ALTERNATIVES TO THE INDIAN POINT ENERGY CENTER FOR MEETING NEW YORK ELECTRIC POWER NEEDS

Committee on Alternatives to Indian Point
for Meeting Energy Needs

Board on Energy and Environmental Systems
Division on Engineering and Physical Sciences

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Preface

The Indian Point Energy Center, with two operational nuclear reactors, is in a densely populated region about 40 miles north of midtown Manhattan. On September 11, 2001, one of the hijacked planes flew past the plant on the way to the World Trade Center. Since then, there has been heightened concern that a terrorist attack on the reactors or the spent fuel pools might lead to a catastrophic release of radioactivity and calls for the plant to be closed.

The Indian Point Energy Center is a vital part of the system supplying electricity to the New York City region. Any significant interruption of power to New York City also could have serious consequences, as shown by the relatively brief blackout that occurred in August 2003. The system delivering power to New York City consumers must be highly reliable, and that depends on having adequate generating capacity available.

This dichotomy led the U.S. Congress to request a study from the National Academies on potential options for replacing the energy services provided by Indian Point. The request, initiated by Representative Nita M. Lowey of New York's 18th District, was directed to the U.S. Department of Energy, which in turn arranged for the study with the National Research Council (NRC) of The National Academies.

The NRC established the Committee on Alternatives to Indian Point for Meeting Energy Needs to conduct the study. Committee members were selected from industry, academia, national laboratories, and other organizations for their expertise on electric power technology and systems and on issues specific to New York. Biographical sketches of the committee members are presented in Appendix A.

The committee was charged with fulfilling the following statement of task:

> The National Academies' National Research Council will form a committee to review options for replacing current electric power generation from the Indian Point Energy Center (New York) nuclear facilities with alternative means for meeting electric power demand and associated energy services. The study may include consideration of fossil-fuel-based options (e.g., coal-fired or natural-gas-fired power generation), renewable-energy-based options (e.g., wind, solar, biomass), imports of required electrical energy, and energy efficiency measures, or some combination thereof. The study should include an assessment of the pros and cons of the alternatives to the continued operation of the Indian Point nuclear power plants. The study will not result in the choice of an option but will compare options based on the criteria adopted by the committee.

In 2005, the committee met twice in Washington, D.C., and once in White Plains, New York to gather information from public sources. The committee was particularly interested in the feasibility of implementing the various options on a scale sufficient to replace the 2,000 megawatts of electric power now produced by Indian Point and to

address the resulting economic, environmental, and societal impacts. It procured the services of General Electric International to model the New York electric system and how the options would affect reliability. It also contracted with Optimal Energy Inc. to detail the efficiency improvements that could be made in the New York City area, based on its statewide assessment for the New York State Energy Research and Development Authority. The committee also met twice in closed session to discuss results and progress on this report, and held numerous conference calls. Details of the meetings are provided in Appendix B.

The report focuses exclusively on options for replacing current electric power generation and ancillary services from Indian Point. In accordance with the original request, it does not examine the potential for terrorist attacks on Indian Point, nor their probability of success, or possible consequences. It makes no recommendations as to whether Indian Point should be closed or how that decision could be implemented. The overriding goal of the study was to evaluate the options that are available to meet electric power demand and to provide the other services required to maintain the reliability of the electric system should a decision be made to close the Indian Point plant.

This report presents the committee's findings. It is the result of a great deal of effort on the part of many highly qualified experts. I greatly appreciate the efforts by the committee members and their enthusiasm, dedication, and insights in conducting this study and preparing the report. The committee operated under the auspices of the NRC Board on Energy and Environmental Systems and is grateful for the able assistance of James Zucchetto, Alan Crane, Panola Golson, and Duncan Brown of the NRC staff.

Lawrence T. Papay, *Chair*
Committee on Alternatives to Indian Point
for Meeting Energy Needs

Acknowledgments

The Committee on Alternatives to Indian Point for Meeting Energy Needs is grateful to the many individuals who contributed their time and effort to the National Academies' National Research Council (NRC) study. The presentations at committee meetings provided valuable information and insight on energy options and constraints in the New York area. The committee thanks the following individuals who provided briefings:

Beth Tritter, Office of Congresswoman Nita M. Lowey
Philip Overholt, U.S. Department of Energy
John Kucek, Oak Ridge National Laboratory
Lawrence Pakenas, New York State Energy Research and Development Authority
John Plunkett, Optimal Energy, Inc.
Randall Swisher, American Wind Energy Association
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Paul A. DeCotis, New York State Energy Research and Development Authority

This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the NRC's Report Review Committee. The purpose of the independent review is to provide candid and critical comments that will assist the committee and the NRC in making its published report as accurate and useful as possible, and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following people for their review of this report:

David Bodde, Clemson University
William L. Chameides (NAS), Environmental Defense
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Michehl R. Gent, Summit Power
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Harry Vidas, Energy and Environmental Analysis, Inc.
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Irvin L. (Jack) White, formerly with Pacific Northwest National Laboratory and New York State Energy Research and Development Authority

Although the reviewers listed above have provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations, nor did they see the final draft of the report before its release. The review of this report was overseen by George Hornberger (NAE), University of Virginia. Appointed by the National Research Council, he was responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with the authoring committee and the institution.

The committee offers special thanks to Mark Sanford, Gene Hinkle, and Gary Jordan at GE Energy, and to John Adams and William Lamanna at the New York Independent System Operator for their efforts on the committee's scenario analysis. The committee also benefited from an analysis of energy efficiency opportunities by John Plunkett and Optimal Energy, Inc.

The committee is also very appreciative of the contributions of Erin Hogan, Paul DeCotis, and John Plath of NYSERDA; Benjamin Sovacool of Oak Ridge National Laboratory; and Lynn Billman, Robert Margolis, Brian Parsons, Ralph Overend, Rich Bain, Phil Shepherd, and Walter Short of the National Renewable Energy Laboratory.

ALTERNATIVES TO THE INDIAN POINT ENERGY CENTER FOR MEETING NEW YORK ELECTRIC POWER NEEDS

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ABSTRACT

This report presents the work of the Committee on Alternatives to Indian Point for Meeting Energy Needs. It reviews various options that are available for replacing the 2,000 megawatts of energy produced by the two nuclear reactors at Indian Point and assesses some of the requirements and impacts of installing the options in an appropriate timeframe.

The Indian Point Energy Center is a key part of the electric power system that serves New York City and densely populated surrounding areas. Maintaining reliability of electric supply in the area is essential.

Even with Indian Point operating, new capacity will be needed to meet expected growth in the region and to replace other retirements. Replacing the two operating Indian Point generation units would add to the complexity of the task. Options are constrained by various technological, regulatory, financial and infrastructure factors which must be considered in planning for a reliable electric energy supply for southeastern New York State.

Based on all of the information available to it, the committee has identified no insurmountable technical barriers to the replacement of Indian Point's capacity, energy, and ancillary services, but significant financial, institutional, regulatory and political barriers also would have to be overcome to avoid threatening reliability. As this report discusses, many replacement options exist, and if a decision were definitely made to close all or some part of Indian Point by a date certain, the committee anticipates that a technically feasible replacement strategy for Indian Point could be achievable. A replacement strategy would most likely consist of a portfolio of the approaches discussed in this report, including investments in energy efficiency, transmission, and new generation.

While the committee is optimistic that technical solutions do exist for the replacement of Indian Point, it is considerably less confident that the necessary political, regulatory, financial, and institutional mechanisms are in place to facilitate the timely implementation of these replacement options. The importance of this issue cannot be overstated in developing options for maintaining a reliable electric energy supply for the New York City metropolitan area. The report discusses in greater detail various aspects of this challenge and includes specific conclusions and findings.

Summary and Findings

This report presents the work of the Committee on Alternatives to Indian Point for Meeting Energy Needs. For over a year, the committee reviewed a wide range of potential options and assessed the feasibility of implementing these options on a scale and a timetable sufficient to replace the capacity, energy, and essential ancillary services now provided by the two operating nuclear reactors at Indian Point.

The committee recognizes the magnitude and the complexity of the issue that it was asked to study. Indian Point Units 2 and 3 provide about 2,000 megawatts (MW) of baseload generating capacity in the one of the most densely populated areas in the nation. Its output represents 11 percent of the total generating capacity in southeastern New York (i.e., Long Island, New York City and Westchester County) and 23 percent of the electric energy delivered in this region.

Based on all of the information available to it, the committee has identified no technical obstacles that it believes present insurmountable barriers to the replacement of Indian Point's capacity, energy, and ancillary services. As this report discusses, a wide and varied range of replacement options exists, and if a decision were definitely made to close all or some part of Indian Point by a date certain, the committee anticipates that a technically feasible replacement strategy for Indian Point would be achievable. Replacements for Indian Point would be in addition to generating and transmission capacity needed for expected growth in the region and other retirements.

The report does not propose a "single solution" to the replacement of Indian Point. That was neither the committee's directive nor its mission. Indeed, from the committee's analysis, no "right" or clearly preferable supply alternative to Indian Point emerged. A replacement strategy for Indian Point would most likely consist of a portfolio of the approaches discussed in this report, including investments in energy efficiency, transmission, and new generation.

While the committee is optimistic that technical solutions do exist for the replacement of Indian Point, it is considerably less confident that the necessary political, regulatory, financial, and institutional mechanisms are in place to facilitate the timely implementation of these replacement options. The importance of addressing the non-technical barriers cannot be overstated in developing options for maintaining a reliable electric energy supply for southeastern New York State. The report discusses in greater detail various aspects of this challenge and includes specific conclusions and findings.

Reliability is a key consideration, especially during peak demand. Adequate generating and transmission capacity exists to replace Indian Point during non-peak hours, although costs might be significantly higher because Indian Point is the low-cost baseload unit. Reliability of power supply depends on several factors, including fuel availability, generation reserve, peaking load, and the growth in electric demand, both locally and regionally. An element of a reliable electricity supply also involves the stability of the transmission-distribution system. In general the electric system in the Northeast is carefully balanced to account for the location and operation of baseload generating plants, as well as peaking units. In southeastern New York, the reliability criteria also impose specific locational resource requirements, reflective primarily of New York City and Long Island's situation as very large demand centers at the end of the transmission grid. For these reasons, the committee's analysis has focused on replacement strategies, i.e., electric energy supply and demand options, primarily in southeastern New York (Zones H, I, J, and K, see Figure 1).

Adding to the complexity of choice is the issue of cost to customers and taxpayers, which could include both the costs of closing Indian Point and providing replacement resources. For example, if the plant's life were shortened, compensation might be owed to the owner. Costs of maintaining site security would be required to keep the spent nuclear fuel secured. There is considerable uncertainty over how the cost of replacement resources, higher fuel prices, and air quality offsets would be addressed in a deregulated wholesale electric market in which price is no longer based on the cost of production but rather on an open competitive bidding process under which all bidders get the same price as the last successful marginal winning bid. Also of concern are potential indirect costs to the community at large and state and local governments, including any loss of tax base from the plant, labor dislocation or loss of income from reduced plant operations that might be associated with the closure of the Indian Point facility.

Indian Point sits on the banks of the Hudson River whose protection has been a focal point of the American environmental law movement so it is no surprise that a complex web of federal and state environmental regulations must also be considered in evaluating replacement resources for Indian Point. These include air quality, water quality, and thermal discharge requirements; regulations regarding toxic releases; and regional and perhaps eventual federal initiatives to reduce greenhouse gas emissions. New power plants can be permitted only under the most stringent environmental review processes, and such projects are also subject to local zoning and land use controls.

CONCLUSIONS AND FINDINGS

The issues associated with the potential shutdown of Indian Point's two operating nuclear units are complex and interrelated. These issues impact the total energy system for New York State, the Northeast region, and beyond. Any analysis of the consequences and potential alternatives to the closure of Indian Point units cannot occur in a vacuum without reference to the context of other events unfolding in the state.

In analyzing replacement options for Indian Point, the committee examined the broader profile of New York State's electric power system to identify what, if any, other existing resources might be available to replace some portion of the energy and capacity now provided by Indian Point. Most germane to its evaluation of replacement options for Indian Point, the committee learned that even with the Indian Point units operational, New York State will require system reinforcements, above those already under construction, as soon as 2008 in order to meet its projected demand for electricity and maintain system reliability in the lower Hudson Valley and New York City area served by the Indian Point units. The state's need for additional electric power resources increases rapidly thereafter. Based on currently scheduled retirements and demand growth projections by the New York Independent System Operator (NYISO), 1,200 to 1,600 MW from new projects that are not yet under construction could be needed by 2010, and a total of 2,300 to 3,300 MW by 2015. Closing Indian Point would increase by 2,000 MW New York's need for additional electric resources, which could be in the form of new generating capacity, transmission lines, improved energy efficiency, and demand-side management.

This need for new resources is occurring at a time when it is problematic whether the existing legal, regulatory, and financial mechanisms provide sufficient incentive to build new resources there. The committee estimates that the generating capacity currently under

construction will be insufficient to meet projected peak demand in 2009, given currently announced retirements (NYISO 2005b). With the expiration in 2003 of its siting statute, Public Service Law Article X, New York State has no law designed to facilitate an integrated environmental review and siting of new power plants. NYISO has just completed its first Comprehensive Reliability Planning Process, and as this report explains in detail, it remains to be seen whether the NYISO's new market and pricing rules will provide sufficient economic incentives to stimulate investment in new electric resources. Developers and financial markets will look for investment opportunities with the best combination of high payback and low risk, whether they are in New York or not. If price signals in New York are low, the markets will wait until they rise. Given the time that it takes to obtain a suitable site, navigate the regulatory issues and obtain permits, and then construct a power plant, new generating capacity may not be available until reserves are dangerously low. Forestalling a crisis may require extraordinary efforts on the part of policy makers and regulators.

The committee examined two time frames for the possible closure of Indian Point: (1) when the current operating licenses expire for the two reactors in 2013 and 2015; and (2) an accelerated schedule of 2008 and 2010. The general conclusions that the committee reached concern the overall ability to replace the capacity and energy required if the Indian Point units were shut down in either of the two time frames. The committee also reached agreement on eight specific findings associated with generation, transmission, and demand-side options; reliability; physical and political infrastructure; the environment; and cost considerations if an early shutdown of Indian Point is effected. The committee emphasizes that the inability to successfully meet any of the requirements set forth in its eight findings would place the general conclusions in jeopardy.

General Conclusion (2013-2015)

The committee concludes that with sufficient time, planning, authority, and investment incentives, options are possible for replacing Indian Point. The Indian Point units could be retired at the end of their current operating licenses (2013 and 2015) without causing a major disruption of power capacity in southeastern New York if sufficient resources were added by 2015 to cover anticipated system retirements and the expected growth in demand, as well as the shutdown of Indian Point. To achieve this goal, the committee estimates that an additional 5,000 to 5,500 MW, or roughly 500 MW per year, in new resources (a combination of generation, transmission and demand side actions) would need to be added by 2015.[1] The 3,300 MW in new resources that are estimated to be required even if Indian Point continues to operate is less than 10 percent of New York's current capacity, and it should be achievable over the next 9 years. The additional 2,000 MW of new resources required if Indian Point is closed should also be achievable if the conditions discussed below are met.

General Conclusion (2008-2010)

[1] All projections in this report should be understood to be approximate at best. Not only are estimates of load growth uncertain, but assumptions of where new generating and transmission capacity will be added, constraints on system operations, and the analytical methodology that is used will all affect the estimates of reliability and the calculated need for new capacity.

The committee concludes that an earlier shutdown of the Indian Point units would be much more difficult to accomplish. In 2008, when Unit 2 (1,000 MW) would be closed, New York will have very little if any excess capacity. To replace it, the committee estimates the need for an additional 700 MW in generating capacity, assuming that demand-side programs could reduce peak demand by several hundred megawatts. By 2010, with the closure of the second unit (1,000 MW), an additional 1,300-1,400 MW in replacement generating capacity would be needed, assuming that demand-side measures would continue to increase, totaling 650 MW in peak demand reductions. That is in addition to the 1,200-1,600 MW that will be need even with Indian Point operating. In the committee's view, this extraordinary challenge could only be met with the firm commitment of a variety of New York government leaders, and tight cooperation amongst many agencies. Such collaboration may be unprecedented, so the difficulty of achieving it should not be underestimated. The impacts discussed for the 2013-2015 scenario would be magnified, with potentially even greater added costs. If new generating capacity is not constructed in a timely manner, system reliability would be threatened. Not only could reserve margins drop below standards, but existing generating units would likely show lower reliability as they are run beyond their normal operation schedule.

Finding 1: Governmental Mechanisms and Regulatory Policy

The committee recognizes that maintaining a reliable supply of electricity for New York City and southeastern New York State is a primary objective for public policy and essential to the region's health and economic well-being. However, the committee finds that current governmental mechanisms and regulatory policy may limit New York State's ability to address in a timely and effective manner the capacity, energy, and ancillary consequences of closing Indian Point. The committee finds that in order to provide alternatives to Indian Point Units 2 and 3, a more considered long-range strategy is likely to be necessary. This strategy would be based on a detailed assessment of the current market structure and might well require significant changes in New York's current laws and regulatory policies, such as reauthorization of the State's Article X power plant siting process and reestablishment of the State Energy Planning Board and the state energy planning process, in order to ensure the continued reliability of the state's electric system.

Finding 2: Market and Financial Uncertainties

The committee notes that even with the continued operation of the Indian Point units, New York State already faces challenges in satisfying the projected growth in its electric demand and in maintaining system reliability. While conceptual planning to address these needs is underway through NYISO and other entities, the response of electric power developers, suppliers and distributors is uncertain, given the current state of evolution of New York's market. Indian Point represents a significant asset, both in terms of capacity and energy, especially for electric customers in southeastern New York, and if Indian Point is retired, replacement of its 2,000 MW capacity will place a substantial additional burden on the state's electric supply system.

Finding 3: Transmission Options

The committee finds that improvements in transmission capability could significantly relieve congestion in the New York system and facilitate the delivery of power from existing and potential electric generation resources to the New York City area. Such improvements should include modifications to the state's existing transmission system and the possible installation of new direct current transmission. A West-to-East line (550 MW) has been proposed across the Hudson River, and a new North-to-South transmission line (up to 1,000 MW) for better access to upstate and Canadian electric resources is under investigation. These lines could supply useful capacity in the 2010 and 2015 time period, respectively, if a variety of institutional and financial issues can be resolved. The committee notes that increasing the importation of power into southeastern New York would also increase the need to install additional reactive power equipment to maintain system voltage within the region, but this problem is relatively easy to solve.

Finding 4: Demand-Side Options

The committee finds that substantial cost-effective opportunities exist for investment in demand-side technologies that could reduce demand for electricity in southeastern New York. These could include a phase-in of programmable energy efficiency and demand-response programs, along with additions of distributed generation and combined heat and power units. These could provide reductions of more than 1,100 MW from projected peak demand by 2010 and 1,700 MW by 2015. The committee notes that these offsets are ambitious and would be in addition to the current effective programs with which the New York State Energy Research and Development Authority, the New York Power Authority, Consolidated Edison and the Long Island Power Authority are already managing demand growth. The committee finds that these offsets are achievable, but only if well-designed programs are implemented promptly and additional resources are provided to overcome many obstacles.

Finding 5: Supply Side Options

The committee finds that even with substantial additional investment in new transmission facilities and aggressive demand-side programs, additional generating facilities, above those already planned, will be required to compensate for the shutdown of the Indian Point units to maintain system reliability. While coal may be a reasonable generating alternative for the 2013-2015 time frame, new near-term generating solutions are most likely to be a mix of simple-cycle gas turbines and combined-cycle natural gas units. The use of the former would provide a short-term solution, but in the longer term, such units would probably be relegated to peaking usage. Owing to the nature of the New York City metropolitan region, renewable energy technologies are unlikely to contribute significant resources by 2015, with the possible exceptions of offshore wind power and distributed photovoltaics.

Finding 6: Alternative Fuel Availability and Security

The committee finds that the availability and price of natural gas will be major considerations, and perhaps constraints, in planning for new generating capacity to replace power from the Indian Point units. A large share of the 2,000 MW from Indian Point is likely to be replaced with natural gas-fired generating plants, and that is over and above the several thousand megawatts of new gas-fired capacity that will be needed to meet the growing demand for energy in southeastern New York State. This increase in New York's dependence on natural gas for power production will stress supplies of natural gas. In addition, increased dependence on natural gas will reduce diversity of fuel supply for the New York electric system, also a serious concern.

