent from 2006 and later. The two Gas options have the similar impact of decreasing SO_2 emissions about 4 percent below RACT Only. In general, the NO_x strategies tend to decrease SO_2 emissions, so SO_2 is of lesser concern than CO_2 which was discussed above. However, it should be noted that the NO_x strategies do not have any adverse affect on SO_2 emissions when used in conjunction with any of the new resource options examined here.

Figure 4-32: Annual SO_2 Emissions with Relaxed Phase II and Southern Seasonal Controls (LI)

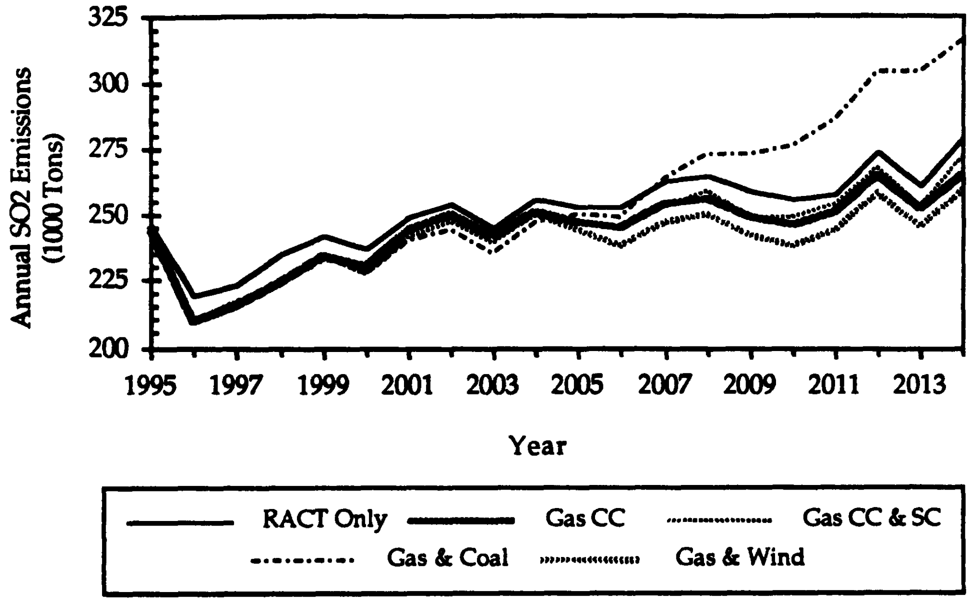
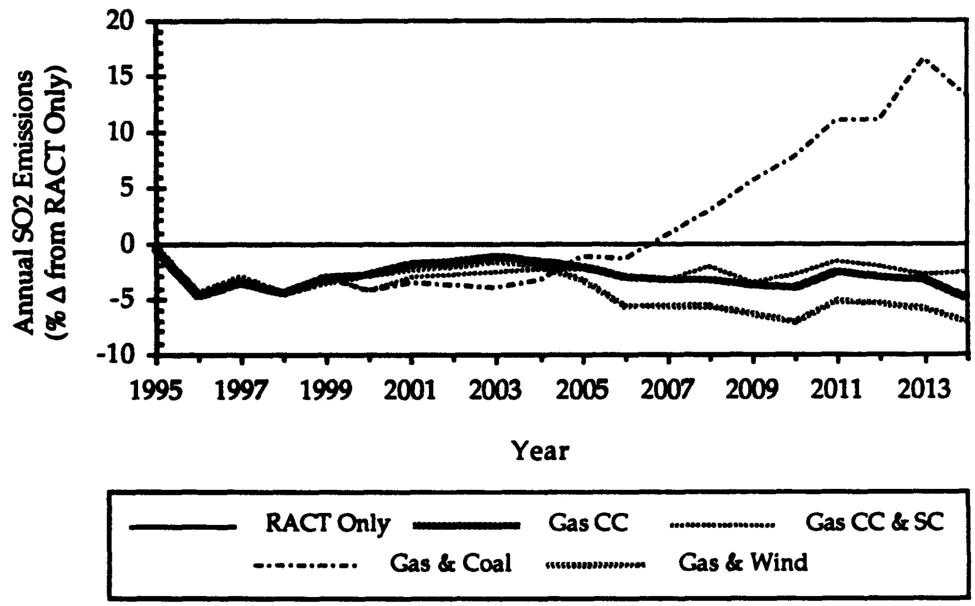


Figure 4-33: Percentage Change in Annual SO_2 Emissions with Relaxed Phase II and Southern Seasonal Controls (LI)



Cost Performance

Figures 4-34 and 4-35 show the cost difference trajectories of the Relaxed Phase II with Southern Seasonal controls scenario across new resource options compares to the RACT Only with Gas reference case. These trajectories show that both of the all gas options have approximately the same cost impact, amounting to about $500 million a year in future dollars. The Gas with Wind option cost somewhat more at almost $1 billion annually by 2014. The Gas with coal option is significantly more expensive than the other three options with a $2.5 billion annual impact by 2014. The cost difference between new resource options is significantly greater than the cost differential resulting from the various NO_x strategies.

Figure 4-34: Total Regional Cost Difference from Reference DSM for Relaxed Phase II and Southern Seasonal Operational Controls

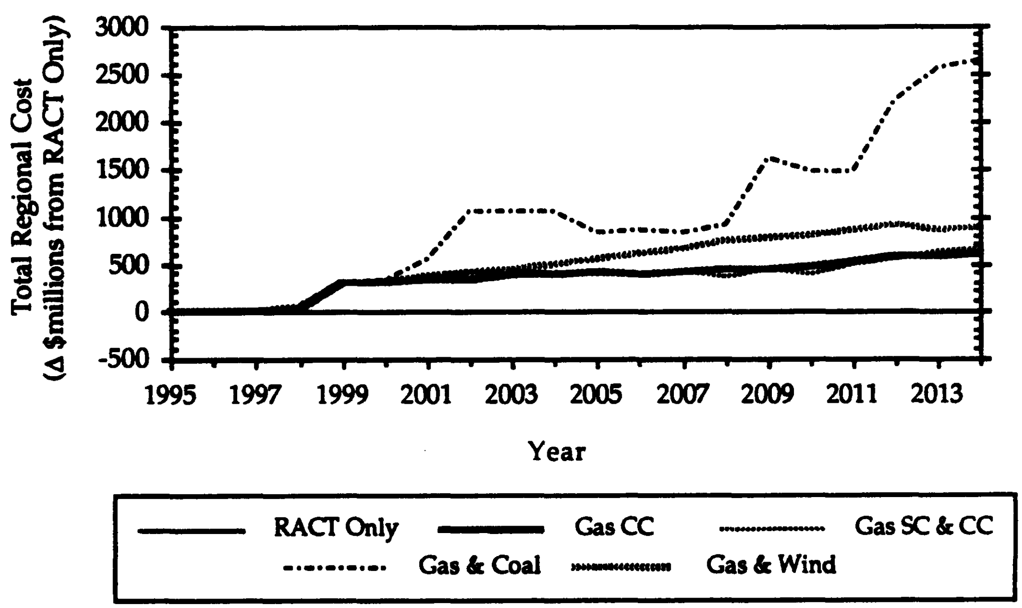
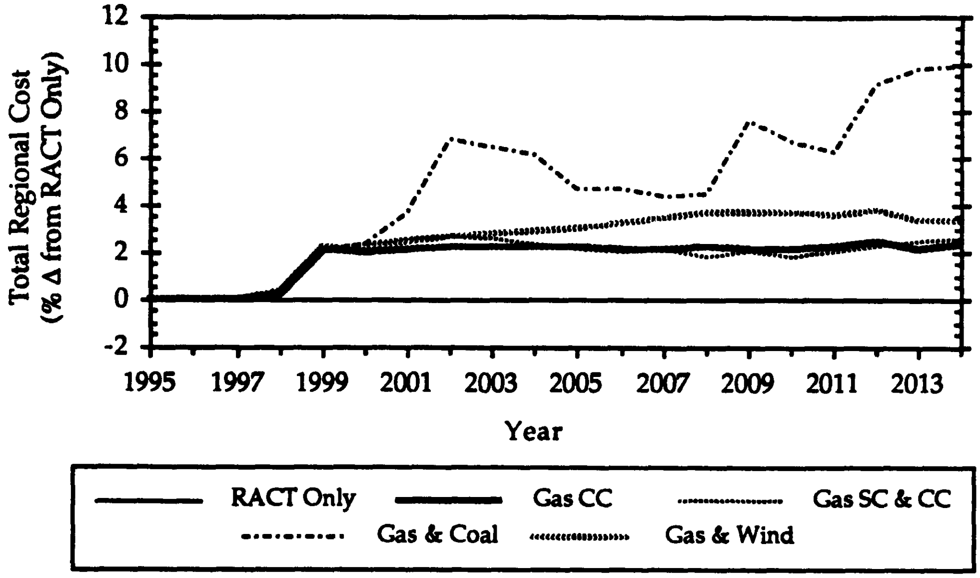


Figure 4-35: Percent Change in Total Regional Cost Difference from Reference DSM for Relaxed Phase II and Southern Seasonal Operational Controls



Cumulative System Impacts

Emissions

Table 4-6 summarizes the NO_x reduction performance of Relaxed Phase II with Southern Seasonal controls and Strict Phase II across the new resource options. None of the new resource options has a significant impact on the performance of the two NO_x reduction strategies. New resource choice has roughly the same impact on all three emissions for the two candidate scenarios. All of the new resource options in combination with a candidate NO_x strategy increase cumulative CO_2 emission compared to RACT Only. The Gas with Wind option results in the lowest CO_2 emissions representing only a 0.7 percent increase from the RACT Only case. All of the options except for the coal strategies decrease SO_2 emissions. The Gas with Wind option decreases SO_2 emissions by a cumulative 4.4 percent.

Table 4-6: Summary of New Supply Resource Emission Impacts for the Relaxed Phase II with Southern Seasonal Operational Controls Strategy

	Total Elec. Sector Emissions			Total Seas. Geographic NOx Emissions			
NOx Strategy Across Resources	NOx Emission	CO2 Emission	SO2 Emission	All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
Gas CC, LI	1.81	1430.0	5.02	0.615	0.304	0.125	0.062
Gas CC & SC, LI	1.80	1436.2	5.02	0.612	0.304	0.124	0.062
Gas CC & Conv. Coal, LI	1.88	1486.1	5.28	0.652	0.301	0.133	0.062
Gas CC & Wind, LI	1.80	1413.6	4.95	0.614	0.303	0.125	0.062
Gas CC, NE	1.70	1429.4	5.03	0.597	0.295	0.122	0.061
Gas CC & SC, NE	1.61	1435.7	5.03	0.595	0.295	0.122	0.061
Gas CC & Conv. Coal, NE	1.70	1485.5	5.30	0.632	0.286	0.129	0.059
Gas CC & Wind, NE	1.62	1413.0	4.81	0.598	0.296	0.123	0.062
	(MTons, 1995-2014)			(MTons, 1995-2014)			
Δ from Gas CC, LI							
Gas CC & SC, LI	-0.01	6.2	0.00	-0.003	-0.001	-0.001	0.000
Gas CC & Conv. Coal, LI	0.07	56.1	0.27	0.036	-0.004	0.008	0.000
Gas CC & Wind, LI	-0.01	-16.4	-0.06	-0.001	-0.001	0.000	0.000
Gas CC, NE	-0.11	-0.6	0.01	-0.018	-0.009	-0.003	-0.001
Gas CC & SC, NE	-0.20	5.6	0.02	-0.020	-0.009	-0.003	-0.001
Gas CC & Conv. Coal, NE	-0.11	55.5	0.28	0.017	-0.018	0.004	-0.003
Gas CC & Wind, NE	-0.19	-17.0	-0.21	-0.017	-0.008	-0.002	-0.001
	(ΔMTons, 1995-2014)			(ΔMTons, 1995-2014)			
Δ% from Gas CC, LI							
Gas CC & SC, LI	-0.52	0.43	0.02	-0.45	-0.29	-0.47	-0.36
Gas CC & Conv. Coal, LI	4.14	3.92	5.29	5.90	-1.28	6.27	-0.59
Gas CC & Wind, LI	-0.32	-1.15	-1.25	-0.19	-0.32	-0.09	-0.22
Gas CC, NE	-6.19	-0.04	0.29	-2.96	-2.96	-2.09	-1.85
Gas CC & SC, NE	-10.85	0.39	0.31	-3.29	-3.03	-2.44	-1.95
Gas CC & Conv. Coal, NE	-5.95	3.88	5.58	2.77	-5.93	3.51	-4.88
Gas CC & Wind, NE	-10.37	-1.19	-4.12	-2.82	-2.64	-1.88	-1.43
	(Δ%)			(Δ%)			

Costs

Table 4-7 below summarizes the cost impact of the new resource options. This table shows that, regardless of discounting method, the two gas options have virtually the same cost impact and that the coal option cost several times more then the other options. The coal option could cost as much as $12.4 million more than RACT Only.

