5. ENVIRONMENTAL IMPACTS OF PROPOSED ACTION

5.1. Overview of Environmental Impact Approach

To the extent possible and as appropriate to a generic environmental impact statement, a consistent theoretical approach was taken in analyzing environmental impacts. A differential approach was utilized, in some respects similar to a sensitivity analysis, to determine the likely differences in impacts that would result among a number of alternative generation scenarios assuming a more competitive utility industry.

The first step was to define the principal differences in the major competitive models as they affect the basic structure and functioning of the electric industry. These model differences and similarities are described in Section 4.1.

The second step (see Section 4) was to determine how a competitive electric industry may affect the environment. For purposes of analysis, the root cause changes identified in the Commission's Environmental Assessment Form were used to define the scope of issues to be addressed in the DGEIS. These issues included:

- Level of Electric Generation
- Plant Retirements and New Plant Construction
- Changes in Plant Dispatch
- Changes in Transmission Facilities
- Changes in DSM Programs
- Changes in Research and Development
- Environmental Liabilities
- Change in Treatment of Externalities
- Changes in Investment in Renewables
- Changes in Fuel Use
- Changes in Development of New Technology

In conducting the environmental impact analysis, the following environmental issues and resources were considered:

- Land resources (including non-renewable resources)
- Solid waste
- Water resources
- Air resources
- Noise
- Natural resources (including flora and fauna)
- Agricultural resources
- Aesthetics
- Socio-economics (including jobs and population shifts)
- Public health

5.2. Analysis of Potential Environmental Impacts

5.2.1. Level of electric generation

It is not feasible to predict whether in-state generation will be competitive with out-of-state generation in a restructured electric industry. Therefore, predicting changes to the overall level of in-state generation is uncertain. The analysis described in Section 4 and its results displayed in Appendix B provide some detail on changes in electric generation resulting from changes in sales levels and imports. It is possible, however, that there may be no significant increase in imports, and that in-state generating levels may not change significantly. Some parties may argue that the increased imports would largely be occurring now if they were economical, and with increased competition, in-state generation may be relatively more competitive. Also, the state's transmission system cannot support a major increase in imports without substantial reinforcement.

5.2.2. Impacts of Plant Retirements

Under certain operating scenarios, there will be competitive pressures to increase the operation or extend the operating lives of currently underutilized fossil fuel facilities, rather than consider plant retirements. In particular, an operating scenario involving high sales growth and/or the early retirement of any of the state's nuclear plants is expected to increase the utilization of fossil generation within the state. Alternate Scenario 5, reflecting a combination of high sales and nuclear retirements, would significantly increase generation from fossil plants compared to the Evolving Regulatory scenario.[1]

The operating scenarios that are most likely to result in increased plant retirements would be either the low sales growth (Alternate Scenario 2) or maximum import (Alternate Scenarios 7, 7A and 7B) situations. However, plant retirements may still be minimized somewhat due to the technical limitations on the amount of power that can be imported from other regions and the need to continue the operation of certain plants in load pocket areas.

As noted, the early retirement of any of the state's nuclear facilities would have a significant negative impact on air emissions in the state. The earliest planned nuclear

[1] See Section 5.2.12 for further discussion of possible fuel use changes.

retirements in New York are currently scheduled for 2009.[2] In terms of air quality, potentially significant environmental impacts could result from a premature retirement of any of the state's nuclear facilities. Offsetting these negative air quality impacts, retirement of nuclear units would have a positive impact in terms of reduced production of spent fuel and low level radioactive waste which pose health and environmental risks. Nuclear plant retirements would also reduce water withdrawals for cooling which would be beneficial in terms of lessened impacts on aquatic resources.

Local impacts from possible plant retirements would be of both an environmental and socio-economic nature. With respect to environmental impacts, retirement of fossil units would result in local environmental benefits (e.g., air, water, solid waste, noise), as well as secondary benefits such as reduced vehicular traffic within a community. The socio-economic impacts of a plant retirement could be significant for a local community or region. Should major generation plants be retired, there will be an impact on employment. Many of the former employees of the facilities or the companies operating the facilities could be dislocated. However, assuming that competition will lead to lower energy service costs and overall greater economic efficiency, the economy of the state could reasonably be expected to improve in the long run, creating employment opportunities in

[2] Nine Mile Point 1 and Ginna.

new or allied industries that evolve with electric competition.

The retirement of uneconomic generating facilities could also result in changes to the tax base of a particular community. Reduction in the tax base due to the retirement of a plant would have a short term adverse economic impact on the affected local community. Nevertheless, with possible growth in the energy services company (ESCO) market and increased economic development, there might eventually be some offsetting increases in local community tax revenues. Obviously the level of tax contribution to a local community and the level of plant employment relative to the size and tax base of the community would be major factors in determining actual impacts. Closing a plant that operates with low staffing and has received property tax relief through IDA funding will have less impact on a community than closing a high employment, fully assessed and taxed unit. The socio-economic impacts of plant retirements and electric competition generally are discussed further in Section 9, Growth Inducing Aspects and Socio-Economic Impacts.

5.2.3. Impacts of New Plant Construction

Over time, there will be increasing pressures and incentives to build new generation capacity due to an increase in sales, the retirement of existing generation, and continued constraints on the amount of power that can be imported into the state. New generation may also be needed to resolve certain load pocket situations.

The input data and modeling assumptions used in preparation of the FGEIS were carefully reviewed and cross-checked with respect to the environmental analysis. In order to estimate the environmental impact of a transition to a more competitive electric industry, it was necessary to model data that, when analyzed, show a date in the future when reserve margins fall below a 23.5% minimum. However, the need for new capacity will be determined by market forces, not by centralized planning and PROMOD modeling.

The FGEIS seeks to assess the general range of possible and likely impacts and ways to mitigate them. The precise timing of the need date is not knowable and is not pivotal to the environmental impact analysis presented in the FGEIS. Moreover, the analysis does not attempt to determine which resources might be appropriate for meeting capacity needs.

Over the time horizon used in the preparation of this FGEIS (1997-2012), 6,400 MW of capacity are expected to be added in the Evolving Regulatory scenario. The amount of new capacity required under the various scenarios fluctuates dramatically with changing assumptions regarding the load and capacity supply.

It should be recognized that the load and resource balance is very sensitive to changes in certain key assumptions, including sales and DSM forecasts, plant retirements, and changes to the reserve margin. For example, the aggregate impact of updating sales to reflect 1995 actuals, increasing assumptions regarding free market DSM, reconsidering certain coal plant

retirements, and lowering the reserve margin from 23.5% to 22% would provide several additional years of adequate capacity reserves. Moreover, if the Commission decides to pursue restructuring for competition in the electric industry, the market, not comprehensive planning studies, will largely determine how capacity needs will be met. Depending on the assumptions used, the year in which New York experiences reserve deficiencies varies between 1997 and 2010. It should be noted that the need for capacity is based upon growth in peak load during the study period. The Evolving Regulatory scenario assumes continuing peak load growth of approximately 1.1 percent per year, which may or may not continue. Growth in peak load can be accommodated by a variety of capacity options, including peaking units such as gas-fired turbines, firm purchases of capacity from out-of-state, and targeted DSM.

For the Scenario 2 (low sales), the new capacity added over the study period is only 300 MW and that capacity is not needed until 2010. On the other hand, in Scenario 5 (high sales and nuclear retirements), the capacity addition over the study period is 15,400 MW and the need for capacity is much sooner. Table 5-0 indicates the date at which load and resources are at a reserve margin of 23.5%.

TABLE 5-0
Date at Which Load and Resources are at the Reserve Margin of 23.5%

SCENARIO	DESCRIPTION	DATE
	Evolving Regulatory Model	2000
HIGHER SALES		
Alternative 1	High Sales	2000
Alternative 1A	No Incremental Utility DSM	2000
LOWER SALES		
Alternative 2	Low Sales	2010
Alternative 2A	High DSM	2005
MODIFIED DISPATCH CONDITIONS		
Alternative 3	IPPs on Economic Dispatch	2000
Alternative 3A	All Coal Units Designated "Must Run"	2000
Alternative 3B	SO_2 Allowances Valued at $1090/ton	2000
Alternative 3C	NO_x Allowances Valued at $1000/ton	2000
Alternative 3D	NO_x Allowances Valued at 2000/ton	2000
ACCELERATED RETIREMENTS		
Alternative 4	Retire Two Nuclear Plants	1997
Alternative 4A	Improved Power Supply Efficiency	1997
Alternative 5	Combination High Sales & Nuclear Retirement	1997
INCREASED SUPPLY		
Alternative 6	IPP Capacity Maximized	2002
CHANGED IMPORTS		
Alternative 7	Import Max: Current Trans. System	2000
Alternative 7A	Import Max: Expand Trans. System	2000
Alternative 7B	Firm Imports	2005
Alternative 7C	Export Excess Power	2000

5.2.3.1. Air Quality

In a restructured industry, competitive pressures are likely to influence generating companies to shorten the planning horizon, and minimize investor risk, in evaluating and selecting new resources. Accordingly, generating companies are likely to embrace resource options that are not capital intensive and minimize reliance on long term financing. Due to advances in technology, it is expected that new units will have significantly lower emission rates of all air pollutants as compared to most older facilities.

Lower emissions result from changes in controlling air regulations, the application of improved technologies, and higher efficiencies. Any new generating unit must also comply with new source review requirements, which require that plants meet the lowest achievable emission rate (LAER). Of particular importance, all new units will need to offset SO_2 and NO_x emissions by purchasing emission allowances under various cap and trade programs.[1] Additionally, new units that are major sources of NO_x are required to offset new permitted emissions at a ratio of 1.15 tons to 1.00 tons in upstate New York and 1.30 tons to 1.00 tons in downstate New York. Emission offsets can be obtained from all categories of permitted air sources by shutdown or installation of emission controls. Thus, new units coming on line may result in net emission reductions due to the capping and offset requirements within New York State.

While new units are expected to be cleaner than most older existing plants, the situation will need to be monitored to determine whether the possible emphasis on short term efficiencies due to competitive pressures ignores fuel diversity or disadvantages potentially long term economic investments in emerging cleaner technologies and resources because of their higher initial cost.

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[1] Sulfur dioxide emission allowances are traded nationally. Nitrogen oxide emission allowances are the subject of an ongoing DEC rulemaking that will serve to implement the OTC-MOU.

5.2.3.2. Audible Noise

In recent years, noise associated with power plants has become more of a problem in New York State. The recent surge of interest in cogeneration has resulted in the construction of a large number of facilities not subject to Article VIII or X. In an effort to avoid potential noise problems, the PSC, in cooperation with DEC, defined "excessive" noise for cogeneration contracts subject to PSC review and approval. However, with the adoption of the "bidding" process, the Commission no longer reviews noise levels. For a few of the cogeneration contracts that were not subject to PSC review, DEC hired a noise consultant to review the applications. But, because of limited staff resources, and because of the limited experience of cogeneration owners with power plant noise control, a number of communities have been subjected to excessive power plant noise.

If additional small (non-Article X) power plants are built in New York State, an increase in power plant related noise problems can be expected unless industrial noise is regulated affirmatively in the SEQRA process specific to those projects.

5.2.4. Impacts of Changes in Plant Dispatch

As discussed in Section 4, changes in the structure of the electric power industry may result in changes in prices and the amounts of electricity used by consumers relative to what might have occurred in the absence of any restructuring. In addition, changes in market structure may influence unit

retirements, life extensions and dispatch of the system. Cumulatively, this suggests that the amount and location of emissions associated with fossil fueled generation are likely to change as a result of industry restructuring. Section 4 further described the annual and cumulative changes in SO_2, NO_x and CO_2 emission levels relative to a Evolving Regulatory scenario (or no Commission action alternative). The emission changes can then be compared with environmental requirements contained in state and federal air pollution control statutes, rules and programs to provide a perspective on the environmental impact of restructuring New York's electric industry. The environmental mandates considered here are extracted from the federal Clean Air Act, the Energy Policy Act of 1992, and the President's Climate Change Action Program (CCAP) concerning global warming. These requirements are also derived from state environmental laws, including the New York State Acid Deposition Control Act (SADCA) and the New York Clean Air Compliance Act (NYCACA).

Section 6.1.1 sets forth the regulatory framework of state and federal air pollution control laws and rules. Section 3.4 and Appendix A provide further background information concerning acid deposition, ozone attainment, and global warming policy. The relationship of changes in plant dispatch to the regulation of ground-level ozone, acid rain and global warming precursor pollutants emitted by electric generators are analyzed in Sections 5.2.4.1 through 5.2.4.4 below. Section 5.2.4.5 discusses the relationship of the changes in plant dispatch to

regulations controlling the emissions of particulate matter and toxic air pollutants. Finally, Section 5.2.4.6 describes how changes in plant dispatch relate to air deposition of nitrates and other pollutants in New York State water bodies and efforts to address these issues in coastal management and other programs.

5.2.4.1. Regulation of Nitrogen Oxide Emissions (NO_x)

Nitrogen Oxides: Electric utilities are a major source of nitrogen oxide (NO_x) emissions in New York State and in the United States. NO_x emissions include nitrogen dioxide a major pollutant regulated by the National Ambient Air Quality Standards. NO_x emissions also contribute to the formation of two other major pollutants, ground-level ozone and acidic compounds and may contribute to the eutrophication of marine waters (see Section 5.2.4.6). All of these are known to adversely impact human health and environmental resources. Ozone is formed through complex photochemical reactions between the NO_x and volatile organic compounds (VOCs) in the presence of sunlight and warm weather. VOCs are primarily emitted by mobile sources (on-road and off-road), manufacturing processes and consumer products. Fossil fueled electric generating stations emit only small amounts of VOCs due to the high combustion efficiencies characteristic of large boilers and the low volatility of typical fuels. Because of the need for sunlight and warm weather to "manufacture" ozone from NO_x and VOCs, ozone is considered

primarily a warm weather problem (the regulatory "ozone season" is from May through September each year). NO_x emissions are also converted into nitrates which contribute to acidic deposition through long distance transport of the emissions by prevailing winds.

Both the ambient ozone and acidic deposition in New York State are affected by the long distance transport of NO_x emissions from air pollution sources inside and outside of (and upwind of) New York borders. The prevailing winds transport and disperse these distant emissions into New York while the atmospheric conditions and chemistry convert the NO_x emissions into nitrates and ozone pollutants. It is currently estimated that about 83% of New York's acid rain problem[1] and a substantial portion of its ozone problem[2] are attributable to out-of-state sources.

The following paragraphs review the current state of regulation of nitrogen oxides and examine the methods and purposes behind NO_x control. Attainment of the ground-level ozone standard is one of the major environmental concerns related to the restructuring of the electric industry in this state.

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[1] NYS-DEC Division of Air Resources, State Acid Deposition Control Act of 1984: Report to the Governor and Legislature, March 1991.

[2] Letter from Attorney General Vacco and DEC Commissioner Michael Zagata to EPA Administrator Carol Browner; March 28, 1996.

NO_x Regulation: NO_x is regulated for three reasons: to attain and maintain compliance with the health-based National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO_2); to achieve compliance with the health-based NAAQS for ozone (O_3); and to control deposition of nitrogen based acidic compounds (acid rain) in acid sensitive regions. The NO_2 standard is 0.05 PPM (average over 12 consecutive months). The O_3 standard is 0.12 PPM (one hour average). No NAAQS standard for acid deposition exists, although the possibility is under consideration by the U.S. EPA.

The structure of regulations applicable to NO_x is based upon a knowledge of the chemical and physical processes. Although the various NO_x regulations seek distinct objectives, regulations for one objective often contribute, at least in part, to the goals of other NO_x objectives. For example, if protection of the environment for ozone is achieved (in part, through NO_x emission reductions), then there would also be benefits for NO_2 ambient air quality and a reduction of acid deposition.

The NAAQS for NO_2 was established in the 1970s. The ambient concentration of NO_2 has a direct relationship to NO_2 stack tip emission rates over distances of about 50 kilometers or less. Given this direct relation, the NO_2 NAAQS can be attained and maintained by individual states by placing emission controls upon individual sources under their jurisdiction. This approach has been successfully implemented by the states over the last two decades to meet the 12-month average limit of 0.05 PPM.

Acid deposition and ozone air pollution are more complicated. Although they are related to the emission of NO_x and several meteorological variables, the distances involved between sources of NO_x emissions and the locations of maximum acid deposition and ozone concentrations can be separated by hundreds of miles. These distances often exceed the limits of state boundaries. Thus, individual states lack the ability to independently protect the public health and welfare of their citizens. States must therefore rely in part on national or regional solutions to these environmental problems.

Regional cooperation, however, is complicated by the high cost of reducing NO_x emissions; although the cost is borne by a source in one state, the benefit may be enjoyed by the residents of another state.

In Titles I and IV of the Clean Air Act Amendments of 1990 (CAAA), Congress has taken steps to create equitable solutions to our nation's environmental problems as described below. The solutions are not direct because they involve several administrative processes (and potentially litigation) that all contribute to the ultimate goals.

Titles I and IV: Title IV of the CAAA seeks to mitigate acid deposition. Although much of Title IV is directed toward SO_2 control this discussion will only consider the NO_x provisions. For NO_x, Congress determined that most utilities in the nation should, at a minimum, retrofit boilers with low NO_x burners. Congress set minimum criteria and delegated finalization of the

regulations to the EPA and individual states. Implementation of Title IV is believed to result in NO_x emission reductions nationwide of about 2.36 million tons per year.

Congress crafted Title I of the CAAA to specifically address ozone nonattainment. In Title I of the CAAA, Congress set goals for ozone attainment and created a quasi-governmental body (the Ozone Transport Commission) to foster inter-state cooperation in implementing programs that will achieve the NAAQS for ozone by 2007 in east coast regions deemed to have a severe ozone problem. Congress required that, until the ozone standard is attained, each state should reduce its 1990 NO_x and VOC emission inventory by an average of 3 percent per year and permit new sources of NO_x only if emissions are offset by more than a one-for-one ratio.

The Ozone Transport Commission (OTC) consists of the 12 eastern states from Virginia to Maine plus the District of Columbia. The EPA is also a member of the OTC; it provides some funding and technical support. The geographic region represented by the OTC is referred to as the Ozone Transport Region (OTR). Within the OTR, states work cooperatively to control the long range transport of ozone and the emission of ozone precursor chemicals---NO_x and volatile organic compounds.

<u>OTC-MOU:</u> Through the OTC, New York State and other participants have developed a joint Memorandum of Understanding (MOU) directed toward the attainment of the ozone standard. The strategy embodied in the MOU is to define emission limits based

upon a model air pollution control regulation that is deemed equitable by OTC members. States are then given the flexibility of promulgating the model regulation or any other regulation that achieves equivalent limits on NO_x emissions. In the following discussion, the MOU model regulations are summarized and then the resulting New York State emission caps are given. The NYSDEC is expected to develop a regulation in 1996 that limits Statewide NO_x emissions according to caps determined pursuant to the MOU.

The OTC MOU divided the OTR into three regions based upon the severity of ozone non-attainment. Those regions are named the "Inner Zone" (the densely populated coastal area from Washington, DC to Boston), the "Outer Zone" and the "Northern Zone." Depending on the zone, different standards apply at different times. Downstate New York is designated as being in the Inner Zone. Within the Inner Zone, beginning on May 1, 1999, actual NO_x emissions from large boilers would be limited to the greater of 35% of actual 1990 baseline emissions or 0.2 pounds NO_x per million BTU heat input. The Adirondack Park and portions of the state north of the Park are designated as being in the Northern Zone. Within the Northern Zone, limitations do not begin until May 1, 2003 when large boilers would be limited to the greater of 45% of their 1990 actual emissions or 0.20 pounds NO_x per million BTU heat input. The remainder of the state is part of the Outer Zone. Beginning on May 1, 1999, large boilers in the Outer Zone would be limited to the greater of 45% of actual 1990 emissions or 0.20 pounds NO_x per million BTU heat

input. Within both the Inner and Outer Zones a second round of reductions begins on May 1, 2003 when large boilers would be limited to the greater of 25% of actual 1990 emissions or 0.15 pounds NO_x per million BTU heat input.

The emission limits described above, when applied to generating units and some other industrial sources that were operating in 1990, can be used to calculate total tons of NO_x which may be emitted each year during the 5-month ozone season (May through September). These calculated NO_x tonnages are expected to become New York State's emission caps; for the state's electric utility industry, the caps are 43,360 tons in 1999 and 30,689 tons for 2003. The DEC is responsible for allocating NO_x allowances to each affected source.[1] Furthermore, the MOU contains provisions for modifying these provisions under certain conditions.

The 1999 and 2003 emission caps are sometimes referred to as NO_x-Phase II and NO_x-Phase III. Each allowable ton of NO_x emissions is sometimes referred to as a NO_x emission allowance. The successive NO_x emission cap reductions contribute toward the 3% per year emission reduction guideline set by Congress. The U.S. EPA and State authorities will be responsible for attaining

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[1] It should be noted that the OTC-MOU NO_x caps for Phase 2 and 3 do not call for imposition of emission rate limitations. Such emission rate limitations would be optional with DEC in their responsibility to best manage air resources both locally and regionally. Emission rate limitations might be needed if regulated sources seek to purchase too many NO_x allowances as a control strategy.

agreed NO_x emission caps in 2003 through the State Implementation Plan process.

New Source Review: Earlier it was noted that Congress also provided the guideline that NO_x emissions from new sources should be offset by reductions in the emissions of existing sources. DEC's "New Source Review" regulations require that new major sources of NOx emissions install control technology to meet the lowest achievable emission rate (LAER); the regulation further mandates that in severe ozone non-attainment regions such as downstate New York, new emissions must be offset at a ratio of 1.30 tons from existing sources for every 1.00 tons of emissions from newly permitted sources. In the remainder of the state, the offset ratio is set at 1.15 tons (existing) to 1.00 tons (new) NO_x emissions. By this offset mechanism, the construction of newly permitted sources will contribute to the average 3% per year reduction of total statewide emissions.

NO_x emission offsets (the amount by which an existing NO_x source must be reduced) associated with the new source program are referred to as NO_x Emission Reduction Credits (NO_x ERCs). NO_x ERCs are created by reducing permitted emissions at existing facilities; the ERCs can be traded (sold) subject to the limitation that Inner Zone sources may not use ERCs created in the Outer Zone. Through the use of these ERCs, annual permitted NO_x emissions will gradually be reduced at least cost.

Note that the ERCs and the new source offsets involve the annual NO_x emissions and apply to all permitted sources; the NO_x

allowances associated with the OTC-MOU apply only to the five-month ozone season and only to large boilers. As a practical matter, any new electric utility boilers (which are generally large boilers) will need to obtain both offsetting NO_x ERCs and NO_x allowances.

Other control measures involving mobile sources (automobiles) and other consumer and industrial products will also be needed to achieve Congress' 3% per year NO_x reduction goal. The EPA determines the attainment of these intermediate goals in its review and approval of the State Implementation Plan (SIP).