Finding 7: Cost Considerations

Cost is a key consideration in evaluating any scenario for the early retirement of the Indian Point units. Three main categories must be taken into account: (1) any compensation that might be due Entergy Nuclear for the early retirement of the Indian Point units; (2) replacement costs, including new generation and transmission, demand-side programs, increased demand for pollution offsets, and the increased price of fuel, particularly natural gas for power production; and (3) the financial impact to Westchester County, the Town of Buchanan and surrounding communities from the loss of Indian Point tax revenues and the labor-commercial base. The committee found that it is difficult to make specific cost estimates for these items. Ultimately, the price consumers pay for electricity in southeastern New York will reflect some of these costs. However, given the current market structure for the sale of electric power in New York, under which wholesale prices are set on a sub-regional zonal basis that reflects competitive bidding behavior, the committee could not satisfactorily determine the increase in the cost of electricity to consumers that might result from the closure of Indian Point. Some costs could be offset by demand-management practices, but new generation, and perhaps new transmission, will likely increase wholesale electric costs, especially in the New York City metropolitan area, depending on competitive bidding in the open wholesale market.

Finding 8: An Integrated Approach is Needed

The committee emphasizes that its findings must be considered as an integrated whole. Replacements for the energy, baseload capacity, and ancillary services currently provided by the Indian Point units will not happen just because they should. The construction and operation of new electric generating facilities, natural gas pipelines, liquefied natural gas (LNG) facilities, or electric transmission lines will each inevitably encounter hurdles that will have to be overcome if that project is to become a reality. Each facility needs a site, financing, permits, delivery contracts and infrastructure agreements, and has facility-specific requirements. This is also true for any demand-side programs, which have their own timing, financial, marketing and implementation challenges to be worked out in order to achieve sufficient participation by the general public.

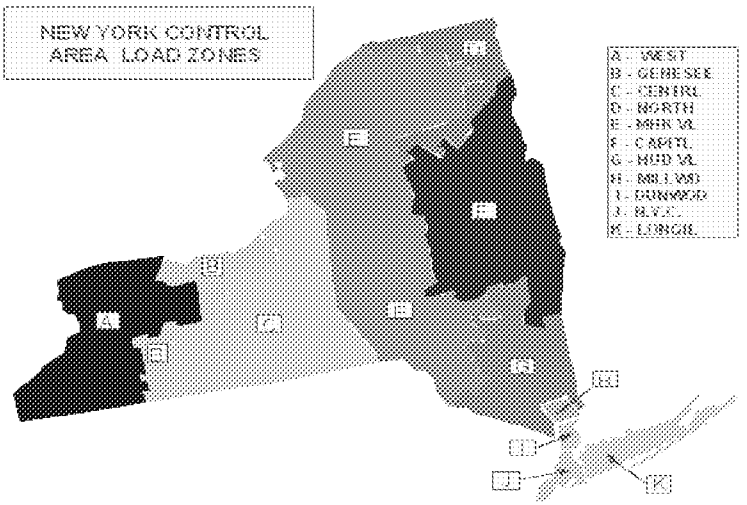


Figure 1. New York Control Area Load Zones
Source: NYISO

1

Introduction

This report presents the work of the National Research Council's (NRC's) Committee on Alternatives to Indian Point for Meeting Energy Needs. It reviews the options that are available and assesses the feasibility of installing them on a scale sufficient to replace the 2,000 megawatts (MW) of electricity from the Indian Point Energy Center.

This chapter presents background information necessary to understand how replacements would be implemented. It also reviews how the committee conducted the analysis.

BACKGROUND

Electricity Supply and Demand

Electricity generally cannot be stored and must be generated at virtually the same instant as it is used, which requires continuous control of the system.[1] New York State has an integrated bulk power system, the New York Control Area (NYCA). Formerly, the New York Power Pool had coordinated the activities of the utility participants on the transmission system. As competition was introduced into the New York electric system, utilities were required to divest their generating assets.[2] The New York Public Service Commission and the Federal Energy Regulatory Commission also required a more independent electric system operator. The New York Independent System Operator (NYISO) was created to operate the high voltage transmission system and to provide a match of load requirements to generation sources in a manner which: 1) ensures the reliability of the State's power system, 2) facilitates open, fair and effective competitive markets, 3) improves regional cooperation for operations and planning, and 4) assures non-discriminatory access to the electric system. NYISO uses the locational based marginal pricing (LBMP) system to accomplish its objectives. LBMP also provides price signals to providers of new generation and transmission. Thus, NYISO has assumed the power dispatching role that integrated utilities used to carry out within their own jurisdictions, but on a statewide level. NYISO uses auctions to select the lowest-cost suppliers consistent with transmission constraints, among other functions. Box 1-1 lists many of the market products that NYISO must monitor. Further details are provided in

[1] Pumped storage facilities are currently the only practical form of large-scale power storage using low cost off-peak power to pump water uphill to a reservoir. The flow is reversed during peak hours when the power that can be regenerated is much more valuable. However, few sites are appropriate for pumped storage. ConEd attempted to build pumped storage on Storm King Mountain up the Hudson River near West Point, but the project was stopped for environmental reasons. Other storage technologies, including batteries, compressed air energy storage, and superconducting magnets, are still under development to reduce costs.

[2] Competition was introduced in part to avoid cost increases, such as had occurred in the 1970s and 1980s because of overbuilding. Those costs had largely been passed onto customers.

Chapter 4. Competitive markets are still evolving, and it is not yet clear exactly how to ensure both reliability and low costs.[3]

BOX 1-1
Keeping Competitive Markets Operating

New York's large and varied power system requires a very complex set of functions for smooth and efficient operation. NYISO conducts energy market auctions in two phases: (1) the Day Ahead Market establishes forward contracts for each hour of the coming day; (2) the Real Time Market is conducted when the load actually occurs to precisely match supply with demand. Most energy transactions in NYISO are conducted in the Day Ahead Markets. NYISO adds up the bids starting with the lowest cost for each time interval until it has sufficient power to meet projected demand. All bidders then receive the price set by the highest accepted bidder.

Other important functions include the Installed Capacity (ICAP) Market, which is designed to ensure that Load Serving Entities (LSE, such as ConEd) have sufficient capacity available to serve their customers. The following are among the NYISO market products, as described in detail on the NYISO website (www.nyiso.com):

Energy Markets

Day-Ahead locational based marginal pricing (LBMP) Energy
Real time LBMP energy

Ancillary Services
Regulation service (frequency control)
Black start capability
Voltage support service (reactive power)

Installed Capacity (ICAP)

Transmission Congestion Contracts

Demand Response Programs
Emergency Demand Response Program
Special Case Resources (SCR) ICAP Program
Day Ahead Demand Response Program

SOURCE: www.nyiso.com; accessed March 29, 2006.

[3] Competitive markets, or "restructuring", encompass 1) allowing generation to be built by nonutilities, 2) breaking up vertically integrated utilities, 3) independently owned and operated transmission, with some degree of open access for all suppliers, 4) spot markets for electricity, 6) retail choice for some customers in some states (including New York), and 7) a substantial shift in regulatory jurisdiction from the states to FERC. They may also include competitive bidding for power supply and the inclusion of energy efficiency in competitive power procurement processes.

NYISO also plans for future growth and makes recommendations for additional capacity, although it does not pick specific sites or technologies. Additional capacity is mainly built by developers, or merchant generators, which could have contracts for the power from a load serving entity (LSE) or which expect to be able to compete profitably in the auction. Under some conditions, the New York Power Authority (NYPA) can build new capacity. NYISO has issued a request for proposals to deal with concerns over potential capacity shortfalls, but that process has just begun.

Reliability standards are set by the New York State Reliability Council (NYSRC) in conjunction with the Northeast Power Coordinating Council (NPCC), which operates under the North American Electric Reliability Council (NERC). NPCC standards also apply to New England and eastern Canada while NYSRC standards are tailored to New York's particular situation (e.g., requirements for generating capacity in New York City and Long Island). NYSRC also sets the amount of installed generating capacity (ICAP) needed to meet the required reserve margin generating capacity at peak electrical load. Reserve margin criteria are set yearly for one year ahead (18 percent for 2006 – 2007) by the NYSRC which also specifies other allowable resources (e.g., specific loads that can be shut off on NYISO's order are equivalent to generating capacity for meeting peak demand) to be included in the reserve margin and correspondingly to be used in calculating the reliability. Finally, the Energy Policy Act of 2005 provides that Federal Energy Regulatory Commission (FERC) will certify a single organization (expected to be NERC) that will propose and enforce mandatory "Reliability Standards for the Bulk-Power System in the United States," subject to FERC approval.

A complicated network of high-voltage transmission lines is required to deliver the bulk power to load centers, which may be hundreds of miles from the generating stations.[4] The bulk power system must be controlled very precisely to keep voltage and frequency within tight bounds and to operate reliably despite the occasional component failure. It also is important to keep the cost of electricity as low as possible, in part by operating the lowest-cost plants as much as possible.

The NYCA has about 38,000 MW of installed capacity within New York State and 4,000 miles of high-voltage transmission lines. Power also can be traded with interconnected control areas in New England, the Mid-Atlantic region, and Canada. The NYCA high-voltage transmission system, including major substations, is shown in Figure 1-1.

Power demand fluctuates both during the day and over the year, as shown in Figure 1-2, so a variety of generating plants must be available to follow the load, including:

- *Base load plants, to meet the steady part of the load.* Base load facilities (such as the Indian Point units) produce power inexpensively. They typically operate all day and most of the year. They are generally nuclear or coal-fired steam generators. The Indian Point units are an important generating resource in the NYCA owing to their low cost and their location near the load centers in New York City and Westchester County.

[4] Low-voltage distribution lines, which are not part of the bulk power system, carry the power to the end-use customer. Most outages that consumers experience are due to failures in the distribution system (e.g. trees falling on overhead lines), but these usually are repaired quickly and are not part of this study.

- Peak*ing plants for periods of high demand.* Combustion turbines, for example, are often deployed in simple cycle, and are used during periods of peak demand, because they can be quickly turned on or off. The operational flexibility of such "peaking" generators, however, is counterbalanced by their low thermal efficiencies, which makes them expensive to operate.
- *Intermediate units, which also follow demand but are used more than peaking plants.* An intermediate generator might use a combustion turbine in combination with a steam turbine to provide a wide range of operating flexibility. Combined cycle facilities are typically fueled with natural gas and often have the capability of burning oil as an alternative fuel supply when supplies of natural gas are curtailed because of high demand, usually during the winter. Modern gas-fired combined cycle plants[5] are much more efficient than older or simple-cycle gas turbines.

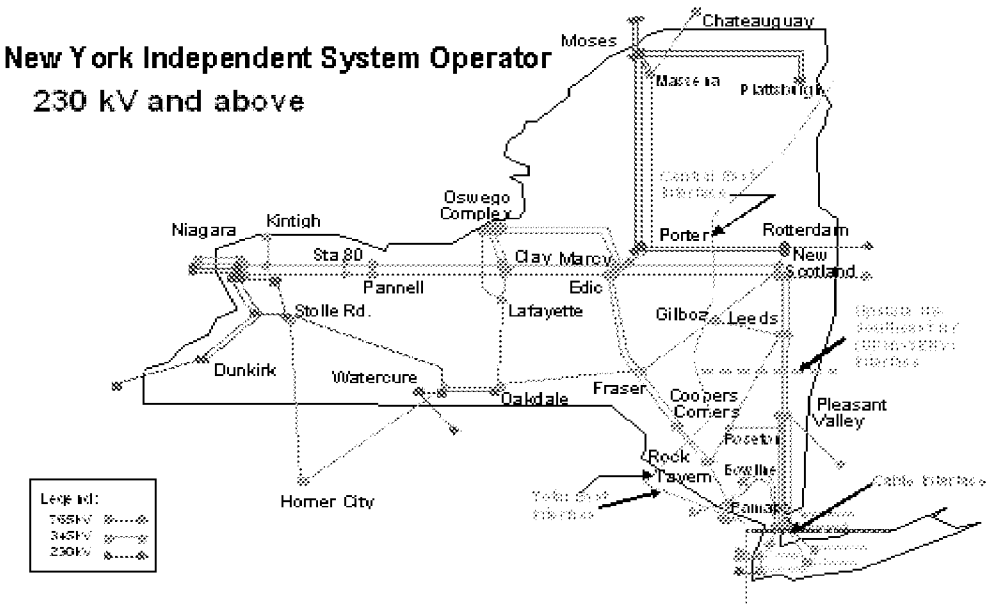
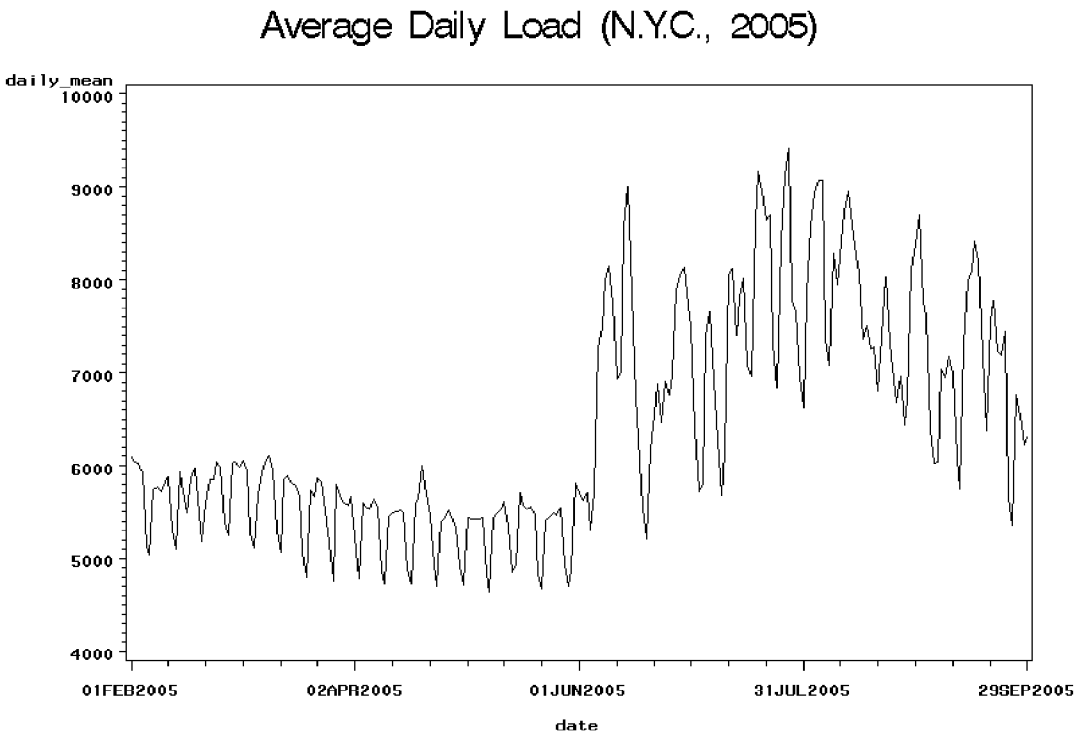


Figure 1-1 The New York Control Area High-Voltage Transmission Network
Source: New York Independent System Operator

[5] These plants combine a gas turbine (similar to a jet engine) with a steam turbine that uses the waste heat from the gas turbine as its energy source. The latest combined cycle plants can be up to 60% efficient, almost twice as high as most coal or nuclear plants.



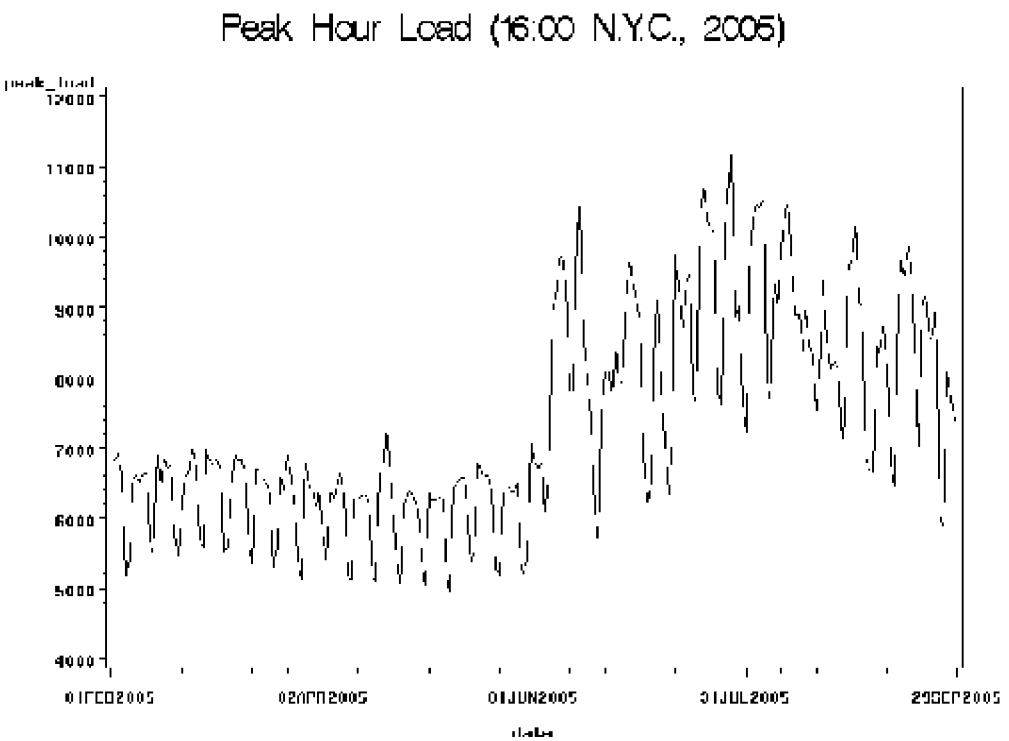


FIGURE 1-2. Average Daily Load (top) and Peak Hour Load (bottom) in New York City.

SOURCE: Personal communication with Timothy Mount, Cornell University, compiled from NYISO data, January 2006.

NYISO has divided the NYCA into 11 zones, shown in Figure 1-3, to assist in pricing and monitoring load flows on the transmission system. The key zones for this report are:

- *H* *which includes the northern portion of Westchester County, where Indian Point is located*
- *I* *the rest of Westchester County*
- *J* *New York City*
- *K* *Long Island outside of New York City*

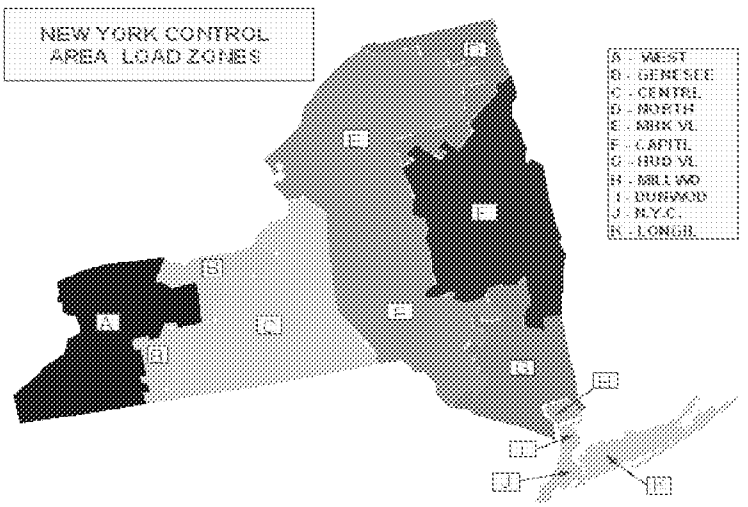


Figure 1-3 New York Control Area Load Zones
Source: NYISO

In accordance with NYSRC standards, NYISO's goal is for the bulk power system to have sufficient capacity that outages will be less than 1 day in 10 years. This loss-of-load expectation (LOLE) is determined by using statistical descriptions of the historical availability of each generator and Monte Carlo calculation techniques to compute the expected number of days in a 10 year period when the load could not be supplied. The LOLE is used in determining how much additional generation a given area will require for expected load growth and is likely to continue to be used if Indian Point is closed.

In addition to sufficient capacity, diversity of fuels provides another element of system reliability. Excessive dependence on one fuel source threatens system reliability if that fuel supply encounters shortages. Figure 1-4 displays the varied contributions of different fuels to the installed capacity (in megawatts) of the NYCA. Natural gas and oil represent 60 percent of the installed capacity, and coal, nuclear, and hydroelectric power account for 39 percent. New York's new Renewable Portfolio Standard should improve fuel diversity. This standard requires 25 percent of electricity to be generated from

renewable sources by 2013, compared with 19.5 percent now (mainly hydroelectricity, most notably from Niagara Falls).[6]

The electrical output (actual kilowatt-hours) generated by each fuel is not proportional to the generating capacity that uses that fuel. Gas and oil fuel about 38 percent of the total. Coal, nuclear and hydro power represents most (61 percent) of the power generated in 2004.