Table 4-7: Summary of New Supply Resource Cost Impacts for the Relaxed Phase II with Southern Seasonal Operational Controls Strategy

NOx Retroft Strategy	Standard Direct Costs Regional Direct	Standard Direct Costs Elec. Ind. Direct	Inflation Adj. Direct Regional Direct	Inflation Adj. Direct Elec. Ind. Direct	Risk Adj. Discounting Regional Direct	Risk Adj. Discounting Elec. Ind. Direct
Gas CC, LI	135.6	134.4	258.5	256.5	153.5	152.3
Gas CC & SC, LI	135.6	134.4	258.5	256.5	153.6	152.4
Gas CC & Conv. Coal, LI	138.7	137.5	266.5	264.5	156.6	155.4
Gas CC & Wind, LI	136.4	135.2	260.4	258.5	154.2	153.0
	(PV-1994$B, r=10%)		(1994$B, r~3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ from Gas CC, LI						
Gas CC & SC, LI	0.0	0.0	0.0	0.0	0.1	0.1
Gas CC & Conv. Coal, LI	3.2	3.2	8.0	8.0	3.2	3.2
Gas CC & Wind, LI	0.8	0.8	2.0	2.0	0.8	0.8
	(PV-1994$B, r=10%)		(1994$B, r~3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ% from Gas CC, LI						
Gas CC & SC, LI	0.0	0.0	0.0	0.0	0.1	0.1
Gas CC & Conv. Coal, LI	2.3	2.3	3.1	3.1	2.1	2.1
Gas CC & Wind, LI	0.6	0.6	0.8	0.8	0.5	0.5
	(Δ%)		(Δ%)		(Δ%)	

F. CANDIDATE SCENARIOS

In the beginning of this chapter, the impact of the viable NO_x strategies on CO_2 and SO_2 emissions was examined. It was shown that these scenarios, in conjunction with Reference level DSM and a Gas Combined Cycle new generation option, have a relatively small impact on these emissions, raising CO_2 emissions by about 2 percent and decreasing SO_2 by 4 percent.

The performance of these NO_x strategies across Demand Side Management level options was then analyzed. It was shown that the Relaxed Phase II with Southern Seasonal controls strategy performs better than the Strict Phase II control strategy for higher levels of DSM. For Double DSM, the Strict Phase II strategy did not meet the NO_x reduction target for starting in 2007, whereas the Relaxed Phase II strategy NO_x emissions were only above the target for one year (2012).

DSM is a very effective means to reduce CO_2 emissions. Higher levels of DSM can easily offset the small increase in CO_2 emissions that results from the NO_x reduction strategy. DSM also tends to reduce electric industry costs by decreasing demand for new generating facilities. This cost savings is generally offset by higher total regional costs. However, DSM may be a very attractive option for utilities and regulators in trying to reduce CO_2 emissions while still meeting the NO_x reduction targets.

The performance of the two NO_x strategies across the new resource options was also examined. New resource options have a very small impact on NO_x emissions due in part to their late introduction. They also have a relatively small impact on SO_2 emissions which stay below the RACT Only with gas new generation SO_2 emissions for all of the new resource options. New resource options do have a sizable impact CO_2 emissions. The coal option increased CO_2 emissions by 6 percent while the Gas with Wind option only increased the CO_2 by 0.7 percent compared to the RACT Only option.

In general, both of the candidate NO_x strategies perform well across the different demand and supply side options. The Strict Phase II option normally has slightly lower NO_x emissions both annually and during the ozone season. However, it does not perform as well as the Relaxed Phase II with Southern Seasonal controls option with higher levels of DSM. Also, as was shown in the last chapter, the Strict Phase II option costs more than the combination strategy. Given that the Relaxed Phase II with Southern Seasonal controls strategy consistently meets the NO_x target over a wide range of system option, at lower cost, without having a detrimental impact on other system emissions, it seems to be the technically and economically superior scenario of the ones considered in this thesis.

Table 4-8 shows the strategies which have the highest overall performance. These candidate strategies will be examined in detail.

Table 4-8: Candidate NO_x Strategies

	Retrofit Level	*Operational Controls*	*Resource Option*	*DSM Level*
GUMINARU*	RACT Only	None	Gas CC	Reference
GUMINERU	Strict Phase II	None	Gas CC	Reference
GUMILIRU	Relaxed Phase II	Southern Seasonal	Gas CC	Reference
GUMILIDU	Relaxed Phase II	Southern Seasonal	Gas CC	Double
WUMILIRU	Relaxed Phase II	Southern Seasonal	Gas CC & Wind	Reference
WUMILIDU	Relaxed Phase II	Southern Seasonal	Gas CC& Wind	Double

* GUMINARU shown for reference

Figure 4-36 below shows that all of the candidate scenarios are effective in meeting the NO_x reduction targets. Both of the Double DSM scenarios are above the NO_x target for one year (2012) but are below the target in later years.

Figure 4-36: Southern Seasonal NO_x Emissions for Candidate NO_x Strategies

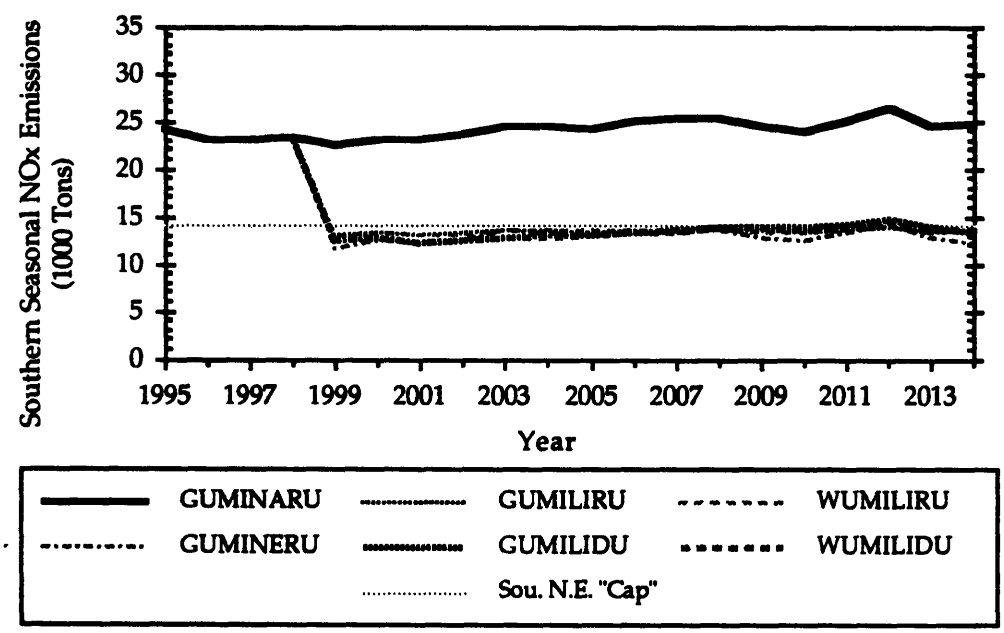


Figure 4-37 and 4-38 detail the impact of the candidate NO_x strategies on CO_2 and SO_2 emissions. The Double DSM scenarios significantly decrease CO_2 emissions. The wind scenarios decreases CO_2 emissions slightly while the remaining strategies (Strict Phase II and Relaxed Phase II with Southern Seasonal controls and gas new generation) tend to increase CO_2 emissions. All of the strategies, except for the two Double DSM scenarios tend to reduce SO_2 emissions. These strategies only increase SO_2 emissions for 2 to 4 years and do not show a consistent trend towards higher emissions.