Non-OTC States: Equivalent NO_x regulations need to be implemented by all OTC member states. All other states upwind (generally west) of the OTR have none of the above described capping regulations or programs that go beyond the minimum requirements of the Clean Air Act;[1] such programs impose substantial costs upon electric utilities. Thus, costs associated with ozone control programs are borne only by OTC member states. This disparity of environmental control programs creates a non-level economic playing field among OTC member states and non-OTC states (and Canadian Provinces).

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[1] Those minimum emission control requirements concern New Source Review, New Source Performance Standards and a requirement for low-NO_x burners under Title IV. However, EPA has granted exemptions applicable to many sources in various midwest non-OTG states. New York State has recently petitioned the U.S. Court of Appeals opposing the exemptions (see Section 6.1.1.6).

Absent Congressional action to address the inequities described above and the need to reduce the long range transport of ozone into the OTR, the OTC member states have joined in a voluntary conference of 37 "eastern" states to study the issue of long range transport of ozone and its precursor air pollutants. This group, the Ozone Transport Assessment Group (OTAG), consists of over 300 technical and policy staff. Representatives are included from government, industry, electric utility and environmental advocacy sectors. Technical and policy work underway now is scheduled for submission to the EPA by January 1997.

5.2.4.2 Acid Deposition

Scientific evidence has shown that the deposition of acidic sulfur and nitrogen compounds can harm ecosystems. Although there is a direct, albeit non-linear, relationship between stack tip emissions and acid deposition, the linkage is too complex to analyze at this generic impact statement level. A best estimate from the State Acid Deposition Control Act (SADCA) suggested that about 17% of all acid deposition at sensitive receptors in New York State is associated with in-state sources of sulfur dioxide. Another 25% of total deposition is believed to originate in the Canadian Provinces and the remaining 58% is believed to originate from all other states.

Title IV of the Clean Air Act Amendment of 1990 (the Act) addresses the problem of acid deposition. Section 404 of the Act

required EPA to report to Congress concerning the feasibility of establishing an acid deposition standard and other issues.[1] That Section 404 report, entitled Acid Deposition Standard Feasibility Study Report to Congress, responds to six areas:

- Identification of sensitive and critically sensitive aquatic and terrestrial resources in the U.S. and Canada which may be affected by the deposition of acidic compounds;
- Description and specification of a numeric value of an acid deposition standard sufficient to protect such resources;
- Description of the use of such standard or standards in other Nations or by any of the several States in acidic deposition control programs;
- Description of measures that would be needed to integrate such standard or standards with the control program required by Title IV of the Clean Air Act;
- Description of the state of knowledge with respect to source-receptor relationships necessary to develop a control program on such standard or standards and additional research that is on-going or would be needed to make such a control program feasible;

[1] Environmental Protection Agency, Acid Deposition Standard Feasibility Study Report to Congress, Report EPA 430-R-95-001a, October 1995.

- Description of impediments to implementation of such control program and the cost-effectiveness of deposition standards compared to other control strategies including ambient air quality standards, new source performance standards and the requirements of Title IV of the Clean Air Act.

The new EPA report "Acid Rain Program Emissions Scorecard 1994"[1] (Scorecard) provides valuable support for targeted emission reductions which are among several measures supported by the Department of Environmental Conservation. With regard to targeted emission reductions, it is shown that New York State has reduced its SO_2 and NO_x emissions, and it also shows that states in the upper Midwest have not reduced their NO_x emissions and are the major contributors to New York's ozone and acid deposition problems. These sources are also outside of the Ozone Transport Region, so they will not be included in NO_x reductions proposed for the OTR in 1999 and 2003. EPA's response to the Ozone Transport Assessment Group (OTAG) report in January 1997 will be critical to dealing with these large Midwest sources of NO_x. In particular, the scorecard indicates that the Ohio River Valley states continue to emit far greater amounts of SO_2 and NO_x than New York and other states. For example, total nitrogen oxides emission of Title IV Phase I units located in Ohio, Illinois and Indiana are 43 times the nitrogen oxides emission

[1] Environmental Protection Agency, Acid Rain Program Emission Scorecard 1994, Report EPA 420/R-95-012, December 1995 (Revised).

from similar Phase I units in New York. Larger reductions in emissions are needed in these states upwind of New York, The Adirondack region is still being impacted by acidic deposition, and it is to the State's benefit to do all that it can do to reduce this deposition.

Due to the complexity of the acid deposition phenomenon, it is unreasonable to calculate specific changes in acid deposition. In lieu of such a complex analysis, this FGEIS resorts to simple comparisons of emission levels with baselines from CAAA of 1990 and SADCA.

Title IV of the Clean Air Act of 1990 established a national priority to mitigate the deposition of acidic compounds arising as a result of electric power industry operations. Congress determined that a reduction of SO_2 emissions of 10 million tons per year accompanied by a reduction of NO_x emissions of 2.36 million tons per year represented an appropriate balance of the nation's environmental goals and economic priorities.[1] The SO_2 reductions are treated under a national cap and trade program where emissions from the electric power industry will remain at an average of 8.9 million tons per year after 2000 (i.e., 10 million tons below the baseline) indefinitely.[2]

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[1] Federal Register; Vol. 61, No. 13; p. 1442; Acid Rain Program; Nitrogen Oxides Emission Reduction Program; January 12, 1996.

[2] The baseline is based upon historic 1985-1987 heat inputs and emissions.

Within this nationwide cap, trading of SO_2 allowances is permitted between affected utility units.

The 2.36 million tons per year NO_x reduction is an estimate based upon the Clean Air Act's requirement that existing boilers should be retrofitted with low NO_x burners. No cap and trade program was implemented for NO_x emissions under Title IV.[1]

It is important to note that the State Acid Deposition Control Act (SADCA) accomplished in New York State the goals of Title IV ahead of schedule; however, in comments to EPA, DEC stated, "Just maintaining the 'status quo' or maintaining the proportion of chronically acidic target surface waters in the Adirondacks near proportions observed in 1984 may require reducing anthropogenic sulfur and nitrogen deposition by 40 to 50 percent or more below levels achieved by the 1990 CAAA."[2] Table 5-1 below displays the effect of SADCA and compares it with Phase II allowance allocations under the CAAA of 1990.

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[1] Other cap and trade programs may be developed by New York State as a part of the State Implementation Plan (SIP).

[2] Comments of NYS DEC to U.S. EPA, February 1995, regarding the U.S. EPA Acid Deposition Standard Feasibility Study.

Table 5-1

	(1) Baseline under SADCA 1980 SO_2 (tons)	(2) Actual under SADCA 1988 SO_2 (tons)	(3) Phase II Allowances under Title IV of CAAA '90	(4) CAAA '90 Reduction from 1980 (tons) (1) - (3)	(5) Reduction from 1980 (%) (4) as a % of (1)
Statewide	489,540	377,627	277,524	212,016	43.3%
Downstate	191,238	124,061	155,461	35,777	18.7%
Upstate	298,302	253,566	122,062	176,240	59.1%

Source: Report by the New York State Dept. of Environmental Conservation to the Governor & Legislature of New York State, 1991.

From Table 5-1 it is apparent that SO_2 emissions have declined from 1980 levels. When compared with the 1980 baseline, the differential reduction compared to Title IV Phase II levels may be about 43% of the 1980 baseline.

Finally, projected emission levels from the PROMOD scenarios can be compared with the state's 1980 baseline and with the CAAA of 1990 Phase II baseline. The approach here is to calculate percent reductions from baseline emission levels for the most distant forecast year (2012) when trends might be expected to be most apparent. From Table 5-2 it is evident that in-state emissions for all scenarios are far below the 1990 electric sector baseline level (417,000 tons).[1] Indeed, they stay well below the level achieved by 1988 under SADCA (377,627 tons).

[1] Draft New York State Energy Plan, 1991 Biennial Update, Volume IV, Table 5A-2 Air Quality: Electric Sector; July 1991.

TABLE 5-2

SO2 Emissions in 2012 Compared to Evolving Regulatory Scenario and Baseline Emission Levels

SCENARIO	DESCRIPTION	Scenario Emissions In 2012 Tons	Changes From Evo. Reg. Scenario Year 1997 245,943	Changes From Baseline Year 1990 417,000	Changes From Phase II Baseline Year 2000 277,524
Evolving Regulatory	Evolving Regulatory Scenario	294,652	19.80%	-29.34%	6.17%
HIGHER SALES					
Alternative 1	High Sales	311,100	26.49%	-25.40%	12.10%
Alternative 1A	No Incremental Utility DSM	282,630	14.92%	-32.22%	1.84%
LOWER SALES					
Alternative 2	Low Sales	281,199	14.34%	-32.57%	1.32%
Alternative 2A	High DSM	292,558	18.95%	-29.84%	5.42%
MODIFIED DISPATCH CONDITIONS					
Alternative 3	IPPs On Economic Dispatch	273,389	11.16%	-34.44%	-1.49%
Alternative 3A	All Coal Units Designated "Must Run"	295,689	20.23%	-29.09%	6.55%
Alternative 3B	SO2 Allowances Valued at $1090/ton	232,883	-5.31%	-44.15%	-16.09%
Alternative 3C	NOx Allowances Valued at $1000/ton	292,888	19.09%	-29.76%	5.54%
Alternative 3D	NOx Allowances Valued at $2000/ton	290,623	18.17%	-30.31%	4.72%
ACCELERATED RETIREMENTS					
Alternative 4	Retire Two Nuclear Plants	294,144	19.60%	-29.46%	5.99%
Alternative 4A	Improved Power Supply Efficiency	230,171	-6.41%	-44.80%	-17.06%
Alternative 5	Combination High Sales & Nuclear Retirement	306,453	24.60%	-26.51%	10.42%
INCREASED SUPPLY					
Alternative 6	IPP Capacity Maximized	297,025	20.77%	-28.77%	7.03%
CHANGED IMPORTS					
Alternative 7	Import Max.: Current Trans. System, Instate	222,333	-9.60%	-46.68%	-19.89%
	Import Max.: Current Trans. System, Out-of-State	128,284	52.16%	30.76%	46.22%
Alternative 7A	Import Max.: Expand Trans. System, Instate	152,784	-37.88%	-63.36%	-44.95%
	Import Max.: Expand Trans. System, Out-of-State	235,046	95.57%	56.37%	84.69%
Alternative 7B	Firm Imports, Instate	161,189	-34.46%	-61.35%	-41.92%
	Firm Imports, Out-of-State*	250,942	102.03%	60.18%	90.42%
Alternative 7C	Export Excess Power, Instate	na			
	Export Excess Power, Out-of-State*	na			

*Assumes AEP system emission factors. Emissions expressed as percent of Evolving Regulatory Scenario emissions.

The comparison with the Title IV allowance baseline (rightmost column) shows that Alternative 1, high sales, has a clear increase in SO_2 emissions by 2012, as do the nuclear retirement scenarios, Alternatives 4 and 5. Only the Alternatives 3, 3B and 4A would result in SO_2 emissions less than Congress' Phase II target for New York (with the exception of the "Changed Imports" scenarios).[1] Scenarios 3B and 4A constitute extreme assumptions about prices of SO_2 allowances or very clean generation. The increased imports scenarios all show substantial reductions of in-state SO_2, but have associated with them increased out-of-state emissions about twice as great as the in-state reductions and cannot be viewed as environmental successes.

Also, as shown in Table 4-2, cumulative annual emissions of SO_2 show increases in comparison to the Evolving Regulatory scenario for four of the scenarios most closely associated with restructuring -- High Sales by 3%, Nuclear Retirements by 4%, Nuclear Retirements and High Sales by 4%, and IPPs on Economic Dispatch by 5%.

Generally, this data indicates that SO_2 emissions are very likely to go up through the study period whether or not there is competitive restructuring of the electric industry--the Evolving Regulatory scenario shows a 20% increase from 1997 to

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[1] Despite meeting Congress' Phase II emission targets, additional SO_2 emission reductions from New York State and other states are needed to protect acid sensitive regions from continued acidification.

2012. Eventually, all of the alternatives have their SO_2 (as well as NO_x and CO_2) emissions driven up by the retirement of nuclear plants. If increased sales result from competitive restructuring, then Scenario 1 suggests SO_2 could rise more in the Evolving Regulatory scenario.

5.2.4.3 Ozone

As previously described in Section 4, PROMOD was used to run an initial Evolving Regulatory scenario and 17 alternative scenarios in order to obtain a range of estimates of SO_2, NO_x, and CO_2 emissions. A deliberate attempt was made to structure scenarios that would provide high and low estimates of pollutants. This section examines the assumptions which were embedded in these scenarios, and provides some additional disaggregated data which focuses on the summer "ozone season."

Section 4.2 above provides a description of the scenarios used. Detailed annual data summaries are provided in Appendix B. NO_x emissions for all scenarios for the year 2012 are shown in Table 5-3. They are compared to 1997 Evolving Regulatory scenario levels and also to the OTC-MOU baseline (1990) tonnage for the electric sector.[1]

It is critical that three major factors be borne in mind when examining this data. First, there are substantial declines in the NO_x tonnage numbers through the period for all scenarios.

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[1] Ibid.

This is driven by the OTC-MOU Phase II (1999) and Phase III (2003) controls on existing large utility boilers. A review of the year-by-year scenario numbers in Appendix B dramatically indicates this drop in 1999 and 2003. Second, notwithstanding these considerable and expensive absolute reductions in NO_x tonnage (even while electric generation is increasing), the reduced ozone goals may still not be met because of NO_x emissions carried into the region from unregulated generators in the Midwest.

Third, there will be a regional cap on NO_x as a result of the Ozone Transport Commission's Memorandum of Understanding (OTC-MOU). This agreement on a cap permits trading, under specified conditions, of emission credits within the OTC. Therefore, absent New Source Review, there would be no improvement to the environment as a result of an alternate scenario which is lower in NO_x, because emission rights will have been freed which can be traded to an entity which will then emit more than it otherwise would. Likewise, an alternate scenario which indicates a higher level of NO_x emissions will mean that the generators will have to back down other emitters' NO_x production by purchasing their emission credits, with no consequent net increase or decrease of NO_x emissions in the trading zone.

In the worst case, the annual in-state NO_x emissions are expected to decrease by only 28.8% compared to the Evolving Regulatory scenario level for 1997. This is Scenario 5, which

assumes a high sales forecast and the early retirement of two nuclear plants. In the best case (with respect to air quality), annual NO_x will decline by 47.1% compared to the 1997 Evolving Regulatory scenario level (Scenario 3, which assumes IPPs on economic dispatch). Scenario 7 (as well as 7A and 7B), like all of the "Changed Imports" scenarios, offers a more ambiguous finding. Three of these four scenarios are based upon maximizing the import of electricity from out-of-state and reducing in-state generation (Alternates 7, 7A and 7B). These scenarios result in about a 49% to 59% reduction in in-state NO_x, relative to the 1997 Evolving Regulatory scenario level, from in-state sources. However, emissions could increase (worst case estimate) from out-of-state generators by 52% to 96% of 1997 Evolving Regulatory scenario levels. As explained in the section on Impacts of Potential Imports, not all of the increased out-of-state emissions necessarily impact New York State, so it is not clear whether net impacts within the state increase or decrease. But, as mentioned frequently, the NO_x-ozone problems are regional, and it seems extremely likely that the Northeast would suffer collectively if imports from the Midwest increase. Clearly, because these problems are regional, they require regional solutions.

TABLE 5-3

NOx Emissions in 2012 Compared to Evolving Regulatory Scenario and Baseline Emission Levels

SCENARIO	DESCRIPTION	Scenario Emissions In 2012 Tons	Changes From Evo. Reg. Scenario Year 1997 101,364	Changes From Baseline Year 1990 167,000
Evolving Regulatory	Evolving Regulatory Scenario	62,989	-37.86%	-62.28%
HIGHER SALES				
Alternative 1	High Sales	71,445	-29.52%	-57.22%
Alternative 1A	No Incremental Utility DSM	62,583	-38.26%	-62.53%
LOWER SALES				
Alternative 2	Low Sales	57,289	-43.48%	-65.70%
Alternative 2A	High DSM	62,158	-38.68%	-62.78%
MODIFIED DISPATCH CONDITIONS				
Alternative 3	IPPs On Economic Dispatch	53,624	-47.10%	-67.89%
Alternative 3A	All Coal Units Designated "Must Run"	63,392	-37.46%	-62.04%
Alternative 3B	SO2 Allowances Valued at $1090/ton	60,911	-39.91%	-63.53%
Alternative 3C	NOx Allowances Valued at $1000/ton	62,511	-38.33%	-62.57%
Alternative 3D	NOx Allowances Valued at $2000/ton	62,102	-38.73%	-62.81%
ACCELERATED RETIREMENTS				
Alternative 4	Retire Two Nuclear Plants	65,009	-35.87%	-61.07%
Alternative 4A	Improved Power Supply Efficiency	56,290	-44.47%	-66.29%
Alternative 5	Combination High Sales & Nuclear Retirement	72,138	-28.83%	-56.80%
INCREASED SUPPLY				
Alternative 6	IPP Capacity Maximized	63,653	-37.20%	-61.88%
CHANGED IMPORTS				
Alternative 7	Import Max.: Current Trans. System, Instate	51,284	-49.41%	-69.29%
	Import Max.: Current Trans. System, Out-of-State	52,943	52.23%	31.70%
Alternative 7A	Import Max.: Expand Trans. System, Instate	41,610	-58.95%	-75.08%
	Import Max.: Expand Trans. System, Out-of-State	97,003	95.70%	58.09%
Alternative 7B	Firm Imports, Instate	42,614	-57.96%	-74.48%
	Firm Imports, Out-of-State*	103,563	102.17%	62.01%
Alternative 7C	Export Excess Power, Instate	na		
	Export Excess Power, Out-of-State*	na		

*Assumes AEP system emission factors. Emissions expressed as percent of Evolving Regulatory Scenario emissions.

Ozone Season Analysis

The results displayed in Table 5-3 are based upon annual data, while the ozone problem is actually limited to the warm summer months. New York's Department of Environmental Conservation is currently moving to establish a statewide NO_x emissions cap. The portion of the cap applicable to electric utility emissions is about 43,360 tons for the May through September ozone season beginning in 1999 and about 30,689 tons (about 19,644 tons for the Inner Zone) starting in the year 2003.

The PROMOD scenarios were tested against these possible caps over the ozone season for years 1997, 2003, and 2012. The scenarios tested were: the Evolving Regulatory scenario; a high NO_x scenario (Scenario 5); and a low NO_x scenario (Scenario 2). Taken together, these alternates provide a reasonable "bounding" of possible outcomes. The results are provided in Table 5-4a for statewide summer NO_x and in Table 5-4b for the Inner Zone NO_x emissions. These same data are presented graphically in Figures 5-1a and 5-1b. The vertical axes indicate the tons of NO_x which PROMOD projects the different scenarios will produce during the ozone season. The heavy dotted lines indicate the possible NO_x tonnage targets for utilities: 43,360 tons for 1999-2002, dropping to 30,689 tons for 2003 and beyond for statewide emissions and 19,644 tons in 2003 for Inner Zone emissions.

The statewide data in Table 5-4a and Figure 5-1a suggest that the "high NO_x" Scenario 5 would just about comply with the cap levels currently being discussed by the Department of

Environmental Conservation through most of the study period. In 2012, NO_x emissions may exceed the statewide target by a small amount, and emission credits would have to be purchased or additional controls installed. The Evolving Regulatory and "low NO_x" scenarios remain below the targets for all years through 2012.

Table 5-4a - Statewide Summer NOx emissions: Possible MOU NOx cap vs. Projected NYPP Actuals

	Possible NOx cap for Ozone purposes (tons)	Projected NYPP Actual Totals [1] (tons)	May	June	July	August	September
Evolving Regulatory Scenario without Phase II and III NOx controls							
1990	-	79,107	-	-	-	-	-
1997	-	38,612	6,934	7,543	8,831	8,455	6,849
1999	43,360	37,438	7,023	7,363	8,619	8,003	6,430
2003	30,689	37,652	7,368	7,367	8,416	8,078	6,423
2012	30,689	41,258	7,997	8,147	8,948	8,957	7,209
Evolving Regulatory Scenario with Phase II and III NOx controls							
1990	-	79,107	-	-	-	-	-
1997	-	42,683	7,411	8,284	9,823	9,344	7,821
1999	43,360	32,847	5,835	6,372	7,615	7,183	5,842
2003	30,689	23,787	4,361	4,568	5,357	5,199	4,302
2012	30,689	26,824	4,736	5,313	5,872	5,906	4,995
Low Sales Scenario with phase II & III NOx controls							
1990	-	79,107	-	-	-	-	-
1997	-	41,711	7,217	8,086	9,599	9,174	7,635
1999	43,360	30,752	5,416	5,995	7,143	6,751	5,447
2003	30,689	21,851	4,013	4,177	4,990	4,763	3,908
2012	30,689	23,889	4,145	4,770	5,375	5,286	4,313
High Sales & Nuclear Retirement scenario with phase II & III NOx controls							
1990	-	79,107	-	-	-	-	-
1997	-	51,510	9,005	10,173	11,595	11,168	9,569
1999	43,360	39,986	7,059	7,871	9,104	8,734	7,218
2003	30,689	27,344	4,836	5,320	6,222	5,942	5,024
2012	30,689	31,750	5,555	6,428	6,823	6,954	5,990

[1] The totals shown here for 1990 are actual emissions and are drawn from the MOU baseline NOx inventory