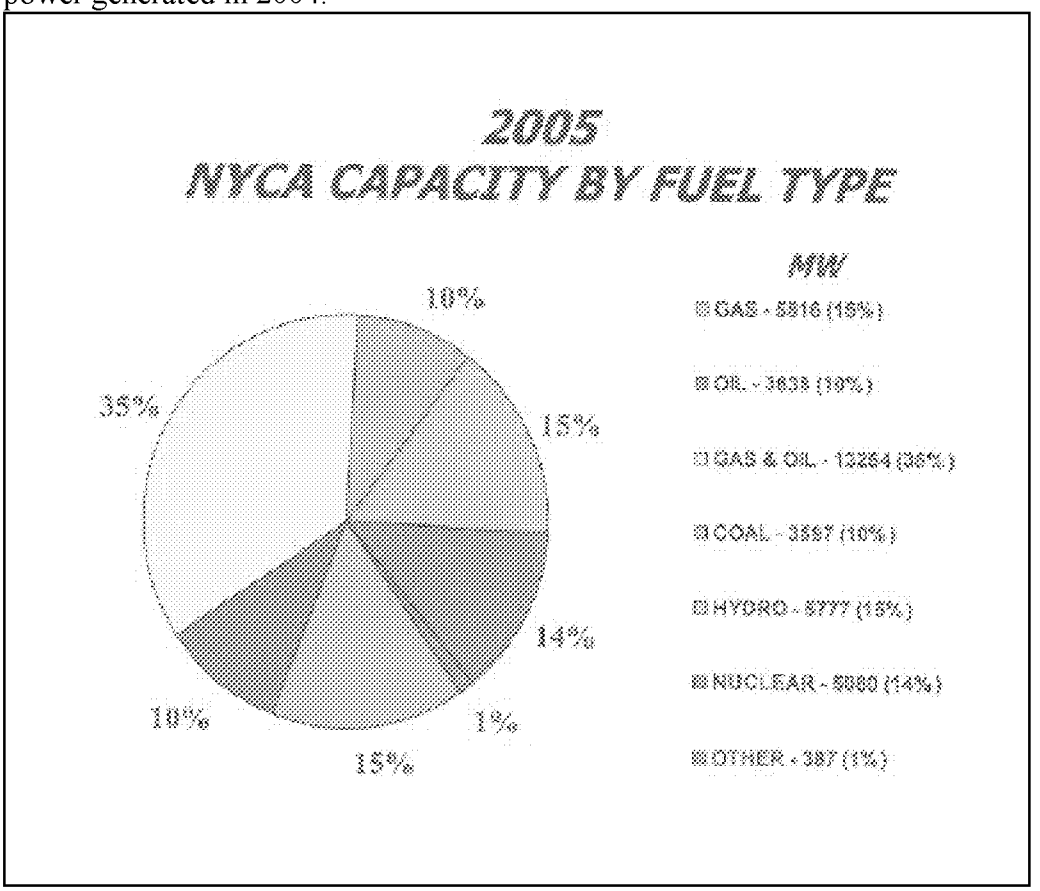


FIGURE 1-4 Generating capacity in the NYCA by fuel type.
SOURCE: New York Independent System Operator, Power Trends 2005, April 2005.

Generator owners in the NYCA operate a diverse mix of generation facilities.. Table 1-1 lists the power that can be generated in each NYCA zone by technology during the summer-peak demand period.[7] The diversity of generator technologies in the NYCA in itself adds to the reliability of the electrical system. Reliability also is a function of

[6] Renewable resources include solar energy, wind, biofuels, and others. Renewables are appealing for a variety of reasons, especially environmental, but most forms have been expensive relative to fossil and nuclear energy. Some technologies (e.g., wind) are now proving to be competitive, and progress in research and development on others is encouraging, as discussed in Chapters 2 and 3. Hydroelectricity is a form of renewable energy, and New York State already receives an abundant supply from Niagara Falls and other sites, but it is questionable whether hydropower can be expanded significantly.

[7] Many generating plants can produce more power in the winter than in the summer. Cooler air is denser, so combustion turbines can be fed more fuel. Steam turbines also exhaust to a lower temperature and thus lower back pressure, increasing their efficiency.

where the location of the generating facilities relative to the load centers that they serve. Indian Point Units 2 and 3 (total 1,970,700 kW) are listed in the column "Zone H" and row "Steam (PWR [for pressurized water reactor] Nuclear)". The two units represent 12.5 percent of the total summer capability in Zone H, I, J and K (NYISO, 2005). Indian Point is virtually the only generating facility in Westchester County.[8]

Even with adequate capacity, an electric grid may fail because of instability. Several types of instability may occur, and they have different time scales and effects on customers. Voltage stability is most important in considering alternatives to Indian Point. The phenomenon of voltage collapse (in which voltage declines to unacceptable levels, as it did in Ohio in August 2003) is associated with insufficient reactive power.[9] The existing generators at Indian Point can supply a large amount of reactive power when it is needed. It will be necessary to verify that alternatives to Indian Point would include sufficient reactive power to maintain acceptable voltage levels under all predicted loads.

[8] Zone I has about 3 MW of hydroelectric power and municipal waste generation in addition to the 2,000 MW from Indian point; see Appendix D-2 for details.

[9] Reactive power is a complex phenomenon in alternating current power. It is discussed further in Chapter 3 of this report.

Capability By Zone and Type

As of April 1, 2005

Generator Type	ZONE A	ZONE B	ZONE C	ZONE D	ZONE E	ZONE F	ZONE G	ZONE H	ZONE I	ZONE J	ZONE K	TOTAL
	Summer Capability Period (KW)						Summer Capability Period (KW)					
Steam Turbine (Oil)	0	0	1648200	0	0	0	0	0	0	0	0	1648200
Steam Turbine (Oil & Gas)	0	0	0	0	0	0	2448100	0	0	4353100	2441700	9242900
Steam Turbine (Gas)	0	0	0	0	0	0	0	0	0	827800	238700	1066500
Steam Turbine (Coal)	1201700	238000	576500	0	52400	0	728300	0	0	0	0	3796900
Steam Turbine (Wood)	0	0	0	14100	20200	900	0	0	0	0	0	35200
Steam Turbine (Refuse)	37800	0	33116	0	0	11500	8200	52000	0	0	120800	263716
Steam (PWR Nuclear)	0	498800	0	0	0	0	0	1970700	0	0	0	2469500
Steam (BWR Nuclear)	0	0	2610000	0	0	0	0	0	0	0	0	2610000
Pumped Storage Hydro	240000	0	0	0	0	1068700	0	0	0	0	0	1308700
Internal Combustion	8812	2100	35212	1705	0	1719	33500	0	0	2900	69740	115582
Conventional Hydro	2396000	57016	122377	621514	459746	423952	105400	0	2260	0	0	4987984
Combined Cycle	462704	115103	1385100	320800	328600	1624300	0	0	0	1363300	239800	5842604
Jet Engine (Oil)	0	0	0	0	0	0	0	0	0	0	528800	528800
Jet Engine (Gas & Oil)	0	0	0	0	0	0	0	0	0	0	172500	172500
Combustion Turbine (Oil)	0	19000	0	0	0	0	15900	46500	0	784100	553900	1419400
Combustion Turbine (Oil & Gas)	0	0	0	0	0	0	194000	0	0	1189000	135400	1518400
Combustion Turbine (Gas)	35000	14050	85305	0	0	0	0	0	0	465400	661500	1264400
Wind	26	6700	30036	0	2566	50	50	0	0	0	0	40447
Other	0	0	0	0	0	0	0	0	520	0	0	520
Totals	5382842	946719	6919031	1261814	870811	3114797	3421119	2068200	2880	8881400	5179340	37547313

TABLE 1-1 Capability of Generating Plants by NYCA Zone and Generator Type
SOURCE: New York Independent System Operator, Power Trends, April 2005.

Peak demand generally occurs during hot summer afternoons when air conditioning loads are highest. Demand on July 26, 2005 was 32,075 MW, a record for the NYCA. Reliability is of greatest concern during hours of peak demand because at such times reserve capacity, both generation and transmission, is at its lowest. Any equipment failure then can threaten continued supply if reserve capacity is too low. NYISO has a general requirement that NYCA capacity must exceed expected peak demand by 18 percent to allow for failures.[10] On July 26, the reserve margin was about 19 percent, indicating adequate reserve capacity for the state.

Regional distribution within the state, however, is more problematic. Upstate New York has some surplus capacity, but very little if any additional power can be delivered downstate because the transmission system is already congested during peak demand. Furthermore, electricity demand has been growing at over 2 percent per year in southern New York, so more capacity will be required in a few years to meet peak demand in that area. Chapter 2 includes an analysis of demand growth and the options for controlling it. Chapter 3 discusses the possibility of building new power plants upstate and transmission lines to bring the power south.

In addition to controlling bulk power flows, NYISO must monitor and control reactive power. Insofar as reactive power cannot be produced by operating generators, it must be supplied by specialized equipment.

Several other factors extremely important in planning for the future of the bulk power system noted here are discussed further in Chapter 3. A reliable supply of electricity depends on a reliable supply of fuel to power the generators. New York has a diverse supply of fuels: hydroelectric, nuclear, coal, natural gas, and oil. Diversity is important because disruptions can occur in fuel deliveries. In recent years, most new generation has been fueled with natural gas, but new supplies of gas are expected to be limited and expensive unless new facilities for importing liquefied natural gas (LNG) are built. Natural gas is generally available during the summer, but it may be curtailed in the winter when demand is high for residential and commercial heating. Oil is frequently used as a backup for natural gas in the winter, but it is expensive, pollutes more, and raises national security issues.

Environmental factors may control what types of facilities can be built where. In particular, air pollution regulations can limit the use of coal, the nation's most abundant fossil fuel. New York has introduced new, lower standards for emissions of sulfur dioxide and nitrogen oxides, which would require expensive emissions controls on coal plants. Carbon dioxide emissions are emerging as an issue. Concerns over global climate change are leading to restrictions on emissions of greenhouse gases, though not yet at the national level. New York is part of the recently adopted Regional Greenhouse Gas Initiative, which will begin to limit emissions of carbon dioxide in 2008.

The changing institutional structure of the electric power industry in New York will also play an important role in efforts to replace Indian Point as described in detail in Chapter 4 and in Appendix E. Formerly, under the regulated approach, an integrated utility would determine its generating, transmission, and other needs, and build whatever was required. A reasonable return on its investments was largely guaranteed by the state's

[10] Reserve margin during off-peak hours is, of course, much higher. It is only high demand hours that are of concern.

Public Service Commission. The introduction of competition in the industry has also introduced an element of uncertainty that affects the willingness of power companies to invest. The expiration of New York's siting legislation in 2003 represents another hurdle to building new facilities.

Finally, societal impacts play an important role in guiding decision making with respect to the bulk power system. These impacts can be seen in issues such as public opposition to new generating or transmission capacity. Employment issues can also be important for some facilities.

The Indian Point Energy Center: Description and Role

Three reactors have been built at the 239 acre Indian Point site. Unit 1 was an early, small reactor that has been shut down since 1974. It is still onsite though not operable, because demolition was deemed easier if carried out simultaneously with the later reactors.

Indian Point Unit 2 was built by Consolidated Edison (ConEd), the utility that supplies power to Westchester County and New York City. Operating since 1974, Unit 2 is licensed until September 28, 2013. It produces 970 MW but is scheduled to be upgraded to 1,078 MW.

Construction of Indian Point Unit 3 was started by ConEd, but financial difficulties forced the utility to sell it to NYPA before completion. It has operated at 980 MW since 1976 and is licensed until December 12, 2015. It is expected to be upgraded to 1,080 MW.

In 2001 and 2002, the units were sold to Entergy Corporation, an integrated energy company that owns and operates power plants. Both sales were accompanied by an agreement to purchase back the power generated by the plant for several years. These agreements are phasing out, and Entergy will soon be able to sell the power at a higher price, as most alternate fuels have risen considerably in cost over the past few years.

Entergy Nuclear operates 10 nuclear power plants, including the Indian Point Energy Center and the FitzPatrick plant in upstate New York. Since Entergy took over Indian Point, it has operated the plants extremely well. From 2003 to 2005, Unit 2 operated at a capacity factor of 96.6 percent and Unit 3 at 93.7 percent (NEI, 2006). The industry average is 89.6 percent. The two Indian Point reactors are among the lowest-cost generators in New York, and they operate whenever possible supplying base load power to the system. Together, they account for 5.3 percent of the total installed generating capacity in New York State, but they produce 10.1 percent of the electricity (Levitan and Associates, 2005).

Entergy can apply for license extensions for an additional 20 years of operation. The U.S. Nuclear Regulatory Commission would review the applications for confirmation that the reactors could be operated safely and in compliance with environmental regulations. The application process can take about 5 years, suggesting that Entergy would have to submit the applications for Units 2 and 3 in 2008 and 2010, respectively.

Both units feed power into the transmission network at the nearby Buchanan substation. The power is delivered to load centers, mainly in New York City.

Indian Point is the largest generating station close to the major load centers in New York City, Westchester County, and Long Island and south of congestion points in the NYCA transmission system that prevent more power from being sent south during periods of peak demand. Indian Point also produces the lowest-cost power in the area. Thus, Indian Point is a critical component of both the reliability and economics of power for the New York City area. In addition, it produces much of the reactive power needed for reliable operation of the system. Replacing Indian Point will call for careful analysis of the choices that are made.

Community Concerns

Community concerns about the Indian Point reactors have a long history (Wald, 1982), but prior to September 11, 2001, they had faded, with only a few people still expressing public concern that the dangerous amounts of radioactivity in the cores of the reactors might be released in an accident (Hu, 2002). Opinions were changed by the 2001 attacks on the World Trade Center (Purdy, 2003; Lombardi, 2002; Hu, 2002.

> Since the Sept. 11 terrorist attacks, growing anxiety over the safety of nuclear power plants has transformed Indian Point from a fringe issue that only antinuclear crusaders care about to a mainstream concern, and not just for Westchester suburbanites, but for New York City and New Jersey residents, who had, until now, barely registered the plant's existence 40 miles north of Midtown Manhattan. (Hu, 2002)

Scenarios leading to catastrophic releases were no longer easy to dismiss on the basis of fault-tree calculations and experience underlying previous assurances of safety, although the Nuclear Regulatory Commission and Entergy point out that it would be very difficult for an airplane or attackers to cause a major release, and, in any case, security would be upgraded. Such assurances were not sufficient to allay public concern. In addition, concerns about accidents at or attacks on the spent fuel pools at Indian Point have been given new attention since 9/11 (Wald, 2005b). For instance, a National Research Council study (NRC, 2005) concluded that "successful terrorist attacks against spent fuel pools, although difficult, are possible"; the type of spent fuel pool at Indian Point, however, was not among those that report considered most vulnerable. It should be noted that closing Indian Point would not by itself eliminate risk from the spent fuel, which may remain onsite for many years until a permanent storage disposal facility is ready.

In Westchester and surrounding counties, some 12 community groups (Hu, 2002) have called for the plant's closing (e.g., Riverkeeper, Public Citizen, and Indian Point Safe Energy Council).[11] Activities by these groups, including advertising and an HBO television special, have kept the issue of shutting down Indian Point on the political agenda. Riverkeeper claims that, "A large radioactive release triggered by a terrorist

[11] Information detailing these concerns can be found at the websites for the respective organizations, including www.riverkeeper.org, www.citizen.org and www.ipsecinfo.org, March 2006.

attack on or accident at the facility could have devastating health and economic consequences…". Entergy, many safety analysts in the industry, and the Nuclear Regulatory Commission are convinced that a terrorist attack, even if it occurred, would be extremely unlikely to result in a large radioactive release. Riverkeeper also is concerned with environmental damage to the Hudson River, especially to fish, eggs, and larvae (van Suntum, 2005). Here, the policy issue, which is currently in the courts, is whether or not the river cooling system should be replaced by a more expensive system (Hu, 2003).

A key community concern has been the perceived inability of emergency plans to work in the aftermath of an accident or successful attack on the facility (Purdy, 2003; Lombardi, 2002). A state-sponsored study (Witt, 2003) found that "The plans do not consider the possible additional ramifications of a terrorist caused release." Early evacuation is not a requirement of Nuclear Regulatory Commission and state emergency planning because scenarios that would lead to early fatalities are not considered credible, even after 9/11. Yet the public appears to see early evacuation as crucial (Witt, 2003), which produces tension, because evacuation in the crowded New York metropolitan area is perceived by many to be impossible (Risinit, 2005). If many people attempted to evacuate or collect their families upon announcement of a potential release, the result could be gridlock (Witt, 2003; Westchester County, 2006).

Local political leaders, such as Westchester County Executive Andrew Spano, call for an Indian Point shutdown, bringing the resources of the county to bear on the campaign. Rockland County Executive Scott Vanderhoef has also called for closure "before terror attacks" (Purdy, 2003). Congresswoman Nita Lowey, from New York's 18th District, has expressed concerns about the Indian Point facility and was responsible for commissioning this National Research Council study. She has also introduced a bill to require relicensed facilities to meet the same standards as those for new nuclear plants, which is currently not the requirement of the Nuclear Regulatory Commission.

As one indication of concern about reactor accidents, Westchester County, in cooperation with New York State, has developed a program to provide potassium iodide to residents who live, work, or travel within the 10 mile Emergency Planning Zone (Westchester County, 2006). Such tablets, if taken early enough, significantly reduce radiation doses to the thyroid, the major risk after the Chernobyl accident.

In addition, Westchester County has commissioned expert studies on issues surrounding Indian Point (e.g., Levitan and Associates, 2005), as has Riverkeeper (Lyman, 2004; Komanoff, 2002; Schlissel and Biewald, 2002). The study for Westchester County highlighted the expense of an early shutdown of Indian Point, leading County Executive Spano to put his hopes on stopping Entergy in the relicensing process (Wald, 2005a).

Local opinion is by no means unanimous against Indian Point. Some political leaders are concerned that the plants have 1,200 employees and pay significant taxes to local schools and governments (Westchester County, 2003). Dan O'Neill, mayor of Buchanan, New York, home of the plant, is supportive of the facility (Purdy, 2003). Others are concerned over the reliability of the New York City power supply and potential increases in the costs of electricity.

CRITERIA FOR EVALUATING REPLACEMENT OPTIONS

The opportunities or options for replacing the Indian Point power plant are constrained by various technological, regulatory, and socioeconomic elements. These need to be taken into account in developing options for maintaining a reliable electric energy supply for southern New York State, while allowing for growth in the region.

Each of the constraints derives from somewhat different technological, regulatory, or cost considerations, many of which are unique to New York State. These constraints will affect both the choice and the timing of change in supply if Indian Point is considered for retirement.

For instance, the electricity supply available in New York currently relies heavily on Indian Point as a major baseload contributor to the power supply needed in the New York metropolitan area. Replacement of this capacity would require major efforts in new generation, transmission, and demand management.

Reliability of power supply depends on several factors, including fuel availability, generation reserve, peaking load, and the growth rate of demand locally and in the region. Reliable electricity also hinges on the stability of the transmission-distribution system. In general, the NYCA system is carefully balanced to account for the location and operation of baseload plants, as well as intermediate and peaking units. Balancing is complicated by the nature of the generation, which includes not only conventional fossil and nuclear power sources but a variety of other technologies in the system, including hydrodroelectric units, wind power, and co-generated power at industrial facilities.

Safety has motivated this study to a great extent. Concern for public safety associated with a nuclear power plant close to the New York metropolitan area is substantial. However, there are additional considerations related to energy security and public safety. Security of the plant site must be maintained whether or not the plant is retired because it contains radioactive material, including stored spent fuel rods. Another energy security concern is fuel availability. In particular, most new generating units are fueled by natural gas, but gas supplies are limited and becoming increasingly expensive. Lengthy blackouts, whether caused by inadequate fuel supplies or transmission system instability, also threaten public health and safety. Imports of LNG may be required, but LNG also raises safety as well as energy security issues.

Adding to the complexity of decisions on closing Indian Point are issues of costs. Electricity costs are likely to rise if the area's low-cost power generator is retired. In addition if the plant's lifetime is shortened, compensation to the owner may be required. Furthermore, the site will continue to require extensive security measures to protect the spent fuel until a more permanent storage facility is available. Costs are discussed in Chapters 4 and 5.