Figure 4-37: Annual CO_2 Emissions for Candidate NO_x Strategies

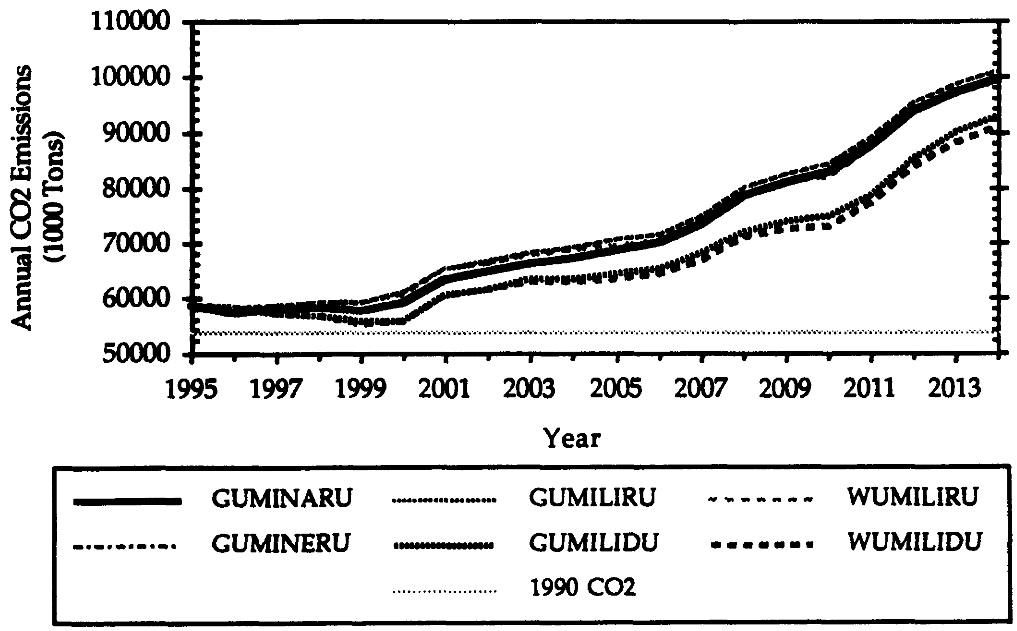
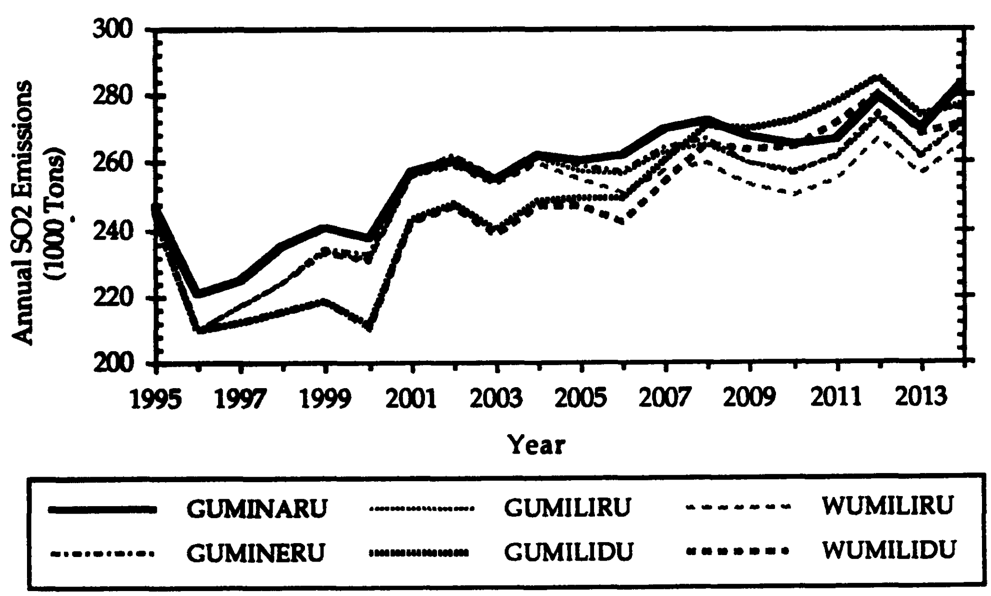
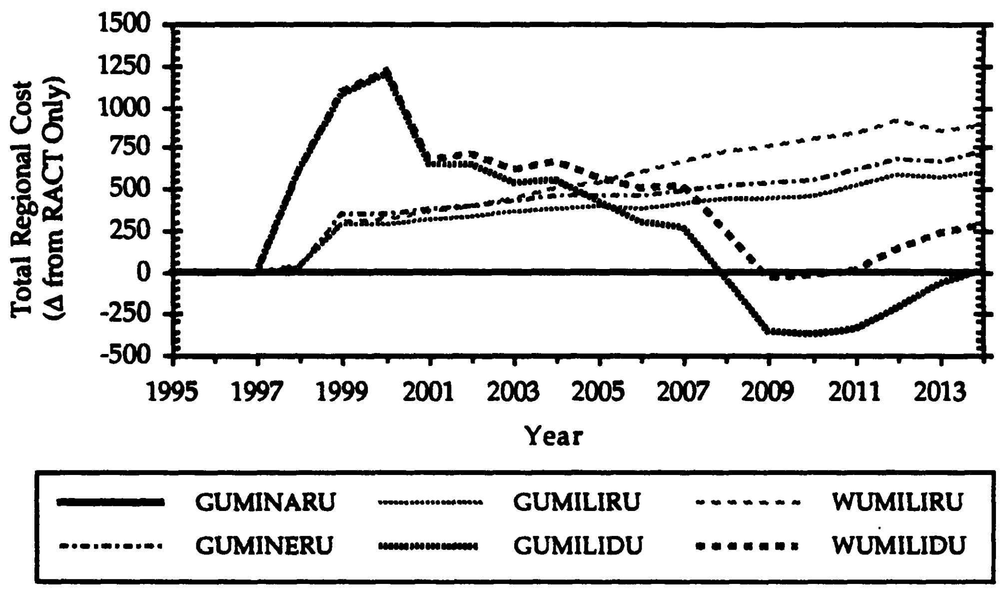


Figure 4-38: Annual SO_2 Emissions for Candidate NO_x Scenarios



The strategy impact on Total Regional Cost is shown in Figure 4-39. The three Reference DSM scenarios tend to increase system costs by varying degrees. The Relaxed Phase II with Southern Seasonal controls and Gas new generation consistently costs the least of these three. The Double DSM scenarios significantly increase costs in early years, but result in decreased costs in later years.

Figure 4-39: Total Regional Cost Difference from RACT Only for Candidate NO_x Scenarios



Total system emissions for the 5 candidate strategies are shown in Table 4-9. All of the strategies have similar NO_x emissions for all three time periods. The Strict Phase II strategy has somewhat lower NO_x emissions than the other four. As discussed above, all of the strategies succeed in reducing Southern Seasonal NO_x below the target. All five strategies also have a similar impact on total SO_2, reducing emission by 2 to 4 percent. Only the Double DSM scenario actually succeed in reducing CO_2 emissions below the RACT Only reference level. By design, the wind strategies decrease total CO_2 emissions by about 1 percent below the similar gas strategy.

Table 4-9: Summary of Emissions for Candidate NO_x Strategies

NOx Retrofit Strategy	Total Elec. Sector Emissions: NOx Emissions	Total Elec. Sector Emissions: CO2 Emissions	Total Elec. Sector Emissions: SO2 Emissions	Total Seas. Geographic NOx Emissions: All NE Season	Total Seas. Geographic NOx Emissions: Sou. NE Season	Total Seas. Geographic NOx Emissions: All NE Episode	Total Seas. Geographic NOx Emissions: Sou. NE Episode
GUMINERU	1.62	1429.4	5.03	0.597	0.295	0.122	0.061
GUMILIRU	1.73	1430.0	5.02	0.615	0.304	0.125	0.062
GUMILIDU	1.71	1315.7	4.97	0.608	0.301	0.124	0.062
WUMILIRU	1.73	1413.6	4.95	0.614	0.303	0.125	0.062
WUMILIDU	1.70	1300.7	4.91	0.605	0.299	0.123	0.062
	(MTons, 1995-2014)			(MTons, 1995-2014)			
Δ from GUMINERU							
GUMILIRU	0.11	0.60	-0.01	0.02	0.01	0.00	0.00
GUMILIDU	0.09	-113.76	-0.06	0.01	0.01	0.00	0.00
WUMILIRU	0.11	-15.83	-0.08	0.02	0.01	0.00	0.00
WUMILIDU	0.08	-128.74	-0.12	0.01	0.00	0.00	0.00
	(ΔMTons, 1995-2014)			(ΔMTons, 1995-2014)			
Δ% from GUMINERU							
GUMILIRU	6.99	0.04	-0.29	3.05	3.05	2.14	1.89
GUMILIDU	5.51	-7.96	-1.12	1.77	1.81	1.38	1.39
WUMILIRU	6.77	-1.11	-1.53	2.85	2.72	2.04	1.66
WUMILIDU	4.92	-9.01	-2.36	1.31	1.23	0.85	0.59
	(Δ%)			(Δ%)			

The cumulative cost impacts of the 5 candidate strategies are shown below. The wind strategy with Reference DSM consistently increases the costs more than the other strategies. The Relaxed Phase II with Southern Seasonal controls, Gas new generation and Double DSM consistently has the lowest Electric Industry Direct Costs and has the lowest Total Regional Direct costs for two of the three discounting methods. In general, the addition of wind generation and further NO_x retrofits tend to increase costs while the addition of higher levels of DSM tend to decrease costs.

Table 4-10: Summary of Costs for Candidate NO_x Strategies

NOx Retroft Strategy	Standard Direct Costs Regional Direct	Elec. Ind. Direct	Inflation Adj. Direct Regional Direct	Elec. Ind. Direct	Risk Adj. Discounting Regional Direct	Elec. Ind. Direct
RACT Only, Base	133.6	132.4	254.1	252.1	150.8	149.5
GUMINERU	136.0	134.8	259.3	257.3	154.0	152.8
GUMILIRU	135.6	134.4	258.5	256.5	153.5	152.3
GUMILIDU	136.3	133.2	258.1	252.6	153.2	150.1
WUMILIRU	136.4	135.2	260.4	258.5	154.2	153.0
WUMILIDU	137.1	134.0	260.1	254.6	154.0	150.9
	(PV-1994$B, r=10%)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ from RACT Only, Base						
GUMINERU	2.3	2.3	5.2	5.2	3.2	3.2
GUMILIRU	2.0	2.0	4.4	4.4	2.7	2.7
GUMILIDU	2.7	0.8	4.0	0.5	2.4	0.5
WUMILIRU	2.7	2.7	6.4	6.4	3.5	3.5
WUMILIDU	3.5	1.6	6.0	2.5	3.2	1.3
	(PV-1994$B, r=10%)		(1994$B, r≈3.2%)		(PV-'94$B, r=10%/6.8%)	
Δ% from RACT Only, Base						
GUMINERU	1.7	1.8	2.1	2.1	2.1	2.1
GUMILIRU	1.5	1.5	1.7	1.7	1.8	1.8
GUMILIDU	2.0	0.6	1.6	0.2	1.6	0.4
WUMILIRU	2.1	2.1	2.5	2.5	2.3	2.3
WUMILIDU	2.6	1.2	2.4	1.0	2.1	0.9
	(Δ%)		(Δ%)		(Δ%)	

The tables and figures above detail the overall performance of the five candidate NO_x strategies. Each of these strategies has advantages and disadvantages in terms of system emissions and costs. The next chapter will examine the performance of these scenarios in the presence of fuel cost uncertainty.

CHAPTER 5 - FUEL COST UNCERTAINTY

The previous chapter examined larger electric sector factors, such as CO_2 and SO_2 emissions as well as demand side and supply resource options. Several strong conclusions were made. Both the Relaxed Phase II with Southern Seasonal Controls and the Strict Phase II scenarios consistently meet the NO_x target. This is independent of DSM level and choice of new generation technology. However, the strategy utilizing operational controls consistently costs less than the stricter retrofit strategy.

Demand Side Management is very valuable as a means for reducing CO_2 emissions while having a relatively small impact on NO_x emissions. Higher levels of DSM also tends to reduce the electric industry costs at the expense of higher total regional costs. For this reason, a higher level of DSM, should be considered. It is also possible to meet the NO_x target with all four new generation resource examined. However, the Gas Combined Cycle and the Gas with Wind options also perform well in terms of other system emissions. The wind generation does not add significantly to the system cost.

The above analysis suggests that there are several scenarios which dominate the others in terms of total electric system performance. These scenarios are detailed in Table 5-1 below. This chapter will examine the robustness of these strategies across natural gas cost uncertainty.