Figure 5-1a

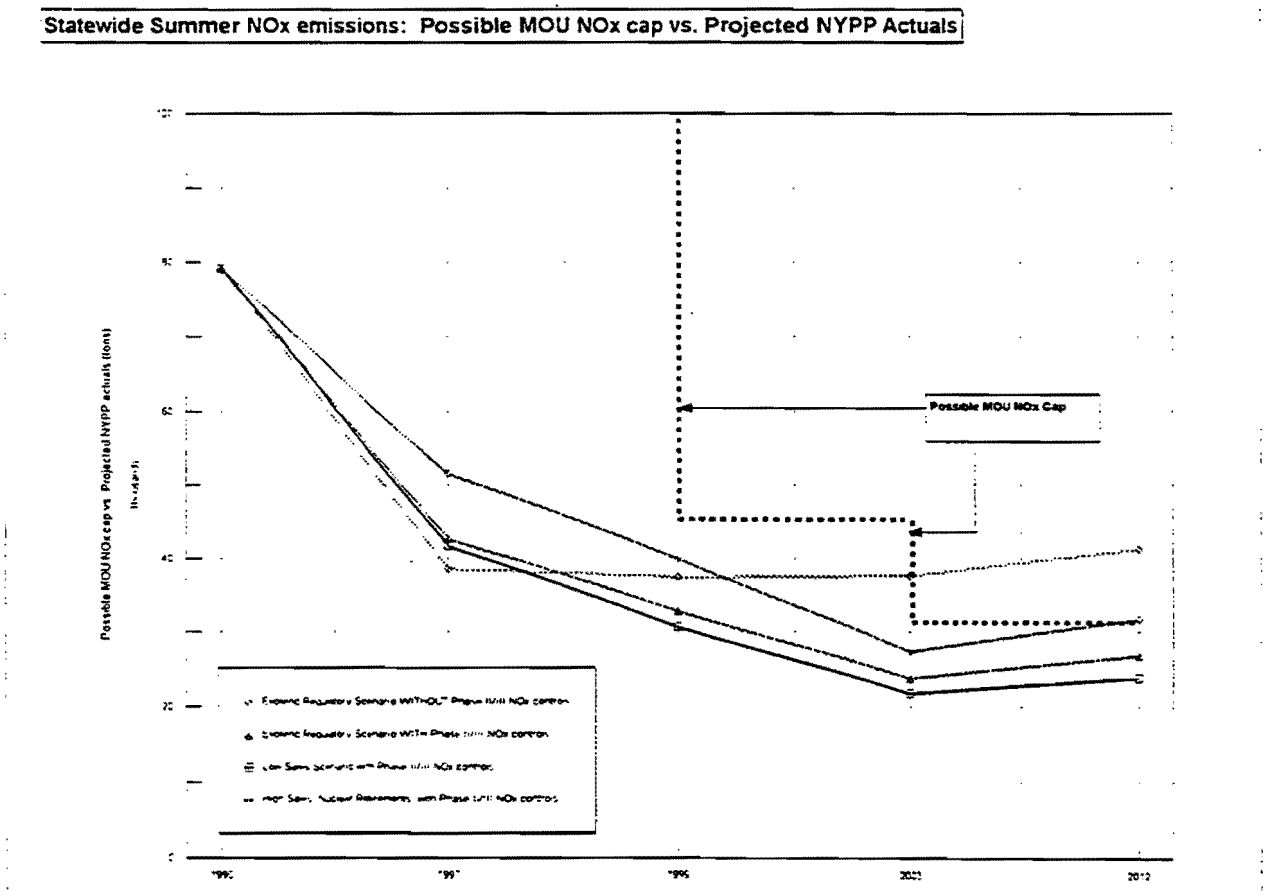
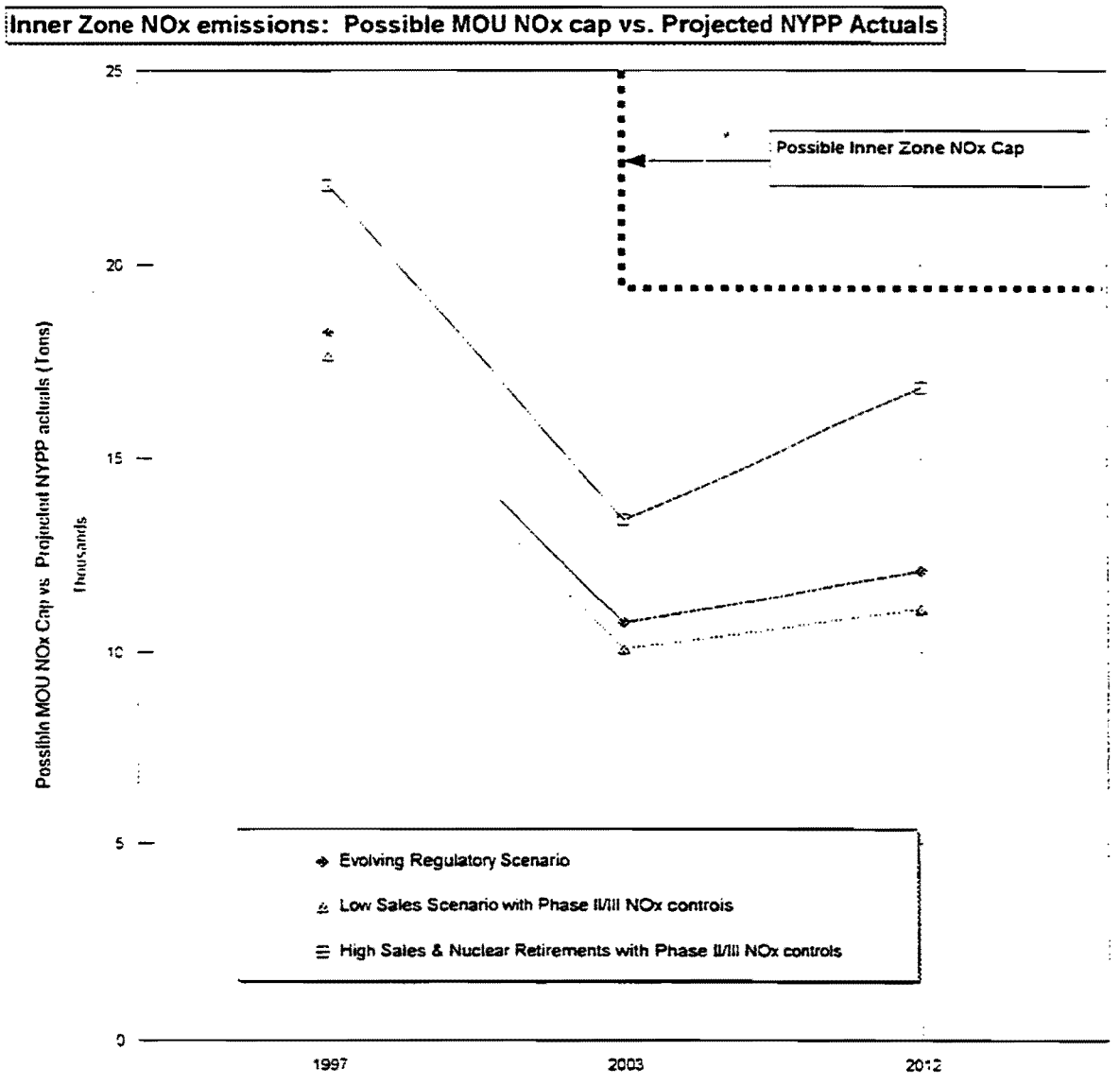


Table 5-4b - Inner Zone Summer NOx Emissions: Possible MOU NOx cap vs. Projected NYPP Actuals

	1997	2003	2012
Possible MOU NOx cap (Tons)	-	19,644	19,644
Projected NYPP Actuals (Tons)			
Evolving Regulatory Scenario	18,274	10,772	12,123
Low Sales Scenario	17,666	10,099	11,128
High Sales & Retirement of 2 Nuclear plants	22,040	13,431	16,831

Figure 5-1b



The data on the projected Inner Zone NO_x emissions are compared with the possible Inner Zone NO_x target in Table 5-4b and Figure 5-1b. This Inner Zone NO_x assessment suggests that all electric generating facilities in the Inner Zone will be able to comply with the possible NO_x target throughout the study period.

There are several observations which should be made about this data:

- These PROMOD runs suggest that the New York electric generators should be able to meet NO_x requirements in a reasonable fashion until 2003 when the Phase III controls are implemented;
- These PROMOD analyses do not disaggregate by utility, and there could be problems for some utilities in some years with respect to compliance;
- Additional NO_x controls may be needed as we approach 2012 to comply with the possible NO_x statewide target.
- For modeling purposes, Phase II and Phase III controls were "installed" on all generating units. This results in the observed "over compliance" for some scenarios. However, in a competitive environment, emission controls might be operated to minimize operating costs such that emissions would rise to the regulatory limit.
- Energy efficiency may be an important consideration in 2003 and beyond to mitigate growth should DEC implement its proposed rules.
- Although the PROMOD runs suggest that most of the scenarios are largely consistent with possible caps, actual caps have not been promulgated; it is expected that DEC will release these caps later.
- While ozone season NO_x emissions are likely to be capped, Table 4-2 shows that cumulative annual emissions of NO_x may increase by 5 to 9 percent in comparison to the Evolving Regulatory scenario for three of the scenarios most closely associated with restructuring (High Sales and Nuclear Retirements, separately and in combination).

5.2.4.4. Global Warming

Widely publicized studies have strongly suggested that the emission of certain gases such as carbon dioxide into the atmosphere may cause the global average temperature to increase. Any change to global average conditions could change and possibly harm ecosystems and humans. Humans could be harmed by rising levels of the world's oceans. Such increased ocean levels would flood low lying coastal regions and displace inhabitants.

Title XVI of the federal Energy Policy Act of 1992 (EPAct) addresses global climate change.[1] EPAct does not require the reduction of emissions of carbon dioxide and other gases that are believed to be precursor pollutants that cause global warming through the greenhouse effect. Rather, EPAct requires the Department of Energy to submit reports to Congress that assess options for limiting greenhouse gas emissions. The policies that must be considered in a least-cost energy plan include initially stabilizing and eventually reducing greenhouse gas emissions, as well as increasing national energy efficiency, increasing reliance on renewable resources, and reducing reliance on fossil fuels for electricity production.[2] EPAct encourages voluntary reductions of CO_2 by electric generators and other industrial sources. In response, on October 19, 1993, the President introduced a U.S. Climate Change Action Plan (CCAP) to

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[1] P.L. 102-486, §§ 1601-1609, 106 Stat. 2999 (October 24, 1992).

[2] Energy Policy Act of 1992, § 1602, 106 Stat. at 2999-3001.

reduce by 2000 national greenhouse gas emissions to below 1990 levels.

The CCAP seeks to freeze the level of global warming gases at 1990 levels by the year 2000 through voluntary supply-side and voluntary demand-side actions that meet a "no regrets" test. The no regrets test is one where if mitigation results in reasonable economic benefit, the mitigation measure should be pursued.

Total U.S. greenhouse gases in 1990 are estimated at 5,556 million tons (carbon dioxide equivalent) and consist of all gases that contribute to greenhouse warming. Such gases include methane and several other trace gases; however, carbon dioxide represents about half of the global warming potential of all gases.

After taking into consideration growth and structural changes in the U.S. economy, it has been estimated that CO_2 emissions in the U.S. need to be reduced by about 279 million tons by the year 2000 to stabilize at the 1990 level.[1] Similar goals have not been set for New York State emissions or for emissions from the electric utility sector in New York State. Absent relevant goals, Table 5-5 presents projected CO_2 emissions

[1] Lee, Henry and Negeen Darani, "Electricity Restructuring and the Environment," Center for Science and International Affairs, December 1995, Report 95-13, page 86.

TABLE 5-5

CO2 Emissions in 2012 Compared to Evolving Regulatory Scenario and Baseline Emission Levels

SCENARIO	DESCRIPTION	Scenario Emissions In 2012 Tons	Change From Evo. Reg. Scenario Year 1997 60,545,022	Change From Baseline Year 1990 75,900,000
Evolving Regulatory	Evolving Regulatory Scenario	82,042,211	35.51%	8.09%
HIGHER SALES				
Alternative 1	High Sales	99,398,117	64.17%	30.96%
Alternative 1A	No Incremental Utility DSM	84,627,182	39.78%	11.50%
LOWER SALES				
Alternative 2	Low Sales	67,359,967	11.26%	-11.25%
Alternative 2A	High DSM	77,690,272	28.32%	2.36%
MODIFIED DISPATCH CONDITIONS				
Alternative 3	IPPs On Economic Dispatch	75,250,252	24.29%	-0.86%
Alternative 3A	All Coal Units Designated "Must Run"	82,604,482	36.43%	8.83%
Alternative 3B	SO2 Allowances Valued at $1090/ton	79,787,734	31.78%	5.12%
Alternative 3C	NOx Allowances Valued at $1000/ton	81,941,330	35.34%	7.96%
Alternative 3D	NOx Allowances Valued at $2000/ton	81,793,958	35.10%	7.77%
ACCELERATED RETIREMENTS				
Alternative 4	Retire Two Nuclear Plants	88,603,366	46.34%	16.74%
Alternative 4A	Improved Power Supply Efficiency	79,518,401	31.34%	4.77%
Alternative 5	Combination High Sales & Nuclear Retirement	105,686,541	74.56%	39.24%
INCREASED SUPPLY				
Alternative 6	IPP Capacity Maximized	82,668,161	36.54%	8.92%
CHANGED IMPORTS				
Alternative 7	Import Max.: Current Trans. System, Instate	68,289,972	12.79%	-10.03%
	Import Max.: Current Trans. System, Out-of-State	20,871,563	34.47%	27.50%
Alternative 7A	Import Max.: Expand Trans. System, Instate	56,116,341	-7.31%	-26.07%
	Import Max.: Expand Trans. System, Out-of-State	38,241,623	63.16%	50.38%
Alternative 7B	Firm Imports, Instate	55,257,046	-8.73%	-27.20%
	Firm Imports, Out-of-State*	40,827,903	67.43%	53.79%
Alternative 7C	Export Excess Power, Instate	na		
	Export Excess Power, Out-of-State*	na		

*Assumes AEP system emission factors. Emissions expressed as percent of Evolving Regulatory Scenario emissions.

in 2012 compared to Evolving Regulatory scenario emissions in 1997 and compared to the Baseline 1990 electric generation tonnage of 75,900,000.[1]

Table 5-5 shows that if the nation decides to seek a stabilization (no increase) of CO_2 emissions, there will be substantial challenges to overcome. Apart from the low sales Scenario 2 which shows a decrease of 11.25% from the 1990 level and the IPPs on economic dispatch Scenario 3 which shows a decrease of 0.86% from the 1990 baseline level, most other scenarios show important increases in CO_2 compared to the 1990 stabilization target. The "Changed Import" scenarios are not included in this analysis because the reductions shown would generally be offset by the imported generation--depending upon the assumed out-of-state mix of sources. Scenario 5 (combination of high sales and nuclear retirements) shows an increase of 39.24%.

These scenarios suggest that the CO_2 emissions from electric generation in New York will tend to converge toward the Evolving Regulatory scenario estimates. This convergence is explained by the fact that all the scenarios assume that more and more natural gas generation will be acquired in the future. Natural gas is much cleaner than oil or coal in terms of CO_2. On a per kWh basis, oil generation produces about 40% more CO_2 than gas-fired generation, while coal produces 80% more than gas.

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[1] Draft New York State Energy Plan, 1991 Biennial Update, Volume IV; Table 5A-2 Air Quality: Electricity Sector; July 1991.

Finally, it is clear from Scenario 2A that mitigation mechanisms are available --such as DSM--which can yield important reductions in CO_2 emissions. Using more nuclear, hydroelectric, renewable and gas generation will also have this effect.

5.2.4.5. Particulates and Air Toxics

Particulates

Particulates are solid or liquid particles suspended in the ambient air. Some particulates can be seen as smoke, but most are too small to be seen with the naked eye.

The larger particulates (respirable particulate matter having a diameter up to 10 micrometers - PM-10) tend to be created by abrasive processes (e.g., the wearing-down of tires and brakes), while smaller particles (particulate matter with a diameter up to 2.5 micrometers - PM-2.5) tend to be associated with combustion processes. Still smaller particles can be formed by various chemical reactions in the atmosphere which convert gases into particulates. Particulates that are directly created by a process or activity are sometimes referred to as "primary particulates;" those created by chemical processes in the atmosphere are designated "secondary particulates."[1]

Because particulates originate from a large variety of mobile and stationary sources (gasoline and diesel powered

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[1] For example, sulfur dioxide can be chemically transformed into sulfates and nitrogen dioxide can be chemically transformed into nitrates.

vehicles, electric generating stations, residential furnaces and wood stoves), their chemical composition and physical properties vary significantly. While there is concern about all respirable particulates, particulates that originate from combustion processes are of greatest public health concern because they are small and can be inhaled more deeply. That concern is greatest for the smallest particulates that may be inhaled most deeply into the human respiratory system. The human health concerns associated with respirable particulate exposure are: 1) effects on breathing and respiratory systems, 2) damage to lung tissue, 3) cancer and 4) premature death. The elderly, infants, children and persons with chronic lung disease, infections and asthma are at greatest risk.

The EPA has established standards for respirable particulates. These "PM-10 standards" are specifically for particulates 10 micrometers or less in aerodynamic diameter. The standards for PM-10 are National Ambient Air Quality Standards (NAAQS) that have been set to protect public health and welfare. The PM-10 standards are 50 micrograms per cubic meter (measured over an annual period) and 150 micrograms per cubic meter (measured over a 24-hour period). The EPA is also considering separate standards for fine particulates, 2.5 micrometers or less in diameter (PM-2.5).[1]

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[1] The existing PM-10 standard is under review. Preliminary EPA opinion is that the existing standard should be supplemented by another standard for particulates 2.5 micrometers or less in diameter. A possible new annual PM-2.5 standard might be set in a

With the exception of one site in Manhattan, the PM-10 standard has been attained across New York State by a large margin. The composite annual PM-10 concentration for 56 sampling sites in 1994 was 21.1 micrograms per cubic meter as compared to the applicable NAAQS of 50 micrograms per cubic meter. The annual arithmetic means ranged from a low of 10 micrograms per cubic meter at the base of Whiteface Mountain to 53 micrograms per cubic meter at a curb-side special-purpose monitor on Madison Avenue in midtown Manhattan. The Manhattan location is the only site where the PM-10 standard has been exceeded; the EPA has declared the metropolitan area to be in non-attainment for PM-10.

There were no recorded exceedances of the 24-hour standard of 150 micrograms per cubic meter anywhere in the State's monitoring network during 1994.[1] The highest 24-hour concentration occurred in Manhattan at Madison Avenue with a level of 132 micrograms per cubic meter during a period of air stagnation on December 22, 1994.

The last three years of data (since the 1994 report) show the Manhattan site to be in compliance with the NAAQS for PM-10. However, the three year average is at the level of the NAAQS and DEC is continuing to study the 1996 data from all Manhattan monitoring sites.

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range of 15 to 30 micrograms per cubic meter. A possible new 24-hour PM-2.5 standard might be set in a range of 25 to 85 micrograms per cubic meter.

[1] The data year 1994 is the latest for which reports are available.

The DEC has examined the sources of PM-10 in New York State. Based on the results of PM-10 monitoring, electric generators do not appear to be significant sources of primary particulates, however, they may contribute to secondary particulates such as ammonium sulfate and ammonium nitrate. Electric generators are subject to strict particulate emission controls and generally utilize high efficiency particulate control devices. However, these controls are not effective for secondary particulates that are formed in the atmosphere.

Since 1987 the statewide composite annual average for PM-10 sulfate (from all sources) has ranged from a high of 7.5 micrograms per cubic meter in 1989 to a low of 5.0 micrograms per cubic meter in 1993 (5.2 in 1994). During the same period, the statewide PM-10 nitrate average has ranged from 0.3 to 0.9 micrograms per cubic meter (0.5 in 1993 and 1994).[1]

Total annual average sulfate and nitrate levels are therefore in the range of 6 to 8 micrograms per cubic meter, while the possible standard for annual PM-2.5 may be in the range of 15 to 30 micrograms per cubic meter.

Possible precursor sources of sulfates and nitrates may include electric generating stations, space heating, boilers, and motor vehicles (diesel and gasoline fueled). To the extent that power plants are responsible for these secondary particulates, it is the more distant in-state and out-of-state generators that are

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[1] NYS Department of Environmental Conservation, Division of Air Resources 1994 Annual NYS Air Quality Report, November 1994.

likely to contribute the most because of the chemical conversions that must take place in the atmosphere.

The following analysis develops bounding estimates concerning electric utility primary and secondary particulate emissions. The approach used here will be to scale PROMOD emission estimates using some limited results from other research efforts.

Although the electric generation industry does not appear to be a significant contributor to primary ambient inhalable particulate pollution, an estimated 8,723 tons of primary particulates are associated with the operation of the State's electrical system in the Evolving Regulatory scenario. Table 5-6 displays estimates of particulate emissions associated with the Evolving Regulatory scenario and the bounding Scenarios 2 and 5. Particulate estimates were derived by using PROMOD generation estimates in Appendix B combined with PM-10 particulate emission factors of 0.200 tons per GWh for oil, 0.030 tons per GWh for natural gas, and 0.200 tons per GWh for coal (based on data from the 1994 State Energy Plan). About 17 percent of statewide PM-10 emissions are estimated to be also PM-2.5 particulates; these are also shown in the Table.

Table 5-6: Primary Inhalable Particulate Emissions in 2012

Scenario	PM-10 Tons	PM-2.5 Tons	Percent Increase from Evolving Regulatory Scen.
Evolving Regulatory	8723	1483	---
Alternate 2	8552	1454	-1.96%
Alternate 5	8880	1510	1.80%

As discussed earlier, secondary fine particulates may result from the chemical transformation of primary gaseous air pollutants. It is estimated that about 15 percent of in-state sulfur dioxide emissions and 6.75 percent of nitrogen oxide emissions ultimately become PM-2.5 particulates. Given that relationship and the emissions projected by PROMOD, secondary fine particulates are estimated in Table 5-7 for the model year 2012.[1]

Table 5-7: Secondary Fine Particulates (PM-2.5) in 2012

Scenario	PM-2.5 Tons	Percent Increase from Evolving Regulatory
Evolving Regulatory	48,450	---
Alternate 2	46,047	-4.96%
Alternate 5	50,837	4.93%

[1] Although NO_x emissions are highest in Scenario 5, SO_2 emissions are highest in Scenario 1. While Scenario 1 is actually the maximum scenario for secondary particulates, Scenario 5 is used to be consistent with other tables in this section.

Comparison of Table 5-6 and 5-7 leads to an important observation; primary utility sector PM-2.5 emissions are dwarfed by secondary particulates. Since on a nationwide basis utility sources emit about 65% of all SO_2 and about 29% of all NO_x,[1] utility boilers may be a significant contributor to secondary PM-2.5. Thus, it is important that SO_2 and NO_x emissions (the precursors of sulfates and nitrates) be minimized to the extent possible, both on an annual basis and during the ozone season. Existing efforts by the Ozone Transport Commission member states to cap nitrogen oxide emissions in 1999 and 2003 will probably reduce PM-2.5 levels. Similarly, a State of New York Petition opposing EPA determinations to exempt portions of midwestern states from requirements to reduce NO_x emissions, if successful, should also reduce PM-2.5 levels in New York State.[2] Furthermore, Title IV of the Clean Air Act Amendments of 1990 may also contribute to the reduction of PM-2.5 levels given the mandated reductions in sulfur dioxide emissions in 2000 and beyond. Thus, as these precursor pollutants are reduced in future years, ambient levels of secondary particulates should decline.

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[1] New York State Legislature; Legislative Commission on Expenditure Review, Program Audit; November 1989; pp 2 & 3.

[2] State of New York v. United States Environmental Protection Agency, et al., United States Court of Appeals for the Seventh Circuit, Docket No. 96-1714, Petition for Review (March 26, 1996).

Hazardous Air Pollutants

Hazardous air pollutants (HAPs) are those that may cause serious chronic and acute health effects, including cancer, poisoning, and breathing difficulty.[1] Other less measurable effects include immunological, neurological, reproductive, and developmental effects. Hazardous air pollutants can affect human health directly, or indirectly through the food chain.