A complex web of environmental regulations must be considered with any alternative to the Indian Point plant. Regulations include national and local air and water quality and thermal discharge requirements as well as for the possibility of constraints on greenhouse gas emissions associated with carbon fuel combustion. At the present time, air quality constraints are the most stringent for most alternative technologies. These are generally specified in terms of emissions of material regulated as criteria pollutants or hazardous air pollutants under the Clean Air Act (CAA) and its amendments and other

requirements for airborne toxic chemical releases. New power plant sources are permitted only under very stringent constraints with regard to the CAA pollutants.

Finally, closing Indian Point and building new facilities, presumably at least partly elsewhere, would make significant differences in employment, tax base and other community impacts. These changes might be positive or negative, but they must be included in the consideration of replacements for Indian Point.

Given the constraints corresponding to these criteria for the selection of options, the range of technologies available can be reduced substantially. It is unlikely that a 2,000 MW power plant would be built as an exact replacement for Indian Point, to be available just as Indian Point was closed. A package of demand and supply options, the latter possibly including new transmission lines as well as new generation, seems more plausible. The committee uses the following criteria to judge the proposed replacement packages for Indian Point:

1. Would the combination of demand and supply options provide adequate energy to replace that provided by Indian Point?
2. Would the generation and transmission system be adequate to deliver the energy reliably to end users?
3. How would the new combination of demand and supply options compare with Indian Point in terms of security of fuel supply for new generation?
4. How would economic costs, especially to the consumer, compare with continued operation of Indian Point?
5. How would environmental emissions and other impacts compare with continued operation of Indian Point?
6. What would be the impacts on local communities from closing Indian Point and replacing it with these options?

CONDUCT OF THE STUDY

This study was initiated by the U.S. Congress in the fiscal year2004 Appropriations for the U.S. Department of Energy. The Committee on Alternatives to Indian Point for Meeting Energy Needs was formed in accordance with National Research Council procedures. The committee's statement of task is presented in the Preface. Biographical sketches of the committee members appear in Appendix A.

The committee held five full meetings over the course of the study. The first three meetings included open sessions at which many experts made presentations to the committee. The second meeting was held in White Plains, New York to allow local residents interested in the issue to attend. Committee meetings and participants are listed in Appendix C. The project's web site also invited viewers to submit comments.

In addition to the full committee meetings, several committee subgroups also conducted many conference calls and collectively prepared sections of this report.

The committee also contracted for two expert analyses. GE Energy built on its work with NYISO to analyze several scenarios for replacing the power from Indian Point. While NYISO generously allowed the committee to use its data base, it should be noted that the scenarios were developed by the committee, not NYISO. Several members of the

committee met in Schenectady, NY to discuss scenarios and analytical methodology with NYISO and GE Energy, in preparation for the committee's analysis.

In addition, Optimal Energy of Bristol, Vermont, refined its 2003 analysis for the New York State Energy Research and Development Authority of energy efficiency potential to focus on the regions that would be impacted by the closure of Indian Point.

ORGANIZATION OF THE REPORT

There are two general options to consider in replacing Indian Point: reducing demand and increasing supply. As noted above, demand is increasing, but the growth rate can be controlled to some extent. Many efforts already are under way to increase the efficiency of use of electricity or to reduce demand during peaks when reliability concerns are highest. Chapter 2 discusses how those efforts could be expanded if it were necessary to compensate for the loss of Indian Point. It also discusses distributed generation and how that could affect load growth and electricity reliability.

Supply options, discussed in Chapter 3, include new generating units and transmission lines that can import power from underutilized generating plants in upstate New York and beyond. In recent years, almost all new generating plants have been fueled by natural gas, but those supplies are becoming strained. Modifying the bulk power system can be complicated, and many factors must be considered. In particular, reactive power has a large effect on transmission capability. The reactive power supplied by Indian Point would also have to be replaced if its units are closed.

Chapter 4 discusses institutional factors and various impacts that might result from the replacement of Indian Point with the options discussed in Chapters 2 and 3. Most new generating plants and transmission lines would be built by private companies, which could face daunting obstacles of regulation and financing. New facilities also would create a set of environmental impacts different from those created by Indian Point.

Chapter 5 analyzes several scenarios to evaluate the impact of closing Indian Point and replacing it with these other options. The scenarios with compensatory actions to replace Indian Point are to be viewed as representative of the actions that could be taken, not as a recommended path. Other combinations of options might prove less expensive or advantageous from other perspectives. Nor do these scenarios include all of the costs that could be involved, such as buying Indian Point in order to close it, or disposing of the spent fuel now being stored onsite.

A series of appendices follow with additional detail on the options considered and the committee's analyses.

The committee's findings and conclusions are discussed in the Executive Summary. This report does not include recommendations as to whether Indian Point should be closed.

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2

Demand-Side Options

DEMAND GROWTH IN THE INDIAN POINT SERVICE AREA

The New York Independent System Operator (NYISO) prepares compilations of historic electricity usage patterns and forecasts future electricity demand in New York State. Table 2-1 shows annual power consumption for selected years between 1993 and 2015 by region, in and around New York City and in the state, and Table 2-2 shows peak power requirements for the same years and areas. These consumption estimates are "weather-normalized" to enable comparisons across a typical year of weather (e.g., electricity use during years with particularly cold winters or hot summers was reduced to reflect what would have occurred during years with more typical numbers of heating and cooling degree-days).

TABLE 2-1 Weather-Normalized Annual Electricity Use, Past and Forecast, in Gigawatt-Hours per Year for Three New York Regions and Statewide, Selected Years from 1993 Through 2015

Year	Lower Hudson Valley: NYCA Zones G,H,I [a] (GWh/yr)	New York City: NYCA: Zone J (GWh/yr)	Long Island: NYCA: Zone K (GWh/yr)	New York State: NYCA (GWh/yr)
1993	16,411	41,828	17,667	144,471
1997	16,206	44,676	18,185	148,008
2001	17,207	49,912	20,728	155,523
2005	19,625	52,836	23,178	164,050
2009	20,775	56,345	25,258	174,290
2013	22,610	58,949	26,598	180,710
2015	23,608	59,717	26,961	182,880
Growth per year:				
1993-2004	1.421%	2.071%	2.222%	1.004%
2004-2015	1.913%	1.194%	1.659%	1.151%

[a]NYCA, New York Control Area; Zone G, Hudson Valley; Zone H, Northern Westchester County; Zone I, rest of Westchester County.
SOURCE: Adapted from NYISO (2005), p. 25.

TABLE 2-2 Weather-Normalized Summer Peak Power, Past and Forecasts, in Megawatts, for Three New York Regions and Statewide, Selected Years from 1993 Through 2015

Year	Lower Hudson Valley: NYCA Zones G,H,I [a] (GWh/yr)	New York City: NYCA: Zone J (GWh/yr)	Long Island: NYCA: Zone K (GWh/yr)	New York State: NYCA (GWh/yr)
1993	3,337	8,365	3,595	27,000
1997	3,650	9,609	4,273	28,400
2001	4,421	10,424	4,901	30,780
2005	4,410	11,315	5,230	31,960
2009	4,849	11,965	5,580	33,770
2013	5,331	12,426	5,981	35,180
2015	5,590	12,648	6,112	35,670
Growth/yr:				
1993-2004	2.365%	2.610%	3.270%	1.382%
2004-2015	2.380%	1.190%	1.618%	1.166%

[a] NYCA, New York Control Area; Zone G, Hudson Valley; Zone H, Northern Westchester County; Zone I, rest of Westchester County.
SOURCE: Adapted from NYISO (2005), p. 26.

Electricity use in the New York Control Area (NYCA) as a whole grew at about 1 percent annually between 1993 and 2004 as shown in Table 2-1. Demand growth in western New York and the Upper Hudson Valley was actually negative during that period. All of New York's demand growth has been downstate (with Long Island growing at 2.2 percent annually, New York City—even with the events of September 11, 2001—at 2.1 percent, and Zones H and I (part of the Lower Hudson Valley) at a rate of 1.4 percent.[1] This growth seems to be driven in part by a continuing expansion of the strong service sector (including government, education, and health care) that characterizes much of the downstate region. The manufacturing that once anchored the upstate economy has been in decline since the 1970s.

Summer peaks (Table 2-2), due largely to air conditioning, have grown more rapidly than has annual electricity use (Table 2-1), with Long Island seeing the highest growth in the state, followed by New York City and then the Lower Hudson Valley.

NYISO forecasts that the current growth rate in annual electricity use (though not that of peak-load growth) will continue out to 2015 in the Lower Hudson Valley, but with some slowing in New York City and Long Island (due to more limited opportunities for commercial and industrial expansion and greater investment in demand-management programs by Consolidated Edison). Consumption and peak load are forecast to grow at an approximately equal pace on Long Island and in New York City. Peak load is expected to grow slightly faster than consumption in the Lower Hudson Valley.

The projections of electricity demand in Tables 2-1 and 2-2 are predicated on the assumption that electricity prices will continue their historical decline as shown in Figure 2-1. This assumption in turn depends on assumptions of fuel prices, generating mix, capital costs and other factors. NYISO's demand forecasts are based on the relative trend in Figure 2-1, which

[1] Ibid, page 13. The growth rates for Zones H and I alone appear to be higher than the overall rate for the lower Hudson Valley, since a different NYISO report shows no growth in Zone G (NYISO, "2004 Load and Capacity Data", Page 7, Table I-4).

was derived from analyses by the Energy Information Administration (EIA) for the Middle Atlantic region (Energy Information Administration, 2006).

Such projections are highly uncertain for several reasons, most prominently:

1. Natural gas, which is the source of a large and increasing share of New York's electric generation, has shown large swings in price in recent years. Some of this has been temporary, for example, owing to shortages in supply because of damage to equipment in the Gulf of Mexico region during the hurricanes of 2004 and 2005. More worrisome, however, has been the declining productivity of U.S. gas fields. The EIA expects gas prices to remain relatively stable over the next ten years (Energy Information Administration, 2006). That may be the case, but probably only if imports of liquefied natural gas (LNG) are significantly increased. The only proposed LNG terminal in the state of New York, in Long Island Sound, faces vigorous opposition, as do other proposed projects. Natural gas is discussed further in Chapter 3. If these supplies do not materialize, prices will rise and electricity costs will follow.
2. Even if the costs of production can be defined well, the wholesale price is a function of the auctions that NYISO conducts to procure supplies, as discussed in Chapters 1, 4, and 5. Price can be either above or below historic levels, depending on how many bidders are participating. The long-term impact of the New York process on prices to consumers is still uncertain.

Overall, if the price decline projected to start in 2006 does not occur, demand will be lower.

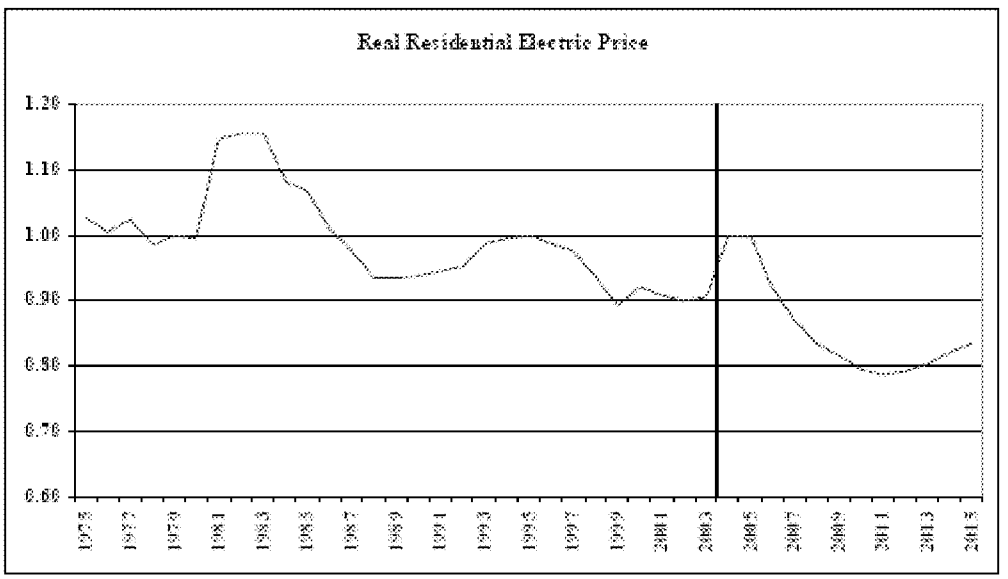

FIGURE 2-1 Past and projected trends in real residential electricity price relative to 1980. SOURCE: NYISO, 2005.

NYISO's new capacity-forecasting program is more rigorous than in the past, but even the best demand forecasts are not destiny. They are simply estimates, based on guesses about a host of parameters, which may prove to be too high or too low. Price increases, economic downturns, changes in fuel prices and availability, policy changes, and technological advance

have all contributed to surprises in years past. Both in the 1970s and in late 1980s, serious power shortages were forecast for New York unless particular power plants were built. Not all were, but no shortages occurred, and the demand for energy services was unfailingly met. The 1980s saga of Long Island's Shoreham nuclear plant, which was eventually closed before it produced any electricity, is one example. It is no criticism of the NYISO forecasts to observe that they do not reflect the full range of possibilities that could come into being if circumstances so required (such as an emergency shutdown of the Indian Point Energy Center or of another large generating source) or if state policies emphasized energy efficiency on the same scale as in California, as discussed later in this chapter.

The range of policy options available to power system operators and regulators has grown wider in recent years. It now includes energy efficiency, load management, integrated resource planning, and performance-based rate making with incentives for cost-effective energy efficiency.

New York State's spending on efficiency in the electric sector declined significantly in the mid-1990s, falling from a peak of some $300 million per year in the early 1990s to a low of some $50 million per year in 1996. The state's only performance-based rate-making plan based on capping revenues[2] lapsed in 1997. The New York Energy Research and Development Authority (NYSERDA) now spends about $150 million annually on energy-efficiency programs, discussed below (NYSERDA 2005b). Comparing trends in consumption and peak load between 1993 and 1997 with those between 1997 and 2001 (Tables 2-1 and 2-2) suggests that the demand-side management (DSM) program cutbacks may have allowed demand to grow faster than it would have with stronger programs.

[2] Revenue-cap plans are more compatible with energy efficiency than are the more common price-cap plans because they adjust revenues to avoid any loss in profitability arising from declining sales. Cost-effective energy efficiency can lower bills while raising prices (because the decline in consumption more than offsets the increase in prices).

POTENTIAL OF DEMAND-SIDE OPTIONS

The impacts of current and planned programs for reducing electricity consumption and peak electrical loads could be among the most cost-effective replacements for the energy provided by the Indian Point Energy Center. This section describes promising demand-side control options, including estimates of their achievable potential and barriers to their implementation. The focus is on the ability of demand-side options to reduce on-peak requirements of consumers for electricity. While Indian Point is a baseload plant, the biggest challenge to replacing its capacity occurs during summer and winter peaks when regional generating resources and transmission capacity are most constrained—hence the focus on demand-side options that could displace peak loads. The ability of energy-efficiency to reduce megawatt-hours of electricity consumption and levels of consumer bills in the residential and commercial sectors is highlighted in Appendix G-1 ("Demand-Reduction Tables").

Definition of Demand-Side Options and Measures of Potential

Demand-Side Options

This chapter considers two types of demand-side options:

- *Energy efficiency programs* (principally in the commercial and residential sectors) and *demand-response (DR) programs* (including permanent and "callable" resources), and
- *Distributed generation (DG)*, which is generally not dispatchable and thus not included in most electrical system reliability analyses. DG includes combined heat and power (CHP) systems and distributed photovoltaics (PV).

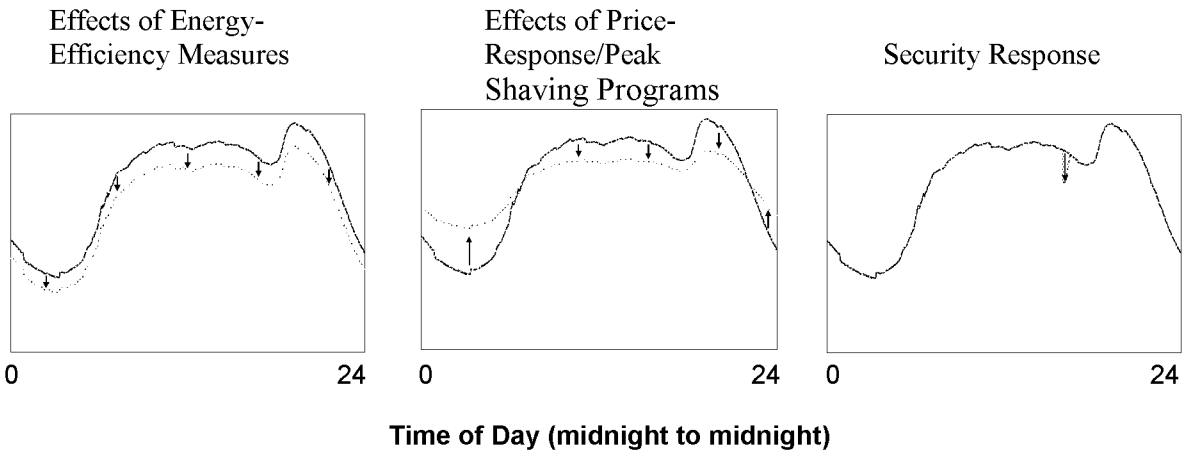

FIGURE 2-2 Effect of demand-reduction programs on daily power demand.

SOURCE: Adapted from Kirby et al., 2005; Gillingham, Newell, and Palmer, 2004.

Energy Efficiency and Demand Response Programs. Energy-efficiency programs allow users to perform the same functions that they normally would, but with less energy consumption. When applied to electricity uses, improved efficiency reduces demand throughout the day, often with the greatest effect during peak demand. The left panel of Figure 2-2 shows a typical daily cycle of demand, low at night, rising during the day, and peaking during the late afternoon. The lower curve shows demand with improved efficiency of use. Energy-efficiency improvements can be expensive, but once implemented they can save energy for many years. Reductions in peak-power requirements can also contribute to system stability in the event of sudden disturbances such as a loss of system components or short circuits.[3] Furthermore, reducing peak demand means that generating capacity and reserve margins can both be reduced. Thus investments in reducing peak demand through energy efficiency measures can have a value of 118 percent of the actual reduction in avoiding the addition of new capacity.[4]

Energy-efficiency mechanisms can include mandatory efficiency standards for buildings and appliances; targeted financial incentives and assistance; codes; information and education programs; and research on energy-efficient technologies (Silva, 2001, pp. 96-104; Brown et al.,

[3] The adequacy and security aspects of electrical system reliability are briefly discussed in NYISO, 2005, the September1, 20005, draft report, NYISO, *Comprehensive Reliability Planning Process and Draft Reliability Needs Assessment*, p. 5.

[4] The North American Electric Reliability Council (NERC) has set a standard of 18 percent for reserve generation. This criterion has been adopted by the New York State Reliability Council.

2005, pp. 45-60). They can take place in a variety of program areas, including residential lighting, single family weatherization, nonresidential heating, ventilating, and air-conditioning (HVAC), and new construction (National Energy Efficiency Best Practices Study, 2004). Stimulating greater investments in energy-efficiency measures is complex, however, since it involves multiple actors and agents, including varied consumers, vendors, independently owned utilities, unaffiliated distribution companies, and federal, state, and local agencies (Harrington and Murray, 2003).

One well-documented stimulant for energy efficiency is that of increased electricity prices. Most models of electricity markets incorporate an estimate of the price elasticity of demand for electricity. Consistent with past research, one recent study of price response based on 119 customers from New York State (Goldman et al., 2005) confirms that customers' price response is generally modest. In particular, the surveyed customers had an average price elasticity of 0.11, which means that their combined ratio of peak to off-peak electricity usage declines by 11 percent in response to a doubling of peak prices (relative to off-peak prices). Thus, price increases in the event of more-constrained supplies could produce a measurable reduction in demand, but the overall effect would be modest in magnitude. While long-term price elasticities of demand are likely to be larger, their impact would occur outside the time frame of interest for this report.

Demand-response programs focus on consumers' actions to change the utility's load profile. These programs are not aimed at saving energy so much as at shifting the time at which it is demanded, as shown in the middle set of curves in Figure 2-2 (Gillingham, Newell, and Palmer, 2004). Price response programs move consumption from day to night or curtail discretionary usage. Peak-shaving programs focus on reducing peaks on high-load days by requiring greater response during peak hours. These programs allow utilities to better match electrical demand with their generating and transmission capacity. By changing the load curve for utilities, system reliability can be enhanced and new power plant construction can be avoided or delayed. Overall costs are reduced because peak power is more expensive than average costs.