<u>Table 5-1:</u> Candidate NO_x Reduction Scenarios

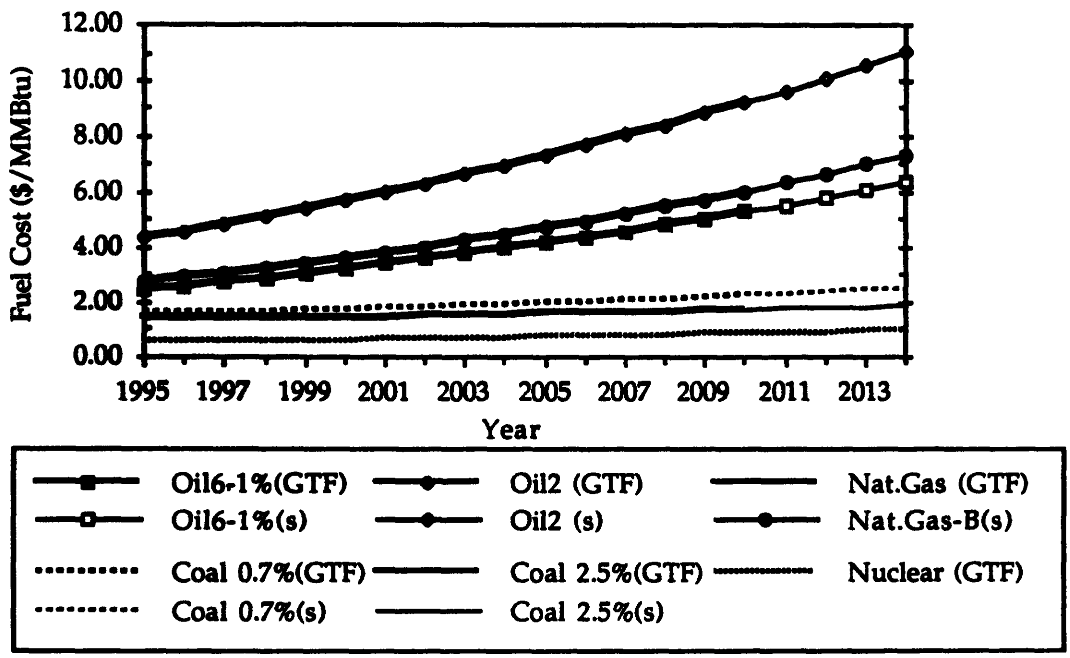
	Retrofit Level	*Operational Controls*	*Resource Option*	*DSM Level*
GUMINERU	Strict Phase II	None	Gas CC	Reference
GUMILIRU	Relaxed Phase II	Southern Seasonal	Gas CC	Reference
GUMILIDU	Relaxed Phase II	Southern Seasonal	Gas CC	Double
WUMILIRU	Relaxed Phase II	Southern Seasonal	Gas CC & Wind	Reference
WUMILIDU	Relaxed Phase II	Southern Seasonal	Gas CC& Wind	Double

A. NATURAL GAS FUEL COST UNCERTAINTY

An important determinant to the emissions of the electric power sector is the fuel cost trajectory used for future years. Fuel costs are a major constituent of total operating cost and, thus, figure heavily into the least cost economic dispatch. The fuel cost trajectory is modeled as an uncertainty and two trajectories are employed in this study: base fuel costs and high natural gas costs. The latter addresses the concern over New England's increasing dependence on natural gas and the potential vulnerability should prices increase substantially in the near or long term. Natural gas costs are the only fuel cost that vary in this study.

Fuel cost estimates for the years 1995 to 2010 are obtained from NEPOOL assumptions and are detailed in Figure 5-1 below. This figure shows the NEPOOL GTF (Generation Task Force) fuel cost projections as well as the extrapolated projections used in the EGEAS modeling, denoted by (s). The trajectory labeled "Nat. Gas - B" represents the base case assumption of future natural gas fuel cost. The percentages listed next to the fuel type specifies the sulfur content of the fuel.

Figure 5-1: Fuel Cost Assumptions



The high natural gas cost uncertainty is modeled as a cost response to some unforeseen supply constraint which hits the region beginning in 2001. Here the cost of natural gas rises to just below that of its substitute fuel in new generation – distillate oil (Oil2). In Figure 5-2 below, the trajectory labeled "Nat. Gas - H" represents this high assumption for future natural gas fuel cost. NEPOOL fuel cost projections are not included in Figure 2-4.

Figure 5-2: Natural Gas Cost Uncertainty

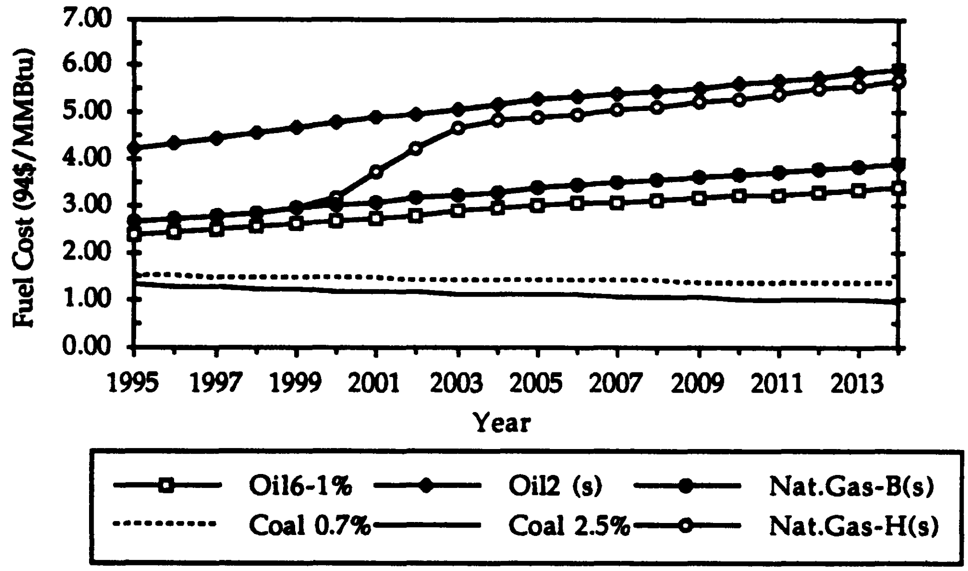
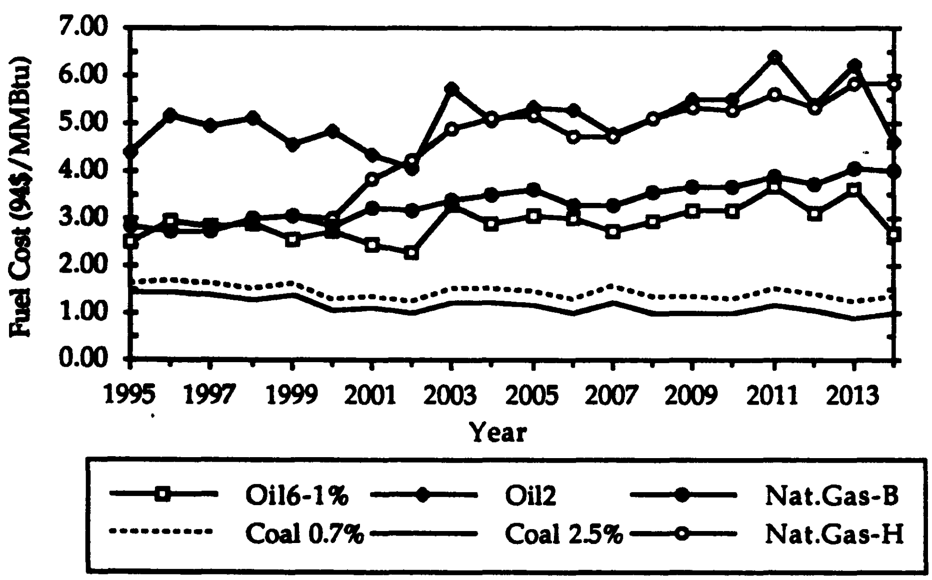


Figure 5-3: Actual Fuel Cost Projections Modeled



The smooth cost projections shown in Figure 5-3 are then modified to reflect short-term variations in the highly volatile fuel markets. Year to year variations in fuel costs are simulated by sampling within a narrowly constrained distribution of annual variations in historical fuel costs. The actual fuel cost projections used in the simulation are shown in Figure 2-5 above.

B. IMPACT OF NATURAL GAS FUEL COST UNCERTAINTY

Figure 5-4 below shows the performance of the candidate NO_X strategy with high future natural gas costs. All of the NO_X reduction strategies perform well across both future natural gas cost assumption, staying within the MOU NO_X target in all but one year for one of the cases. In 2012, the candidate scenarios with Double DSM are only 600 tons (or 4 percent) above the seasonal cap. However, in both 2013 and 2014, the scenario is under the target, suggesting that the problem was a one time spike, not a systemic problem. This reflects the same trend that was observed for the base future natural gas costs.

Figure 5-4: Southern Seasonal NO_X Emissions for Candidate Strategies with High Future Gas Costs

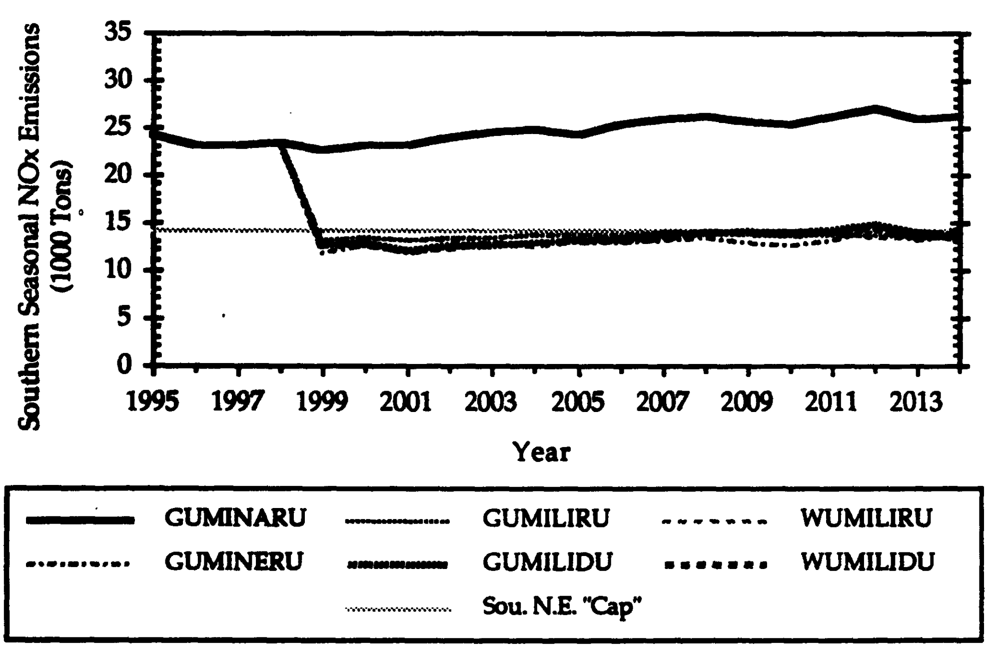
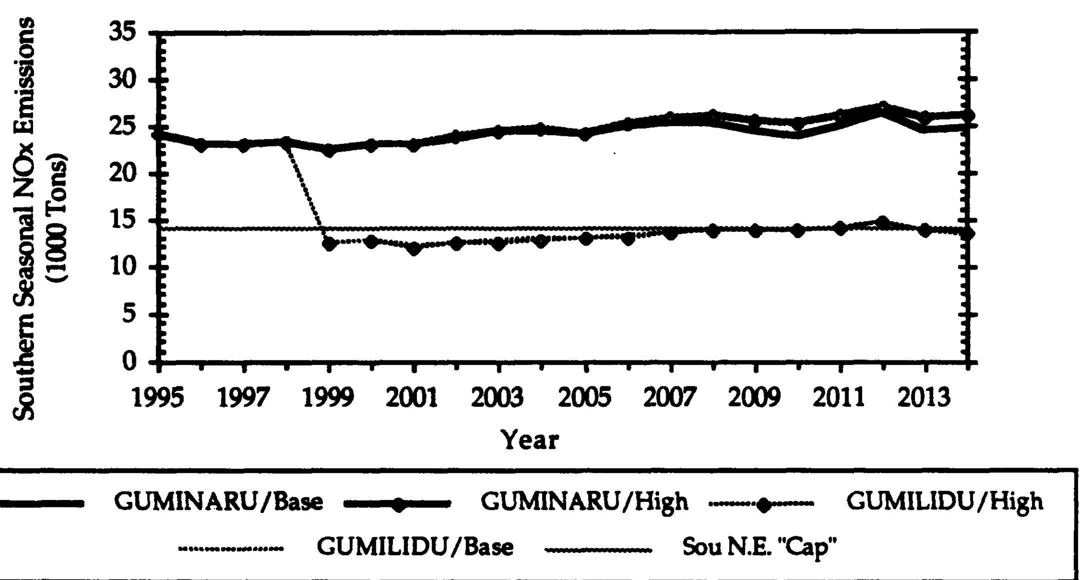


Figure 5-5 below reflects the southern seasonal NO_x emissions for the Reference RACT Only and the Relaxed Phase II with Southern Seasonal controls, Double DSM and gas new generation scenarios.. This graph shows that there is very little difference in NO_x emission between these two options across fuel cost uncertainty. Natural fuel cost uncertainty has very little impact on Southern Seasonal NO_x emissions.