Mercury, for example, can be inhaled directly into the lungs or deposited on the land or water.[2] Mercury deposited in water bodies can become methylmercury which may be biologically concentrated and bioaccumulated. Accumulated methylmercury can become transported up the food chain thus increasing the potential to produce illness in humans.[3]

Title III of the Clean Air Act Amendments of 1990 (CAAA of 1990) targeted 189 air toxics for control; the list includes dioxin, benzene, arsenic, beryllium, mercury and a large number of volatile organic compounds (VOCs). The 189 Title III air toxics fall into six categories: 1) mercury; 2) other metals; 3) other inorganics; 4) volatile organic compounds (VOCs); 5) semi-

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[1] The greatest ground level concentration of air toxics from an electric power plant is normally within several miles of the stack location. Thus, the largest potential impacts are to be expected in close proximity to the source.

[2] Mercury bound to particulate matter can be deposited within several miles of stack tips. In contrast, mercury in its elemental form can be emitted as a gas and remain in the atmosphere for up to a year before being oxidized and deposited.

[3] Environmental Protection Agency, Mercury Study Report to Congress, Report EPA-452/R-96-001a, Volume 1, December 1995.

volatile compounds; and 6) other organic compounds. The metals, including mercury, are the primary toxic air pollutants of concern for electric generation facilities; utility boilers are generally not significant sources of VOCs and other organic compounds.

Emissions of hazardous air pollutants from utility boilers are not currently limited by the Clean Air Act Amendments. Upon completion of an EPA study of hazardous air pollutant emissions by utility generators, EPA may place limitations on utility emissions. Regardless of whether limits are adopted by EPA, these emissions are of concern in New York State.

The EPA has defined a weighting system to prioritize efforts to reduce emissions. Although emissions of mercury and other metals comprise a very small proportion of estimated air toxics, mercury emissions are considered to be highly toxic. The toxicity weighting factor for mercury is 100 while most other metals such as arsenic, beryllium, manganese and nickel have weighting factors of 10. Furthermore, mercury is now one of EPA's leading candidates for possible regulation. Accordingly, this analysis focuses on mercury as the air toxic pollutant of greatest importance and as a surrogate for the study of other metal emissions.[1]

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[1] Ongoing impact assessments by the Center for Clean Air Policy being performed in cooperation with the New York State Energy Research and Development Authority concerning the restructuring of the electric industry and the environment have also adopted

Table 5-8 provides estimates of air toxics emissions by economic sector before and after toxicity weighting. After toxicity weighting, the transportation sector is estimated to contribute 82 percent of total air toxics in New York State, while electricity generation contributes about 11 percent.

Table 5-8: 1990 NYS Air Toxic Emissions by Economic Sector

	Estimated Emissions Tons/Yr	Emissions Percent	Toxicity Weighted Tons/Yr	Toxicity Weighted Percent
Electric	5,292	9.0	16,960	10.7
Industrial	5,700	9.7	7,743	4.9
Commercial	1,005	1.7	1,490	0.9
Resident'l	1,292	2.2	1,790	1.1
Transport	45,445	77.4	130,751	82.4
TOTAL	58,734	100.0	158,734	100.0

Source: NYS Energy Plan, October 1994 Vol. III, Table 27

Table 5-9 indicates that mercury emissions from fossil fuel combustion statewide are about 4.2 tons per year, representing about 20 percent of total statewide mercury emissions. Electricity generation is responsible for about 2.5 tons per year or 12% of statewide emissions. The largest mercury emitters are municipal waste and medical waste combustion, which are each estimated to contribute a total of 13.9 tons or 34% of statewide mercury emissions. If competitive forces result in a significant increase in refuse-fired steam electric generation,

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this methodology of focusing on mercury emissions in lieu of studying all 189 possible air toxic emissions.

the electric sector's percentage of hazardous air pollutants could increase as the municipal sector's percentage decreases.

Table 5-9: Distribution of New York State Mercury Emissions for 1990 by Economic Sector

	Estimated Tons/Yr	Percent of Emissions
Fossil Fuel Comb'n		
Electric	2.5	12.1
Industrial	0.7	3.4
Commercial	0.3	1.5
Residential	0.4	1.9
Transportation	0.3	1.5
Subtotal	4.2	20.4
Other Combustion		
Municipal	7.0	34.0
Medical	6.9	33.5
Sewage	0.2	1.0
Subtotal	14.1	68.5
Miscellaneous		
Paint	1.1	5.3
Electrical Uses	0.7	3.4
Other	0.5	2.4
Subtotal	2.3	11.1
Total	20.6	100.0

Source: NYS Energy Plan October 1994, Vol. III, Table 28

The data contained in Table 5-9 for the electric industry is based upon data from the time period 1990-1994. Since that time period efforts have been undertaken by the New York Power Pool (NYPP) to refine estimates of mercury emissions associated with the State's fossil fueled electric generators. Refinements come from the testing of coal samples "as fired" as compared to "as mined" and other updated analytical methodologies. Using NYPP refinements, statewide mercury emissions in 1992 were estimated to be 152 pounds from oil fired generation and 1930 pounds from coal fired generation or in total 1.04 tons.[1] Thus, NYPP's refined estimate, using more realistic values for the amount of mercury in fuel, is about 42% of the more generic estimate provided in the 1994 State Energy Plan.

Estimates of nationwide electric sector mercury emissions range from 93 tons per year (US Geological Survey) to 52.9 tons per year (US EPA) to 43 tons per year (EPRI).[2] Thus, New York State's electric sector emissions of mercury are less than would be expected based on New York's 7.2% of the US population.

Although it is clear that New York State electric sector emissions of mercury are low compared to total statewide emissions or national electric sector emissions, the following assessment uses PROMOD fuel use data to provide bounding

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[1] Letter from Sandra Meier (NYPP) to Peter Smith (NYSERDA) dated June 21, 1995.

[2] Ibid.

estimates of possible changes in mercury emissions due to the introduction of competition. Tonnage estimates are based upon 1994 State Energy Plan mercury emission factors of 0.0606 tons per 1000 Gwh for coal firing and 0.0152 tons per 1000 Gwh for residual oil firing.[1]

Table 5-10 provides estimates of the differential mercury emissions associated with the Evolving Regulatory, Scenario 2 and Scenario 5 using the methodology described above. These results indicate that any changes in electric sector mercury emissions resulting from restructuring are probably very small (less than one percent).

Table 5-10: Estimated Mercury Emissions for the Year 2012

Scenario	From Coal Tons/Yr.	From Oil Tons/Yr.	Total Tons/Yr.	Percent Increase from Evolving Regulatory
Evolving Regulatory	1.6713	0.1992	1.8705	----
Alternate 2	1.6636	0.1903	1.8538	-0.88%
Alternate 5	1.6432	0.2148	1.8580	-0.66%

Summary

The foregoing discussions of emissions of air toxics and particulates (both PM-10 and PM-2.5) from fossil-fueled electric generators indicate that, although electric generation is associated with appreciable amounts of particulates and mercury

[1] State Energy Plan, Volume III Supply Assessments, October 1994, Table 12, Page 561.

in the atmosphere (and that those emissions should be minimized to the extent feasible), it is unclear when and how emission reductions should be required of the electric generation sector as compared to all other source categories. The analyses done of the Evolving Regulatory and bounding scenarios reveal that the level of toxic metal and particulate emissions vary with changes to fossil plant dispatch. Plants that are utilized infrequently will produce fewer emissions. Concomitantly, fossil fuel units that run more under competition could reasonably be expected to produce more particulates and metals. EPA and DEC regulations to be promulgated under the Clean Air Act, however, are expected to limit emissions of mercury and other toxic metals and PM-10. EPA is also expected to restrict ambient air concentration of PM-2.5 emissions that threaten human health.

5.2.4.6. Water Resource Impacts

The redispatch of the generation system under a restructured electric industry has the potential for affecting water resources both directly in terms of altered plant operations and indirectly with respect to air deposition of contaminant to waters. For steam-electric plants, the major concerns are the magnitude of cooling water withdrawals and the size and nature of pollutant discharges to surface waters. For hydroelectric plants, the issues of concern are alterations in upstream water levels and downstream water releases and entrainment of aquatic life. With respect to the deposition of

air contaminants, the concerns to water resources are acidification, eutrophication and toxification.

Unlike the emissions of air contaminants from generating plants which have additive, long-range impacts on regional air quality, water resource impacts tend to be much more localized and are dependent on the location and characteristics of specific generating facilities and the affected water body. Thus, attempting to predict these impacts quantitatively on a generic basis would not yield meaningful results. It can be concluded, however, that overall potential adverse water resource impacts from plant redispatch under the scenarios considered in this GEIS would tend to be minimal, if any, and in some cases changes in plant operations could be beneficial. Furthermore, potential direct impacts would be controlled and mitigated through conditions of State Pollution Discharge Elimination System (SPDES) permits which are issued for each generating facility, and reviewed and revised as necessary every five years.[1]

The most important direct water resource impact of a steam-electric generating facility is the withdrawal of large quantities of water for condenser cooling. Nuclear and fossil generating units in New York withdraw about 20 billion gallons of water per day. These withdrawals cause mortality of aquatic organisms through the entrainment of small organisms and

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[1] Environmental Conservation Law, Article 17, Title 8, 6 NYCRR Part 751.

impingement of fish on the intake screens. This is a particular concern for plants located on the Hudson River which is an important regional fisheries resource. In fact, in the case of the Hudson River, the Department of Environmental Conservation is currently preparing a separate environmental impact statement to address these impacts as part of the SPDES permit reissuance process for plants operating on the river.[-]

It is not possible to predict reliably changes in water withdrawals that might occur under the scenarios considered in this GEIS because plant cooling water withdrawal is not directly related to plant load. Cooling water pumps at steam-electric units are typically operated continuously, regardless of load, to maintain flexibility to respond to load changes at short notice. In addition, with some plants water withdrawals are varied seasonably under SPDES permit conditions to minimize adverse impacts to aquatic life. Thus, increases or decreases in a plant's electrical output resulting from redispatch do not translate into changes in water withdrawals.

Given the above circumstances, any changes in withdrawals under the various scenarios would likely be small and would have

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[-] In 1993, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., the New York Power Authority and Orange & Rockland Utilities Inc. prepared a Draft Environmental Impact Statement (DEIS) pursuant to the State Environmental Quality Review Act to support their application for renewal of the SPDES permits for the Bowline Point, Indian Point 2 & 3, and Roseton steam electric generating plants on the Hudson River for the period 1994-1999. This DGEIS is currently under review and is being revised.

to be evaluated on an individual plant basis in order to assess the environmental impact. This analysis is done as part of the SPDES permit review and reissuance process. Plants that would seek to withdraw more water than allowed by their existing SPDES permits would have to apply for permit modifications in order to do so.[:]

One situation where there could be significant changes in withdrawals are scenarios where plants would be retired. Here water withdrawals could be reduced with resulting beneficial impacts. This could occur under Scenarios #4 and #5 where nuclear plants would be retired. Nuclear plants tend to have relatively large cooling water requirements and retiring these units could result in a net overall reduction in cooling water requirements. This would be particularly true if nuclear capacity were replaced with combined cycle units or facilities with closed cycle cooling systems. Under the scenarios, where imports are increased, there would also be greater economic pressures to retire in-state plants; this would net reductions in cooling water withdrawals.

Changes in the discharge of heat and other contaminants from steam-electric plants as a result of plant redispatch are also expected to be minor in terms of environmental impact. Unlike water withdrawals, the discharge of waste heat is a direct function of plant output which could change appreciably for some

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[:] 6 NYCRR Part 751 and 6 NYCRR Part 704.5.

plants under the certain scenarios. These changes are not meaningful from an environmental impact perspective, however. Thermal pollution is not a problem in any of the major water bodies in New York and conditions imposed by current SPDES permits assure that thermal discharges will remain within limits where no adverse impacts occur.[1] Steam-electric plants also discharge metals and other contaminants to waters, but these discharges are largely independent of plant load and would not be affected by changes in plant dispatch, except when plants would be retired. Again, plants seeking to discharge more or additional pollutants than allowed by their SPDES permits would require permit modifications.[2]

Water resources issues relative to the operation of hydroelectric projects include the effects of reservoir fluctuations on shoreline erosion, the effects of low flows on water quality, and the entrainment of aquatic organisms which may be injured as they pass through the turbines. The dispatch of the state's hydroelectric plants is unlikely to change under a competitive industry, however. With low marginal electric production costs, these plants would continue to be fully dispatched as they are now under the current regulated regime. Additionally, hydroelectric plants are constructed and operated under licenses issued by the Federal Energy Regulatory Commission

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[1] 6 NYCRR Part 704.

[2] 6 NYCRR Parts 700-704, 750.

(FERC) which are also reviewed by other federal and state agencies. Under its permitting authority, FERC may impose requirements to protect affected water, land and recreational resources.[1] States also issue water quality certifications for hydroelectric facilities under Section 401 of the Clean Water Act.[2]

The deposition of air contaminants on surface waters or on watersheds tributary to water bodies poses an indirect but important potential water resources impact. The burning of fossil fuels for electric generation emits large quantities of sulfur and nitrogen to the atmosphere which can be transported long distances and may cause increased acidification and injury to aquatic life when deposited to certain waters. Fossil fuel burning may also emit contaminants such as cadmium, lead, mercury and other toxic compounds which can be deposited to waters via atmospheric transport.

Due to the direction of prevailing winds, air emissions from fossil plants both from within and outside New York State result in the deposition of sulfur and nitrogen compounds on acid sensitive regions of the state such as the Adirondacks and the Hudson Highlands. It is estimated that more than 20 percent of the Adirondacks' 2,850+ waters are acidified and nearly 50

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[1] 16 U.S.C. §§ 797(e), 803(a)(1), 817(1).

[2] 33 U.S.C. § 1341(a)(1).

percent of its waters are critically sensitive to acidic deposition.[1]

Research and computer modeling show that for the Adirondack region, emission reductions under Title IV of the Clean Air Act will not be adequate to mitigate acid deposition. Water chemistry in Adirondack streams and lakes is not improving at the rate expected. Moreover, EPA computer models forecast that even with all the emission reductions required by current regulations, the number of acidic lakes in the Adirondacks will double by the year 2040. DEC has provided numerous comments to the EPA over the past year urging further reductions of acidic deposition and placement of a cap on NO_x emissions.

It is also significant that nitrate deposition impacts on New York's lakes and streams are greatest during the winter and spring coinciding with snowmelt periods. Therefore, reducing NO_x only during the "ozone season" does not necessarily relieve the acid deposition impacts of NO_x. During the summer months nitrate is rapidly taken up by vegetation in the watershed, but during the winter nitrate deposition accumulates in the snowpack and may cause acidic episodes during the spring snowmelt. These episodes are often the most acidic of the year and occur at a time when young trout may be in the streams. In order to reduce the acid

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[1] March 18, 1996 letter, Michael D. Zagata, DEC Commissioner to Ms. Mary D. Nichols, Assistant Administrator for Air and Radiation, "Comments of the New York State Department of Environmental Conservation on the Nitrogen Oxides Emissions Reduction Program" - 40CFR Part 76, RIN 2060-AF48 (AD-FRL-5400-2).

deposition impacts of NO_x emissions, it is important to reduce emissions year-round and not only during the ozone season.

The deposition of airborne nitrogen compounds may also contribute to the eutrophication of marine waters. For example, atmospheric deposition contributes an estimated 25 to 40 percent of the total nitrogen loading to Chesapeake Bay, 14 to 25 percent of the total to Delaware Bay and about 10 percent to New York Bay.[1] It is also an important contributor of nitrogen to Long Island Sound where problems of eutrophication and hypoxia have been encountered. The primary sources of excess nutrient loadings are discharges from sewage treatment plants, runoff from farms and commercial and residential fertilizer treatments, and air deposition of nitrates from automotive tailpipe emissions. Deposition of nitrogen from utility plants both in New York State and from out-of-state is thus a partial contributor to eutrophication problems in coastal waters. Water quality management plans to improve water quality in coastal areas such as Long Island Sound have been adopted and are being implemented.[2]

Similar to other environmental impacts to water resources, impacts from changes in the deposition of air contaminants associated with electric competition would be highly

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[1] "Deposition of Air Pollutants to the Great Waters," First Report to Congress, EPA-453/R-93-055, U.S. Environmental Protection Agency, May 1994, page 55.

[2] Comprehensive Conservation and Management Plan, Long Island Sound Study, March 1994.

dependent on the particular water resource affected. Water resources issues of acidification, eutrophication and toxification are complex problems and have multiple causalities of which the deposition of air contaminants is one important component. It is thus not possible to predict specific water resources impacts on a generic basis. In general, any future impacts will be reduced by future air quality control requirements of the Clean Air Act. Future actions to meet nitrogen oxide, acid deposition, ozone, particulate and hazardous air pollutant control requirements discussed in Sections 5.2.4.1, 5.2.4.2, 5.2.4.3 and 5.2.4.5 will also substantially reduce potential water resource acidification, toxification and eutrophication impacts. Additional controls of out-of-state air emissions, however, may be required to mitigate residual impacts.

5.2.5. Impacts of Potential Imports

As described in Section 4, maximizing imports into New York will have a beneficial impact on the level of SO_2, NO_x, and CO_2 emissions produced by generators of electricity in-state. However, part of the emissions that occur out-of-state due to increased out-of-state generation will find their way to New York and may affect the New York environment. The extent of the air quality impacts of increased air emissions, however, will depend on the precise location of the emission increases and the meteorological conditions. In general, the emissions from sources located upwind of New York and closer to the state

borders will result in more adverse impact on New York air quality. Likewise, any decreases in air emissions from reduced electric generation within the state will benefit New York air quality. The extent and duration of environmental impacts of the changes in air emissions will depend on the magnitude and locations of the emissions relative to population centers and other environmental receptors. The prevailing winds transport and disperse the emissions while the atmospheric conditions along the transport path chemically convert them into more stable compounds. Many of those compounds are deposited on or absorbed by landscape along the transport path while some stable emissions such as carbon dioxide may linger in the atmosphere for a long time. The relationship between the air emissions and any resulting environmental damages cannot be determined at this time because exact locations of the emissions increases and decreases and ambient chemistry data are not available in this generic assessment.

In the absence of precise locations for emissions, a clear relationship between emission changes and resulting environmental damage cannot be established. However, some general observations can be made on the potential environmental damages based on the New York State Environmental Externalities Cost Study, a project sponsored jointly by ESEERCO and NYSERDA, and published in January 1995. The New York study developed a computer model for estimating damage costs for environmental impacts of new electric generating plants in New York. Case

studies conducted as a part of the research project showed that environmental damages from air emissions will greatly depend on the distance between sources and the receptors. For example, the impacts of air emissions from a new generating plant located in New York City will be about four to eight times greater than the impacts of emissions from a similar plant located at a rural site on Lake Ontario.[1] Considering these factors and the greater distances between the generating facilities in the exporting regions and New York population centers, it is reasonable to expect the environmental impacts of increased emissions in those regions will be offset by the environmental gains resulting from the decreases in the in-state air emissions. The extent of offset would depend on the locations of emissions increases in the exporting regions relative to the locations of emissions decreases within the state. The air emissions impacts can be further reduced if the generating facilities in the exporting regions also eventually control their emissions to meet emission rates equal to those set forth for electric generating plants in the Ozone Transport Region (OTR).[2] Capping air emissions from generating facilities in the upwind regions of the OTR provides assurances that emerging competition will not impair the diligent efforts being made by the OTR states to comply with the air quality standards. New York State's concerns about the possible

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[1] New York State Environmental Externalities Cost Study Research Report 4: Case Studies, Table 3-2, January 1995.

[2] See Sections 110 and 126 of the Clean Air Act noted supra.

increase in air quality impacts of potential exports from the upwind regions as a result of the FERC proposal to allow open access to transmission service are expressed in the comments filed jointly by the Department of Public Service and the Department of Environmental Conservation.[1] The joint comments suggested that U.S. EPA develop a cap on NO_x emissions for each region based on controls on NO_x emissions to eliminate inequities in air pollution requirements among the states.

Besides the interstate air quality impacts discussed previously in this section, increased imports to New York could have other adverse environmental impacts. Increased imports could accelerate the retirement of existing plants and preclude the construction of new plants in the state. This could have adverse employment and tax base impacts which are discussed in Section 5.2.2 and Section 9. Increased imports could also create the need to expand and upgrade transmission facilities; these impacts are discussed in Section 5.2.6. There could also be air, land, water and other impacts from increased generation at existing plants that would occur within other states or Canada and would not affect New York because of their local nature. It is not possible to define these impacts at a generic level and whether these impacts would be greater or lesser than the reduced in-state impacts of lower electric production in New York. In

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[1] Letter dated February 1, 1996 to Lois D. Cashell, Secretary to the Federal Energy Regulatory Commission (FERC) by PSC Chairman John F. O'Mara and DEC Commissioner Michael Zagata.

general, any differences in impacts are considered likely to be small.

Greater imports to New York could also result in the need to construct additional generation facilities in other states or Canada to serve the export market. With the uncertainties of predicting future electric costs and technological progress with new generation facilities, it is not possible to predict reliably the types of generating facilities that might be constructed and to assess the likely environmental impacts. In general, any fossil generating facilities located upwind of New York would affect long range air quality conditions. However, the air quality impacts of these new fossil facilities would be mitigated to some degree by the requirement for these facilities to meet new source performance standards and other requirements of the Clean Air Act. In any case, these increased out-of-state air emissions would have to be compared against the comparable emissions and air quality impacts from new plants that would have to be constructed in New York if the imports didn't occur.

One possibility that has been suggested is that introduction of competition in New York will lead to dramatically increased imports from Quebec and make feasible the construction of the Great Whale or other large hydroelectric projects, causing significant adverse environmental impacts.[1] A previous draft

[1] Comments of the Grand Council of Crees (of Quebec) and Public Interest Intervenors on the Draft Generic Environmental Impact Statement, Case 94-E-0952 - In the Matter of Competitive Opportunities Regarding Electric Service, April 4, 1994.

generic environmental review prepared by the Department of Environmental Conservation regarding the purchase of power from Hydro-Quebec concluded that impacts both positive and negative could result to New York State from purchasing Quebec hydropower.[1]

The construction of additional hydroelectric power in Quebec could occur in the future, and given the scale and nature of such facilities, has the potential for causing significant environmental impacts that would warrant detailed study. However, the likelihood of these facilities being developed will not turn on whether the Commission introduces competition in the state's electric industry. In fact, projects such as Great Whale and others in Quebec have not been economically feasible to date under the current regulatory structure. A prior contract between NYPA and Hydro-Quebec to purchase hydroelectric power from Canada was cancelled by NYPA in large part because the power was not competitive with other sources. Accordingly, contracts to purchase power from very large, capital intensive hydroelectric projects like Great Whale are even less likely to be feasible under competition with its greater emphasis on efficiency and cost reduction.

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[1] New York State Department of Environmental Conservation, New York State Energy Office and New York State Department of Public Service, Draft Generic Environmental Review of the Impacts in New York State from the Cancellation of the 1000 MW Contract with Hydro-Quebec, June 1992.