Demand-response programs allow consumers to respond to electricity prices directly, offering mechanisms to help manage the electricity load in times of peak electricity demand in order to improve market efficiency, increase reliability, and relieve grid congestion. Significant consumer benefits can also accrue from real-time demand-response programs, chiefly in the form of cost savings due to lower peak electricity prices, less opportunity for market manipulation by electricity providers, and additional financial incentives to induce consumer participation in these programs.

Security response programs enable utilities to drop loads in response to electric system contingencies. These programs can be implemented quickly and inexpensively, usually with the agreement of large users of electricity, who receive lower rates in return for relying on interruptible power. These programs have no impact on the load except during peak periods, as shown in the right panel of Figure 2-1.

Distributed Generation. Distributed generation is the production of electricity at or close to its point of use. DG technologies include internal combustion engines, fuel cells, gas turbines and micro-turbines, Stirling engines, hydro, and microhydro applications, photovoltaics, wind energy, solar energy, and waste and biomass fuel sources. DG is usually installed on the customer side of the meter and is not dispatchable by the utility. DG ranges in size from a few kilowatts (kW) to 20 or even 50 megawatts (MW). Recent manufacturer interest and sales growth have been particularly strong in the 50 kW to 5 MW range. An objective has also been to

move away from traditional diesel generators, up to now a common but relatively "dirty" source of distributed generation.

Combined heat and power, a subset of DG, generally involves reciprocating engines or turbines to drive electric generators, with the waste heat captured and used for other purposes. Typically, CHP systems generate hot water or steam from the recovered waste heat and use it for process or space heating. The heat can also be directed to an absorption chiller where it can provide process or space cooling. CHP systems may offer economic benefits, security, and reliability.

Siting generation close to its point of use, as with CHP systems, enables greater use of a device's overall energy output. Historically the average efficiency of central-station power plant systems in the United States has been approximately 33 percent, and until quite recently had remained virtually unchanged for 40 years. This means that about two-thirds of the energy in the fuel cannot be converted to electricity at most power plants in the United States and is released to the environment as low temperature heat. CHP systems, by capturing and converting waste heat, achieve effective electrical efficiencies of 50 to 80 percent. Furthermore, centrally located facilities typically lose 5 to 8 percent of their rated output through transmission and distribution losses.[5] CHP systems, by being at or near the point of use, avoid most of these losses.

The improvement in efficiency provided by combined heat and power reduces emissions of carbon dioxide and usually other air pollutants. Since CHP requires less fuel for a given energy output, it reduces the demand for key fuels such as natural gas, coal, and uranium.[6] CHP can help reduce congestion on the electric grid by removing or reducing load in areas of high demand and can also help decrease the impact of grid power outages. NYSERDA comments that "energy savings [from CHP systems] represent a social benefit in lowering the pressure on fuel and electricity supply and infrastructure, thereby providing lower prices for all consumers."[7] Mayor Michael Bloomberg's New York City Energy Task Force, in considering options to reduce electrical capacity problems in the city, concluded that "distributed resources can reduce or reshape electric system load and thereby mitigate the need for increased generation and/or transmission resources. . . . With appropriate policies and incentives, distributed resources are often the most readily available, cost-effective, and underutilized clean energy resources that can potentially reduce or defer the amount of required new electric supply from generation and transmission systems. While it can take many years to plan, design and build electric generation plants, most distributed resources can be deployed within a year." A dispersed network of DG units is also less vulnerable to terrorism, whether from direct attacks or computer hacking, than a single large power station.

Photovoltaic (PV) technology generates electricity from sunlight in a system with no moving parts. PV units can be mounted on rooftops and left largely untended. This DG option, when installed for the end user, competes against retail, not wholesale, electricity rates. Since its production profile is nearly coincident with the summer peak demand, it can contribute significantly to grid stability, reliability, and security. Thus, from a planning perspective PV should be valued at a rate closer to the peak power rate than the average retail rate.[8] The cost of

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[5] Available online at http://www.epa.gov/chp/what_is_chp/why_epa_supports_chp.htm. Accessed October 3, 2005.
[6] Available online at http://www.epa.gov/chp/what_is_chp/benefits.htm. Accessed October 3, 2005.
[7] Available online at http://www.nyserda.org/programs/pdfs/CHPFinalReport2002WEB.pdf. Accessed October 3, 2005.
[8] PV power replaces power that the homeowner or business owner would have had to buy from the grid. Therefore, its value is at the retail level. PV power usually peaks around midday, when sunlight is strongest. Air conditioning loads peak several hours later as buildings heat up, but a PV system would still be putting out a high fraction of its peak output at that time of day.

PV-generated electricity is expected to decline considerably over the next decade, falling from a current cost of 20 to 40 cents per kilowatt-hour (¢/kWh), to a projected cost of 10 to 20 ¢/kWh by 2016, less than the retail price of electricity in New York City (USDOE 2004, Margolis 2004, SEIA 2004).[9] Thus, PV may be in the economic interests of New York customers sooner than others in sunnier parts of the country.

Growth of the global PV market from 1999 to 2004 has averaged 42 percent annually (see Figure 2-3). Large-scale production will contribute greatly to continuing cost declines. As shown in Figure 2-3, the fastest growth was in the grid-connected residential and commercial segments.

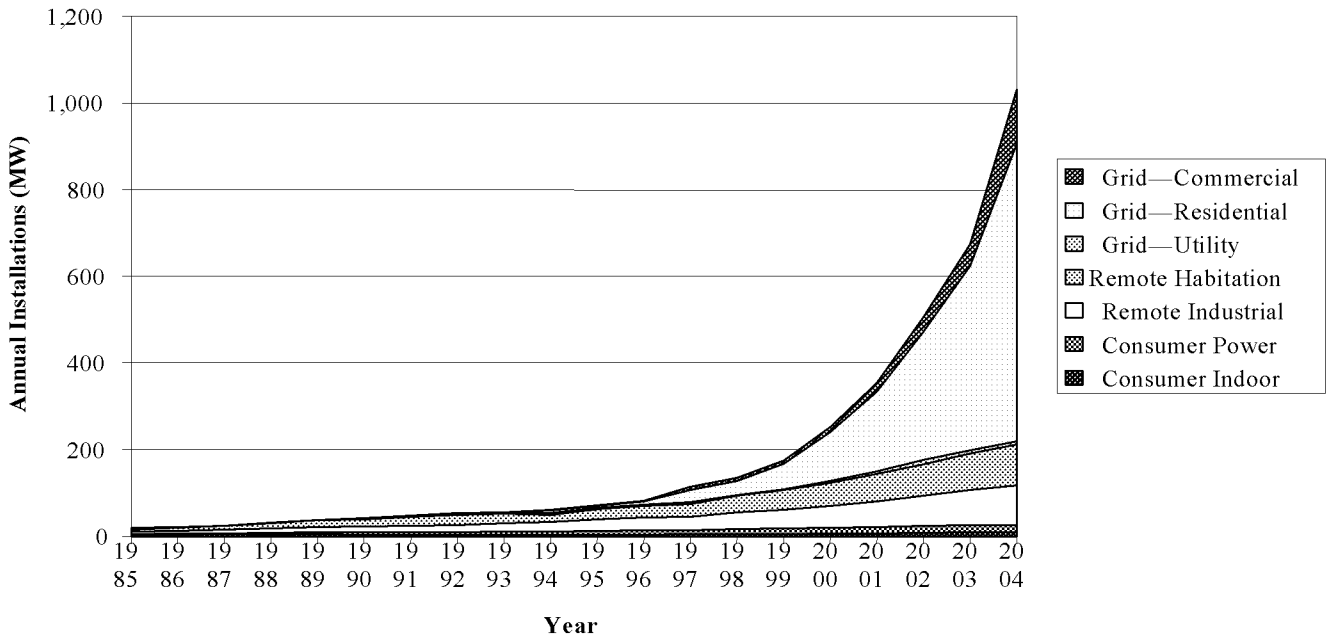

FIGURE 2-3. Global photovoltaic market evolution by market segment, 1985–2004 (42-percent average annual growth).

SOURCE: Personal communication from Paula Mints, Senior Photovoltaic Analyst, Strategies Unlimited, Mountain View, Calif., February 11, 2005.

Measures of Potential

When evaluating the potential for additional demand-side options to be deployed in future years, four types of estimates are generally used.

- *Technical potential* refers to the complete penetration of all applications that are technically feasible.

[9] There is wide variation in retail rates across New York State, but a New York City resident may pay over 20 cents per KWh. See http://www.dps.state.ny.us/bills.htm. Commercial and industrial customers would pay less for larger quantities.

- *Economic potential* is defined as that portion of the technical potential that is judged cost-effective.
- *Maximum achievable potential* is defined as the amount of economic potential achievable over time under the most aggressive program scenario possible. It takes into account administrative and program costs as well as market barriers that prevent 100 percent market penetration.
- *Program potential* is the amount of penetration that would occur in response to specific program funding measures (Rufo and Coito, 2002; NYSERDA, 2003).

Current Programs Operating in the Indian Point Territory

When assessing the additional potential for demand-side options in the Indian Point service territory, it is necessary to characterize the programs that are currently in place and the results achieved to date. The New York State Energy R&D Authority is spending a total of $1.2 billion (or $175 million annually over a 7-year period) in public and private funds in the state of New York (NYSERDA, 2005a, p. ES-7). NYSERDA estimates that its programs have reduced peak demand by 860 MW and reduced electricity consumption by 1,400 gigawatt-hours (GWh) annually. At a delivered price of about $0.03/kWh, NYSERDA, estimates that the technical potential for its efficiency programs in New York State is 20,000 GWh and a cumulative 3,800 MW reduction of peak load by 2012, with corresponding forecasts for 2022 of 41,000 GWh and 7,400 MW.[10]

New York State's 2002 State Energy Plan sets forth "the goal of becoming a national leader in the deployment of distributed generation technology" and recommends that the State "should take all reasonable steps necessary to facilitate the interconnection of DG and CHP resources into the electricity system and increase the use of DG and CHP resources in the State."[11]

Progress has been made on several fronts over the last several years in advancing combined heat and power systems in the United States. The Bush administration promoted CHP in its National Energy Plan, and the Energy Act of 2005 directs states to consider adopting interconnection standards for CHP and to promote the development of CHP technologies. National model emissions regulations are under development by several organizations, and the Federal Energy Regulatory Commission (FERC) has issued small generator interconnection standards as well as a model state rule.

Many states and regions are conducting their own rule-making processes on interconnection policies, emissions barriers, and tax issues for CHP. Most relevantly, the New York Public Service Commission has both reduced the standby electricity rate charges for CHP and set up an attractive natural gas rate structure for CHP. Both of these actions apply in the Consolidated Edison service territory. New York State, through NYSERDA, also has the largest incentive program for CHP in the nation.

New York also has enacted policies aimed at encouraging the adoption of photovoltaic technology as shown in Table 2-3. The result is a comprehensive set of incentives for residents and businesses to install PV. The incentives take the form of tax exemptions and credits, loan subsidies, rebates (administered by the Long Island Power Authority and NYSERDA), and

[10] Paul A. DeCotis, NYSERDA, 2005. "New York State's Public Benefits Energy Efficiency Programs," Presentation to the National Academy of Sciences Committee on Alternatives to Indian Point, Washington, D.C., June 1, p. 5.

[11] Available online at http://www.nyserda.org/sep/sepsection1-3.pdf. Accessed October 3, 2005.

standard interconnection and metering rules that are exceeded in the northeast only by New Jersey.

TABLE 2-3 Current Photovoltaic (PV)-Related Policies in New York State

Incentive	Description
Sales tax exemption (R)	100% sales tax exemption
Property Tax Exemption (C, I, R, A)	15 year tax exemption for all solar improvements
Personal tax credit (R)	25% tax credit for PV (<10 kW) and solar hot water (SHW), capped at $5,000
State loan program (C, I, R, A, G)	$20,000 to $1 million loan for 10 years at 4–6.5% below the lender rate for PV and SHW
State rebate program (C, I, R, A, G)	$4 to $4.50 / W (<50kW) up to 60% of total installed costs. Investor owned utilities' customers only
Municipal utility rebate program (C, R, G)	$4 to $5 /W (<10kW). LIPA customers only.
Interconnection standards (C, I, R, A)	Standard Agreement for PV requires additional insurance and an external disconnect. Up to 2 MW max.
Net metering standards (R, A)	All utilities must credit customer monthly at the retail rate for PV systems under 10 kW

NOTE: C = commercial R = residential I = industrial A = agricultural G = government
SOURCE: Incentive data available at www.DSIRE.org. Accessed April 21, 2006.

New York's existing rebate or "buy-down" program is administered by NYSERDA. It is called New York Energy $mart and includes customers of all major investor-owned utilities. New York Energy $mart provides customers who purchase and install PV systems with a $4 per watt rebate. This incentive, in combination with state tax credits and exemptions, has resulted in the installation of more than 1.5 MW by the summer of 2005. The program currently has $12 million allocated to its PV incentive program, of which about $6.5 million has been reserved as installer/customer incentives. The remaining funding should take the program through 2006.

The following subsections describe the energy-efficiency, demand-response, and distributed-generation programs that are in operation or planned for implementation in the near future by the three major power providers in downstate New York: Consolidated Edison (ConEd), the New York Power Authority (NYPA), and the Long Island Power Authority (LIPA).

Consolidated Edison

Consolidated Edison has established demand management subsidy programs as follows (Plunkett and Gupta, 2004):

- Overarching goal: Reduce projected peak-load growth by 535 MW through demand management.
- NYSERDA Systems Benefit Charge (SBC) II programs: 250 MW (80 MW permanent) in ConEd service territory (already accomplished)
- NYSERDA SBC III programs: 300 MW (120 MW permanent) in ConEd service territory

- "Incremental" programs to provide 300 MW of peak-load reduction, including the following:
  - ConEd: up to 150 MW in constrained networks
  - NYSERDA: up to 150 MW throughout ConEd's electric territory (after accomplishing the 550 MW in SBC II and III). Budget is $112 million.

The following measures are being emphasized in NYSERDA's incremental programs:

- Energy efficiency (goal of 68 MW)—Commercial and Industrial Performance program (CIPP), New Construction, Smart Equipment Choices, Energy $mart Loan Fund, Building Performance Program, Flexible Technical Assistance.
- Load management (goal of 55 MW)—Peak Load Reduction and Aggregated Load Reduction programs.
- Distributed generation (goal of 27 MW)—Clean DG Incentives Program for engines and microturbines.

New York Power Authority (NYPA)

The following energy services programs are operated or planned by the New York Power Authority:

- NYPA has committed $100 million a year for energy-efficiency projects through performance contracting with its private- and public-sector customers.
  - Cumulative reductions for 1987 through 2004 were 900 GWh and 194 MW.
  - Cumulative estimated emissions reductions were approximately 491,000 tons of CO_2; 1,350 tons of SO_2; and 675 tons of NO_x.
- NYPA materials state that 1,200 energy-efficiency projects have taken place at approximately 2,200 public buildings across New York State.
- Measures through the NYPA's energy services programs are primarily lighting, motors, and HVAC and limited to a maximum payback period of 10 years.

The NYPA also has established three renewable resources projects including the follow:

- Nine fuel cell installations totaling 2.4 MW using waste gas produced from sewage plants
- 18 rooftop photovoltaic systems with a combined capacity of 570 kW
- As of December 31, 2004, 4 million electric-drive vehicle miles for hybrid-electric transit buses, all-electric school buses, station commuter cars, electric delivery trucks, electric low-speed vehicles, and other technologies.

Long Island Power Authority (LIPA)

Beginning in May 1999, LIPA committed $355 million over 10 years for energy efficiency projects, clean distributed generation, and renewable technologies. Through the end of 2004, LIPA had spent approximately $170 million, or approximately $34 million a year. This Clean Energy Initiative is estimated by LIPA to have had the following impacts:

- Annual savings are estimated at 330 GWh, with 326 MW of permanent demand reductions and 145 MW of curtailable demand reduction.
- Annual emissions reductions are approximately 1,400 tons of SO_2; 500 tons of NO_x; and 355,000 tons of CO_2.
- Through the first 5 years of deployment, cumulative emissions reductions are estimated at 1.3 million tons of CO_2; 1,900 tons of NO_x; and 5,000 tons of SO_2.
- LIPA estimates that approximately 3,500 "secondary" jobs have been created as a result of the program.

The Clean Energy Initiative includes the following kinds of programs:

- *Residential*—Lighting and appliances; HVAC; and the Residential Energy Affordability Program (REAP), which provides free installation of efficiency measures and education for low-income households. In addition, LIPA launched the Solar Pioneer Program for photovoltaics in 1999, offering customers a substantial rebate. The rebate's budget is tied into LIPA's 5-year Clean Energy Initiative with funding totaling $37 million annually (covering multiple technologies). The Clean Energy Initiative is expected to receive funding through 2008. To date, 511 rebates have been disbursed for PV systems totaling more than 2.63 MW installed on Long Island. LIPA's rebate is currently set at $4/W.
- *Commercial and industrial*—Commercial construction and peak reduction programs.
- *General*—The Customer-Driven Efficiency Program, providing custom assistance for residential and commercial customers; LIPA*edge*, a direct load-control program.
- *Research and development*—Wind power, fuel cells, electric vehicles, hybrid-electric buses, tidal power, wave power, geothermal, and various electrotechnologies
- *New York ENERGY STAR Labeled Homes Program* introduced by LIPA with NYSERDA in July 2004.

Potential for Additional Energy-Efficiency Improvements

The preceding review shows that New York State is reaping substantial gains from its programs for reducing electricity consumption. In fact, NYISO projects that the growth rate of consumption for the New York City area will be lower than in the recent past, in part because of these activities by NYSERDA, ConEd, NYPA, and LIPA. This subsection estimates the potential for further gains if these programs are expanded.

Targets for Additional Energy-Efficiency Improvements

One study (NYSERDA, 2003) estimates the potential for energy efficiency improvements in New York State and provides details for Zones J (New York City) and K (Long Island outside of New York City. The study focuses on three years—2007, 2012, and 2022—and analyzes residential, commercial, and industrial sectors separately. The study is based on

detailed information about technologies (e.g., 87 technologies or technology bundles for commercial buildings). It concludes that most of the economic potential for energy-efficiency improvements is concentrated in the commercial and residential sectors and not in the industrial sector.

For instance, NYSERDA (2003) forecasts that 3,726 GWh of economic potential would exist by 2007 in the residential sector of New York City, and that this would grow to 4,461 GWh by 2012. The residential efficiency measures that hold the most promise include the following:

- *Lighting*—compact fluorescent light bulbs, fluorescent light fixtures, outdoor light controls, light-emitting diode (LED) nightlights, ceiling fans with fluorescent lights, multifamily common areas with specular reflectors, motion sensors, and LED exit signs;
- *Cooling*—efficient central air conditioners, air source heat pumps, ground source heat pumps, duct sealing, duct insulation, room air conditioners, humidifiers, new-construction HVAC systems;
- *Refrigerators*—upgrades to more efficient refrigerators, removal of second refrigerators or freezers;
- *Electronics*—computer monitors, computer's central processing units (CPUs), laser printers, fax machines, exhaust fans, power supply, waterbed mattress pads, and waterbed replacement;
- *Space heating*—efficient furnace fans, programmable thermostats, ENERGY STAR windows, blower door guided air-sealing, attic insulation, wall insulation, foundation insulation, heating controls, heat-recovery ventilators, and improved baseboard systems; efficient clothes washers; efficient televisions, VCRs, and DVD players; and
- *Domestic hot water*—upgrade of heat pump water heaters, upgrade of efficient well pumps, waste-water heat recovery, hot-water conservation measures, desuperheater off-ground source heat pumps.