Figure 5-5: Southern Seasonal NO_x Emissions for Relaxed Phase II with Southern Seasonal Controls and RACT Only Across Fuel Cost Uncertainty



Natural gas fuel cost uncertainty also has a very small impact on CO_2 emissions. Figures 5-6 and 5-7 below show that CO_2 emissions trajectories are similar for both fuel cost assumption. CO_2 emissions are slightly higher (less than 1 percent) for the base natural gas cost assumption. CO_2 emissions decrease for higher natural gas fuel costs due to a shift towards oil-fired units (and to a lesser extent hydro/pumped storage) and away from older simple cycle gas units. The Double DSM options perform well in reducing CO_2 emissions for both future gas cost trajectories. CO_2 emissions are approximately 3 percent lower for the Gas and Wind strategy than for the comparable Gas only option. In general, there is significantly higher CO_2 emission reductions from DSM than from wind generation.

Figure 5-6: Annual CO_2 Emissions for Candidate Strategies with High Future Gas Costs

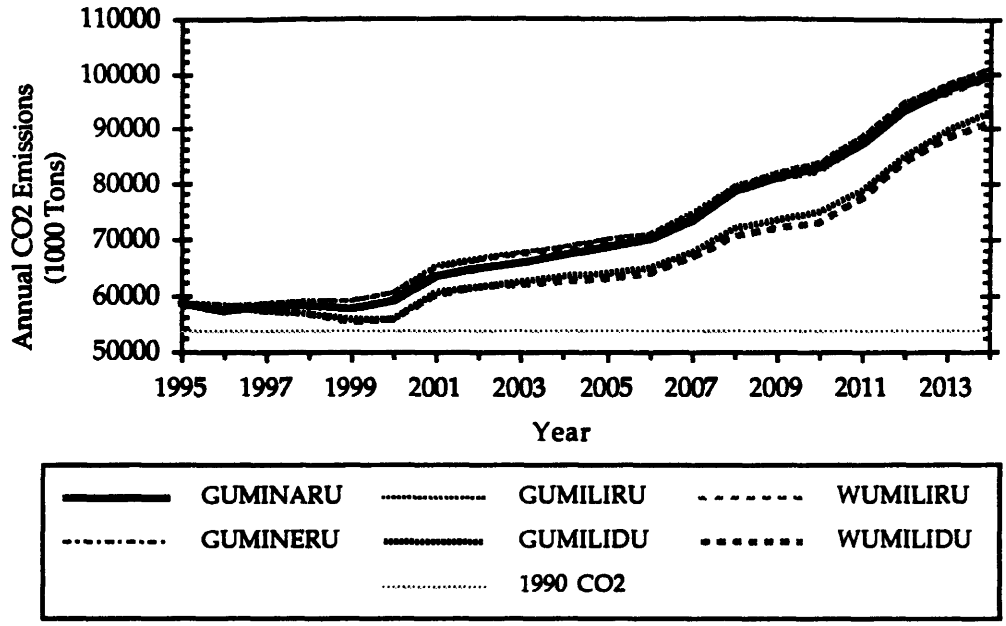


Figure 5-7: Annual CO_2 Emissions for Relaxed Phase II with Southern Seasonal Controls and RACT Only Across Fuel Cost Uncertainty

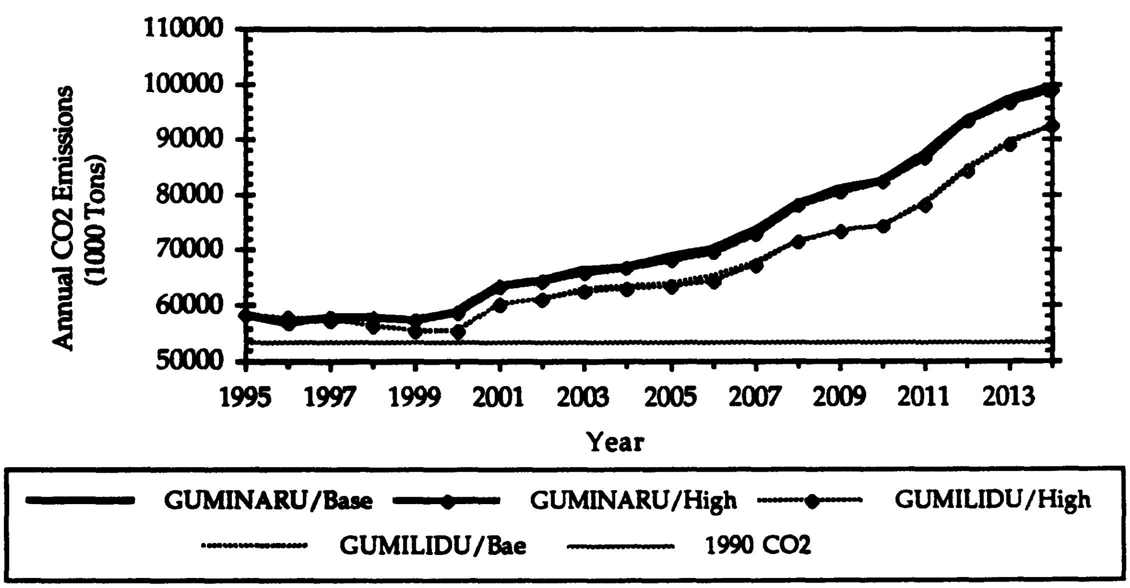
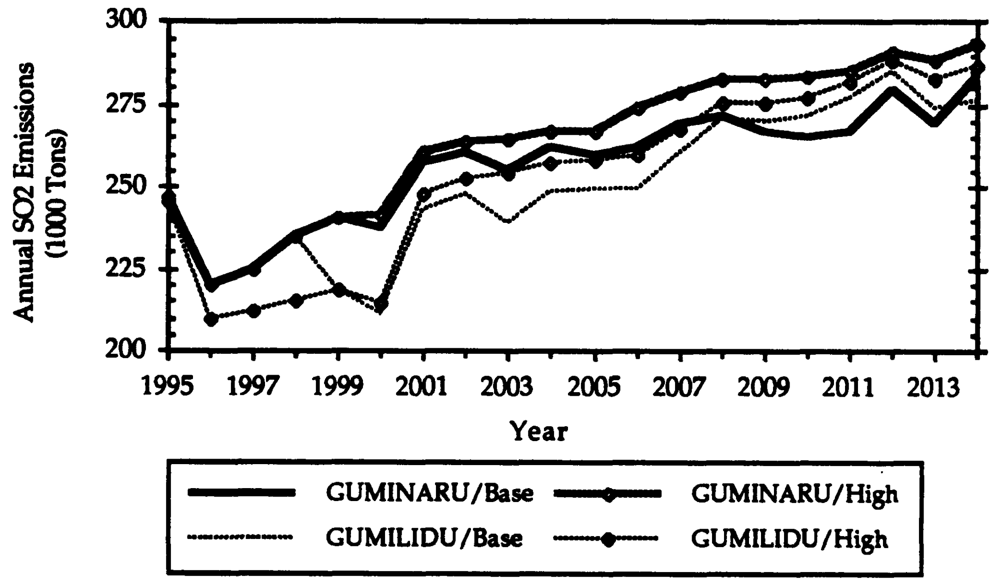


Figure 5-8 below shows trajectories for SO_2 emissions for the RACT Only Reference and the Relaxed Phase II with Southern Seasonal controls and Reference DSM scenarios. Natural gas cost does have a significant impact on SO_2

emissions. As gas fuel becomes more expensive, generation is shifted towards oil, resulting in higher SO_2 emissions. However, it should be noted, that compared to the comparable RACT Only case, the NO_x strategies still reduce SO_2 emissions. Compared to the RACT Only with high natural gas cost, the NO_x strategy shown exhibits lower SO_2 emissions. Similar trends for SO_2 emissions are apparent for all five of the NO_x reduction strategies. Thus, the NO_x strategies continues to perform well across fuel cost uncertainty.

Figure 5-8: Annual SO_2 Emissions for Relaxed Phase II with Southern Seasonal Controls and RACT Only Across Fuel Cost Uncertainty



The cost impacts of natural gas fuel cost uncertainty for the Reference DSM NO_x candidate scenarios are shown in Figure 5-9 below. This diagram shows that the fuel cost uncertainty impacts all of the strategies in a similar manner. The candidate NO_x scenarios exhibit the same cost trajectory in relation to the RACT Only reference for the base and high gas costs. The difference between the candidate scenario with Reference DSM and the RACT Only case is approximately $650 million for both gas future cost trajectories. Figure 5-10 shows that the Double DSM scenarios perform even better compared to the RACT Only case with the high gas costs.

Figure 5-9: Cost Impact of Fuel Cost Uncertainty on NO_x Candidate Strategies with Reference DSM