5.2.6. Impacts from Changes in Electric Transmission

Adoption of either the Retail or Wholesale Model will not, in and of itself, directly necessitate immediate physical changes to the existing electric and gas pipeline transmission system in New York. In the short term (i.e., less than 3-5 years), the transmission system should not change significantly because most capacity should continue to be used to serve native load.

In the longer term, the effects of increased competition could increase demands on certain elements of the transmission system and present the need for upgrading or additional transmission lines. FERC action to promote wholesale electric competition and interstate transmission of electricity could have a significant effect. The need for increased transmission capacity from outside the state or to load centers distant from generation sites could also increase the need for new transmission lines or other alternatives. New transmission lines are only one of several alternatives that might be considered to increase power to "load pockets" such as New York City and Long Island.

The environmental impacts from reinforcing or building new transmission lines can be characterized by their location. Changes near or in load pockets such as New York City and on Long Island are most likely to occur from construction of underground electrical lines in heavily populated residential and commercial/industrial settings. Some overhead powerlines may

need to be constructed on Long Island along existing transportation or utility corridors. Underground gas transmission pipelines might be built to serve gas-fired generators to alleviate load pockets. Such construction could cause temporary, local traffic inconveniences and impact residential ornamental plantings and driveways. Underground lines also have the potential for disturbing buried archeological resources and historic sites.

Increasing the import of energy and transfer across the state along the bulk power system could require new transmission lines in rural areas of New York with its characteristic mix of forest, abandoned fields, croplands and scattered residential areas and small cities. In such areas, environmental impacts are likely to affect the more common natural resources and land uses. Increasing the width of existing utility corridors or creating new rights-of-way would result in the clearing of woodlands, forests and overgrown fields. They would be replaced by permanently maintained shrublands for transmission line rights-of-way by mowing, cutting and herbicide applications. Transmission rights-of-way have been found to increase plant diversity and provide favorable sites for some rare plants. Local changes in wildlife habitat would occur favoring shrubland and edge species. Portions of forested wetlands would be converted to shrubby open wetlands.

Temporary and permanent access roads for construction and maintenance would likely cause some soil erosion and

sedimentation of waterways which could impact streams, fishing and water quality. Buried natural gas pipelines are likely to cause temporary water quality impacts from increased sedimentation and turbidity during construction across waterways. Construction of support structures for electric transmission lines would likely disturb farmland operations which are so prevalent in upstate New York. Structures placed in agricultural fields would cause an inconvenience to farming and result in minor, long-term loss of cropland; if placed near farm buildings, the problem of stray voltage may affect dairy productivity. Permanent rights-of-way would reduce available land for housing and commercial development, especially in densely populated areas, but at the same time, increase land for potential recreational use and "greenbelts." However, until the possible health effects of electric and magnetic fields are better understood, Commission policy does not encourage recreational use of rights-of-way.

Overhead electric transmission lines with their conductors and support structures and associated substations would result in increased visual impacts to scenic, recreational and cultural resources. People in residential settings, and as travelers on roadways, would be affected by the visual impact of electric lines set out on the landscape. Visual impact will vary depending on the distance from the facility and the use of the existing landscape and structure color and placement to lessen the visual impacts. In general, new overhead powerlines have the

potential to cause significant long-term visual impacts.

Underground lines in the more populated areas such as New York City and any submarine lines to Long Island are likely to result in minimal visual impact. Long-distance transmission lines have successfully been routed in the past to avoid regionally significant visual resources such as the Adirondack and Catskill Parks. Important rivers such as the Hudson River can be crossed with underground cables encased in pipelines to reduce or eliminate visual impacts. As with distribution lines, transmission lines can be placed underground to reduce impacts on visually significant resources.

Long distance electric lines are likely to be routed along existing powerline corridors or replace older, lower voltage lines. Natural gas transmission lines are also likely to be constructed along existing lines except where needed to supply generation plants. This would mitigate the visual impact of any needed increase in transmission transfer capacity.

Major transmission facilities would also be scrutinized for need and environmental compatibility under Article VII of the Public Service Law (see Section 6.1.3.1). New lines associated with new generation plants would undergo full environmental review under Article X of the Public Service Law (see Section 6.1.3.2). The environmental impact of smaller transmission lines would be reviewed through the State Environmental Quality Review Act (see Section 6.1.5).

5.2.7. Impacts from Changes in Demand Side Management

The amount of electricity that would be saved in the future through demand side management (DSM) could change under a competitive industry structure. The regulated, vertically integrated electric utilities in New York have conducted large-scale programs that have helped customers to reduce their electricity consumption and corresponding electricity bills (see Section 2.2.5). The decreased electric use due to cost effective utility DSM implemented to date has provided environmental benefits resulting from decreased emissions from electric generators and potentially from reduced need to expand or reinforce T&D facilities. Utility DSM programs have decreased statewide emissions from generating plants, including SO_2, NO_x, CO_2, and small particulate emissions. The size of utility DSM programs, especially as measured in terms of money spent, has been dropping significantly in recent years as pressure to keep rates in check has intensified.

Under the Evolving Regulatory Model, the utilities may be expected to continue the reduced level of their budgets and energy saving goals of their DSM programs and redesign programs in response to their perceptions of the pressures of increasing competition in the electric industry, and concern with the level of rates. With the continuation of regulated vertically integrated monopolies, the Commission could mandate that these companies continue to conduct programs to improve the energy efficiency of customers but mechanisms would need to be developed

to ensure that the costs of programs are collected in ways that do not place utilities at a competitive disadvantage. Performance-based ratemaking (PBR) could continue to be used in an attempt to align the economic interests of utilities and their customers.

The Wholesale Competition and Retail Competition Models of a future electricity industry separate, in some fashion, generation from transmission and distribution. Under these models, generation would be deregulated and its owners have an economic interest in not improving the energy efficiency of end-use customers (unless they also form energy service companies to serve end users). The Commission could not mandate them to continue DSM programs currently conducted by the regulated vertically integrated utilities. Under both Competition Models, transmission and distribution (T&D) companies would be separated from generation resources,[1] and might also be prohibited from entering into long-term contracts for power supply. Hence, T&D companies would also not have economic incentives to pursue DSM for the purpose of avoiding long term generation supply or capacity investments. The Commission could, however, either direct them to continue DSM programs currently conducted by the regulated vertically integrated utilities, offer a basic package of DSM services, or find mechanisms to encourage the development

[1] Generation and T&D companies might be owned by the same holding company.

of independent suppliers of these services. Further, as regulated monopolies, the T&D companies could be required to employ a long term planning process for the T&D system that balances transmission and distribution investments with DSM alternatives.

Under the Wholesale Competition model, T&D companies would deliver electricity to customers (possibly only at pool spot prices), and might provide other limited energy services. If the T&D companies were permitted to enter into long term contracts, they might also be expected to continue some form of portfolio management. The unbundling of prices into various cost components could remove most "lost revenue" considerations, if stranded costs are not primarily recovered through a usage based charge. However, such a rate design mechanism would result in lower monetary savings to customers from reductions in usage, and this may tend to decrease their incentives to invest in energy efficiency.

Although the T&D companies would remain the only sellers of electricity to customers under the Wholesale Competition Model, an energy service company (ESCO) industry may further develop, but incentives to do so could be more limited because the market may be largely restricted to the delivery of energy efficiency services, and not also the delivery of electricity. Some parties, however, claim that ESCOs could offer a variety of services through financial contracts for differences.

The Retail Competition Model envisions the development of a competitive ESCO market that would compete for customers. ESCOs may offer customers packages of services that include both sales of electricity and energy efficiency services, with the overall objective of reducing customers bills. ESCOs could actively promote energy efficiency as a means of distinguishing their company from their competitors and of providing profitable value-added services to their customers. However, some parties believe that an undue focus on short-term economics and uncertainty about changes in the industry during the early stages of restructuring may limit the attention ESCOs pay to energy efficiency services at the outset of competition.

Under the Retail Competition Model, regulated T&D companies may serve customers who choose to remain with the local utility or who have no competitive alternatives, largely as a provider of last resort. A T&D company might also provide a basic package of DSM services to all customers, as long as it does not impede the development of competitive demand side markets, but it would have no market incentives to sell energy efficiency.

Compared to the present, in which utility DSM programs may be inhibiting the development of a competitive ESCO market, some parties believe retail competition has the potential to promote a more robust and diverse DSM industry. In the long term, competitive ESCO markets may develop that would serve all customer classes. This could also result in increased levels of

electricity savings produced by market based energy efficiency.

Utility DSM energy savings accomplishments peaked in 1993 at 1330.6 GWH. Proposed 1996 energy savings goals are 558.8 GWH, compared to 644.2 GWH in 1995 (see Section 2.3). The 771.8 GWH difference between 1993 and 1996 energy savings may indicate that much of the reduction in utility DSM savings due to the downward pressure on rates has already occurred. Although utility DSM goals have declined, the untapped potentially cost effective energy savings from DSM may remain large.

While it is unknown what the utilities might propose as goals for their DSM programs in 1997, it appears safe to estimate that they would not be larger than the 1996 goals, and would likely be lower. If 1997 and future utility DSM energy savings goals would have been equal to the 1996 goals, and if industry restructuring resulted in the loss of the total energy savings projected for 1997, then the maximum increase in generation would be 558.8 GWH. (As noted above, utility DSM cutbacks since 1993 may have already resulted in an additional increase in annual generation requirements of 771.8 GWH above the 558.8 GWH).

However, generation would probably not increase by these amounts over the long term. More competitive and responsive demand side markets (especially ESCOs) may be likely to secure some or potentially more of these energy savings from their customers. Energy efficiency may be pursued aggressively either as a customer service and retention strategy or as a stand alone profit center.

There are risks associated with these new directions for DSM programs, most notably that private markets for demand side services may not develop adequately, or that they do develop but insufficient consideration may be given to long term resource costs of decisions. Section 6 discusses mitigation options available to the Commission.

5.2.8. Changes in Research and Development

In 1972, the Commission recognized that the utility industry in general and the electric companies in particular were "the object of much controversy with regard to environmental questions" (Case 26105). It was anticipated that increasing demands and greater public awareness would continue to focus ever greater attention on aspects of power generation such as air pollution, discharge of waste heat to the environment, and depletion of natural resources.

The Commission was concerned that the electric utility industry, to a great extent, had relied on equipment manufacturers to carry the research burden. But the manufacturers' efforts were limited by profit considerations and by the need to protect proprietary information. The New York electric utilities, it was found, were not bearing their proportionate share of needed research and development costs. The Commission, therefore, established research guidelines, defining valid R&D, establishing research reporting requirements,

and directing that about 1% of revenues be devoted to research.[1]

The Commission re-examined its R&D spending guideline in 1978 and, following extended hearings on the utility R&D programs, stated that "...the 1% figure is a reasonable minimum target and that expenditures of between 1% and 2% of revenues are not, per se, unreasonable."[2]

On average over the past several years, statewide R&D expenditures have been slightly less than 1%. Recently, however, some utilities have cut back their funding from previous levels. Utilities have generally maintained strong internal research programs (addressing company-specific problems), but have also contributed to the Electric Power Research Institute (EPRI) and Empire State Electric Energy Research Corporation (ESEERCO), which were able to undertake the larger research projects on behalf of member companies, and to the New York State Energy Research and Development Authority (NYSERDA).

Department staff routinely reviews the utility research programs to ensure that they are balanced and conform to Commission guidelines. The result has been a cost-beneficial[3] R&D program that regularly introduces money- and energy-saving

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[1] NYS Department of Public Service, Research and Development Guidelines for New York State Electric Utility Companies, September 1973.

[2] Case 27145 - Long-Range Electric Plans, March 6, 1978.

[3] For example, the ESEERCO program from 1979 to 1984 showed projected benefits that were three times the cost of the program. NYS Department of Public Service, Staff Annual Report on Electric Utility Research and Development in New York State, 1988.

improvements and efficient environment control methodologies to the industry. In 1992 (the most recent staff report), the state electric utilities spent about $114 million on total RD&D (0.88% of revenues). About 56% of that was used for internal company projects, the remaining 44% was used for industry group research programs (primarily through EPRI, ESEERCO and NYSERDA). From internal programs, 18% was devoted to environmental research; another 10% was devoted to end-use research.

The financial pressures of recent years have prompted several utilities to severely cut research expenditures and suspend their memberships in EPRI and ESEERCO. Both EPRI and ESEERCO have attempted to encourage independent power producers to participate in industry research programs with little success.

Manufacturers of generation, transmission, and distribution equipment, as well as those who produce industrial equipment and consumer products, also maintain research programs. The programs are generally focused on cost efficiencies, but if consumer or regulatory demands require environmental improvements, the programs address those issues as well.

In a wholesale market, generation would become a competitive industry. In comparison to the Evolving Regulatory Model, owners of generation (unless they are part of very large entities) may be less likely to develop internal research programs, but may be more likely to depend on (and push) manufacturers to be more competitive by pursuing technological improvements for their products. Large entities will probably

pursue research and development that improves the efficiency of their plants, since this would improve profitability. On the other hand, the loss of a monopoly market will take away the safety net of assured recovery for R&D expenditures. Ultimately, whether generation R&D increases or decreases will depend on the weight of these factors. It is expected, however, under both competitive models, that regulated T&D companies will continue to maintain T&D related R&D programs.

Similar factors come into play when considering the Retail Model. Competitive forces will tend to encourage retail providers to look for ways to efficiently serve the customers, including technological improvements, in order to maintain their own profitability. Once again, however, regulation has provided assured recoverability of R&D in energy efficiency programs, tending to reduce the risk of these expenditures. Again, the direction of any change in expenditures will depend on the balance between these factors.

Utility research has been a major source of new techniques for environmental impact mitigation. As a result of competition, research sponsored by the competitive generators could suffer an immediate decrease during the transition to competition. Manufacturers will probably increase their programs gradually to compensate, but the increases will probably be in areas that will improve profitability, maintain competitiveness and meet required regulatory limits for the major pollutants (air and water emissions and solid waste).

Generation research in the more lightly regulated environmental areas (natural resources, noise, aesthetics, etc.) will likely decline unless demanded by the public.[1] Lastly, if vigorous competition develops in the energy delivery sector, it is possible that research in DSM and energy efficiency might increase over current levels.

5.2.9. Impacts of Environmental Liabilities

The move to a competitive electric industry could impact the funding available to address environmental liabilities at operating or formerly used utility facilities. The two largest liabilities are the cleanup of utility-owned manufactured gas plants and decommissioning of nuclear units.

5.2.9.1. Manufactured Gas Plants

Nine utilities in New York State are responsible under current environmental laws for the cleanup of approximately 120 sites contaminated by coal tar, cyanide, metals and organic hazardous wastes. The contamination results from residues remaining from plants that supplied gas manufactured from coal and oil during the 19th century up through the 1940s, before natural gas became widely available. Manufactured gas plant (MGP) residues were mostly left on-site in pits or containers,

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[1] NYS Energy Research and Development Authority, Toward The 21st Century - A Multi-Year Research Plan for New York's Energy, Economic and Environmental Future, 1995, p. 2-7.

placed in nearby ponds or lagoons, or taken to off-site areas for land disposal, resulting in contamination of soil and ground water.

Federal and state laws require abatement and remediation of sites contaminated by hazardous substances, including MGP wastes (see Section 6.1.8). Moreover, the current laws impose strict retroactive liability upon current property owners. The total estimated cost to remediate these sites ranges between $0.5 billion and $2 billion over the next 30 years. Seven of the affected utilities have entered into consent agreements with DEC for cleanup of these sites.

Adoption of either the Retail or Wholesale Competition Models would not remove the liability to clean up these MGP sites. However, the manner in which the costs for remediation would be recovered could be affected, and in turn could affect the ultimate cost and rate of progress with the cleanup.

In the past, the Public Service Commission has addressed the recovery of MGP remediation costs in response to a number of rate requests and deferral petitions. In its decisions, the Commission has found that the expenditure of funds for these purposes was a reasonable cost of doing business and generally allowed full recovery of prudently incurred costs. The Commission has not adopted a generic policy for the allocation of MGP cleanup costs between the electric and gas departments of the seven utilities with combined services. Where there has been no demonstration that the sites were directly related to either

current electric or gas operations, the Commission has generally treated these costs as a corporate (common) expense. In some cases, the Commission has determined that the costs should be fully allocated to the utility's gas department.

The manner of future recovery of such costs under a Retail or Wholesale Model would depend on whether these liabilities remain with regulated transmission and distribution company, are assumed by a competitive company, or are assumed or guaranteed by a governmental entity. Since the liability represents a large, potentially stranded cost for the current utilities, it is improbable that the liability would be assumed by a competitive company. While it is possible that a public entity might assume the liability, it is much more likely that responsibility would remain with the regulated utility.

Specific requirements to achieve cost recovery, control remediation costs and minimize delays in cleanup are discussed in Section 6.2.4.5.

5.2.9.2. Nuclear Power Plant Decommissioning

Six investor-owned utilities and the NYPA own and operate six nuclear generating plants in New York State. These plants produce about 18 percent of the state's electric energy. In addition, Consolidated Edison owns a retired nuclear facility (Indian Point No. 1). Associated with these seven plants is a substantial environmental liability in terms of the costs necessary to ultimately remove and dispose of the radioactive

components and wastes from these facilities when they are decommissioned.

Proper handling and disposal of radioactive materials and wastes is an important environmental issue. In sufficient doses, radiation is harmful to human health and the environment. Current regulatory policy is to keep radiation exposures as low as is reasonably achievable. The spent fuel from a reactor is considered a high level radioactive waste (HLRW) and under current law is the responsibility of the federal government for disposal. However, the federal government has not yet developed a HLRW disposal facility as it was required to do so in the Nuclear Waste Program Act of 1983. Moreover, although a lawsuit is pending by New York and other states and bills have been introduced in Congress on this issue, it is unclear whether an interim or permanent storage facility will be available in the future. In the interim, spent fuel is being stored on-site in spent fuel pools. The disposal of low-level radioactive waste (LLRW) from plant operations and ultimately from decommissioning of the plants is a state responsibility. A LLRW disposal site has not yet been selected in New York State and these wastes are currently being stored on-site or shipped out-of-state for disposal.

Commercial nuclear generating facilities in the U.S. are regulated under federal law by the Nuclear Regulatory Commission (NRC) and require both a construction permit and operating license (see Section 6.1.7). One of the conditions imposed on a

licensee under NRC regulation is the establishment of a fund that is adequate to finance decommissioning of the facility when it is finally abandoned. The total cost to decommission the seven plants in current dollars is estimated to be about $3.5 billion. Pertinent information on the seven nuclear plants is presented in Table 5-6 below.

Table 5-6

Plant	Owner	License Life	% NYS Generation (Total MWhs)	Decommissioning Cost ($ millions)
NnNine Mile Pt.1	NMPC	2009	2.1	626
NNNine Mile Pt.2	Cotenant ownership of Nine Mile 2 is: NMPC: 41% NYSEG: 18% LILCO: 18% RG&E: 14% CHG&E: 9%	2026	2.2	806
Ginna	RG&E	2009	2.5	296
Indian Pt. 1	Con Ed	Retired	-	231
Indian Pt. 2	Con Ed	2013	4.4	427
Indian Pt. 3	NYPA	2015	3.5	518
Fitzpatrick	NYPA	2014	3.7	538
TOTALS			18.4	$3,442

Adoption of either the Retail or Wholesale Competition Models would not remove the liability to decommission plants. However, the manner in which the costs for decommissioning would

be recovered might be affected.[1]

In the past, the Public Service Commission has addressed the recovery of decommissioning costs in response to a number of rate requests for the five investor-owned nuclear plants. In its decisions, the Commission has found that the expenditure of funds for decommissioning was a reasonable cost of doing business. The Commission has allowed the utilities to establish separate decommissioning funds, and monies have been collected from ratepayers to augment the funds. The rate of cost recovery has been based on the estimated decommissioning costs of the plants and the period of time to the end of the plant's operating license.

The manner of future recovery of such costs under a Retail or Wholesale Model would depend on whether these liabilities remain with a regulated utility transmission and distribution company, are assumed by a competitive generation company, or are assumed or guaranteed by a governmental entity. Since the liability represents a large stranded cost for the current utilities, it is improbable that the liability would be assumed by any competitive company. It has been suggested that a public entity such as the New York Power Authority might take over the operation of all of the state's nuclear plants and thus assume the decommissioning liability (along with monies in the

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[1] The Nuclear Regulatory Commission has prescribed requirements for methods, timing and the funding of decommissioning.

current decommissioning funds). Barring takeover by a public entity, it is probable that responsibility would devolve to the regulated T&D utilities.

In the expectation that the regulated T&D utilities would recover decommissioning costs, the issue of cost sharing between ratepayers and stockholders may become important. Because the NRC imposes strict requirements on decommissioning methods, timing and financing, these costs would probably not be appropriate for sharing.[1]

Specific requirements to achieve cost recovery, control costs, and minimize delays in decommissioning are discussed in Section 6.2.4.2.

5.2.10. Impacts from Change in Treatment of Environmental Externalities

Externalities are costs and benefits to society that result from production and consumption activities that are not accounted for in production costs and prices. Consideration of externalities is not now a major operational consideration for utilities, and any future reliance on externalities potentially concerns the import of power from states upwind. For electric resource options, environmental and social impacts and the associated economic costs or benefits are externalities only when

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[1] The NRC recently issued an advanced notice of proposed rulemaking concerning amendments to its financial assurance requirements for decommissioning of nuclear power plants in light of electric industry restructuring. 61 Fed. Reg. 15427 (April 8, 1996).

they have not been internalized into the price of electricity. Consideration of externality costs by the New York electric industry was largely limited to procurement of new electric resources beginning in 1989 when competitive bidding was adopted by the Commission for choosing electric resource options. Utilities also consider the impact of potential environmental externalities when evaluating the benefits and costs of prospective demand side management programs.

In competitive electric markets, the Commission's ability to force internalization of externality costs will be limited. Further, there are concerns about requiring the consideration of externalities inconsistently across the nation as it would have its own distortion of the competitive markets. The ideal solution may be a national policy that would require internalizing externalities in all energy markets. Instruments for doing this include emission taxes, fees, offsets, caps and marketable permits. Indeed, the CAAA has taken a major step. While the CAAA of 1990 forced internalization of SO_2 emission costs by the electric industry, efforts are currently underway to apply market based methods for treating NO_x control costs in a similar manner. In the absence of a national action which internalizes the external costs of electric generation, the choice of considering external costs will become optional to the future electric generators. Under those circumstances, it will be unlikely that the future owners of electric generators in a de-regulated competitive market will consider external costs in

choosing resource options unless such consideration will not increase their internal cost.

5.2.11. Impacts from Changes in Investments in Renewables

Renewable energy resources which displace other types of electric generation can have positive environmental impacts. Hydro, wind, photovoltaic and fuel-cell electric generation generally have a lesser impact on air quality than do fossil-fueled generators. Renewable generators at remote locations may also eliminate the need for T&D facilities with their attendant environmental impacts (e.g., disruption of agricultural and forest lands).