In the commercial sector of New York City, NYSERDA (2003) forecast that 12,567 GWh of economic potential would exist by 2007 and that this would grow to 13,712 GWh by 2012. The commercial efficiency measures that hold the most promise include these:

- *Indoor lighting*—lamp ballasts, fixtures, specular reflectors, compact fluorescent lightbulbs, high-efficiency metal halides, occupancy sensors controls, daylight dimming, LED exit signs;
- *Refrigeration*—high-efficiency vending machines, vending misers, high-efficiency refrigerators, high-efficiency reach-in coolers, high-efficiency ice makers, walk-in refrigeration retrofit package, heat pump water heater;
- *Cooling*—high-efficiency air conditioning, high-efficiency heat pumps, high-efficiency chillers, optimized HVAC systems, optimized chiller distribution and control systems, water source heat pump, ground source heat pump, emergency control, dual enthalpy control, high-efficiency stove hoods, high-performance glazing;
- *Ventilation*—emergency management system control, premium efficiency motor, variable-frequency drive;
- *Office equipment*—high-efficiency CPU, high-efficiency monitors, low-mass copiers, high-efficiency fax machines, high-efficiency printers, high-efficiency internal power supplies);

- *Whole building controls*—retrocommissioing, commissioning, integrated building design, high-efficiency transformers;
- *Water heating*—high-efficiency tank-type water heater, point-of-use water heater, booster water heater, heat pump water heater;
- *Outdoor lighting*—LED traffic lights, LED pedestrian signs, pulse-start metal halides, compact fluorescent bulbs, improved exterior lighting design; miscellaneous: high-efficiency clothes washer, water and wastewater optimization; and
- *Space heating*—high-efficiency heat pumps, water source heat pumps, ground source heat pumps, optimized HVAC systems, optimized chiller control systems, emergency management control systems, high-efficiency stove hood, high-performance glazing).

For a more detailed account of the potential for these measures Appendix G-1.

NYSERDA's $175 million New York Energy $mart Program (funded by New York's Systems Benefit Charge program, through a surcharge to each consumer's bill) has shown that efficiency programs can be successful. A 2004 evaluation of New York Energy $mart concluded that five efficiency programs have saved around 1,000 GWh from 2003 through 2004. The same review concluded that full implementation of New York Energy $mart is expected to achieve 2,700 GWh in the next 2 years.

These programs already are accounted for in the NYISO demand projections. Expanding current programs and creating new ones could achieve further gains in efficiency. If Indian Point is to be closed, that is one of the replacement options that can be considered.

Potential for Peak Demand Reduction

Energy-efficiency programs can save considerable electricity, and the NYSERDA (2003) study documented that a great many improvements are available at modest cost. However, not all improvements will save at the same moment. The key consideration in the possible replacement of Indian Point is that of maintaining reliability during periods of peak load. By lowering overall demand, energy-efficiency programs also reduce peak demand, but not by the total of all the improvements.

The committee estimated the peak-load reduction that might realistically be achieved as a result of efficiency programs in the Indian Point region, as shown in Table 2-4. Details of the estimation are provided in Appendix G-2, "Estimating the Potential for Energy-Efficiency Improvements."

It is unlikely that programs can be put in place with sufficient resources to deliver all of the maximum achievable potential. The program potential is estimated at half the achievable potential. This factor is intended to introduce additional conservatism into estimates of the potential for energy efficiency. It is consistent with the estimate of Rufo and Coito, (2002, Table 3-3) of the lower bound for advanced efficiency in California at one-half the higher bound for maximum achievable efficiency. The application of this factor results in estimates for program potential that grow from a reduction of 420 MW in 2007 to a reduction of 550 MW in 2015.

TABLE 2-4 Committee Estimation of Potential of Energy-Efficiency Programs in New York Control Area Zones I, J, and K, Selected Years Between 2007 and 2015 (MW)

Maximum achievable potential	Reductions in year:				
	2007 (MW)	2008 (MW)	2010 (MW)	2013 (MW)	2015 (MW)
Zone I (Westchester County)	113	119	127	140	148
Zone J (New York City)	502	529	563	624	658
Zone K (Long Island outside of New York City)	226	239	253	285	297
Total maximum achievable potential	842	887	943	1,046	1,103
Total program potential (50% of achievable)	420	440	470	520	550
Phased-in programmable potential	100	200	450	525 [a]	575[a]

[a] Note that the "phased-in programmable" estimates exceed the "total program potential" in these years. This reflects the fact that more efficiency investments are cost-effective with the increased price of fuels today, and this is likely to be the case well into the future. These figures are based on historic (and low, by today's standards) Energy Information Administration price forecasts to calculate cost-effective energy efficiency.

SOURCE: Derived from NYSERDA 2003.

Two final adjustments are shown in the bottom line of Table 2-4. First, some lead time is required to phase in and establish new programs and expand existing activities. Programs established or expanded in 2006 will have very limited effect in 2007. Therefore, the program potential of 420 MW in 2007 is reduced to a phased-in programmable potential of 100 MW. The phased-in programmable potential is assumed to grow rapidly to 450 MW in 2010 and to reach the level of the full program potential of 550 MW by 2015. In addition, the committee expects that high fuel prices will increase the incentive to improve efficiency. Therefore the estimated phased-in programmable potential in 2015 is increased to 575 MW.

The estimates in Table 2-4 are consistent with those of other studies. The New York Energy $mart review noted above expected a reduction of peak demand of 880 MW within 2 years (statewide) as a result of program activities. A study presented to the New York State Public Service Commission concluded that the achievable potential for efficiency measures in New York City was 283 MW for residential and 1,392 MW for commercial buildings over 10 years (Plunkett and Gupta, 2004).

Finally, a study of the energy-efficiency potential in the New York City area, sponsored by the Pace Law School Energy Project and the Natural Resources Defense Council, concluded that savings of 1,163 MW to 3,032 MW peak demand could be achieved by aggressive energy-efficiency programs within 2 years (Komanoff, 2002).[12] To accomplish such reductions, the study suggested applying the rapid "crash efficiency" techniques—targeting the deployment of more efficient lighting, air conditioners, and appliance standards—employed by the state of California after its energy crisis in 2001. The extreme conditions associated with California's

[12] This "lowest" estimate included adjustments for climate, forecast uncertainties, and consumption patterns.

2001 programs are not the context within which options for Indian Point are being evaluated, but they do illustrate a higher bound of possibilities if energy efficiency were to become a political rallying cry in New York City.

Potential for Future Demand Response

Several of NYSERDA's existing programs illustrate the ability of demand-response programs to reduce peak electrical loads for costs per kilowatt that are far lower than the cost of installing new peak capacity. Three of these programs alone have already avoided the need for over 700 MW of peak capacity:

- *Peak Load Reduction Program:* avoids the need for between 355 and 375 MW,
- *Enabling Technology for Price Sensitive Load Management Program:* avoids the need for 308 MW, and
- *Keep Cool Program:* avoids the need for between 38 and 45 MW.

NYSERDA divides its efficiency programs into three types: business/institutional (which include the Commercial and Industrial Performance Program, New Construction Program, and Peak Load Reduction Program); residential (which includes the Keep Cool Program); and low-income (which includes the Low-Income Assisted Multi-Family Program).[13]

In the studies referred to here, the prices reflect capacity costs and expenses for the downstate and urban areas. The analyses use avoided costs based on wholesale-electricity bid prices (rather than production costs), and they use energy-efficiency load profiles to differentiate savings by time of day (NYSERDA, 2004b, p. 1).

The studies evaluating NYSERDA programs also distinguish between proposed megawatts (demand target), enabled megawatts (coincident demand reduction), pledged megawatts (based on self reporting), and delivered megawatts (averaged hourly reduction). Most of the estimates below (unless otherwise noted) refer to pledged megawatts. When some of the evaluations listed the delivered megawatts, they were typically only half the pledged rate. On the other hand, the estimated cost per MW of demand reduction is generally much lower than that of new supply options.

Peak Load Reduction Program

The Peak Load Reduction Program (PLRP), created in 2000, uses four different program segments:

1. *Permanent demand-reduction efforts*, which result in reduced demand through the installation of peak-demand-reduction equipment;
2. *Load curtailment and shifting*, through enrollment in the NYISO demand-response program;
3. *Dispatchable emergency generator initiatives* which allow owners of backup generators to remove their load from the grid in response to NYISO requests; and
4. *Interval meters* which reduce peak demand at the site of consumption.

[13] For more on these programs, see the useful tables in "New York Energy $mart Program Cost-Effectiveness Assessment," (NYSERDA, 2004b, p. 2-3).

The program avoids between 355 and 375 MW of peak demand. However, 340 MW of this is "callable," and only about 15 to 20 MW are permanent. Participants that are callable receive annual capacity payments and are required to perform when called. The program costs around $42.7 million over 8 years, or approximately $120/kW of peak load reduction.

Enabling Technologies Program

The Enabling Technologies Program (ETP), created in 2000, supports innovative technologies that enhance load-serving entities (LSEs), curtailment service providers (CSPs), and NYISO. It directs customers to reduce load in response to emergency or market based price signals. The technologies used include advanced meters, transaction-management software, and networking and communication solutions. As of 2003, the EPT has saved 308 enabled peak MW. The program costs around $34.4 million per 8 years or approximately $110/kW of peak load reduction.[14]

Together, the PLRP and ETP saved 174 MW in 2001, 311 MW in 2002, and 288 MW in 2003.[15]

Keep Cool Program

The Keep Cool program was started in 2001 and ended in 2003. It encouraged the replacement of old, inefficient air conditioners with new ENERGY STAR-rated room air conditioners and through-the-wall units. The program has two main components: it includes rebates and incentives for customers, and it uses a significant marketing campaign that encourages customers to shift appliance use to nonpeak periods. As a result of the wide scope of its multi-media marketing program, the Keep Cool Program resulted in about 361,000 units being replaced, of which 141,000 units were given incentives through the program.

The program is estimated to have avoided approximately 41 MW of peak demand in every year of the program. The program costs around $19.9 million over 8 years or approximately $490/kW of peak-load reduction.[16]

In conclusion, these three programs document the potential for NYSERDA demand programs to cost-effectively reduce peak loads.

Estimating the Potential for Demand Reduction

The committee estimated the potential for demand-response programs to reduce peak demand in the Indian Point service area, as shown in Table 2-5. Details of the estimation are provided in Appendix G-3, "Estimating Demand Response Potential."

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[14] An updated program evaluation report (Heschong Mahone Group, 2005) evaluated the Peak Load Reduction and Enabling Technologies Programs together. It estimates peak reductions of 178 MW (p. 25), costs of $28.8 million (Table 3-9, p. 24), for a cost per peak reduction of $163/kW.

[15] See NYSERDA, 2004b, p. 34.

[16] An updated program evaluation report (Heschong Mahone Group, 2005) estimates peak reductions of 19.7 MW (Table 3-1, p. 16), costs of $18.4 million (Table 1-3, p. 4), for a cost per peak reduction of $934/KW.

TABLE 2-5 Potential Peak Reduction from Demand Response Programs in New York Control Area Zones I, J, and K, Selected Years Between 2007 and 2015

Reductions in Year:				
2007 (in MW)	2008 (in MW)	2010 (in MW)	2013 (in MW)	2015 (in MW)
50	100	200	275	300

NOTE: Zone I , southern part of Westchester County; Zone J:, New York City; Zone K, Long Island outside of New York City. Details of the estimation are provided in Appendix G-3, "Estimating Demand Response Potential."

In total, energy-efficiency and demand-response programs in Zones I, J, and K are estimated to be able to deliver peak-demand reductions of 150 MW in 2007, rising to 650 MW in 2010, and 875 MW in 2015 (see Tables 2-4 and 2-5).

Potential for Expanded Combined Heat and Power

Many studies have assessed the potential for Combined Heat and Power in New York State, with some looking more specifically at opportunities within the Consolidated Edison service territory and/or the relevant New York Control Area load zones in the vicinity of Indian Point.

A 2002 study in New York State (NYSERDA, 2002) noted that there are approximately 5,000 MW of CHP already installed in the state; it assessed the "technical potential" for additional CHP, that is, "the remaining market size constrained only by technological limits." Technical potential does not consider other factors such as capital availability, natural gas availability, and variations in consumption within customer application and size class. The report looked only at CHP, not at other DG technologies that do not involve heat production. It identifies nearly 8,500 MW of technical potential for new CHP in New York at 26,000 sites. Close to 74 percent of remaining capacity is below 5 MW and is primarily at commercial and institutional facilities.

The largest proportion of this capacity is in the ConEd service territory. NYSERDA (2002) identified almost 3,000 MW of technical potential among its customers, the largest opportunities being office buildings, hotels and motels, apartments, schools, and colleges and universities. The report also identified about 300 MW of CHP technical potential among ConEd industrial customers, the largest opportunities being chemical and food plants and textile, and paper manufacturers.

The NYSERDA (2002) study stressed that the actual market penetration of CHP will depend on several factors, including the economic advantage of CHP over separately purchased fuel and power, the sites with economic potential, and the speed with which the market can ramp up in the development of new projects. The study developed base case and accelerated case models for CHP market penetration; the models differed in terms of assumptions about power costs, standby rates, technology advances, CHP policy changes including tax incentives, and customer awareness and adoption rates. In the base case, an additional 764 MW of CHP is projected to be installed in New York State by 2012. Nearly 70 percent of this capacity (or 535 MW) is projected to be in the downstate region that includes Indian Point. In the accelerated

case, cumulative market penetration reaches nearly 2,200 MW statewide. About 60 percent (1,320 MW) of the penetration is projected in the downstate region in 2012.

Using a trajectory of market expansion for CHP similar to that for energy-efficiency and demand-response programs, the base case estimate of 535 MW in 2012 could be phased into the marketplace as estimated by the committee and presented in Table 2-6.

TABLE 2-6 Potential Peak Reduction from Combined Heat and Power in New York Control Area Zones I, J, and K, Selected Years Between 2007 and 2015

Reductions in Year:				
2007 (in MW)	2008 (in MW)	2010 (in MW)	2013 (in MW)	2015 (in MW)
100	200	450	550	600

NOTE: Zone I, southern part of Westchester County; Zone J:, New York City; Zone K, Long Island outside of New York City. Details of the estimation are provided in Appendix G-3, "Estimating Demand Response Potential."
SOURCE: Derived from NYSERDA (2002)

The Potential for Expanded Distributed Photovoltaics

Photovoltaics can provide high-value peak-time power in a distributed fashion and with minimal environmental emissions. Thus, PV could contribute significantly to grid stability, reliability and security (Perez et al., 2004). Rapidly declining PV costs could make this technology a significant contender for replacement power within the time frame of this study even though PV is an intermittent source of electricity. Throughout the 2006–2015 period, installations would have to be subsidized, but the end result could be an important new energy source with many desirable attributes and a thriving industry.

Unlike the options discussed above, projections of PV installations on the scale envisioned here cannot be based on current prices or U.S. programs and progress. Rather, the accelerated PV-deployment scenario described here is modeled on the Japanese program that provided a declining subsidy to residential PV systems over the past decade. Residential PV installations expanded in Japan from roughly 2 MW in 1994 to 800 MW in 2004 (Ikki, 2005). Results are presented in Table 2-7; the analysis is in Appendix D-7, "Distributed Photovoltaics to Offset Demand for Electricity," and Appendix G-4, "Estimating Photovoltaics for Demand Reduction." (The analysis of PV potential is based on solar insolation data from the National Solar Radiation Data Base of the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). This database has data from seven sites in New York State, including one site in New York City.) It might also be noted that, in January 2006, California announced a solar initiative with a goal of 3,000 MW of photovoltaics by 2017 (California PUC, 2006).

TABLE 2-7 Potential Peak Reduction from Photovoltaics in New York Control Area Zones I, J, and K, Selected Years Between 2007 and 2015

	Achieved in Year:				
	2007	2008	2010	2013	2015
Installed system cost ($/W)	7.36	7.02	6.34	5.40	4.80
Subsidy rate (%)	47	44	38	27	19 (declining to 0 in 2019)
Annual subsidy (million $)	29	36	56	74	72 (declining to 0 in 2019)
Annual installations (MW)	8.4	11.8	23.0	50.4	78.8
Cumulative installations (MW)	18.6	30.4	69.9	192.9	334.7
Reduction in peak demand (MW)	14	23	52	144	250

NOTE: Zone I, southern part of Westchester County; Zone J:, New York City; Zone K, Long Island outside of New York City. Details of the estimation are provided in Appendix G-3, "Estimating Demand Response Potential."

Summary

Additional cost-effective demand-side investments in energy efficiency, demand response, and combined heat and power facilities can significantly offset peak demand, as presented in Tables 2-4 though 2-6. These new initiatives (beyond those currently anticipated) could reduce peak demand by 1 GW or more by 2010 and 1.5 GW by 2015. If the cost of distributed photovoltaics can be brought to near-competitive levels over the next decade (see Table 2-7), demand-side measures could contribute 1.7 GW by 2015, thus approaching the capacity of Indian Point (about 2 GW).

The effectiveness of demand-side options in downstate New York, to date, has been variable owing to numerous obstacles to deployment, and forecasted program performance is always uncertain. However, there is a growing body of evidence from New York (through NYSERDA), California, and other states and communities that demand-side options can be implemented swiftly and cost effectively. Conclusions for each of four demand-side opportunities are summarized in Figure 2-4.

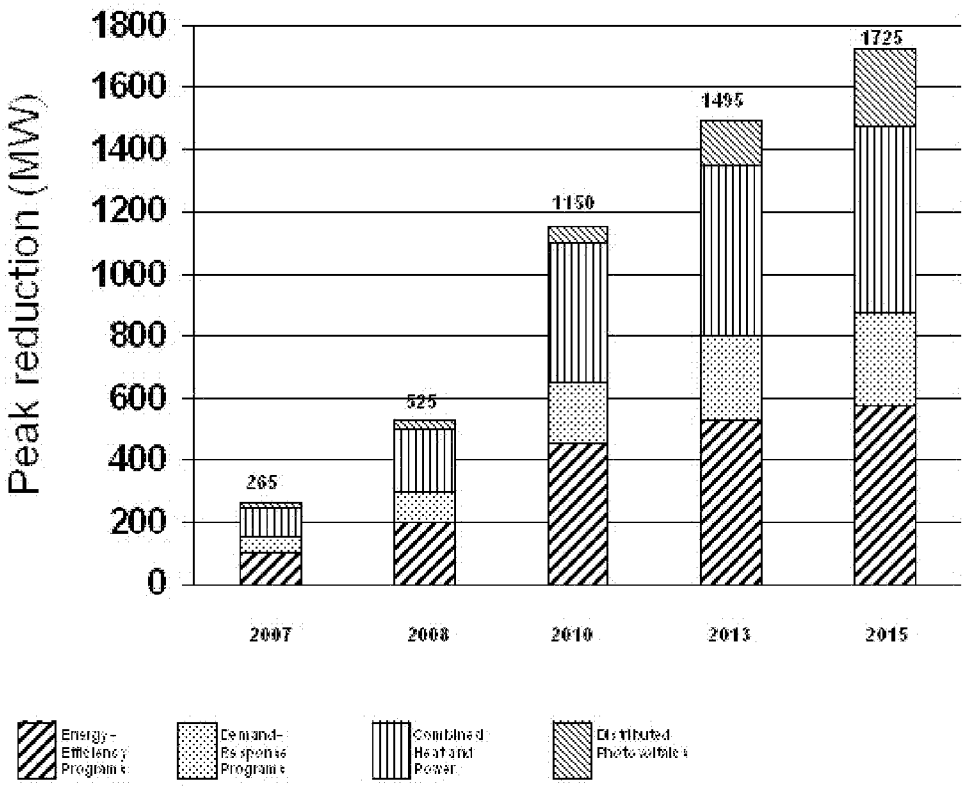

FIGURE 2-4 Phased-in programmable potential for expanded demand-side options in the Indian Point service territory (in megawatts of Peak reduction)

Energy efficiency programs offer significant potential for peak-demand reduction. Based on prior assessments of hundreds of energy-efficiency measures for residential and commercial buildings, it is estimated that 100 MW of additional peak reduction could be achieved in 2007 if new and expanded programs were to begin in January 2006. This economic and programmable potential is assumed to grow to 450 MW in 2010 and to reach 575 MW by 2015 (Table 2-4).

The estimated potential for demand response programs to reduce peak demand in the Indian Point service territory is based on the experience to date with three NYSERDA programs that avoided the need for 715 MW of peak demand in the state of New York in 2004. Evaluations of the recent performance of these programs suggest that they offer a highly cost-effective mechanism for reducing peak demand. Assuming that a doubling of program budgets could expand the demand reduction by 50 percent, the committee estimates that the Indian Point service territory has the potential for expanded summer peak reductions of approximately 200 MW in 2010 and 300 MW in 2015 (Table 2-5).

The actual market penetration of combined heat and power will depend on several factors including fuel prices, standby rates, and the speed with which the market can ramp up its production and services. Under the assumption of accelerated deployment policies, the phase-in

programmable potential for expanded CHP is estimated to grow from 100 MW in 2007 to 450 MW in 2010 and 600 MW in 2015 (Table 2-6).