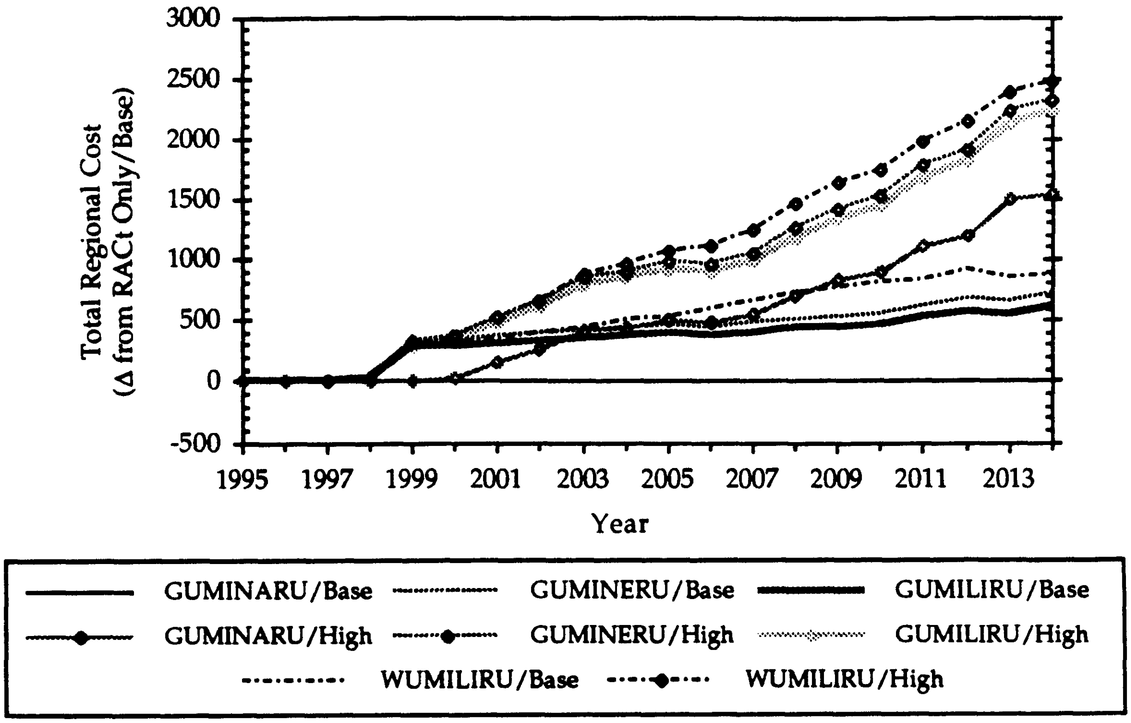
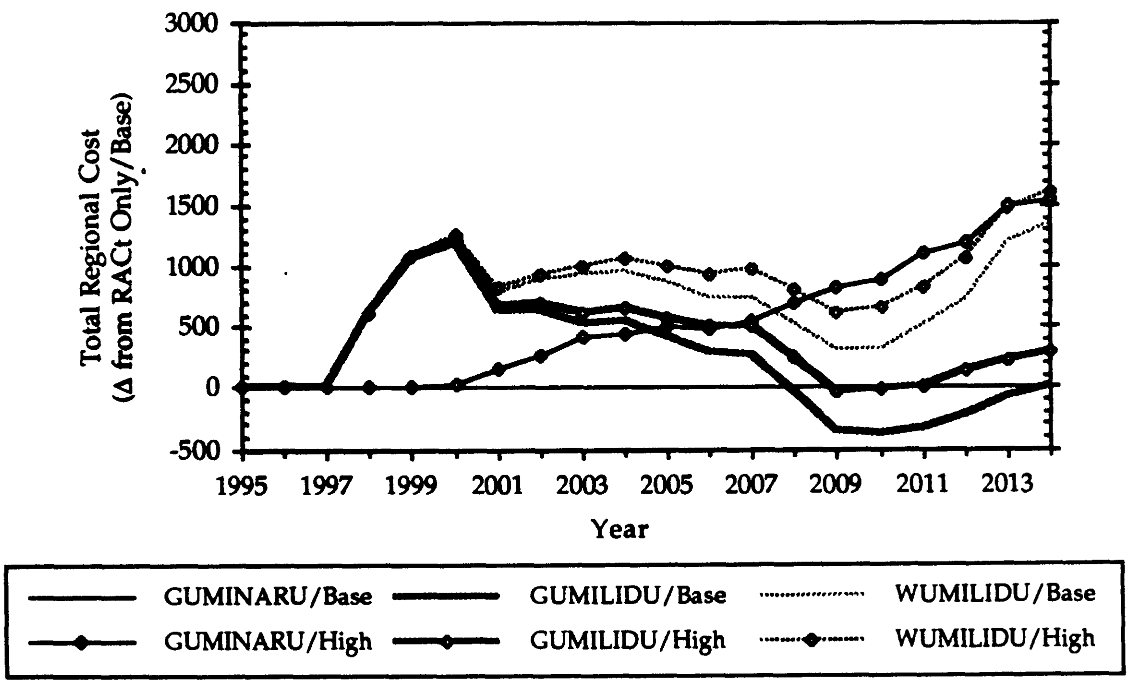


Figure 5-10: Cost Impact of Fuel Cost Uncertainty on NO_x Candidate Strategies with Double DSM



These diagrams also show that the Gas and Wind scenarios are consistently more expensive than the Gas only options. The wind option is consistently $250 million more expensive than the Gas only option for all of the NO_x scenarios. The Strict Phase II option remains approximately $100 million more expensive than Relaxed Phase II with Southern Seasonal controls even with high gas costs.

Summary

Table 5-2 summarizes the emissions impact of natural gas fuel cost uncertainty for the five candidate scenarios compared to the RACT Only, No Operational with gas new generation scenarios. High natural gas costs have a very small impact on NO_x for all three of the periods examined. While higher gas costs do tend to increase NO_x emissions, all of the NO_x reduction strategies were still able to meet the NO_x target.

Counter to what might be expected, higher natural gas costs do not results in higher CO_2 emissions. Gas is generally not competing with coal as a fuel, it is competing with oil (see Figure 5-3). In general, the high gas cost strategies exhibited a less than one percent lower CO_2 emissions than their comparable base gas scenarios. The shift towards more oil (and to a limited extent power purchases and hydro/pumped storage) explains this small decrease in CO_2. The shift towards oil generation also explains the observed increase in SO_2 emissions.

The cost impact of fuel cost uncertainty on the candidate NO_x strategies is summarized in Table 5-3. High gas costs do tend to increase both Regional Direct and Electric Industry costs. However, similar to the emissions impact, the NO_x strategy does not perform any worse than the RACT Only strategy in economic terms. The method of cost calculation also does not change this result.

The relative economic performance of the NO_x strategies does not change with high natural gas fuel costs. The Strict Phase II option remains the most expensive option. The wind options tend to increase both Total Regional and Electric Industry costs above the comparable gas strategies. Double DSM level scenarios significantly decrease Electric Industry costs and only increase Total Regional costs for the standard financial discounting method. High gas costs does not change the relatively economic performance of any of the strategies for any of the discounting methods.

Table 5-2: Emissions Summary for the Relaxed Phase II with Southern Seasonal Across Gas Fuel Cost Uncertainty

NOx Retrofit Strategy	Total Elec. Sector Emissions: NOx Emissions	CO2 Emissions	SO2 Emissions	Total Seas. Geographic NOx Emissions: All NE Season	Sou. NE Season	All NE Episode	Sou. NE Episode
RACT Only, Base Gas	2.22	1401.8	5.13	0.807	0.481	0.165	0.099
GUMINERU, Base	1.62	1429.4	5.03	0.597	0.295	0.122	0.061
GUMILIRU, Base	1.73	1430.0	5.02	0.615	0.304	0.125	0.062
GUMILIDU, Base	1.71	1315.7	4.97	0.608	0.301	0.124	0.062
WUMILIRU, Base	1.73	1413.6	4.95	0.614	0.303	0.125	0.062
WUMILIDU, Base	1.70	1300.7	4.91	0.605	0.299	0.123	0.062
RACT Only, High Gas	2.25	1398.0	5.29	0.819	0.490	0.167	0.101
GUMINERU, High	1.62	1425.0	5.24	0.596	0.293	0.122	0.061
GUMILIRU, High	1.74	1425.9	5.17	0.620	0.305	0.126	0.062
GUMILIDU, High	1.71	1311.8	5.08	0.611	0.300	0.125	0.062
WUMILIRU, High	1.74	1409.7	5.12	0.619	0.304	0.126	0.062
WUMILIDU, High	1.70	1296.8	5.02	0.608	0.298	0.124	0.061
	(MTons, 1995-2014)			(MTons, 1995-2014)			
Δ from RACT Only, Base Gas							
GUMINERU, Base	-0.60	27.66	-0.10	-0.21	-0.19	-0.04	-0.04
GUMILIRU, Base	-0.49	28.26	-0.12	-0.19	-0.18	-0.04	-0.04
GUMILIDU, Base	-0.51	-86.10	-0.16	-0.20	-0.18	-0.04	-0.04
WUMILIRU, Base	-0.49	11.83	-0.18	-0.19	-0.18	-0.04	-0.04
WUMILIDU, Base	-0.52	-101.08	-0.22	-0.20	-0.18	-0.04	-0.04
RACT Only, High Gas	0.03	-3.75	0.16	0.01	0.01	0.00	0.00
GUMINERU, High	-0.60	23.22	0.11	-0.21	-0.19	-0.04	-0.04
GUMILIRU, High	-0.48	24.08	0.04	-0.19	-0.18	-0.04	-0.04
GUMILIDU, High	-0.51	-89.98	-0.05	-0.20	-0.18	-0.04	-0.04
WUMILIRU, High	-0.48	7.88	-0.02	-0.19	-0.18	-0.04	-0.04
WUMILIDU, High	-0.52	-105.00	-0.12	-0.20	-0.18	-0.04	-0.04
	(ΔMTons, 1995-2014)			(ΔMTons, 1995-2014)			
Δ% from RACT Only, Base Gas							
GUMINERU, Base	-27.15	1.97	-2.02	-26.00	-38.56	-25.86	-37.96
GUMILIRU, Base	-22.06	2.02	-2.30	-23.75	-36.69	-24.27	-36.79
GUMILIDU, Base	-23.14	-6.14	-3.12	-24.69	-37.45	-24.84	-37.10
WUMILIRU, Base	-22.22	0.84	-3.52	-23.90	-36.89	-24.35	-36.93
WUMILIDU, Base	-23.57	-7.21	-4.33	-25.04	-37.81	-25.23	-37.59
RACT Only, High Gas	1.34	-0.27	3.05	1.56	1.87	1.50	1.85
GUMINERU, High	-27.18	1.66	2.10	-26.19	-38.99	-26.00	-38.28
GUMILIRU, High	-21.60	1.72	0.76	-23.20	-36.60	-23.73	-37.23
GUMILIDU, High	-22.85	-6.42	-1.04	-24.33	-37.65	-24.39	-37.32
WUMILIRU, High	-21.76	0.56	-0.30	-23.34	-36.80	-23.80	-37.37
WUMILIDU, High	-23.28	-7.49	-2.29	-24.67	-38.01	-24.78	-37.81
	(Δ%)			(Δ%)			

Table 5-3: Cost Summary for the Relaxed Phase II with Southern Seasonal Across Gas Fuel Cost Uncertainty

NOx Retroft Strategy	Standard Direct Costs: Regional Direct	Standard Direct Costs: Elec. Ind. Direct	Inflation Adj. Direct: Regional Direct	Inflation Adj. Direct: Elec. Ind. Direct	Risk Adj. Discounting: Regional Direct	Risk Adj. Discounting: Elec. Ind. Direct
RACT Only, Base Gas	133.6	132.4	254.1	252.1	150.8	149.5
GUMINERU, Base	136.0	134.8	259.3	257.3	154.0	152.8
GUMILIRU, Base	135.6	134.4	258.5	256.5	153.5	152.3
GUMILIDU, Base	136.3	133.2	258.1	252.6	153.2	150.1
WUMILIRU, Base	136.4	135.2	260.4	258.5	154.2	153.0
WUMILIDU, Base	137.1	134.0	260.1	254.6	154.0	150.9
RACT Only, High Gas	136.2	134.9	260.6	258.7	154.6	153.4
GUMINERU, High	138.6	137.4	266.2	264.2	158.0	156.8
GUMILIRU, High	138.3	137.1	265.4	263.5	157.6	156.4
GUMILIDU, High	138.5	135.4	263.7	258.2	156.5	153.4
WUMILIRU, High	139.0	137.8	267.3	265.3	158.3	157.1
WUMILIDU, High	139.2	136.1	265.6	260.1	157.3	154.1
	(PV-1994$B, r=10%)		(1994$B, r=3.2%)		(PV-'94$B, r=10%/6.8%	
Δ from RACT Only, Base Gas						
GUMINERU, Base	2.3	2.3	5.2	5.2	3.2	3.2
GUMILIRU, Base	2.0	2.0	4.4	4.4	2.7	2.7
GUMILIDU, Base	2.7	0.8	4.0	0.5	2.4	0.5
WUMILIRU, Base	2.7	2.7	6.4	6.4	3.5	3.5
WUMILIDU, Base	3.5	1.6	6.0	2.5	3.2	1.3
RACT Only, High Gas	2.5	2.5	6.6	6.6	3.9	3.9
GUMINERU, High	5.0	5.0	12.1	12.2	7.3	7.3
GUMILIRU, High	4.6	4.7	11.4	11.4	6.8	6.8
GUMILIDU, High	4.9	2.9	9.6	6.1	5.8	3.9
WUMILIRU, High	5.4	5.4	13.2	13.2	7.5	7.5
WUMILIDU, High	5.6	3.7	11.5	8.0	6.5	4.6
	(PV-1994$B, r=10%)		(1994$B, r=3.2%)		(PV-'94$B, r=10%/6.8%	
Δ% from RACT Only, Base Gas						
GUMINERU, Base	1.7	1.8	2.1	2.1	2.1	2.1
GUMILIRU, Base	1.5	1.5	1.7	1.7	1.8	1.8
GUMILIDU, Base	2.0	0.6	1.6	0.2	1.6	0.4
WUMILIRU, Base	2.1	2.1	2.5	2.5	2.3	2.3
WUMILIDU, Base	2.6	1.2	2.4	1.0	2.1	0.9
RACT Only, High Gas	1.9	1.9	2.6	2.6	2.6	2.6
GUMINERU, High	3.7	3.8	4.8	4.8	4.8	4.9
GUMILIRU, High	3.5	3.5	4.5	4.5	4.5	4.6
GUMILIDU, High	3.6	2.2	3.8	2.4	3.8	2.6
WUMILIRU, High	4.0	4.1	5.2	5.2	5.0	5.0
WUMILIDU, High	4.2	2.8	4.5	3.2	4.3	3.1
	(Δ%)		(Δ%)		(Δ%)	

The candidate NO_x strategy, Relaxed Phase II with Southern Seasonal controls, performs well across fuel cost uncertainty. This strategy, in combination with both Reference and Double levels of DSM, still met the NO_x reduction targets. Although the gas and wind new generation options do achieve slightly lower CO_2 emissions, they do not have a significant impact on NO_x and increase system costs. Also, the CO_2 reductions due to this renewable resource are not as great as the benefits achieved through higher levels of DSM. The Strict Phase II strategy does reduce NO_x emissions more than the Relaxed Phase II with Southern Seasonal controls option. However, this strategy consistently costs more and, when used in conjunction with Double DSM, it no longer meets the seasonal NO_x cap.