One of the most significant factors expected to affect the expansion of renewable technologies is the future cost of fossil fuels. This is especially true for those technologies which need further development and market acceptance to compete successfully over the long term. With either a retail or wholesale model, and without public support, there is a diminished likelihood that utility R&D funding will continue for those types of renewable technologies which do not appear competitive with conventional forms of generation in the near term. If the Commission determines that a system benefits charge is warranted to pay for certain public benefit programs, funding for selected renewables projects might be considered among the recipients of these funds in those instances where renewable

energy investments are expected to prove cost-effective in the long run (see Section 6.2.1).

It is worth noting that New York currently relies on renewable energy resources to meet a portion of its electrical energy needs. In 1995, New York State derived about 16.7% of its electrical energy generation from renewable resources. The New York Power Pool (NYPP) projects[1] that in the year 2000 about 13.2% of the state's 35,927 MW of generating capacity (i.e., utility and non-utility generators) will be derived from renewables. The NYPP renewable generation breakdown for the year 2000 is conventional hydroelectric (4,510 MW); wind turbines (10 MW); photovoltaics (4 MW); fuel cells (3 MW); methane-fired steam-electric (23 MW); wood-fired steam-electric (43 MW); and refuse-fired steam-electric (211 MW).

Some of the forms of renewable energy noted above are already cost-effective for use in electric generation and they would likely continue to be used under either competitive model. In New York State, these renewables include conventional hydro as well as wood-fired and refuse-fired steam electric generation. Other renewables such as wind, solar and fuel-cells may be practical on a lesser scale for generating electricity in remote areas where customers do not have access to the grid or where T&D improvements may be costly. Renewable technologies (e.g., wind, photovoltaics, fuel cells), because of their modularity, may also

[1] "Report of the Member Systems of the New York Power Pool, LOAD & CAPACITY DATA - 1995."

have value to customers with smaller loads who seek to self-generate and thereby avoid expensive power purchases from sources off-site. Renewable technologies may also be one of the resource options considered when addressing load pocket problems in the state. Electric generation from renewable energy resources can also result in negative environmental impacts. These impacts need to be weighed against the environmental impacts of other generation alternatives when making generation facility siting decisions.

5.2.12. Impacts of Changes in Fuel Use

The greatest environmental impact from changes in fuel use would be caused by the deposition of pollutants (and perhaps, carbon dioxide) emitted from power plants. This section will outline the changes in fuel use that result when several underlying assumptions were changed from the Evolving Regulatory scenario. The discussion focuses on three of the alternate scenarios: #2, Low Sales; #3, IPPs on Economic Dispatch; and #5, High Sales/Nuclear Retirements.

The Low Sales scenario is likely to have a positive effect on the environment, relative to the Evolving Regulatory scenario, because of the reduction in electric production. Since hydroelectric and nuclear outputs are virtually fixed from year to year, the reduction in output will be absorbed by fossil-fueled plants. As Table 5-7 shows, coal-fired generation is approximately 25,000 gigawatt hours (GWh) lower during the study

period. Oil-fired output is essentially unchanged. Utility-owned gas-fired output also falls by about 25,000 GWh.

IPP output, virtually all of which is gas fired, is 167,000 GWh lower than in the Evolving Regulatory scenario. The large decrease in that output is due to the fact that new plants are not needed under this scenario until 2010, while the new generators are needed earlier in the Evolving Regulatory scenario.

Under Alternate Scenario #3, IPPs on Economic Dispatch, sulfur dioxide emissions increase by about 11 percent above the Evolving Regulatory scenario emissions by 2012 (see Table 5-2). The reason for that increase is an increase in coal-fired generation of some 31,000 GWh during the study period. Coal output increases because that is the lowest priced fossil fuel available. Coal is displacing both oil-fired output and IPP output which is placed on economic dispatch in this scenario.

The total IPP output for the study period, however, actually increases relative to the Evolving Regulatory scenario; and utility owned gas output falls. The increased IPP output is due to the fact that new units are modeled as more efficient (8,000 Btu/KWh) generators. These units displace utility-owned gas and oil generation.

Under Alternate Scenario 5, there is also an increased amount of sulfur dioxide emissions, though not to the extent observed under the IPP-on-Dispatch scenario. This is the worst-case scenario in terms of NO_x and CO_2 emissions. These increases

in emission are understandable, as fossil generation replaces two retired nuclear plants under a scenario of rapidly growing sales.

Table 5-7 Fuel Use over Study Period (1997-2012) under Selected Scenarios

Evolving Regulatory Scenario	Generation (GWhs)	Percent of Total
Coal	424.500	16.9%
Oil	136.594	5.4%
Natural Gas	305.011	12.2%
Hydroelectric	400.706	16.0%
Nuclear	505.589	20.2%
Non-Utility	735.105	29.3%
Total	2.507.505	100%

Alternate Two	Generation (GWhs)	Percent of Total
Coal	399.352	17.5%
Oil	135.549	5.9%
Natural Gas	277.762	12.1%
Hydroelectric	400.706	17.5%
Nuclear	505.589	22.1%
Non-Utility	568.475	24.9%
Total	2.287.433	100%

Alternate Three	Generation (GWhs)	Percent of Total
Coal	455.826	18.2%
Oil	120.173	4.8%
Natural Gas	262.024	10.5%
Hydroelectric	400.706	16.0%
Nuclear	491.173	19.6%
Non-Utility	773.494	30.9%
Total	2.503.396	100%

Alternate Five	Generation (GWhs)	Percent of Total
Coal	433.244	15.7%
Oil	125.609	4.6%
Natural Gas	317.684	11.5%
Hydroelectric	400.706	14.6%
Nuclear	310.555	11.3%
Non-Utility	1.164.567	42.3%
Total	2.752.365	100%

Note:Non-Utility generation includes new, gas-fired plants, whose ownership is irrelevant for the purpose at hand.

5.2.13. Impacts of Changes in Development of New Technology

Competition, by definition, implies creativity and ingenuity. Consequently, a move to a more competitive environment may bring with it an increase in the development of new technologies. Certainly, there will be strong incentives for owners of generation to find ways to improve operating efficiencies and to reduce the cost of the generation units. Where new environmental restrictions appear imminent, economic incentives will exist for generation owners to find new technologies that reduce emissions of contaminants and minimize environmental impacts. Similarly, with more competitive retail markets, there could be increased economic incentives (through competitive pressures for attraction and maintenance of customers) to find new and better ways to serve customers (such as through new mechanisms to integrate electricity, telephone, security, television, computer, household environment, and other services).

Other new technologies could also result, such as the development of cost-effective electric vehicles and new forms or sizes of generation equipment appropriate for use in congested locations, possibly even in individual homes. Even in the areas that would continue to be regulated (i.e., the wires), new technologies are even now being developed to allow increased use of existing facilities. Such technologies would allow the wires companies to benefit by meeting the needs of a growing market

that should be expected as competition encourages growth.

While many of the developments noted above might eventually come about under a regulated environment, the incentives associated with the risks and rewards of competition indicate that the speed of new developments would quicken. And, indeed, there could be developments in some areas that might not even be pursued in a regulated environment. On the other hand, some technology improvements thought desirable by regulators might not be pursued by competitive entities. To the extent that research and development might continue to be deemed appropriate, other approaches might be considered, such as the funding of certain initiatives through a system benefits charge.

6. REGULATORY FRAMEWORK AND MITIGATION OF ADVERSE IMPACTS

As described in Chapters 4 and 5, the proposed action to adopt policies leading to competition in the electric generation and energy services industries could lead to industry responses that are harmful to air, water and land resources, and create undesirable impacts on the human environment that are physical, social and economic. The magnitude of these adverse impacts are limited in the first instance by the existing comprehensive framework of federal and state environmental laws and regulations. Rather than mitigating adverse impacts, it is the purpose of these laws and regulations to prevent adverse environmental impacts from actions by people, regardless of whether the source of those actions are the pressures of economic competition or simple disregard for the need to preserve natural resources. Section 6.1 below describes the existing framework of environmental laws and regulations, and how these measures will prevent untoward environmental consequences of the proposed action to supplant rate regulation with increased competition in the generating and energy services sectors of the electric industry.

As discussed in Chapter 5, however, the existing framework of environmental law and regulations appears to be insufficient to prevent adverse environmental impacts from competition in the electric industry. Notwithstanding the law, adverse impacts to the air quality of New York State can occur

due to the interstate transport of acid rain and groundlevel ozone precursors that can harm acid sensitive areas of New York State and human health in ozone nonattainment areas of New York City and other parts of the state. Accordingly, Section 6.2 describes specific conditions, thresholds and measures that can be taken by the Public Service Commission to mitigate adverse environmental impacts. It also describes measures that can be taken by the Public Service Commission in cooperation with state and federal environmental regulatory agencies.

6.1. Regulatory Framework

6.1.1. THE FEDERAL CLEAN AIR ACT AND NEW YORK AIR POLLUTION CONTROL LAWS

6.1.1.1. Overview

The Clean Air Act of 1967, as amended in 1970, 1977 and 1990 is the legal basis for air pollution control throughout the United States. The Environmental Protection Agency has primary responsibility for carrying out the requirements of the Act, which specifies that air quality standards be established for certain types of pollutants. These standards are in the form of concentration levels that are believed to be low enough to protect public health. Source emission standards are also specified to limit the discharge of pollutants into the air so that air quality standards will be achieved. The Act was also designed to prevent significant deterioration of air quality in areas where the air is currently cleaner than the standards

require. The Amendments of 1990 identified ozone, carbon monoxide, particulate matter, acid rain and air toxins as major air pollution problems. These pollutants cause acidification and eutrophication of lakes, streams and waterways, and ground level ozone and emissions of hazardous air pollutants that adversely affect human health and the environment. Enforcement of the Clean Air Act is delegated to the states. The New York State Department of Environmental Conservation implements the requirements of the Act as well as state air pollution laws.

Electric generating facilities that burn fossil fuels, including oil, coal and natural gas, emit pollutants that are of primary concern under federal and state air pollution and control programs. The details of federal and state air pollution control programs and how they apply to electric generators are discussed in Sections 3.4, 4.1, 5.2 and in Appendix A. This section outlines the federal and state statutes and programs that limit air emissions from electric generating facilities. It then describes how enforcement of these requirements will continue to limit the emission of air pollutants by electric generators. Discussion then turns to the deficiencies of the federal and state statutes in addressing air pollution from in-state and out-of-state sources of air contamination. The section concludes with a description of actions the Commission can take to mitigate changes in air emission patterns from electric generators that could result under a competitive regime.

6.1.1.2. Clean Air Act Programs Affecting Electric Generating Facilities

The Clean Air Act ("CAA" or "Act") establishes a comprehensive program to control and abate air pollution through regulation of mobile and stationary sources of air emissions.[1] The 1990 amendments to the Act contain complex and extensive new provisions that require hundreds of EPA and state implementing regulations. Title I of the Act provides a broad regulatory framework applicable to stationary sources of air emissions. A stationary source is any building, structure, facility or installation which emits any regulated air pollutant, including electric generating stations.[2]

Title I of Act requires EPA to promulgate national ambient air[3] quality standards (NAAQSs) for pollutants adverse to human health or welfare.[4] EPA has adopted NAAQS for the following pollutants: sulfur dioxide, nitrogen oxides, carbon monoxide, particulate matter, ozone and lead.[5] Electric generating facilities are a large source of nitrogen oxides, which cause ground level ozone smog, as well as sulfur dioxide, carbon monoxide and particulate matter.

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[1] 42 U.S.C. §§ 7401-7671q.

[2] 42 U.S.C. § 7411(a)(3).

[3] Ambient air is the air that the public breathes.

[4] 42 U.S.C. § 7409.

[5] 40 CFR Part 50.

Title I of the Act also limits emissions 189 listed hazardous air pollutants (HAPs).[1] The 1990 amendments initially excluded emissions from electric utility generating units from the hazardous air pollution control program. Instead, the Act requires EPA to report the results of a study of hazards to the public caused by emissions by electric utility generating units. The Act specifically requires EPA to study mercury emissions from electric utility generators.[2] EPA continues to work on this study, and is expected to report to Congress that mercury emissions from electric utility generators should be limited. Subsequently, EPA is expected to promulgate regulations limiting these emissions.

Title I imposes additional requirements on major stationary sources of air pollutants that emit or have the potential to emit at least 100 tons per year of any regulated pollutant. Existing, new and modified sources of air pollution located in a nonattainment area for one or more NAAQS are required to obtain permits for their emissions under the Act.[3] New or modified major stationary sources located in attainment areas must obtain an emission permit from EPA or the state in order to prevent significant deterioration of air quality,

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[1] 42 U.S.C. § 7412.

[2] 42 U.S.C. § 7412(n)(1).

[3] 42 U.S.C. §§ 7502, 7503.

including impairment of visibility.[1] Title V of the Clean Air Act establishes a detailed operating permit program that must be complied with by all major stationary sources of air pollution.[2]

Title IV-A of the Clean Air Act controls the emissions of precursor pollutants that cause acid rain, principally nitrogen oxides and sulfur dioxide.[3] Title IV adopts a market-based approach to pollution control, creating a nationwide sulfur dioxide emission allowance trading program.[4] Sources regulated under Title IV must obtain SO_2 allowances equal to the amount of SO_2 that they are authorized to emit. An emission allowance is a limited permit to emit one ton of SO_2. Allowances may be bought, sold and banked for future use, enabling each source to comply with applicable SO_2 emission limitations in the most efficient and cost-effective manner possible.

Beginning in January 1995, Phase I of the SO_2 program limited SO_2 emissions from 111 generating facilities nationwide, including facilities owned and operated by New York utilities.[5] By January 2000 (Phase II), virtually all fossil-fueled generating units 25 MW and larger in capacity will be subject to a decreased SO_2 emission limit of 1.2 pounds per million BTU

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[1] 42 U.S.C. §§ 7470-7479.

[2] 42 U.S.C. §§ 7661-7661f.

[3] 42 U.S.C. §§ 7651-7651o.

[4] 42 U.S.C. § 7651b.

[5] 42 U.S.C. § 7651c.

multiplied by an energy use baseline. From that formula, existing units will be allocated a specified number of emission allowance each year. This process will lead to a 10 million ton reduction and a nationwide cap on SO_2 allowance of 8.95 million tons from electric generating stations per year.[1] Although emission limitations on nitrogen oxides are not subject to an allowance trading program for acid rain, Title IV requires reductions in emissions of nitrogen oxide emissions that also contribute to acidification of waterbodies and acid deposition on land.[2]

6.1.1.3. Enforcement of Clean Air Act Requirements

Major stationary sources of air pollution, including electric generating facilities, are prohibited by the Clean Air Act from emitting or increasing emissions of criteria pollutants without obtaining required permits and allowances covering all of their emissions. Section 120 of the Clean Air Act imposes compulsory civil noncompliance penalties on any emission source that seeks to avoid timely compliance with air emission laws.[3] Moreover, as a delegated program, each state is required to establish and submit for EPA approval a state implementation plan (SIP) that describes how NAAQS and other air pollution control

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[1] 42 U.S.C. § 7651d.

[2] 42 U.S.C. § 7651f.

[3] 42 U.S.C. § 7420.

programs will be implemented.[1] The details of New York's compliance with the SIP requirements are discussed in section 6.1.1.5, below. Finally, states have legal remedies available to require EPA to take regulatory action against upwind sources of air pollutants that adversely affect downwind areas. Section 110 of the Act requires each state's SIP to contain provisions prohibiting sources from emitting pollutants that "contribute significantly" to non-attainment in another state. If EPA makes a finding of significant contribution by upwind sources, the state where those sources are located must submit SIP revisions to correct the inadequacy. EPA may give the state up to 18 months from the date of the finding to make the SIP submission.[2] Moreover, Section 126 of the CAA enables states to petition EPA with a scientific showing that a major source or group of stationary sources emits air pollutants in an amount that violates the prohibition against "contribut[ing] significantly to nonattainment downwind."[3] In this manner, upwind sources can be prohibited from continued operation until they achieve emission reductions deemed appropriate by EPA.

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[1] 42 U.S.C. § 7410.

[2] 42 U.S.C. §§ 7410(a)(2)(D), 7410(k)(5).

[3] 42 U.S.C. §§ 7410(a)(2)(D), 7426.

6.1.1.4. Energy Policy Act of 1992

Title XVI of the federal Energy Policy Act of 1992 (EPAct) addresses global climate change.[1] EPAct does not require the reduction of emissions of carbon dioxide and other gases that are believed to be precursor pollutants that cause global warming through the greenhouse effect. Rather, EPAct requires the Department of Energy to submit reports to Congress that assess options for limiting greenhouse gas emissions. The policies that must be considered in a least-cost energy plan include initially stabilizing and eventually reducing greenhouse gas emissions, as well as increasing national energy efficiency, increasing reliance on renewable resources, and reducing reliance on fossil fuels for electricity production.[2] EPAct encourages voluntary reductions of CO2 by electric generators and other industrial sources. In response, on October 19, 1993, the President introduced a U.S. Climate Action Plan to reduce by 2000 national greenhouse gas emissions to below 1990 levels.

6.1.1.5. New York Air Pollution Control Measures

Congress delegated authority to implement the complex requirements of the Clean Air Act to the states, including the New York State DEC.[3] The Act requires the development of state implementation plans (SIPs) for achieving compliance with the

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[1] P.L. 102-486, §§ 1601-1609, 106 Stat. 2999 (October 24, 1992).

[2] Energy Policy Act of 1992, § 1602, 106 Stat. at 2999-3001.

[3] 42 U.S.C. § 7410.

NAAQSs for ground level ozone and other pollutants. SIP is a set of regulations that sets forth, in detail, the measures to be required by the state to comply with the NAAQSs.[1]

Under the Clean Air Act, the New York SIP must implement stringent compliance measures to address ozone nonattainment areas, acid rain and air toxics. To meet these requirements, DEC submitted SIP revisions in 1992, 1993 and 1994. A major element of the SIP is reduction of emissions from fossil-fueled electric generating plants. Existing generators must install reasonably available control technology (RACT) to reduce NO_x emissions from boilers. Moreover, new generators must meet the lowest achievable emission rate (LAER) by installing the maximum available control technology (MACT). New sources must also obtain offsetting emission reductions from other sources that exceed the amount of emissions from the new source. Detailed descriptions of these and other New York programs implementing the Clean Air Act are contained in Sections 3.4, 4.1, 5.2 and Appendix A.

New York State is also part of the Northeast Ozone Transport Region (OTR), which stretches from Maryland to Maine. The member states of the OTR are represented on the Ozone Transport Commission, which coordinates regional nitrogen oxide emissions reductions from major stationary sources throughout the OTR. On September 24, 1994, New York and other member states

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[1] 42 U.S.C. § 7410; 40 CFR Part 51.

approved a Memorandum of Understanding (MOU) to significantly reduce NOx emissions from states within the Northeast OTR and achieve compliance with the NAAQS for ozone. The MOU divides the Northeast OTR into inner, outer and Northern Zones, with the Inner Zone being most severe in ozone nonattainment. The MOU establishes emission limitations for each zone. Moreover, the members states of the OTC have agreed to a federally-enforceable cap and trade program that would limit NO_x emissions within the OTR to levels established in a budget.

New York has also enacted statutes addressing the emission of air pollutants from electric utility generators and other stationary sources. The State Acid Deposition Control Act (SADCA) predates the Clean Air Act Amendments of 1990 and imposed stringent controls to curb the effects of acid precipitation.[1] The Act set forth a procedure for controlling sulfur dioxide and nitrogen oxide emissions, and required DEC to identify the state's sensitive areas and promulgate and enforce threshold levels. These provisions apply to all steam electric generating facilities with a generating capacity over 50 MW and which burn fossil fuels.[2] Additional discussion of DEC implementation of SADCA is contained in Chapter 5 and Appendix A.

In 1993, the New York State Legislature also enacted the New York Clean Air Compliance Act (NYCACA) to ensure New

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[1] Env. Conserv. Law §§ 19-0901-0923.

[2] Env. Conserv. Law § 19-0905.

York's compliance with the stringent air quality standards and timetables of the CAA.[1] NYCACA provided DEC the authority to develop and implement measures through the New York SIP to control air emissions from power plants, other stationary industrial sources, and emissions from mobile sources. With respect to stationary sources, NYCACA authorizes DEC to revise its operating permit program to be consistent with the federal Clean Air Act.[2]

6.1.1.6. Effects of Legal Requirements on Emissions from Electric Generation

The federal and New York State statutes, regulations and programs discussed in Chapter 5 and Appendix A have a common purpose to limit emissions from electric generating facilities owned by utilities, independent power producers and public authorities located in New York State. Title I of the Clean Air Act, as implemented by EPA and DEC regulations, the New York State Implementation Plan and the Ozone Transport Commission Memorandum of Understanding will cap NOx emissions by generating stations located in New York State. Emissions of hazardous air pollutants, such as mercury, will be limited by regulations implemented and permits enforced by EPA and DEC on fossil-fueled electric generating stations in New York State. Moreover, federal and state air pollution controls will curb emissions of

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[1] New York Clean Air Compliance Act, 1993 N.Y. Laws ch. 608 (August 4, 1993); Env. Conserv. Law art. 19, titles 1 and 3.

[2] Env. Conserv. Law § 19-0311.

particulate matter (PM-10) and, potentially, fine particulate matter (PM-2.5) from power plants. Finally, the emission of acid rain precursors that harm deposition-sensitive areas in the Adirondack Mountains and other parts of New York State, such as sulfur dioxide and nitrogen oxides, will be restricted by the Clean Air Act and the Stat Acid Deposition Control Act.

This complex network of federal and state laws and regulations will ensure that electric generating facilities located in New York State will have only a limited ability to increase their emission of air pollutants in response to pressures to increase production or cut costs to meet the forces of competition in the electric industry in New York State. Electric generators seeking to compete in a competitive wholesale or retail electric marketplace in New York State will be forced to function within operating permit limitations enforced by DEC or face severe penalties. Generators seeking to increase their emissions will have some flexibility to increase emissions of certain pollutants, such as SO_2 and NO_x, by purchasing emission allowances in the national SO_2 allowance program or through the OTC MOU NO_x allowance cap and trade program. Allowance purchases are limited, however, to caps on allowance levels for both SO_2 and NO_x. As implementation of federal and state clean air requirements proceeds, these emission caps will be ratcheted down. These provisions will continue to require electric generators to operate within the confines of the air pollution limitations imposed by federal and state law.