Under an aggressive deployment scenario, it is estimated that 70 MW of distributed photovoltaics could be installed in the Indian Point service territory by 2010, and 335 MW by 2015 (Table 2-7). Realizing this accelerated scenario would require reductions in the cost of PV systems and a long-term commitment to expanding New York's existing PV programs. Such an initiative could establish a self-sustaining PV market in New York, resulting in the continued growth in PV distributed power well beyond the time horizon of this study.

It should be noted that the discussion in this chapter has been relevant to the summer peak only. The New York Control Area also has a winter peak that is about 80 percent of the summer peak. Some of the efficiency measures (e.g., air conditioners) discussed here will not apply in the winter, and PV will contribute little or nothing to the winter peak. The committee did not have the time or resources to examine the winter peak, but this analysis should be performed before it can be fully concluded that demand-side measures would play a large role in replacing the electric power from Indian Point. This analysis also should include a full assessment of the availability of natural gas to enable expanded CHP use in winter (curtailments of gas deliveries to electric generators already occur in the heating season) and the somewhat higher efficiency of many generators and transmission lines in cold weather.

Impediments to Demand-Side Programs

If demand-side programs are so cost-effective, why are they not in more widespread use? If individuals or businesses can make money from energy efficiency, why don't they all just do so? If electricity providers can reduce demand more cheaply than they can deliver new energy supplies, why isn't energy efficiency a larger part of their services? These questions can be answered in large part, by describing the range of obstacles that prevent the full exploitation of energy efficiency, including misplaced incentives, distortions of fiscal and regulatory policies, electricity pricing policies, insufficient and incorrect information, and others as discussed below. These are the targets that policies would have to address if demand-side options are to play their full role.

As suggested in that long list, the impediments to energy efficiency are numerous and variable. They depend on the characteristics of a region, the technology, and the supply infrastructure. At the outset, misplaced incentives inhibit energy-efficient investments whenever an "intermediary" has the authority to act on behalf of a consumer, but does not fully reflect the consumer's best interests. The landlord-tenant relationship is a classic example of misplaced incentives. Decisions about the energy features of a building (e.g., whether to install high-efficiency windows and lighting) are often made by people who will not be responsible for the energy bills. For example, landlords often buy the air conditioning equipment and major appliances, while the tenant pays the electricity bill. As a result, the landlord is not generally rewarded for investing in energy efficiency. Conversely, when the landlord pays the utility bills, the tenants are typically not motivated to use energy wisely. As a result, tenants have no incentive to install efficient measures benefiting the landlord, and the landlord has little incentive to invest in measures that benefit the tenant (Ottinger and Williams, 2002). About 90 percent of all households in multifamily buildings are renters, which makes misplaced incentives a major obstacle to energy efficiency in urban housing markets such as New York City.

Distortionary fiscal and regulatory policies can also restrain the use of efficient energy technologies. A range of these obstacles was recently identified in an analysis of projects aimed at installing distributed generation, which is modular electric power located close to the energy

consumer; it includes photovoltaics, diesel generators, gas turbines, and fuel cells. Regulatory barriers to these new technologies include state-to-state variations in environmental permitting requirements that result in significant burdens to project developers. Utilities also set high uplift charges (a fee that taxes the amount of revenue gained from selling electricity) and demand fees (a charge that penalizes customers for displacing demand from utilities) that discourage the use of distributed power systems (Allen, 2002). A recent study by the NREL found a variety of "extraneous" charges associated with the use of dispersed renewable technologies (Alderfer and Starrs, 2000). The senior editor of *Public Utilities Fortnightly* described such charges as "a major obstacle to the development of a competitive electricity market" (Stavros 1999, p. 37).

Electricity pricing policies can also prevent markets from operating efficiently and subdue incentives for energy efficiency. The price of electricity in most retail markets today is not based on time of use. It therefore does not reflect the real-time costs of electricity production, which can vary by a factor of ten within a single day. Because most customers buy electricity as they always have—under time-invariant prices that are set months or years ahead of actual use—consumers are not responsive to the price volatility of wholesale electricity. Time-of-use pricing would encourage customers to use energy more efficiently during high-price periods. These market failures can be exacerbated by competitive wholesale markets since generators have no incentive to promote efficiency or load management because they profit handsomely from high peak prices. Under current rate designs, wires companies also profit from throughput, finding their profits mitigated by energy efficiency programs. In this way, current market structures "actually block price signals from reaching service providers" (Cowart, 2001, p. vii).

In sum, because of these market barriers, neither electricity generators, transmission companies, nor consumers see the real value of efficiency. Without better price signals, it is challenging for the providers of energy-efficient products and services to transform consumer markets; as a result, incentives such as rebates and tax credits for improved end-use technologies are needed above and beyond those that already exist.

Furthermore, insufficient and incorrect information can also be a major obstacle to energy efficiency. Reliable information about product price and quality allows firms to identify the least costly means of production, and gives consumers the option of selecting goods and services that best suit their needs. Yet information about energy-efficient options is often incomplete, unavailable, expensive, and difficult to obtain. With such information deficiencies, investments in energy efficiency are hindered. It is difficult to learn about the performance and costs of energy-efficient technologies and practices because the benefits are often not directly observable. For example, residential consumers get a monthly electricity bill that provides no breakdown of individual end uses, making it difficult to assess the benefits of efficient appliances, televisions, and other products. The complexity of design, construction, and operation of commercial buildings makes it difficult to characterize the extent to which a particular building is energy efficient.

While there are tools such as ENERGY STAR branding, studies have shown that many consumers do not understand them. Further compounding the problem of measuring gains from efficiency concerns the notion of "take-back." When a device has a gain in energy efficiency, consumers have additional resources to spend or save. Some of these resources may be spent on additional energy-consuming activities, which means that the full potential for energy savings does not materialize. Blumstein (1993, p. 970) noted "that low-income programs have a higher than average 'take-back' effect (the participants take back some of the energy saved by taking other actions to increase their comfort." Based on a recent review of a wide range of markets

(Geller and Attali, 2005, Table 1), the take-back, or rebound, effect would appear to be relatively small, generally ranging from 10 to 20 percent.

Decision-making complexities are another source of imperfect information that can confound consumers and inhibit "rational" decision making. Even while recognizing the importance of life-cycle calculations, consumers often fall back to simpler first-cost rules of thumb. While some energy-efficient products can compete on a first-cost basis, many of them cannot. Properly trading off energy savings versus higher purchase prices involves comparing the time-discounted value of the energy savings with the present cost of the equipment—a calculation that can be difficult for purchasers to understand and compute. This is one of the reasons builders generally minimize first costs, believing (probably correctly) that the higher cost of more efficient equipment will not be capitalized into a higher resale value for the building. Moreover, the decentralized nature of the construction industry—home to more than 100,000 builders in the United States—usually means that those engaged in building design and construction have little interaction with one another. The result is lack of information awareness among builders, consumers, and specialists in the building process (Alliance to Save Energy, 2005; Loper, et al., 2005). The complexity of the building market is accompanied by confusing and uncoordinated institutional arrangements, with different government agencies sometimes in charge of regulating, implementing, and enforcing the same statute. For example, 18 states have adopted the International Energy Conservation Code of 2003, while 9 states have energy codes that are more than a decade old or follow no energy code at all.

Energy efficiency is not a major concern for most consumers because energy costs are not high relative to the cost of many other goods and services. In addition, the negative externalities associated with the U.S. energy system are not well understood by the public. The result is that the public places a low priority on energy issues and energy-efficiency opportunities, which in turn reduces producers' interest in providing energy-efficient products. In most cases, energy is a small part of the cost of owning and operating a building or a factory. Of course, there are exceptions. For low-income families, the cost of utilities to heat, cool, and provide other energy services in their homes can be a very significant part of their income—averaging 15 percent compared with 4 percent for the typical U.S. citizen. For energy-intensive industries such as aluminum and steel, energy can represent 10 to 25 percent of their production costs. Many companies in these more energy-intensive firms have decided to incorporate energy management as a key corporate strategy.

Since energy costs are typically small on an individual basis, it is easy (and rational) for consumers to ignore them in the face of information-gathering and transaction costs (Harrington and Murray, 2003, p. 3). However, the potential energy savings can be important when summed across all consumers. A little work to influence the source of mass-produced products can pay off in significant efficiency improvements and emissions reductions that rapidly propagate through the economy owing to falling production costs as market shares increase.

Energy prices, as a component of the profitability of an investment, are also subject to large fluctuations. The uncertainty about future energy prices, especially in the short term, seems to be an important barrier. Such uncertainties often lead to higher perceived risks and therefore to more stringent investment criteria and a higher hurdle rate. An important reason for high hurdle rates is capital availability. Capital rationing is often used within firms as an allocation means for investments, leading to hurdle rates that are much higher than the cost of capital, especially for small projects.

Lack of availability of energy-efficient technologies is also often a problem. For example, the purchase of heat-pump water heaters and ground-coupled heat pumps has been handicapped

by limited access to equipment suppliers, installers, and repair technicians (Brown, Berry, and Goel, 1991; Optimal Energy and the State Grid Corporation DSM Instruction Center, 2005). The problem of access is exacerbated in the case of heating equipment and appliances; because they are often bought on an emergency basis, choices are limited to available stock. Retrofitting can also be expensive, time consuming, and intrusive for home-owners and commercial enterprises, especially for businesses that cannot afford the "downtime" needed for installation. Building stock also turns over very slowly, suggesting that inefficient structures remain in use for decades (Ferguson and White, 2003, pp. 15-16).

Finally, managerial and commercial attitudes impede the use of energy-efficient technologies. In the manufacturing sector, energy-efficiency investments are hindered by a preference for investments that increase output compared with investments that reduce operating costs (Hirst and Brown, 1990; Alliance to Save Energy, 1983; Sassone and Martucci, 1984). Similarly, electric utilities believe that they possess the duty and obligation to serve customers' needs. Electric utility regulations have been built on ancient common law duty, known as the "duty to serve" the customer, applied to public utilities such as ferries, flour mills, and railroads. In the words of James Rossi, professor of law at Florida State University, "In the public utility context the duty to serve requires service where it is not ordinarily considered profitable." As one utility executive exclaimed in a recent editorial, "We can't hide behind restructuring and deregulation. Even with unbundled generation, the obligation to serve the load remains" (Lovins, et al., 2002, p. 88). Thus, the belief among utility managers and policy makers persists that they need only provide the energy that the customer requires, rather than reforming their customers' consumption requirements through energy-efficiency measures.

Collectively, these social, economic, and cultural impediments greatly inhibit the use of demand-side options. Aggressive policy measures are required to overcome them.

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3

Generation and Transmission Options

When an electric generating plant is retired, it usually is replaced with other generating capacity—perhaps a new generating unit or a new transmission line from an area with surplus power. Either or both reactors at the Indian Point Energy Center could be replaced with these options. However, demand growth projected by the New York Independent Service Operator (NYISO) for the New York City area (see Chapter 5) would require considerable additional capacity even without the retirement of Indian Point. That growth can be moderated, as discussed in Chapter 2, but it is likely to be significant. The supply options discussed in this chapter must be adequate to handle growth, retirements of existing capacity, and the potential replacement of Indian Point, if reliability of supply is to be maintained.

This chapter discusses the options for generation, transmission infrastructure, and reactive power in New York. Distributed generation is discussed in Chapter 2 with other end-user options because it generally is not dispatchable by NYISO and is not included in reliability calculations.

EXISTING GENERATING CAPACITY

New York's existing electricity generation is a diverse supply resource, including natural gas, oil, coal, hydroelectric, nuclear, and wind power, as described in Chapter 1. However, much of this generation is far from the large and growing load centers of the New York City area. Western New York (New York Control Area [NYCA] Zones A through E) has surplus of capacity, while New York City (Zone J) is an importer of power, as shown in Table 3-1. The Lower Hudson Valley (Zones G through I) currently has a small surplus capacity above its reserve requirement of 18 percent, but that will more than disappear if Indian Point is closed. Long Island also must have imported power available to meet its reserve requirement (NYISO, 2005b).

TABLE 3-1 Approximate (Noncoincident) Summer Peak Load and Capacity in New York State, by Region

Zone	Peak Load (MW)	Capacity (MW)
West (A through E)	8,900	14,430
Upper Hudson Valley (F)	2,180	3,470
Lower Hudson Valley (G through I)	4,490	5,490
New York City (J)	11,150	8,940
Long Island (K, outside of NYC)	5,050	5,180

NOTE: Numbers are approximate and based on the summer of 2004.
SOURCE: NYISO (2005a). Comprehensive Reliability Planning Process October 25, 2005.

The NYCA, taken as a whole, had approximately 1,300 megawatts (MW) of excess summer resource capability in 2005, representing an excess reserve margin of 3.5 percent.[1] However, the situation by 2008 will be tighter. NYISO expects peak demand to increase by 1,370 MW, and capability may actually decline because of plant retirements. Thus reserve margins could be lower than the standard requires, even without the retirement of either of the Indian Point reactors.

In addition to the excess capacity in the western section of the state and the Upper Hudson Valley region, some underutilized capacity might be found in the neighboring control areas: the mid-Atlantic counterpart to the NYCA, known as "Pennsylvania Jersey Maryland" [PJM]; Canada; and New England. In the past five years, the NYCA imported approximately 10 percent of its energy requirements from PJM and Canada. The annual energy exchange between the NYCA and New England is essentially neutral. It is difficult to determine exactly how much capacity might be found (much of the key information is proprietary) and whether the transmission capacity (discussed later in this chapter) to deliver it to the New York City area is available. In addition, with demand growing elsewhere and more retirements likely, current excess capacity may not be available in a few years.

Currently, at most only a few hundred megawatts could be imported to the New York City area during peak periods, and demand growth is likely to account for that in a few years (Hinkle et al., 2005; discussed in Chapter 5 of this report). Additional power could be imported during peak periods if the transmission grid was upgraded (and in non-peak periods even without upgrades).

POTENTIAL NEW GENERATING CAPACITY

Having concluded that the existing generation and transmission system could make little contribution to replacing Indian Point, the Committee on Alternatives to Indian Point turned to the question of potential new generation. The committee examined 18 potential alternative generating technologies for possible use in the Lower Hudson Valley/New York City region, including 5 natural-gas-based options, 5 coal-based options, 2 biomass options, 3 wind options, 2 solar options, and 1 advanced nuclear power plant option. Many of these technologies were determined to be unlikely to make a significant contribution to the power needs of the New York Control Area in the time frame of this study. Appendix D-1, "Cost Estimates of Electric Generation Technologies," lists all of the technologies considered with their key cost elements, and Appendix D-2, "Zonal Energy and Seasonal Capacity," presents data for comparisons of zonal energy and seasonal capacity, including the use of supplemental oil with gas turbines.

Technologies Considered

Potential generating technologies include natural-gas-fired units, coal-fired units, biomass-powered units, wind systems, solar-based technologies, and advanced nuclear reactors. Table 3-2 lists the technologies considered and some of their characteristics.

[1] The NYISO (2005b) report, *Comprehensive Reliability Planning Process* lists total capability of 38,772 MW and an expected peak demand of 31,960 MW (demand actually peaked at 32,075 MW in July 2005). The required capability with 18-percent reserve margin is 37,395 MW. Thus there was an excess capability of 1,327 MW.

Natural Gas

The use of natural gas as a relatively clean fuel for electric power generation has grown rapidly over the past 20 years as the supplies became more available from various areas of the United States and Canada compared with the period of the mid-1970s. Appendix D-3, "Electric Generation from Natural Gas in Zones H Through K," shows power generation from natural gas in the New York City area in 2003 and 2004. It also shows that replacing all of Indian Point's power with natural gas would require about a one-third increase in the consumption of gas for electricity.

The technologies that are currently used to convert natural gas to electricity are much more efficient and reliable than earlier versions. The environmental benefits of natural gas relative to other fossil fuels are also a big advantage. Unlike coal, the combustion of natural gas emits no oxides of sulfur, and emissions of nitrogen oxides can be held to standards through stack-gas emission-control systems.

The current supplies of natural gas cannot always accommodate the increased demand for the product. The owners of gas-fired units in New York State are frequently required to power their gas-fired units with oil products during cold weather periods since the residential sector, with firm delivery service, has priority over the utility sector which typically has interruptible service tariffs. Generators with backup fuel systems have been providing nearly 20 percent of the electric production derived from the gas turbine facilities in New York State (NYISO 2005b). For future natural gas turbine facilities to contribute to the electric system during cold weather periods, they should have either backup fuel capability with adequate fuel inventory or firm natural gas pipeline capacity for these periods. Oil tanks could necessitate a larger site footprint, and the combustion of the oil would change the characteristics of the stack-gas emissions, which would have to be addressed. Appendix D-3 lists the oil products used in the overall production of electricity from gas turbines in the New York City area.

The availability of natural gas in the general area of the Indian Point facility is a key parameter in evaluating alternative generation technologies to replace the two nuclear units. The Algonquin pipeline system crosses the Hudson River close to the Indian Point power plant on the way to Connecticut. Algonquin's two pipes have a combined capacity of 1.15 billion cubic feet per day (bcf/d), providing natural gas from the Gulf of Mexico into New York and on to New England. New York diverts some 0.12 bcf/d of the gas before it reaches Connecticut. A possibility exists that some of New York's share could be combined with one or more other supplies to assist in generating about 800 MW. The current and future gas supplies would be considered interruptible, since the market environment does not compensate generators for the extra reliability from firm gas supplies or backup fuel supplies.

TABLE 3-2 Potential Generating Technologies Considered by the Committee for Replacing Indian Point

Type of Plant	Assumed Capacity (MW)	Relative Potential by 2015 [a]	Electricity Cost (¢/kwh) [b]	Output at Peak Demand [c]	Additional Considerations [d]
Natural gas					
Conventional gas combined cycle	250	Large	4.4	High	F, C
Advanced gas combined cycle	400	Large	4.1	High	F, C
Advanced combined cycle with carbon sequestration	400	Small	6.4	High	F, R, D
Conventional combustion turbine (simple-cycle)	160	Large	5.8	High	F, C
Advanced combustion turbine (simple-cycle)	230	Large	5.3	High	F, C
Coal					
Pulverized coal	600	Large	3.7	High	T, CC
Pulverized coal supercritical	500	Large	3.8	High	T, CC
Integrated coal gasification combined cycle (IGCC)	550	Large	3.7	High	T, D, CC
IGCC with carbon sequestration	380	Small	6.0	High	T, R, D
Fluidized-bed coal	500	Large	4.7	High	T, CC
Renewable energy					
Biomass	80	Small	7.2	High	
Municipal solid waste landfill gas	30	Small	3.5	High	P
Wind					
Large	100	Moderate	5.7	Low	P
Medium	50	Small	6.0	Low	P
Small	10	Small	9.9	Low	
Solar photovoltaics	5	Small [e]	25	Moderate	
Solar thermal	100	Small	30	Moderate	
Advanced Nuclear	1,000	Small	4.2	High	T, P

[a] "Large": the total contribution could be more than 500 MW. "Small": the total likely to be less than 100 MW. Rated on the basis of readiness of technology, fuel availability, siting difficulties, permitting time, etc.
[b] Costs are from Appendix D-1 and are representative for the nation, not the region, which is higher.
[c] "High": virtually all of the maximum capacity can be expected to be available during peak demand. "Moderate": At least half the maximum capacity is likely to be available during peak demand. "Low": it cannot be counted on.
[d] F: additional fuel supply needed; R: research needed; D: demonstration needed; T: additional transmission needed; P: public acceptance questions, CC: high carbon dioxide emissions (>1 lb CO_2/kwh); C: moderate CO_2 emissions (< 1lb/kwh; no C means little or no CO_2 emissions).
[e] PV may make a significant contribution as a demand-reduction technology, as discussed in Chapter 2
SOURCE: See Appendix D-1

In addition, a new gas pipeline, the Millennium Pipeline, is currently being installed in New York State. Phase 1 of the project is expected to be complete by November 2006. The line comes from central New York and crosses the Algonquin system near the Ramapo substation in Rockland County. This line also might supply enough gas for an additional 1,000 MW beyond commitments to customers. The Lovett Power Station site could be served by either line. The three coal-fired units (totaling 431 MW) at the site—on the west side of the Hudson River just across from and south of the Indian Point site—are scheduled to be shut down by 2008, so that site might be available for new gas-fired turbines. Thus, there is likely to be enough gas to supply a significant amount of new capacity at Lovett Station or elsewhere in the area. In addition, other pipelines have been proposed, as shown in Appendix D-4, "Proposed Northeast Pipeline Projects." However, two other factors must be considered: namely: the price of gas and other growing demands for the gas (also discussed in Chapter 5).