The Relaxed Phase II with Southern Seasonal controls has been shown to perform well both technically and economically across fuel cost uncertainty, as well as supply and demand side options. It appears that the highest system benefit in terms of cost and multiple emissions reductions can be achieved through a combination of this NO_x strategy, Double DSM and Gas Combined Cycle new generation.

CHAPTER 6 - DISCUSSION AND CONCLUSIONS

This chapter discusses the implementation options for NO_x reduction policy, including the consideration of NO_x emissions trading and electric utility industry restructuring. Most of the implementation discussion will focus on the market-based "Cap and Trade" system because this policy is the most consistent with the best performing strategy identified in previous chapters. The end of this chapter summarizes the technical and policy results and recommendations of the thesis.

The previous chapters identified the most effective strategies for attaining the seasonal NO_x reduction goals identified in the Ozone Transport Committee's Memorandum of Understanding. First it was shown that the NO_x reduction target was achievable through the installation of retrofit control technology. Second, a less expensive strategy consisting of a combination of retrofit and operational controls was identified. Third, in order to offset the increase in CO_2 emissions that the least cost NO_x strategy caused, a Double DSM strategy appeared valuable. Lastly, the Gas Combined Cycle new resource option allows for the attainment of the NO_x goals at least cost without increasing the other system emissions.

Thus, this analysis suggests that a preferred least cost strategy for achieving the current NO_x target is comprised of a combination of Relaxed Phase II retrofit controls, Southern Seasonal operational controls, Double level Demand Side Management and Combined Cycle Gas-fired new generation. This strategy was also shown to be effective in reducing NO_x emissions over a range of electric system parameters including future natural gas cost uncertainty, DSM level and new resource options. Note that this strategy performed the best for the set of options examined in this thesis. There are several factors, such as the larger urban air-shed area (i.e. all of the Northeast) and load growth uncertainty, that were not considered in this strategy evaluation and could significantly impact these results.

Now that a technically and economically preferable scenario has been identified within the context of this study, the best means to implement it or a similar strategy should be considered. Implementation may become especially challenging since the most attractive scenario is a combination of reduction strategies.

A. VIABILITY OF NO_x "CAP AND TRADE" POLICIES

Prior to 1990, clean air legislation typically required specific standards or technologies for controlling the rate of pollutant emissions. Regulatory agencies were absorbed in monitoring and enforcing these detailed prescriptions which were generally applied uniformly and without regard to cost. This approach has been coined "Command and Control" regulation. While the rate of emissions was regulated, the total amount of emissions was not. This resulted in a continued increase in the total amount of emissions as new generating plants were installed. The CAAA of 1990 started an experiment with an emissions trading program for acid rain pre-cursors (mainly SO_2). This regulatory approach has been coined "Cap and Trade".

The OTC MOU that details the specific NO_x reduction requirements stated that a "trading program should be included as a necessary component of this [reduction] strategy" for the Ozone Transport Region. This trading program could function in a manner similar to the SO_2 system that was established as part of the acid rain portion of the CAAA of 1990. This program is intended to promote intra-regional trading as part of a state's implementation plan. The specific implementation mechanism for a NO_x trading system is under consideration by the OTC. There are many factors that make trading in NO_x emissions difficult but there are also many marked advantages to this system. These pros and cons will be discussed below.[2]

Emissions Trading

The "retrofit control only" strategies and the combination strategies discussed in chapters 3 and 4 roughly correspond to "command and control" and "cap and

[2]See Tietenberg, 1995 for a more detailed discussion of cap and trade policies.

trade" policies. The idea behind the retrofit strategy is to place technological controls on units with high NO_x emission rates across most generation. This is similar to mandating a specific control level in that it roughly equalizes NO_x emission rates. This strategy does allow over controls and under control on selected units to take advantage of cost-effective opportunities. The combination of retrofits and operational controls resembles a cap and trade policy in that the system dispatches to meet a specific cap through a least cost combination of control strategies. The changes in dispatch resemble the emission trades that would come about between utilities and generating units allowing some plants to have higher NO_x emission compensated by plants with lower emissions.

The principle behind an emission trading system is a fundamental and fairly straightforward economic idea. The cap and trade system introduces flexibility which at best leads to an equalization of marginal compliance costs across utilities and generating units and at least allows the ability to implement lower cost control methods. Units with lower marginal costs of compliance will control more and sell allowances, and units with high compliance costs will buy these allowances and control less. This emissions market functions according to the same rules of supply and demand that govern any other good. As stated above, this is fundamentally the same as the operational controls modeled here which dispatches according to a specified NO_x cap in order to achieve the lowest system cost.

Geographic Concerns

The Ozone Transport Region includes parts of 12 states plus Washington D.C. This poses two problems for implementing an effective NO_x trading policy. First, the extent of ozone pollution varies greatly within the OTR, ranging from states and counties in attainment to those in severe non-attainment. The ozone problem is generally worst along the highly industrialized coastline. A cap and trade system that results in heavy concentration of NO_x emission allowances, and therefore emissions, in the coastal areas will not be effective in reducing ozone levels. Second, although the chemistry of ozone formation is not perfectly understood, long-range NO_x transport is a significant concern (OTC, 1994). These two factors make NO_x trading problematic. A heavy concentration of allowances in upwind areas could cause serious non-attainment problems for downwind states.

A similar geographic problem also exists for SO_2 trading. SO_2 emissions from generating plants in the Midwest have much higher environmental consequences than the emissions from plants on the eastern seaboard that are blown out over the ocean. Although the transfer of SO_2 allowances from Eastern to Midwestern generators could potentially lead to the concentration of a high number of allowances in the Midwest, this has not historically been a problem. This can be explained at least in part by the fact that the units with the highest emissions are also the ones with the lowest marginal cost of reduction. For SO_2, these units are located in the Midwest, not the Northeast. Consequently, Midwestern generators select the least cost option of reducing emissions rather than purchasing allowances from Eastern generators. Unfortunately, there is nothing to suggest NO_x allowances in the OTR will naturally flow from downwind to upwind states.[3]

There are several possible actions that can be taken to help mitigate this geographic imbalance. It is possible to reduce the value of the NO_x allowance depending on the distance it is being traded. However, this presents the problem of discouraging trades in any direction, even though trading emissions towards attainment regions such as northern Maine should be encouraged. Trading could also be limited to within regions of similar non-attainment level or limited in direction (i.e. disallow trading emission allowances from a region in attainment to a non-attainment region). The analysis presented in this thesis suggests that setting a NO_x cap only in southern NE, where the relative non-attainment problem is largest, is an effective means of reducing Southern Seasonal NO_x without significantly increasing the cost impact. This is similar to a uni-directional trading scheme.

Geographic policies may invite political conflict because they distribute costs and benefits explicitly to specific areas. However, for the case of NO_x and the subsequent ozone formation, the areas which would bare the higher cost of ozone compliance are also the areas which will receive the greatest benefits. Regions which are currently in attainment would experience higher emissions,

[3]Detailed economic analysis of OTR utilities could identify the probable geographic trend in NO_x emissions trading assuming rational economic decision-making from electric utility owners.

but would also receive monetary compensation through higher electricity demand and correspondingly higher revenues.

Ozone Season Concerns

The temporal nature of the ozone formation also poses a problem for the implementation of a trading policy. If units are limited only to tons per season, trading may concentrate emissions on ozone problem days. This temporal concern is especially problematic since ozone episodes fall on hot summer days when the demand for electricity is highest and ozone problems are most likely to occur.

There are several ways in which a Cap and Trade policy can be structured to address the potential temporal problem. First, the maximum daily emissions from each unit, or utility, could be limited as a function of the average emissions. For instance, the cap could be established such that no individual day could exceed the seasonal daily average by more than a specified percentage. It makes more sense for this restriction to be placed on each utility as a whole rather than on individual units to allow the utilities' the flexibility to determine the most cost effective way to comply with the cap.

Albert Nichols, from the National Economic Research Associates, argues that trading will:

> allow utilities to reduce controls on peaking units (relative to what they would be with standards), thus increasing emissions on days with high generation levels, which also tend to be days with ozone problems. Although trading would require that higher-utilization units control more to balance total emissions over the ozone season, the equivalence would be on a seasonal basis, which *could* lead to net increases on days with potential ozone problems. Trading tends to reduce controls at low-utilization units and increase them at high-utilization units, because NO_X controls tend to be capital intensive, which makes the cost per ton sensitive to utilization.
>
> Nichols, 1996

The analysis presented here suggests that the dynamic described above is not very strong. The operating costs of NO_X retrofits dominate the capital costs (refer to Figure 3-7). In this analysis, units were chosen for retrofit based on having high utilization rates. This partially explains why operating costs are so high for retrofit controls. This analysis suggests two significant things. First, results presented here suggest that no strong incentive exists only to retrofit highly utilized units due to the high operating costs of retrofits. Second, even if units with high utilization rates are the only ones retrofit, the system is still capable of achieving the NO_x reduction target. This implies that installing retrofit controls and only operating them during ozone episodes could be a very cost effective means for complying with the OTC MOU reduction target.

The above discussion raises another important concern. If NE is only out of compliance for ozone 20-30 days a year, is a cap for the entire 5 month ozone season really necessary? As stated above, the cost of retrofit controls is predominantly operating and maintenance. The cost of operational controls is entirely O&M. This suggests that there is a significant amount of flexibility in terms of when the NO_x strategy is implemented. So if it were possible to accurately predict when the conditions are conducive to ozone formation, it would not be difficult, or costly, to implement this same strategy for those 20-30 days. However, it is difficult to accurately predict ozone episodes.

NO_x Emissions Banking

A discussion of trading raises the question of whether or not to allow the banking of allowances. Banking has several significant advantages. It provides an incentive to reduce emissions early in order to bank allowances for future years. It also provides greater flexibility in meeting demand variations. And lastly, banking can help avoid the end of season spike likely to occur when allowances are leftover in September. Currently, the SO_2 trading policy allows the banking of SO_2 allowances for use in future years. However, the acid rain problem associated with SO_2 emissions is not a fundamentally time dependent problem.