Nevertheless, the Clean Air Act Amendments of 1990, SADCA, and implementing regulations by EPA and DEC appear to be inadequate in addressing air pollution problems in New York State. Notwithstanding federal and state mandates, the acidification of deposition-sensitive areas of New York State in the Hudson highlands and Adirondack Mountains continues to worsen.[1] Moreover, existing laws and regulations do not appear adequate to ensure that the New York City metropolitan and other areas of the state that are non-attainment for ground level ozone will be able to attain the national ambient air quality standards for ozone established in the Clean Air Amendments of 1990. Instead, the effects of long range transport of the precursor pollutants that cause acidification and ground level ozone problems in New York State will continue to be caused by emissions from areas to the west and upwind of New York State. Specifically, emissions of nitrogen oxides and sulfur dioxide from tall-stack, fossil-fuel burning electric generating stations located in the Ohio Valley will have an adverse impact upon the ability of New York State to comply with the Clean Air Act restrictions on air pollutants. More importantly, these upwind sources continue to cause acidification of New York's lakes and waterways, ground level ozone problems in the New York City metropolitan area and other parts of the state, and the formation

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[1] Environmental Protection Agency, Acid Deposition Standard Feasibility Study Report to Congress, EPA 430-R-95-001a (October 1995).

of fine particulate matter that is harmful to human health. Out-of-state upwind emission sources located in the Ohio Valley and other parts of the midwest are not currently required by EPA or their state environmental enforcement agencies to place controls on emission sources that have a direct impact on New York State.

New York State is in the unenviable position of receiving the environmental burdens of these emissions regardless of whether the Public Service Commission implements a system of wholesale or retail electric competition in New York State, or selects the no-action alternative evolving regulatory model.

Under the provisions of the Federal Power Act as amended by the Energy Policy Act of 1992, out-of-state utilities are already able to compete on the wholesale level of sell electricity into New York State. Implementation of proposed rules to open access to the interstate transmission system to wholesale competition by the Federal Energy Regulatory Commission will serve to open New York markets to further wholesale competition. A Commission determination seeking to promote a competitive wholesale and retail electric market in New York State, however, could affect incrementally the level of market penetration of sales from out-of-state generators in New York State.

A Commission determination seeking to promote a competitive wholesale and retail electric market in New York State, therefore, could result in some increase in generation in

the Ohio Valley and other areas of the midwest. These regions produce emissions that will have an adverse environmental impact on ground level ozone and acidification of New York's deposition sensitive areas.

By way of mitigation, the New York Public Service Commission can act to reduce overall emissions from in-state generation and out-of-state facilities by encouraging energy efficiency. For example, a systems benefits charge to help fund DSM measures during the transition to a fully competitive retail market could ensure that energy efficiency activities continue to limit energy consumption and, concomitantly, emissions from electric generating facilities.[-]

Moreover, the New York Public Service Commission can monitor the formation of a robust competitive market for energy efficiency services that promote reduced consumption and lower emissions. A competitive electric market is expected to increase the level of energy efficiency activities as competing energy service companies (ESCOs) provide these services directly to end users in New York State. Finally, to the extent that a competitive market for demand side management does not form in New York State, the Public Service Commission can continue to encourage energy efficiency measures through a system benefits charge that subsidizes these activities. The mitigation measures

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[-] Energy efficiency initiatives supported through the system benefit charge should be designed to complement rather than impede the development of competitive markets for demand side services.

that the Commission can take are described in detail in Section 6.2.

On the whole, the magnitude of the acidification and ground level ozone impacts that are caused by emissions from electric generating facilities in the Ohio Valley and other midwestern areas upwind of New York suggests that mitigation of these impacts will require the coordinated actions of the EPA, the New York DEC and the environmental agencies responsible for controlling emissions in Ohio and other midwestern areas that directly affect New York State. As described in Section 6.1.1, above, Sections 110 and 126 of the Clean Air Act Amendments of 1990 require EPA to take actions to limit emissions by generating facilities that affect the air quality of any downwind area. New York State has already brought these issues to the attention of EPA. In response, EPA has called for the formation of an ozone transport assessment group (OTAG), the membership of which includes all 37 states east of the Rocky Mountains. The OTAG states have devoted the effort of more than 300 technical personnel to evaluate the nature, magnitude and severity of the interstate transport of ozone and ground level ozone precursors.

New York State has been active in the Ozone Transport Commission for the Northeast Ozone Transport Region, as well as in OTAG. New York State is also pursuing commitments from the EPA to ensure that upwind sources are required to limit their emissions so that acidification of New York waterways and the health of New York citizens is not harmed by emissions of

pollutants upwind of New York. Finally, New York State recently filed a lawsuit to enforce the provisions of Sections 110 and 126 of the Clean Air Act Amendments of 1990 against EPA.[1] This lawsuit challenges exemptions from nitrogen oxide emission limitations granted to certain midwestern states on the grounds that such exemptions will allow these states to continue to contribute to acid rain and ground level ozone pollution in New York State in violation of the Clean Air Act. To mitigate the adverse environmental effects of upwind emissions on New York State, the New York Public Service Commission can support and assist in these efforts to ensure that upwind sources curb emissions of harmful air pollutants.

6.1.2. The Clean Water Act

As discussed in Section 5.2.3.6, adoption of wholesale or retail competition by the Commission could result in changes in plant dispatch which could affect water resources. For steam-electric plants the major concerns are the magnitude of cooling water withdrawals and the discharge of heat and other pollutants to surface waters, whereas for hydroelectric plants the principal issues are alteration of water levels and downstream water releases. The federal Clean Water Act (CWA) described in this section will continue to be enforced and will serve to mitigate impacts to water resources. Major provisions of the CWA which

[1] State of New York v. United States Environmental Protection Agency, et al., United States Court of Appeals for the Seventh Circuit, Docket No. 96-1714, Petition for Review (March 26, 1996).

would affect electric generation and transmission facilities include:

- Ambient water quality standards
- New discharge source performance standards
- Pollution discharge permits
- State water quality certifications
- Dredge and fill permits
- Wetlands disturbance permits

The CWA embodies a comprehensive regulatory scheme that governs the discharge of pollutants into surface waters. Prior to 1972, water pollution was regulated through water quality standards.[1] Congress subsequently concluded that the difficulties associated with establishing a direct link between the pollutant discharges and the quality of the receiving waters rendered a pollution control program based on water quality standards alone unworkable.[2] In its place, Congress enacted the Federal Water Pollution Control Act ("FWPCA"), now known as the Clean Water Act.[3] Minor amendments to the CWA were enacted in 1977 and 1987.

The CWA directly regulates the discharge of pollutants by electric generation facilities. Specifically, the Act requires the Environmental Protection Agency (EPA) to establish effluent limitations based on application of progressively more

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[1] Water Quality Act of 1965, Pub. L. No. 89-243, 79 Stat. 903.

[2] S. Rep. No. 414, 92d Cong., 1st Sess. (1971), reprinted in 1972 U.S.C.C.A.N. 3668, 3675.

[3] Pub. L. No. 92-500, 86 Stat. 816 (codified as amended at 33 U.S.C. §§ 1251 et seq.).

stringent technological standards.[1] The Act also authorizes the imposition of additional controls to the extent necessary to protect water quality.[2] Hence, Section 301(a) of the CWA prohibits discharge of any pollutant without a permit.[3] Pursuant to the Act, EPA established an effluent discharge permit regime that requires all point sources of regulated pollutants to obtain a National Pollutant Discharge Elimination System (NPDES) permit.[4] Enforcement of the CWA for most categories of point sources located in New York State has been delegated to the New York State Department of Environmental Conservation (DEC). DEC enforces water pollution discharge limitations through the State Pollutant Discharge Elimination System (SPDES) permit system.[5] The SPDES program permits discharges only in conformance with effluent limitations and water quality standards enforced by DEC.[6]

Fossil and nuclear fueled electric generating facilities are frequently located on large water bodies and waterways in New York State because they are large users of water for cooling purposes. Withdrawal of cooling water from any New

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[1] 33 U.S.C. § 1311(b).

[2] 33. U.S.C. § 1312(a).

[3] 33 U.S.C. § 1311(a).

[4] 33 U.S.C. § 1342; 40 CFR Part 22.

[5] Env. Conserv. Law Art. 17, Title 8.; 6 NYCRR Article 3, Parts 750-758.

[6] 6 NYCRR Art. 2, Parts 700-705.

York State water body requires a SPDES permit. In connection with point source thermal discharges by electric utility plants, SPDES regulations require that the location, design, construction of cooling water intake structures, reflect the best technology available for minimizing adverse environmental impacts.[1] These rules require electric generators to employ the best available technology to prevent entrainment of aquatic wildlife and impingement of fish. Any significant changes in water withdrawals or the design of water withdrawal and discharge structures design of a facility requires modification of its SPDES permit.

The primary pollutant discharged by electric generating stations in New York State is thermal energy. Thermal discharges by generating facilities require SPDES permits that restrict the discharge of waste heat to protect aquatic wildlife and water quality.[2] Any significant changes in thermal discharges by an electric generating facility would require modification of its SPDES permit. Electric plants also discharge small amounts of solids, salt solutes, oil, grease and iron. These and other discharges of utility boiler blowdown and agents to prevent biofouling are limited in SPDES permits. Finally, generating facilities fired by coal must limit leachate discharges from large coal piles located on site. Hence, non-thermal discharges

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[1] 6 NYCRR § 704.5.

[2] 6 NYCRR Part 704.

are also limited by each facility's SPDES permit, and cannot be increased without a permit modification approved by DEC.[1]

Any new source of effluent discharge must also obtain a SPDES permit before commencing operations. Accordingly, any new electric generating facilities in New York State will be required to comply with new source performance standards. For major generation facilities sited under Article X of the Public Service Law, these standards would be enforced by the New York State Board on Electric Generation Siting and the Environment (See Section 6.1.3.2), and, for other generation facilities, by DEC.[2]

With respect to hydroelectric facilities, the Federal Power Act vests the Federal Energy regulatory Commission (FERC) with authority over the environmental impacts of the construction, operation and maintenance of hydroelectric facilities located on navigable waters of the United States (See Section 6.1.6). Like all proposals that affect waters of the United States, hydroelectric projects are also governed by the Clean Water Act. Section 401 of the Clean Water Act requires applicants for a federal license or permit authorizing an activity that may result in a discharge to navigable waters to obtain a water quality certification from the state in which the facility is located.[3] State water quality certifications may

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[1] 6 NYCRR Part 703.

[2] 33 U.S.C. § 1316; Env. Conserv. Law § 17-701; 6 NYCRR § 752.1(c), 754.1(a)(2).

[3] 33 U.S.C. § 1341(a)(1).

be based upon state water quality standards adopted by each state, and may also encompass broader impacts, such as the effect of projects on water levels and fish.[1] Accordingly, in exercising authority over water quality certifications under Section 401 of the CWA, conditions affecting the quality of New York waters may be imposed.

Under Section 404 of the CWA, any activity at or in the vicinity of an electric generating facility involving the dredging or filling of a waterway or wetland requires a permit approved by the U.S. Army Corps of Engineers.[2] Dredging and filling activities in the waters of the state also require state approvals under a variety of state statutes, including stream disturbance regulations.[3] Moreover, any dredge and fill activity requires a state-issued water quality certification before the Corps of Engineers issues a permit.[4] Finally, any activity associated with electric generation, transmission or distribution that would disturb a tidal or freshwater wetland

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[1] 6 NYCRR Parts 701-704; PUD No. 1 of Jefferson County v. Washington Department of Ecology, ___ U.S. ___, No. 92-1911, slip op. (U.S. 1993).

[2] 33 U.S.C. § 1344.

[3] Env. Conserv. Law §§ 15-0501 to 15-0515; 6 NYCRR Title 6, Part 608.

[4] 33 U.S.C. §1341.

would entail extensive review and permitting by federal, state and local authorities.[1]

6.1.3. Articles VII and X of the Public Service Law

Environmental licensing programs established under Articles VII and X of the Public Service Law (PSL) will continue to mitigate adverse environmental impacts of new electric generation and major transmission facilities resulting under a competitive electric service industry.

6.1.3.1. Article VII

Article VII requires an applicant to obtain a certificate of environmental compatibility and public need from the Public Service Commission before construction of a major transmission facility in New York State. Major transmission facilities include electric transmission lines longer than a mile at 125 kV or more, or longer than ten miles between 100 and 125 kV, except those located wholly underground in cities; and fuel gas transmission facilities longer than 1,000 feet operated at pressures of 125 psi or more, except those located wholly underground in cities or wholly within highway or street rights-of-way.

Except for certain gas transmission lines, the Public Service Commission must determine, inter alia, the basis of the

[1] 33 U.S.C. § 1344; Env. Conserv. Law arts. 24 (freshwater) and 25 (tidal).

need for the facility, the nature of the probable environmental impact, and that the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives, and other pertinent considerations including but not limited to, the effect on agricultural lands, wetlands, parklands, and river corridors traversed. The Commission is authorized to consider all environmental impacts of transmission siting, including the individual and cumulative impacts of transmission siting applications on land use and on air quality. The Commission also issues water quality certifications for new transmission facilities pursuant to Section 401 of the Clean Water Act.

The Commission requires applicants to provide detailed environmental management and construction plans (EM&CP), and monitors environmental and safety compliance during construction. Hundreds of Article VII projects have been successfully completed over the last 25 years.

6.1.3.2. Article X

Article X requires an applicant to obtain a certificate of environmental compatibility and public need from the New York State Board on Electric Generation Siting and the Environment (Board) for many types of electric generation facilities of 80 megawatts or greater in capacity. Article X does not apply to generation facilities over which the federal government has

exclusive jurisdiction, facilities which generate electricity using solid waste as fuel, and industrial generation facilities less than 200 megawatts in capacity. The Board has seven members, including the Chairman of the Public Service Commission, the Commissioners of the State Energy Office,[1] and the Departments of Environmental Conservation, Health, and Economic Development, and two public representatives from the area where the facility is proposed.

The Board must determine, inter alia, the basis of the need for the generation facility, the nature of the probable environmental impact, and that the facility represents the minimum adverse environmental impact, considering the state of available technology and the nature and economics of the various alternatives, and other pertinent considerations including but not limited to, the effect on the normal environment and ecology, public health and safety, aesthetics, scenic, historic and recreational value, forests and parks, and air and water quality. The Board also issues water quality certifications for new generation facilities pursuant to Section 401 of the Clean Water Act.

No facilities have been approved yet under Article X, which was enacted in 1992. Article X replaced similar siting legislation adopted under Article VIII of the PSL. Under Article VIII, the Board required applicants to provide detailed

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[1] The NYS Energy Office was abolished in 1995.

environmental compliance and construction plans, and the Public Service Commission monitored environmental and safety compliance during construction.

6.1.4. National Environmental Policy Act

The National Environmental Policy Act (NEPA), enacted in 1969, requires federal agencies to review their actions with respect to their potential impact on the environment.[1] The purpose of NEPA is to have federal agencies incorporate environmental values into the decision-making process at an early stage. For those actions that may significantly affect the environment, NEPA requires an agency to prepare an environmental impact statement (EIS) which must evaluate the likelihood and magnitude of the impacts and alternatives to the proposed action. NEPA has been and will continue to be an important statute for mitigation of environmental impacts of actions by Federal agencies. Affected agencies with important licensing and policy making responsibilities in the electric industry include EPA, the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission.

6.1.5. State Environmental Quality Review Act

The State Environmental Quality Review Act (SEQRA)[2] plays a role similar to NEPA with regard to the review of actions

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[1] 42 U.S.C. § 4321 et seq.

[2] Env. Conserv. Law Art. 8.

by state and local agencies that may affect the environment. Enacted in 1975, SEQRA imposes both procedural and substantive requirements upon responsible agencies. Under SEQRA, actions having the potential for significant impact on the environment require the preparation of an EIS before agency action can be taken. Besides evaluating potential impacts and alternative actions, the EIS must also explore ways to minimize adverse environmental impacts. The SEQRA process is an important mechanism in New York State for mitigating adverse impacts of proposed electric generation and transmission facilities that fall outside the purview of PSL Articles VII and X.

6.1.6. Federal Power Act

Under authority of the Federal Power Act (FPA),[1] the Federal Energy Regulatory Commission (FERC) may impose conditions to mitigate the effects of electric energy facilities under its jurisdiction. FERC has responsibility for the regulation of hydroelectric plants and the interstate wholesale transmission of electricity. FERC also issues licenses for hydroelectric plants and, as a condition of licensing, may impose requirements to protect and enhance affected water, land, fish and wildlife, and recreational resources during the construction and operation of these facilities.

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[1] 16 U.S.C. § 824 et seq.

6.1.7. Atomic Energy Act

The Atomic Energy Act[1] grants to the Nuclear Regulatory Commission (NRC) broad authority to regulate the use of nuclear materials for the production of commercial electric power. A power producer must obtain a permit in order to construct a commercial nuclear power plant and must then operate the facility under terms of an operating license issued by NRC. Through a large body of regulatory requirements, the NRC assures that the facility will be constructed, operated and decommissioned in a manner that is protective of the public health and safety and the environment. The NRC controls decommissioning of a nuclear plant through various rules that govern decommissioning planning and funding[2] and transfer of a license.[3]

6.1.8. RCRA, CERCLA & SARA

There are several related federal statutes that impose obligations on electric utilities with regard to retroactive liability for prior environmental contamination of sites such as former Manufactured Gas Plant facilities. These statutes include:

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[1] 42 U.S.C. § 2011 et seq.

[2] 10 CFR 50.33(k), 10 CFR 50.75.

[3] 10 CFR 50.80.

- The Resource Conservation and Recovery Act (RCRA),[1] enacted in 1976, empowers EPA to control the disposal of hazardous liquid and solid wastes on land.

- The Comprehensive Environmental Response Compensation and Liability Act (CERCLA or Superfund)[2] was enacted in 1980 and imposes broad and retroactive strict liability on generators, transporters and those who arrange for disposal of hazardous substances with the intention of promoting voluntary remediation.

- The Superfund Amendments and Reauthorization Act (SARA)[3] enacted in 1986 intensified Superfund activities and set a goal of achieving "permanent" solutions at Superfund sites.

Many of the requirements relating to the regulation of hazardous substances and wastes under federal statutes have been delegated to DEC, with EPA retaining the right to undertake enforcement action under certain circumstances.

Superfund imposes strict and retroactive liability for environmental response costs against any person or entity that was or is associated with either the hazardous substances that gave rise to those costs or the land or water that was contaminated. These statutes provide assurance that any environmental liabilities for hazardous substances that are currently borne by electric utilities will have to be addressed in a restructured electric industry.

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[1] 42 U.S.C. §§ 6901-6991.

[2] 42 U.S.C. §§ 9601-9675.

[3] 42 U.S.C. §§ 6901-6987; Pub. L. 99-499, 100 Stat. 1613 (1986).

6.1.9. Coastal Zone Legislation

As described in Section 5.2.3.6, the deposition of air contaminants on surface waters and tributary watersheds poses an indirect but potentially important impact on marine waters. With respect to coastal areas, long range transport of nitrates formed in the atmosphere from generation facility NO_x emissions contribute to nitrogen loadings in tidal waters. Such nitrogen loadings can add to eutrophication and hypoxia conditions in coastal areas.

The coastal area in New York State encompasses Lake Erie and Ontario, the St. Lawrence and Niagara Rivers, the Hudson River south of the federal dam at Troy, New York City's waterways, Long Island Sound, and connecting water bodies. The New York State Secretary of State administers coastal policy for the state. Coastal programs include the state Waterfront Revitalization of Coastal Areas and Inland Waterways Law[1] and the federal Coastal Management Program administered pursuant to the Coast Zone Management Act of 1972.[2] Under these programs and the CWA, eutrophication and hypoxia problems in coastal water bodies such as Long Island are being addressed pursuant to overall water quality management plans.[3]

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[1] Exec. Law §§ 910-920; 19 NYCRR tut, 19, §§ 600.1-600.5.

[2] 16 U.S.C. §§1451-1464; 15 CFR Part 930.

[3] Comprehensive Conservation and Management Plan, Long Island Sound Study, March 1994.

6.1.10. Other Statutes

There are many other federal and state laws that affect the electric industry and serve to mitigate environmental impacts from changes resulting from the introduction of competition. Some of the more important federal and state laws that could be applicable include:

Federal

- Toxic Substances Control Act
- Safe Drinking Water Act
- Occupational Safety and Health Act
- Endangered Species Act
- National Historic Preservation Act
- Oil Pollution Act

State

- Air Pollution Control, ECL Article 19
- Water Pollution Control, ECL Article 17
- Mineral Resources, ECL Article 23
- Collection, Treatment and Disposal of Refuse and Other Solid Waste, ECL Title 27
- State Acid Deposition Control Act (SADCA)
- Adirondack Park Agency Act, Exec. Law Article 27
- Freshwater Wetlands Act, ECL Article 24
- Wild, Scenic and Recreational Rivers System Act, ECL, Art. 15, Title 27

6.2. Mitigation of Adverse Impacts

While the existing framework of applicable federal and state environmental protection laws and regulations will serve to mitigate most of the adverse impacts of the proposed action, there are some impacts, primarily the potential loss of public policy programs and the potential increase of acid rain and particulates, that lie outside this legal framework and their mitigation falls within the Commission's specific action in this

proceeding. Some of the conditions and criteria under which future Commission action could be taken to mitigate these environmental impacts are described in the remainder of this section. Some of these specific mitigation measures would be defined in greater detail in subsequent rate and other utility-specific proceedings that would implement the Commission's action in the current proceeding.[1]

One way to finance mitigation techniques that has been recommended by several parties is a wires charge. A wires charge is a charge levied on customers that connect to the distribution system. This charge can be used to collect stranded costs and administrative costs. A wires charge collected to support public benefits programs is termed a system benefits charge.

6.2.1. Air Pollution Mitigation

Increased competition is expected to reduce generating costs which will lead to reduced prices. This should, in turn, increase sales through elasticity of demand. A broad range of models was developed to examine alternative emissions patterns under competition. The results were mixed, but under some scenarios increases in acid rain and airborne particulates. The basic cause of the increase in pollutants would be the increase

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[1] Depending on the nature of these future utility-specific proceedings and actions taken by the Commission, they could be subject to review under SEQRA and require the preparation of an environmental assessment form and possibly an environmental impact statement.

of sales, placing IPPs on economic dispatch, and retirement of nuclear plants. Discussed below are measures by which the Commission can mitigate these and other adverse impacts including a System Benefits Charge.

6.2.2. System Benefits Charge (SBC)

Public policy programs producing environmental benefits that might not otherwise be conducted by competitors could be conducted under future competitive electric industry structures through the use of a "system benefits charge." These programs could include ones which are currently conducted by the regulated integrated utilities (such as DSM, R&D, renewables, and certain environmental protection programs) and possible new initiatives such as incentives for environmentally benign types of new generation and some means of acquiring greater reductions of SO_2 and NO_x if that is needed.

A non-bypassable SBC, imposed on all customers that connect to the transmission and distribution system, could be a way to fund such programs without competitively disadvantaging any market participants.

Under the Retail Competition Model, the SBC could be used to fund certain public policy programs until they were adequately provided through the competitive market. Programs could be conducted by the regulated utilities, by government or not-for-profit entities, or through bidding.

Under the Wholesale Competition Model, funding of programs through a SBC would probably continue longer than under retail competition, since it is less likely that efficiency programs would be provided through the more limited ESCO market. For example, with the utility as the only seller of electricity to customers, the vigorous, thriving ESCO market envisioned in the Retail Competition Model would be far less likely to develop.

The SBC could be collected from all customers connected to the transmission and distribution system. The SBC preferably should be collected in a non-usage based manner, as a customer charge rather than volumetrically, so that prices more accurately reflect the marginal costs of electricity and thus provide customers with the correct economic signals. Rate design issues, including the size and rate of increase of customer charges, could be addressed in individual utility rate cases.

The Public Service Commission should continue to oversee the public benefit programs conducted by the regulated utilities. Under the Retail Competition Model, the utilities may conduct more limited programs for the period until programs are provided by the market. Under the Wholesale Competition Model larger programs would probably be needed for a longer time.

It may be desirable for the regulated utility to collect the SBC and then conduct bidding and/or other solicitations from ESCOs and other entities to operate programs using these funds. Alternatively, another organization such as the New York Power Authority or the New York State Energy

Research and Development Authority could conduct these solicitations. This procedure could serve to encourage the development of an ESCO market while continuing the provision of programs during the transition to a more competitive market.

6.2.2.1. Demand Side Management (DSM)

DSM has proven to be a cost effective means of reducing electric usage. Several New York utilities conducted DSM programs that achieved a 1% annual reduction level. The current cost effective potential of DSM programs probably varies somewhat from the levels previously estimated, since avoided generation and transmission costs now differ from those at the time of the estimates, and the general level of efficiency of devices in use is greater. Reductions in electric usage through DSM programs could mitigate increases in environmental impacts that might result from any tendency of electric industry restructuring to result in increased electricity use.

As discussed in Section 5.2.7, electric industry restructuring may lead to the development of a vigorous ESCO industry that could deliver energy efficiency services that would mitigate increases in electric usage. If that ESCO industry does not develop sufficiently, or until it does, DSM programs could be supported through a system benefits charge. It is important, however, that such DSM programs not impede the development of competitive DSM markets. The regulated utility could collect the SBC and then conduct bidding and/or other solicitations from

ESCOs and other entities to operate programs using these funds. Alternatively, the regulated T&D company could be directed to continue to provide certain limited energy efficiency services during the transition to retail competition, so that it: (1) remains responsive to customer needs, (2) does not terminate promising and valuable energy efficiency efforts, and (3) provides services that complement the development of a competitive demand side market.

DSM may also be considered, along with other resource options, as alternatives to T&D equipment investments during the planning of T&D system upgrades and expansions or in the case of load pockets.

6.2.2.2. Renewable Energy Sources

Under either Wholesale Competition or Retail Competition Models, a SBC could be used to provide financial incentives for generation or end use renewable energy sources. For example, support could be given to renewables to offset their higher capital costs, and then these renewables and other generators could compete in the market.

6.2.3. Monitoring During the Transition to Competition

If the Commission decides to go forward with competitive restructuring, it will be necessary to monitor a number of activities during the transition to competition in order to identify and potentially mitigate adverse impacts.

Specific types of monitoring include: system reliability, development of ESCO competition, and development of unregulated monopolies in load pockets, as well as environmental impacts. Depending on the results of this monitoring, it may be necessary or appropriate to apply legal, regulatory and other mitigation remedies. Some additional areas where environmental monitoring during transition would be appropriate are discussed in the following subsections.

6.2.3.1. Plant Dispatch

As previously noted, the Clean Air Act Amendments provide built-in restrictions on net increases of SO_2 and NO_x--basically a ceiling or "bubble" approach which uses tradeable pollution rights to encourage least-cost compliance. A major weakness of this approach is that it does not take into account that a ton of pollution in one place can do a lot more damage than a ton of pollution somewhere else. New York must be especially vigilant on this point because of the substantial pollutants it receives from upwind; the fact that the Midwest is not actually restricted by NO_x requirements; the clear sensitivity of the Adirondacks and Catskills to acid precipitation; and the stress from NO_x related ozone in the New York Metropolitan area.

There are conditions in the Clean Air Act Amendments which require the U.S. EPA to intervene if some of these regional imbalances occur. The most important mitigation action available

to the Commission in this area is to join aggressively with other state and regional agencies to demand that the U.S. EPA promulgate equitable pollution requirements for the Midwest.[1]

Since there is a possibility that competitive restructuring could lead to increased imports of electricity from the Midwest, one important form of possible mitigation would be to monitor whether such increased imports in fact occur. Another would be to provide additional resources to monitor impacts of such imports on vital habitats and on the New York Metropolitan Area. Any such monitoring and research would need to be carefully coordinated with the various environmental authorities.

As noted, a decision to completely restructure New York's electric industry is likely to result in negative impacts with regard to acid rain and particulates. This is a possibility which needs to be monitored. If such deterioration occurs, the Commission should consider exploring, with the New York Department of Environmental Conservation, mitigation strategies which are consistent with federal and state requirements and which are competitively neutral.

It might be possible, as an example, to reduce acid rain precursor emissions from plants upwind of impacted areas by holding a special auction. Bids to reduce emissions could be ranked not only by price, but also by their location with respect

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[1] Chairman O'Mara has already initiated this process in his joint letter with Commissioner Zagata to the Federal Energy Regulatory Commission on February 1, 1996 on the need to control NO_x and SO_2 emissions in the Midwest.

to impacted areas. Bids directly upwind of the Adirondacks and Catskills would receive more than bids only partially upwind. The payment for such reductions could be collected as part of a competitively neutral wires charge. New York's Department of Environmental Conservation would presumably play a central role in managing such an auction. The purpose here is not to propose a specific solution, but to indicate that solutions are possible.

It is also useful to consider dollar magnitude. An increase of SO_2 of 5% to 10% per year is about the right range. A 10% increase would mean additional emissions of approximately 24,000 tons per year. If it is assumed that flue gas desulfurization costs $500 per ton, the cost of avoiding 24,000 tons of SO_2 per year is about $12 million. If fuel switching were possible, the cost could be about half this figure. Mitigation of NO_x, if it were found to increase, could be handled in some similar fashion.

Monitoring of all major electric generators is presently required by the NYSDEC under the provisions of the Clean Air Act. Air pollutants subject to continuous emission monitoring and reporting requirements are sulfur dioxide and nitrogen oxides, among others; these are the pollutants of concern for acid deposition and ozone attainment. However, in a competitive electric industry it will be important to correlate monitoring of in-state and purchased generation, emissions, and resulting impacts.

6.2.3.2. Research and Development Expenditures

Expenditures for research and development should be monitored to measure the levels and types of R&D expenditure by generation companies and suppliers, T&D utilities, and ESCOs during the transition to competition. R&D related to environmental impact, resource protection measures, and the use of more environmentally benign technologies should be supported by a System Benefits Charge during the transition. Given the price signals provided by allowance trading programs, competing entities will have a full profit motive to undertake R&D that can lower the cost of emission reduction measures. If shortfalls continue after the transition, mitigation measures funded through the use of a System Benefits Charge (Section 6.2.2) could be considered to subsidize these activities.

6.2.3.3. Creation of ESCOs and DSM Services

The growth of ESCOs under a Retail Model and the types of services offered to customers should also be monitored. Of major importance is monitoring of whether and to what degree ESCOs provide DSM services as part of the overall package of services they provide to customers. If it is found that DSM services are not being provided, mitigation measures could be considered such as use of a System Benefits Charge to fund these services.

6.2.3.4. Use of Renewable Energy Sources

Trends in the use of renewable energy sources that may be less polluting and have lessened environmental impacts should also be monitored during the transition to competition under either a Retail or Wholesale Model. If it is observed that a competitive market results in diminished use of renewable energy sources and, if it is judged to be desirable as a matter of public policy to encourage use of these types of energy sources, subsidies through a System Benefits Charge or application of Portfolio Management tools (Section 6.2.4) could be considered.

6.2.3.5. Socio-Economic Impacts

If the Commission decides to competitively restructure the electric industry, the Commission must carefully coordinate with the State's Department of Economic Development and other economic agencies so that untoward economic impacts can be anticipated and dealt with. State programs in retraining and relocation would need to be directed to the areas affected. Information should be made available to prospective new industry about the availability of the existing site.

With regard to low income and payment-troubled customers, reduced rates for all classes of ratepayers will be particularly beneficial. However, there still may be a need to continue to explore and develop new mechanisms to help certain customers resolve their energy problems. The Commission should

continue to seek solutions in this difficult area. The System Benefits Charge is one mechanism which could be employed.

6.2.4. Portfolio Management

Portfolio management for electric utilities generally refers to practices to select an assortment of supply sources in order to achieve various goals. Portfolio management could be employed under any of the industry models considered in this proceeding if it was seen as necessary to do so. Under the evolving Regulatory Model, the regulated utilities could be directed to purchase electricity from generators based in part on their environmental impacts, and/or to balance energy efficiency with electricity purchases. Under either wholesale competition or retail competition models, a "renewables portfolio standard" could be required. Such a standard mandates that a specified proportion of electricity purchased or generated must come from renewable resources. There are two ways to do this: (1) each generator selling in New York, in order to be allowed to bid in New York, would have to arrange for generation from renewables, or (2) each T&D company would be required to purchase the specified electricity from renewable resources. The use of a renewables portfolio standard may require pool and Independent System Operator rules that accommodate intermittent renewable resources and a separate market-clearing price within the pool for renewables. Alternatively, under either wholesale competition or retail competition models, a system benefits

charge (SBC) could be used to provide support to generation that is desirable but that would not currently be competitive in the spot market due to higher costs.

6.2.5. Environmental Liability Cost Recovery

6.2.5.1. Hazardous Waste Site Remediation

Continuation of the Commission's policy of reviewing specific manufactured gas plant and other hazardous waste site remediation costs on a utility-by-utility basis in rate proceedings and allowing recovery of prudently incurred costs would mitigate concerns regarding the efficient and timely clean up of these sites.[1] The number of sites, potential cost exposure, timing of clean-up, the financial situation of each utility, and each company's handling of site investigation, clean up, and third party and insurance recovery expenses would vary with each utility and would be best addressed in individual rate proceedings.

Remediation costs could be treated as any other utility expense. Each utility would bear the burden of demonstrating that: (1) it has employed the lowest cost techniques for site investigation and clean-up, (2) that it has pursued recovery from other parties' responsible for contaminating manufactured gas plant sites, and (3) that it has taken all reasonable steps to obtain coverage from insurance companies that underwrote the risk

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[1] This rate recovery will be conducted consistent with the Commission's existing generic proceeding on coal tar site investments and remediation cost recovery (Case 94-M-1016).

of property damage at the time the sites were contaminated. This approach will adequately mitigate any effects of restructuring on utility liabilities for remediation.

6.2.5.2. Nuclear Power Plant Decommissioning

If responsibility for the state's investor-owned nuclear power plants is transferred to a public entity such as the New York Power Authority, it would provide assurance that sufficient funds would be available to decommission these facilities in a satisfactory and timely manner, and in compliance with NRC rules.

Compliance with NRC rules is required. The Commission should review specific costs for nuclear power plant decommissioning on a utility-by-utility basis in rate or other proceedings and the allowance in rates of reasonable costs for decommissioning consistent with NRC requirements. This would mitigate concerns regarding the provision of adequate funding for the effective and timely clean up of nuclear plants.

If instead, a nuclear facility is acquired by a private, unregulated entity, the NRC would have sole responsibility to assure adequate funding for decommissioning.

7. UNAVOIDABLE ADVERSE IMPACTS

Some unavoidable adverse environmental impacts may result with either competitive electric industry model, even after the application of mitigation measures identified in Section 6. These residual adverse environmental impacts are described in the following sections.

7.1. Impacts from Increased Electric Energy Use

A lowering of the real price of electricity, an inspected result of a competitive industry, is likely to cause growth in statewide electric energy use. This is likely to increase air emissions. Conformance with requirements of the Clean Air Act would serve to control SO_2, NO_x and other emissions within regulatory limits but, within those limits, emissions might still be higher than under the current evolving regulatory model. As noted above in 6.2.1, different mitigation strategies should be explored for increases in air pollutants. To the extent that such mechanisms are not completely successful, there could remain unavoidable adverse impacts.

In the longer range, increased electric energy growth may eventually require the construction of additional generation facilities or increased emphasis on demand side initiatives. The former will result in some unavoidable, adverse impacts to air, land, water and other natural resources and the human

environment. These impacts would be mitigated to a large extent through conformance with requirements of federal and state pollution control laws and regulations and generation facility siting laws such as Article X, but some unavoidable impacts could still result because of increased emissions to air and water and alterations of the natural environment and communities at or near these facilities.

To the extent that the increased growth in electric use simply represents a switching from other more polluting or less efficient energy uses to electric use, the total net residual environmental impacts of increased electric use could be reduced or even eliminated.

In the long run the evolution of new, less-polluting generation technology may also be fostered under a competitive industry. These technologies could significantly reduce air and water emissions and lower environmental impacts even further.

New generation facilities also produce positive economic benefits in terms of increased employment and tax base.

7.2. Impacts of Accelerated Plant Retirements

A competitive electric industry, would increase the likelihood that plants whose operations are not economical would be retired more rapidly than under a regulated industry. Accelerated plant retirements would cause some adverse impacts

that could not be entirely mitigated, such as increased local unemployment and decreased tax base. These changes would have significant adverse impacts on individuals and communities. In the longer term, competition will lead to lower electric prices and an enhanced state economy which would more than offset these impacts on a statewide basis. However, permanent displacement of some workers who cannot adapt to the new business environment could result. Also, all regions and communities would probably not share uniformly in the benefits of increased economic development and tax bases that could result from competition.

7.3. Impacts of New Transmission Line Construction

In the long term, increased competition could increase demands on the transmission system, requiring upgrading or additional transmission lines which would have some unavoidable adverse environmental impacts. The need for additional transmission capacity could result both from the need to increase the import of electricity and transfer it across the state, and as one way to increase power to load pockets such as New York City and Long Island.

Article VII of the Public Service Law, and for smaller transmission facilities, the State Environmental Quality Review Act, would mitigate adverse impacts to the maximum practical extent. However, not all impacts can be avoided. Transmission

lines in heavily populated residential and commercial/industrial locations would likely be built underground and these facilities have the potential for causing unavoidable disturbances during construction to water quality, aquatic wildlife, traffic, archeological resources, historic sites, and vegetation. Overhead transmission lines in more rural areas would have some unavoidable impacts during both construction and operation in terms of visual impacts, disturbance of farmland operations, changes in wildlife habitat, and changed land use.

8. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENT OF RESOURCES

As discussed in Section 7, adoption of a competitive electric industry model could cause some unavoidable adverse impacts. Some of these unavoidable impacts might also have effects that are irreversible or might represent an irretrievable commitment of resources.

An increase in statewide electric use over the long term may eventually require the construction of additional generation facilities. If constructed at new locations, these generating facilities would permanently alter land use and natural resources at the sites.

Upgrading or construction of new transmission lines would permanently alter land use in the transmission corridors of these facilities. These permanent changes would include visual impacts, altered land uses and disruptions of natural systems. Any permanent commitment of resources caused by construction of new generation or transmission will be evaluated in specific licensing proceedings and balanced against the need for such facilities and the alternatives available.

Accelerated retirement of nuclear plants would likely cause increased use of fossil fuels as replacement for electric generation, and an increase in the use of non-renewable resources. The greater use of coal for electric generation would produce larger amounts of solid waste requiring disposal. Offsetting these impacts would produce larger amounts of solid waste requiring disposal.

9. GROWTH-INDUCING ASPECTS AND SOCIO-ECONOMIC IMPACTS OF THE PROPOSED ACTION

The principal objective of adopting a competitive industry model is to promote greater overall efficiency in the production, transmission, distribution and consumption of electricity, and by doing so achieve lower electricity costs. Lower electricity costs in turn can be expected to enhance growth in the state's overall economic activity. This growth would be beneficial in terms of enhanced economic and social well-being.

Economic growth resulting from industry restructuring would likely be statewide in nature, although not all areas of New York would necessarily be affected equally. However, given the large number of unpredictable variables, it is not possible to forecast whether any given metropolitan area or geographic region would be affected adversely or positively.

Changes in the level and location of electric generation under wholesale or retail competition will have social and economic impacts on communities across New York State. These impacts will initially take the form of changes in employment levels, in the character of communities where generating stations are located, and in local taxes paid by generating facilities.

9.1. Impacts on Employment

The electric industry in New York State is a major employer, with thousands of people working for the seven investor-owned utilities, public power authorities, independent power producers and municipal electric utilities. The electric and combination electric and natural gas utilities currently

employ approximately 39,000 people in New York State. These numbers reflect significant downsizing that has already occurred at electric utilities. In the electric industry, 17063 jobs were lost nationwide in 1993.[1] In New York, all of the investor-owned utilities except for Central Hudson have experienced significant reductions in employment levels. Between 1993 and present, New York electric and combination utilities reduced job rolls by over 4,000 workers.[2] These job reductions are in part the result of the national trend toward downsizing at utilities and in all industries. Specific to the electric industry, utility staff cuts are the result of mounting competitive pressures in the electric industry nationally and efforts to stabilize escalating electric rates in New York State.

A Commission determination favoring access and competition in New York's electric industry at the wholesale or retail level can reasonably be expected to further current downsizing at New York utilities' generating facilities. Public authorities and independent power producers may also reduce employment to become more competitive in response to a Commission action promoting competition in the generation and energy service sectors. These staff reductions can be expected to harm local

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[1] Electric Briefing by State of New York Department of Public Service staff to the Public Service Commission, February 1994.

[2] Statewide electric utility employment reduction estimates were prepared by staff from utility annual reports and other company sources.

economies and employment levels in all parts of the state where electric generation is a significant part of the local employment base. In smaller communities where electric utilities are keystone employers due to the location of generating stations or central offices, these effects are likely to be pronounced. Individually, some workers currently employed in the electric industry, may not be able to adjust to these economic changes. Others may not be able to secure jobs that are similarly remunerative, and may have to take jobs that pay much less.

Counterbalancing the negative local employment and economic impacts of utility downsizing, however, will be job additions at utilities, independent power producers or public authorities that compete successfully to provide generation and energy services. Accordingly, local communities where successful competitors locate can expect employment and economic activity to stabilize or increase. Moreover, supplanting rate of return regulation of electricity with competition in the generation and energy services sectors should lower electric rates. Lower rates, in turn, will translate into increased disposable income in the hands of ratepayers and increased economic development in New York. Promoting competition in the electric industry may also lead to technological advances in generation, transmission and energy services that create new employment opportunities in these and allied industries. These trends, in turn, should increase employment opportunities in the electric industry and overall as economic growth continues.

If competitive restructuring was successful in creating a high level of market-driven energy efficiency, this could have very positive employment impacts because energy efficiency is much more job intensive than electricity production.

In sum, continuing decreases in employment and economic activity from electric industry downsizing will affect local communities. These negative impacts, however, should be counteracted by increasing employment by successful competitors, new opportunities in electric industries and allied businesses, and the stabilization or increase of employment statewide from reduced electric rates under competition. Certain smaller communities in which the electric industry is a principal employer may experience long-term job losses. Moreover, some electric industry employees may be permanently displaced. It is not possible to predict at this time, however, which communities will be affected or how many employees will be permanently displaced.

9.2. Impacts on Community Character

The character of communities that host independent, public or utility offices or generating facilities may also change as the result of competition. Plant retirements or staffing reductions at plants may depress economically locations that were once active commercial or industrial centers. Closure of generating facilities that are no longer economic may leave large tracts of land occupied by structures that are not suitable

for alternative uses. Concomitantly, areas that host companies that successfully compete in the generation and energy service industries can expect increased economic activity. Moreover, energy service companies (ESCOs) that market or broker power and aggregate smaller customers can be expected to set up local operations under electric competition. Some locations that experience persistent constraints on transmission of competitive power may find that competing generators will seek to site new small facilities to serve those areas. For new generation, environmental impact review processes under SEQRA or, in the case of generating facilities of 80 MW capacity or more, Public Service Law Article X, would address impacts on neighborhood character. At this time, it is not possible to predict what communities will experience changes in character due to electric competition, or what will be the magnitude of those impacts.

9.3. Impacts on Local Taxes

Electric competition could also affect local taxes collected by communities across New York State. Electric utilities are among the largest local taxpayers in the state. In 1993, the seven electric and combination utilities collectively contributed $818,697,000 in local taxes to municipal governments in New York. [1] These taxes fund education and other community

[1] This figure was derived from utility reports and staff calculations.

services. In some smaller communities that host large generating station, local tax payments by electric utilities are a principle source of revenue. Moreover, there is frequently a large differential in the assessment of local taxes on generating facilities owned by utilities versus those that are independently owned, with independent power producers paying substantially less property taxes on the whole.

As competition in the electric industry takes hold, the retirement of uneconomic generating facilities could result in reductions in the tax base of communities where those facilities are located. For example, the retirement of two nuclear units in Alternate Scenarios 4 and 5 would negatively affect the local tax assessments on those properties. Moreover, it is reasonable to expect that electric utilities will aggressively challenge their local property tax assessments to reduce their costs. In fact, utilities have already been active in challenging local property taxes. For years, electric utilities have sought reduced assessments from the New York State Board of Real Property Services.[1] A recent settlement entered into with the Board of Real Property Services will allow the utilities to pay $19.49 million less in property taxes to local governments in 1996.[2] In sum, communities that host large utility generating stations

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[1] The Board of Real Property Services was formerly known as the Board of Equalization and Assessment.

[2] Citation to settlement agreement coming.

may experience reductions in tax base under electric competition due to retirements or continuing challenges to assessments. Electric competition, however, is expected to promote growth in the energy service market as ESCOs provide access to competitive sources os supply and energy conservation services. Also, as stated above, competition is expected to promote economic development through decline in electric rates. The location of new business and general economic expansion could eventually provide offsetting increases in local community tax revenues. Nevertheless, in communities that host large utility generating stations, there could be a long-term loss of net property tax collections. It is not possible now to predict what communities will experience losses of tax revenues due to electric competition, or what will be the magnitude of those losses.

9.4. Impact on Low Income and Payment Troubled Customers

Principle No. 2 for guiding the transition to competition in the electric industry states that, "The Commission should strive to minimize 'bill shock' for any class of customers. A basic level of reasonably priced service must be maintained for all New Yorkers." The reduced rates for all classes of ratepayers that are expected in a competitive wholesale or retail electric industry will be particularly beneficial to low income and payment-troubled customers. Nevertheless, there may still be a role in helping certain customers meet their energy needs.

Programs funded at the federal and state levels and administered by the Department of Social Services, such as the Low Income Home Energy Assistance Program (LIHEAP), are expected to continue to provide direct financial assistance and energy efficiency services to customers otherwise unable to meet their energy needs. Moreover, the Department of Public Service administers certain programs implementing the Home Energy Fair Practices Act (HEFPA), including service connection and disconnection rules, and billing practices and deferred payment programs. These issues have been the subject of extensive discussion, briefing and argument in the main case. In a competitive environment, there may be a need to continue to explore and develop new mechanisms to help customers solve their energy problems. The System Benefits Charge is one mechanism which could be employed to fund such efforts.

10. EFFECTS ON ENERGY CONSUMPTION

The effects of adopting a competitive industry model on the use and conservation of energy is discussed in Sections 5.2.7 and 5.2.12.

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