The major problem that banking presents in NO_x control regulation is the possibility of concentrated cashing in of allowances on ozone episode days. This would subsequently lead to high emissions and a potential ozone exceedances. There are several factors that could help mitigate this possibility. First, banking does have a cost due to the transactions costs and lack of interest on the deposit. This encourages utilities to use their yearly allocation of allowances. An appropriate policy structure could also help mitigate this impact. For instance, restrictions on the amount that can be withdrawn in any given year, or a reduction in the allowance value over time could be established. It should also be understood that the traditional command and control emission standard approach allows substantial variation in daily and aggregate emissions because of day-to-day and year-to-year changes in electricity demand and the mix of units available. Trading with a cap will reduce this variability even if banking is allowed.

Fine Tuning Cap and Trade Systems

It is possible that the current NO_x reduction targets specified in the OTC MOU will not bring New England into compliance with the CAAA standard for ozone. This may result in further emission reduction requirements in the future. This analysis has shown that, with current technology, NO_x emissions in NE can be reduced well below the current MOU target. The preferred strategy recommended here leaves a large degree of flexibility through the use of a combination of control approaches. More retrofit controls can be installed in the future should the NO_x target decrease and operational controls could still be pursued if they were cost effective at that emissions level.

The science behind ozone formation is not well understood. Future research into this process may lead to changes in the regulatory strategy. The Relaxed Phase II retrofit control with Southern Seasonal controls option discussed here is a flexible means to comply with current legislation while leaving room for different control measures in the future.

It is also possible, in the context of a cap and trade system, to reduce NO_x emissions across industrial sectors. If it is cheaper for an electric utility to pay another point source, such as a manufacturing plant, to reduce their NO_x emissions, the trading system provides a mechanisms whereby this can be achieved. Therefore, the marginal cost of reduction would be equated not only within the electric sector, but across all manufacturing. This could even extend to non-point source such as mobile and area sources. Such a plan might increase the policy monitoring costs, but could also have a significant impact on the mobile NO_x emissions which are comparable to stationary source emissions.

In general, market based policy instruments, such as the cap and trade system discussed here, are politically popular at this time. This system is equitable because it does not target specific generation technologies, plant sizes or fuel types. Cap and trade policies also work well in combination with the current NO_x offset policy. Presently, in order to build a new generating plant, the amount of NO_x emissions that the new plant will introduce needs to be reduced from another source in the region. This is consistent with the way an emission market would function where a new source would buy allowances for its share of emissions.

B. BROADER ECONOMIC AND ENVIRONMENTAL CONSIDERATIONS

Competition and Electric Industry Restructuring

Any policy for bringing New England into attainment for ozone should be designed to work in conjunction with the current restructuring of the electric power sector mentioned in Chapter 1. This restructuring makes it difficult (if not impossible) for utilities to directly pass through environmental compliance costs to rate-payers. Therefore, making a policy that is in line with the competitive economic environment becomes very important. In this new competitive industry, a cost effective policy, such as the cap and trade system discussed above has many advantages.

This competitive environment increases the importance of cost. Capital investments will no longer be automatically recovered through a rate structure approved by the state utility commission and imposed on a service territory. This concern over minimizing costs extends into the realm of environmental compliance. Utilities are very concerned about meeting ozone attainment at the lowest cost to the system. While capital costs which need to be recovered over an extended period of time are particularly unattractive at this time, this analysis suggests that this is not really a large part of the compliance cost.

Mandated retrofit controls, which do not impose equal costs on all the utilities in the region, are problematic in this environment. The cap and trade system leaves it up to the utilities to find a low cost means of compliance. All of the utilities and NUGs are subject to the same compliance requirements but have the flexibility to respond to the regulation in a way consistent with their capital stock and other resources.

Emission trading also provides an incentive for emitters to devise cheaper new methods and technologies for reducing emissions because reductions so obtained yield credits that can be sold. This incentive for innovation is not present in the traditional command and control approaches which mandate a particular means for achieving compliance.

Broader Environmental Concerns

After NO_x, probably the next most important air pollution concerns for electric utilities in New England are ultra-fine particulates, air toxics and CO_2. Chapter 4 revealed that NO_x reduction strategies tend to increase system CO_2 emissions through shifting generation to older dirtier plants in Northern New England. However, several options examined later in Chapter 4 showed that this increase in CO_2 emissions can be offset through the implementation of higher levels of DSM or the installation of non-fossil generating plants such as the wind turbines modeled in this analysis.

There has been an SO_2 trading program since the passage of the 1990 CAAA. Although trading has not been as active as originally predicted, the program has been effective in reducing SO_2 emissions and compliance costs. Therefore reducing SO_2 is not presently as great a concern as reducing NO_x and CO_2 emissions in New England.

C. CONCLUSIONS

Several important conclusions can be drawn from the analysis presented here. Some of these conclusions include the following:

1. It is possible to meet the NO_x reduction targets specified in the OTC MOU. Both retrofit controls alone and a combination of retrofit and operational controls can achieve the desired emissions level.

2. The least cost NO_x strategy consists of a combination of Relaxed Phase II retrofit and Southern Seasonal operational controls. This option consistently costs $125/year million less than retrofit only options for the entire modeling period. This amounts to a $700 million cost difference in base year dollars.

3. The least cost NO_x strategy tends to increase CO_2 and decrease SO_2 emissions slightly compared to the RACT Only strategy. CO_2 emissions are increased by about 2 percent and SO_2 emissions are decreased by 4 percent.

4. Demand Side management programs significantly decrease CO_2 emissions without substantially increasing NO_x emissions. The Double DSM program decreases CO_2 emissions by 6 percent below RACT Only while still allowing the least cost NO_x strategy to achieve the specified NO_x reduction target. Double DSM decreases electric industry costs by $1.4 billion while increasing total regional direct costs by $700 million.

5. Although renewable wind resources do reduce NO_x emissions they perform better at reducing CO_2 emissions. Wind plants had no impact on Southern Seasonal NO_x emissions due to the timing of the wind. However, wind reduced CO_2 emissions by 1 percent and only increased costs by a total of $700 million in future year dollars.

6. The combination NO_x strategy can be implemented through a cap and trade system. Although this system has several potential problems, there are also solutions within the regulatory structure that can address these concerns. A cap and trade is an economically attractive policy instrument which would be consistent with the current competitive utility environment.

Although the OTC MOU calls for a very substantial reduction in NO_x emissions, this thesis suggests that the targets are attainable through several different strategies. Of the strategies examined here, a combination of Relaxed Phase II retrofit controls and Southern Seasonal operational controls performs the best. This strategy consistently costs the least and perform well across various demand and supply side options. It also performs well across natural gas cost uncertainty. There is a slight increase in CO_2 emissions resulting from the NO_x strategy as well as a much larger increase due to other system-wide factors. Therefore, a higher levels of DSM or a new generation resource option including a mix of renewables seems very attractive.

The combination NO_x strategy also works well in conjunction with an emissions trading system. There are some concerns in implementing this system. However, this analysis suggest that these concerns can be addressed through well formulated regulations such as placing tighter restriction on the Southern New England region. In conclusion, the least cost strategy for meeting the OTC MOU NO_x reduction targets appears to be the Relaxed Phase II retrofit controls with Southern Seasonal operational controls. This option can be effectively implemented through a cap and trade system taking into account the specific temporal and geographic concerns surrounding ozone formation.

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APPENDIX A - LIST OF ACRONYMS

AG	Advisory Group
AGREA	Analysis Group for Regional Electricity Alternatives
AttPro	Attribute Processor
BACT	Best Available Control Technology
CAAA	Clean Air Act Amendments (of 1990)
CC	Combined Cycle
CELT	Capacity, Energy, Loads, and Transmission
CLF	Conservation Law Foundation
CT	Combustion Turbine
DSM	Demand Side Management
EGEAS	Electric Generation Expansion Analysis System
EPACT'92	Energy Policy Act of 1992
EV	Electric Vehicle
FIP	Federal Implementation Plan
GTF	Generation Task Force
IA	Inflation Adjusted
MATA	Multi Attribute Trade-off Analysis
MOU	Memorandum of Understanding
MW	Mega Watt
NAAQS	National Ambient Air Quality Standards
NE	New England
NEES	New England Electric System
NEPLAN	New England Planning
NEPOOL	New England Power Pool
NIMBY	Not in my back yard
NOx	Nitrous Oxides (mainly NO and NO2)
NUG	Non-Utility Generator
NUMB	Not Using My Bank
O&M	Operating and Maintenance
OP4	Operating Procedure 4
OTC	Ozone Transport Commission
OTR	Ozone Transport Region
RA	Risk Adjusted
RACT	Reasonably Available Control Technology
ppb	parts per billion
ppm	parts per million
SC	Simple Cycle
SCR	Selective Catalytic Reactor
SF	Standard Financial
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reactors
SSI	Steam Injection Unit
VOC	Volatile Organic Compound

APPENDIX B - DSM ALLOCATION AND COSTS

The second DSM scenario parameter is the allocation of GWh savings between utility sponsored DSM and standards. As mentioned above, the approach taken was to develop projections of the percentage of total conservation savings that could be attributed to standards, and then to assume that utility-sponsored DSM achieved the remainder. The allocation between utilities and standards was based on information from two sources: the NEPLAN DSM forecast and a paper by Steven Nadel published by the American Council for an Energy Efficient Economy[4]. Both sources divide customers into two classes: residential/ miscellaneous and commercial/industrial.

Two scenarios for the percentage of savings by customer class ("Utility" and "Utility/Standards") are modeled. These estimated savings are based on the Energy Information Administration's forecast of new end-use standards on lighting, appliances, motors, and office and HVAC equipment. These percentages were multiplied by the "No DSM" load forecast to determine the annual GWh savings by customer class in New England under each of the three DSM projections.

The savings projections were then applied to each of the three AGREA conservation options. For each of the two customer classes, savings due to standards were divided by conservation savings under each of the three conservation scenarios to determine the percentage of savings due to standards. The greater the total projected savings under the different forecasts (Reference, Double, Triple), the smaller the share of savings attributable to standards. The following graphs present the percentage of total savings attained through standards under the two savings scenarios for each of the three conservation forecasts.

The allocation of DSM savings between utilities and standards and among customer classes is used to determine the total cost to utilities of conservation

[4] Nadel, Steven, "Incorporating New Efficiency Standards and Codes in Utility Forecasts," American Council for an Energy Efficient Economy (June 1994).

programs. No attempt was made to estimate the incremental cost to customers of standards, so these costs are not included in this analysis. The overall cost (revenue requirements) of the DSM level is determined by multiplying the levelized direct cost of conservation (cents per kilowatt-hour) by the total number of kWh saved (by customer class). This total cost is then allocated to installation years based upon the distribution of the conservation impacts, and then "collected" via "rates" and direct participant contributions. The GWh allocation for the three standards options, as well as the No DSM and Reference DSM, are shown in Figure B-1.

These contributions are based upon assumptions of percentage participant contribution and utility amortization/expensing accounting assumptions. The "cost" of meeting stricter standards based on the Energy Policy Act of 1992 (EPACT'92) standards are not included in any of the cost calculations. Levelized cost assumptions used in the analysis are 2.5¢/kWh for Commercial/Industrial savings, 5¢/kWh for Residential/ Miscellaneous savings, and $40/kW-yr. for peak management programs. Since conservation initiatives in the future are likely to focus predominantly on "lost opportunity" conservation, diminishing return multipliers were not added to these levelized cost factors in the higher conservation level options.

Figure B-1: DSM GWh Allocation