Current prices for natural gas have been high since the two hurricanes in 2005 damaged some of the infrastructure in the Gulf of Mexico (DOE/EIA, 2005b). Also, the overall supply to the State does not appear likely to be increased after the Millennium Pipeline is completed, for the foreseeable future. If so, the New York City area may not be able to continue increasing its use of natural gas for the near term. Furthermore, the longer-term gas supply picture is not encouraging unless resources such as liquefied natural gas (LNG) imports are increased, and LNG imports are uncertain with respect to timing, volumes and locations for terminal facilities. Investors will have little incentive to build greater pipeline capacity should the supply return only to pre-storm levels in the Gulf region.

Data suggest that gas production from western Canada is declining. Diversions to other users may further limit deliveries to New York. Gas production levels in eastern Canada have experienced poor performance to date, although some gas may become available from Canadian Grand Banks fields. Overall, imports from Canada are not likely to increase significantly unless LNG is routed through Canada. It should be noted that natural gas exploration has increased in the areas south of the Finger Lakes in New York State, and gas production is at record levels for that area (40 bcf per year, or enough for about 800 MW of power generation).

Although it seems as if sufficient gas might be available to replace Indian Point generating capacity, in fact all of the excess may well be committed some time before the plants are shut down. Electricity demand is growing in the New York City area, and several other plants are scheduled to be retired and must be replaced. All new generating capacity currently being built in New York State, over 2,000 MW, is gas-fired. As discussed in Chapter 5, as much as 1,600 MW could be needed by 2010 to meet reliability requirements even without closing Indian Point. Almost all of the generating capacity in the planning stage that could be brought online by 2010 also is gas-fired (883 out of a total of 1033 MW).

Advanced natural-gas combined-cycle turbine generation facilities can provide reliable and environmentally attractive electric production service to the New York City region but the production costs are essentially driven by the price and availability of the natural gas obtained from distant sources. At current prices, fuel costs alone are about 4 cents per kilowatt-hour (¢/kWh) in combined-cycle plants and 6 ¢/kWh in simple-cycle plants. In comparison, coal and nuclear plants have fuel costs of only 1 to 2 ¢/kWh,

although their operating and capital costs are higher than for gas-fired plants.[2] Table 3-2 shows estimates of the total costs of electricity for all the options considered by the committee. The breakdown by fuel operations and capital are in Appendix D-1, "Summary of Total Cost Estimates for Electric Generation Technologies."

One possibility would be to replace older, simple-cycle gas turbines with modern combined-cycle plants. This switch, called repowering, can result in 50 percent more power from the same supply of natural gas. In New York City, the East River plant is being repowered, and two units at Astoria are expected to be repowered. Other plants could also be considered.

Coal

Coal-based power production provides approximately 14 percent of the electric energy used in New York State, versus some 50 percent for the nation as a whole. No coal powered facilities are located in Zones H, I, J, or K, but there are two small coal-fired units (at Lovett Station) in Zone G. The major coal-based electric generating facilities are located in western sections of New York State. The amount of coal-based electricity produced in the state decreased by 1 percent between 2004 and 2005. The closing of the Lovett Station coal-burning generators will reduce this even more.

Coal plants require larger sites than do natural gas plants, in order to accommodate the storage of a 30-day supply of coal, associated ash-management systems, and defined areas to accommodate storm-water-management programs. Coal plants, therefore, are located in areas where property values are relatively low. Land values in the lower Hudson Valley and New York City areas are among the highest in the nation.

Environmental considerations such as stack-gas emissions, noise from unit trains bringing coal and removing ash, and cooling water requirements all contribute to major siting challenges when using any coal-based generation technology in major urban areas. Coal-based technologies that were considered and evaluated with respect to operating costs are discussed in Appendix D-5, "Coal Technologies." Coal-based power plant technologies that could produce power for the New York City region would be located at some distance from the region, requiring long transmission lines. Therefore, the cost of the power would include transmission costs as well as production costs. In addition, some air quality issues could arise, depending on the location of the associated site.

Coal plants also emit more carbon dioxide per kilowatt-hour produced. Technologies are being developed to capture and sequester the carbon dioxide, but that process will add significantly to the cost of the electricity. Appendix D-5 discusses the technology (integrated gasification, combined cycle—IGCC—that will be most appropriate for capture of carbon dioxide).

A new coal plant built upstate from the New York City area might be the lowest-cost replacement for Indian Point, even with a new transmission line. Thus it should be included in the list of options. However, the committee believes that it is unlikely for a coal facility to be permitted and constructed even in upstate New York by 2015, especially considering the uncertainties over carbon dioxide.

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[2] Locational-based marginal prices for the NYISO-run wholesale power market are given at https://www.nyiso.com/public/market_data/pricing_data.jsp. Accessed March 2006. As an example, the 4:00 p.m. wholesale clearing price of electricity on January 23, 2006, was 11.9 ¢/kWh in New York City.

Biomass

Biomass represents a renewable fuel source for power generation. In the New York City area, biomass consists of municipal solid waste, sewage sludge, wood waste, agricultural waste, and other residues. Today there are five waste-to-energy plants in the downstate area, with one in Zone H and four in the Zone K area. The total capacity for these five units is 166 MW, and collectively they produced 1,274 gigawatt-hours (GWh) of power in 2004 of the 52,000 GWh generated in Zones H, I, J, and K. Methane derived from biomass sources can be burned in gas turbines, and biomass in a solid form can be burned directly or gasified. It also can be co-fired in coal-based plants, but as noted above, coal plants are unlikely to be sited in the zones of interest for a variety of reasons.

In the 1980s, there was a move to have a waste energy facility located in each of the five counties of New York City as a measure to assist the city in managing its wastes and to address the need for fuel diversification in the city. The plan was dropped by the New York City government primarily because of strong and widespread public opposition to waste-to-energy plants being located in the city. The principal concerns were air quality and health issues. Municipal solid waste and sewage sludge currently produced in the city are shipped out of state, even though today's technologies are cleaner and might engender less public resistance.

Biomass appears unlikely to be a significant new source of electricity for the New York City region. Additional information on the potential of the biomass resources is contained in Appendix D-6, "Generation Technologies—Wind and Biomass."

Wind

Wind energy systems have entered the New York State market with some 100 MW of capacity installed by 2005, and more is expected. The wind facilities are located in the central and northern areas of the state. The New York State Energy Research and Development Authority (NYSERDA) has initiated a wind development program that is installing some 500 MW of new wind capacity as a component of the State's Renewable Portfolio Standard development program. This program mainly provides support to developers after the units are placed into service. The developer has the responsibility to site, license, construct, and place into service its wind facility.

New York State has several excellent wind sites that are being evaluated by developers for near-term application. At this point, few land-based sites are located close to the Indian Point facility that have the desired wind characteristics and available land to install wind turbines that could contribute to the replacement of the generation from the Indian Point plants. A project has been proposed at a site in the ocean off the south shore of Long Island. This project is proceeding, but at a pace slower than originally anticipated, owing to rising costs. Experience with offshore wind projects is limited, and the developers are monitoring projects located elsewhere in the world. The Long Island project and other offshore sites have the resource potential for considerable generation of electric power, but no units have been installed there, and considerable opposition can be anticipated, as has occurred in Massachusetts.

Technically there is sufficient wind resource in New York State to replace the Indian Point units, but resolving site location and permitting issues is key to successfully placing units into service. The greatest challenge for using wind to replace large base

load electric generation units is the intermittent nature of the resource. The availability factor for wind is 30 to 40 percent, compared with about 90 percent for nuclear and coal plants, and the resource is available only when the wind is blowing, not when demand is high. Storage will smooth out the intermittent nature of the resource, but that technology is not yet readily available. The issues associated with expanding the use of wind in the state are discussed in Appendix D-6.

Solar

Solar energy can be used to generate electricity either through the use of solar photovoltaic (PV) systems or through solar thermal power generation technologies. Solar PV electricity is increasingly being used for many applications around the world.

PV use has increased as the price of solar cells and the resultant power costs have decreased and the reliability of the products have risen to a level that is acceptable to consumers for some applications. PV applications are limited by the dependence on the availability of sunlight, but for some applications either that does not matter or else a small amount of battery storage can suffice. The technology promises to grow substantially in distributed generation systems market, as discussed in Chapter 2. PV would require large land areas to collect sufficient energy to contribute to the bulk power markets and is unlikely to be a factor in New York State by 2015.

Solar thermal generation involves the use of mirror-like collectors designed to focus sunlight onto metal surfaces, which in turn through various systems can produce a steam product. The steam is then used in a steam turbine to produce electricity. One advantage of the solar thermal concept is that the energy of the Sun can be stored in a liquid material on a clear day and then later extracted to produce steam at night or on cloudy days. Solar thermal generation requires large land areas to house the collectors and very direct sunlight to be economically attractive. The earliest applications of solar thermal technologies will be in the deserts of the southwestern part of the United States. The specific characteristics of the two solar technologies are discussed in Appendix D-7, "Distributed Photovoltaics to Offset Demand for Electricity."

Advanced Nuclear

Several advanced nuclear technologies are being explored for possible application in the 2015-2020 time frame (EPRI, 2005). The concepts are being supported through programs initiated in part by the recently enacted federal Energy Policy Act of 2005. The Nuclear Regulatory Commission has certified three designs, which could be started shortly after an appropriate site is found and certified. Several consortia of energy companies (including Entergy Corporation) are moving forward on various plans. A site at Oswego, New York, on Lake Ontario, had been considered but is not part of any current plan. That site had strong local support and may be considered in future plans.

Nuclear power could provide New York State with an electric power option that has no carbon dioxide emissions (which contribute to global warming), and no contribution to acid rain or mercury contamination. However, the committee concluded that a new nuclear plant in New York State is unlikely before 2015. One or two of the projects now being planned in other states might be completed by 2015, but most companies are likely to wait in order to see how these plans progress before starting more projects.

Overall Considerations

A variety of supply options could contribute to replacing one or both reactors at the Indian Point Energy Center. As suggested in the previous discussion and in Table 3-2, the committee concludes that advanced natural-gas-fired combined-cycle plants are the generation option capable of making the biggest contribution at the lowest cost by 2015. This position assumes the ability to site such facilities in the Lower Hudson Valley/New York City area, favorable economic and regulatory conditions for investors, sufficient advance notice that the power will be needed, and a long-term fuel supply.

One option that could be considered in the near term is to locate some 2,400 MW of natural-gas-fired combined-cycle plants at the current Lovett Station site, described earlier in this chapter. The site is currently being used for electric production. However, the current operator is just emerging from bankruptcy and may not be in a position to develop any new facilities. If that issue can be resolved, the site could be developed for natural-gas- and/or oil-fired generation. The site has a transmission corridor, with limited transmission currently installed, a developed waterfront, and basic elements of infrastructure. However, environmental impacts would need to be addressed, as would fuel delivery.

The greatest challenge would be to secure sufficient natural gas supplies to satisfy the projected production levels, including very high capacity factors. Two large natural gas lines are located near the Lovett Station site, and more natural gas might be added to the two existing systems from gas wells located in the state. If new sources of gas and new pipelines are required, the issues of gas availability and price must be examined in much greater detail than that allowed by the committee's resources.

Coal-based technologies potentially offer attractive production costs but the physical requirements of a large plant site in the region of the Indian Point Energy Center, combined with air quality issues, new rail lines to bring in the coal and related technical challenges limit potential opportunities for investors to promote this fuel source for application in the greater New York City area. If natural gas prices remain high, a coal plant upstate with a new transmission line to the New York City area might be a cost-effective solution.

Both natural gas and coal plants emit carbon dioxide (coal plants emit about twice as much per kilowatt-hour as natural gas plants), which nuclear plants do not. New York is part of the Regional Greenhouse Gas Initiative (RGGI) which proposes to limit emissions of carbon dioxide and other greenhouse gases. Achieving RGGI goals will be more difficult if Indian Point is replaced, as discussed in Chapter 4.

New York State is supporting renewable energy development for power production, including a recently adopted Renewable Portfolio Standard. Nevertheless, renewables are unlikely to provide the Lower Hudson Valley/New York City area with a significant share of the power provided by Indian Point within the time frame of this study.

ELECTRICAL TRANSMISSION

Existing Transmission

Most Americans are generally unaware of the vast electrical transmission network that connects a myriad of power-generating stations to the local power lines servicing their homes and businesses. Electricity is typically generated in large central power stations at 13,800 volts (13.8 kV) then often "stepped up" to 345 kV through power transformers and associated equipment in order to transmit the power efficiently over long distances. These high-voltage transmission lines provide the backbone for the bulk electrical power system throughout the United States. Transmission lines, however, can be designed to be operated at voltages other than 345 kV. Other typical voltages for transmission lines in the United States include 765 kV, 500 kV, 230 kV, 138 kV, 115 kV, and 69 kV. Power system engineers select the optimal voltage for a particular transmission line based on a number of design considerations, including the line's proximity to generation and customer load. In general, however, transmission lines with higher voltages are utilized to interconnect generating plants to the bulk power system.

The bulk power system in New York State is similar to that in many other regions throughout the United States and Canada. According to NYISO, the bulk power system in New York State, the New York Control Area, contains more than 10,000 miles of transmission lines with voltages equal to 115 kV and more. Figure 1-1 in Chapter 1 shows the major transmission facilities in the NYCA with voltages of 230 kV and greater.

The NYCA is electrically connected to neighboring control areas in the northeastern United States and the Canadian Provinces of Quebec and Ontario through special high-voltage transmission lines, often referred to as "ties" or "interfaces," such as those shown in Figure 1-1. The total nominal transfer capability between the control areas in the Northeast is less than 5 percent of the total peak load of the region and is declining as a percentage of such load (Hinkle et al., 2005). This minimal import and export capability over the ties between the Northeast regional control areas means that the NYCA power system places even greater reliance on the internal generation resources located within a particular control region and the NYCA is certainly no exception.

Transmission constraints or "bottlenecks" are not just associated with the constrained ties between New York and its neighboring control areas, however. The NYCA has several major transmission bottlenecks within New York State, which significantly affect the free flow of power on its bulk transmission system. In particular, the electrical transmission system around southeastern New York State, including greater metropolitan New York City and Long Island is severely constrained owing to a lack of adequate transmission capacity into this area. As a result of the limited transfer capability into southeastern New York State, this sub-region must place greater reliance on the generating plants located within greater metropolitan New York City and Long Island. As shown in Chapter 5, a new transmission line could deliver a large fraction of the power provided by Indian Point.

Table 3-3 further describes the approximate location of the three major transmission constraints within the NYCA. The Total East Interface constrains power flowing from western New York State, PJM, and Canada into eastern New York State. The Central East Interface is located east of the Total East Interface and serves to further

constrain power flowing from the west and central portions of the NYCA. Finally, the Upstate New York-Southeast New York (UPNY-SENY) Interface severely constrains power flowing into southeastern New York State from the rest of New York and from PJM and Canada.

TABLE 3-3 Nominal Transfer Capability Between New York Regions

Transmission Interfaces	Transfer Capability (MW)
Total East Interface	6,100
Central East Interface	2,850
Upstate New York-Southeast New York Cable Interface	5,100
New York City	4,700
Long Island	1,270

SOURCE: NYISO

NYISO has segmented the NYCA into eleven (11) distinct zones, as explained in Chapter 1, to accommodate the location of the transmission interfaces and to respect the service territories of the transmission owners. These NYCA zones (see Figure 1-3 in Chapter 1 of this report) function as separate pricing zones under the locational-based marginal pricing (LBMP) wholesale power market operated by NYISO. Given the limited transfer capability shown in Table 3-3 at the transmission interfaces, and the supply-and-demand balance for electricity, the southeastern New York zones (Zones H, I, J, and K) experience the highest average and peak prices within the NYCA. Table 1-1 in Chapter 1 shows the approximate consumer load and associated generating capacity in each NYCA Zone. Generating plants in southeastern New York are particularly valuable, because they are on the high-demand side of the constraints. The Indian Point generating plant is located in the premium southeastern New York Zone H; hence the consumers in Zones H, I, and J heavily rely on it to meet demand. It is therefore very important to take the bulk transmission system into account when the retirement of Indian Point Units 2 or 3 is considered.

New Transmission

New transmission capacity, if designed to adequately increase the transfer capabilities among the Total East, Central East, and UPNY-SENY Interfaces, may provide a partial solution to the retirement of Indian Point, including system reliability benefits. Such new transmission capacity would likely come in the form of either an expansion of the existing alternating current (AC) high-voltage transmission systems or the addition of new high voltage direct current (HVDC) transmission facilities.

New AC transmission facilities may include the replacement of conductors on existing transmission facility structures or the installation of new transmission facilities including new tower structures and related components. Such new AC transmission facilities may also require additional right-of-way land resources and potential system outages during construction periods. An expansion of the existing AC transmission system would likely serve to increase system reliability and decrease the marginal cost of electricity in southeastern New York.

New AC transmission facilities may also be coupled with dedicated generation resources to further support New York's "in-city" generation requirements. An

illustrative example of such a new AC Transmission Facility would be the proposed 550-MW Public Service Electric & Gas (PSEG) Cross Hudson Project. That project includes the interconnection of an existing 550 MW natural-gas-fired combined-cycle generating unit located at a New Jersey-based utility, PSEG's Bergen generating plant, with the Consolidated Edison substation at West 49th Street in New York City, via underground 345 kV transmission conductors and associated facilities. Combinations of dedicated power-generating resources and interconnection facilities such as the PSEG Cross Hudson Project may offer additional alternatives to adding new generation resources directly into transmission-constrained zones such as Zones H, I, J, and K. However, as useful as this project could be, it is currently inactive and may not be revived.

HVDC transmission projects may also provide partial solutions to the loss of Indian Point Units 2 and/or 3. Such HVDC transmission projects typically require the installation of an AC/DC converter station, HVDC conductors, and a DC/AC converter station. The process entails the conversion of alternating current to direct current (in the AC/DC converter station located near a sending substation), transmission of the power (typically long distances) through high-voltage direct current conductors, and finally the conversion of direct current to alternating current (in the DC/AC converter station) adjacent to the receiving substation. Because an HVDC line is isolated from the regular HVAC grid, it is not subject to the same reliability issues, and the power that it delivers is considered to be equivalent in reliability to that from a plant within the zone of the end point. In particular, New York City and Long Island (Zones J and K), which have requirements for locally produced power (80 and 98 percent, respectively), obtain the same reliability benefit from a dedicated HVDC line as they would from a local power plant. The Neptune transmission line from New Jersey to Long Island will provide reliability benefits as well as cheaper power when it commences operation in 2007.

The addition of a new 1,000 MW HVDC transmission facility between Marcy and Rock Tavern Substations could serve as a suitable alternative to the compensatory action of adding 800 MW of new generation in Zone J. This alternative also serves to increase New York's statewide electric system reliability and could lower total system production costs within the greater Northeast region, including New York State. Further, an additional benefit may include a reduction in imports of electricity from outside the Northeast region owing to the more efficient use of indigenous generation located in upstate New York and PJM (Hinkle et al., 2005).

In summary, it is clear that new transmission projects can play an important role in the ultimate energy and capacity solution relating to the potential loss of power from the Indian Point Units. It is likely that a combination of modifications to the existing AC transmission system and the installation of new HVDC transmission projects will provide the best complement to the addition of new generating resources and efficiency programs to solve New York's future electricity needs.

RELIABILITY AND REACTIVE POWER

Reliability

Most of the power interruptions of the typical customer are brief, affecting only a small area, although even very short interruptions that disturb computers and voltage variations that affect voltage-sensitive equipment can be damaging. Many power

interruptions are due to local problems, such as an automobile accident knocking down a power distribution pole or a squirrel getting inside a vulnerable piece of equipment in a substation. Outages in distribution systems are outside the scope of this report, which is concerned with the bulk power system.

When the transmission system goes down, perhaps due to severe weather, earthquakes, or multiple equipment failures, entire regions can be blacked out, and recovery can be lengthy. Very large multistate disturbances such as that experienced in August 2003 are rare and involve a combination of many unlikely events. Reliability is measured by the frequency, duration, and magnitude of interruptions and other adverse effects on the electric supply.

The regional reliability councils formed after the 1965 Northeast blackout (New York is in the Northeast Power Coordinating Council) have tried to quantify these disturbances by requiring a measure of reliability based on computing the likelihood that the demand for power cannot be met. Load is modeled as a demand for power that is weather-dependent and varies with the season, the day of the week, and even the hour of the day. The maximum load tends to occur on the hottest summer days. Statistical descriptions of the historical availability of each generator are used to compute the expected number of days in a 10 year period when the load could not be supplied (the loss of load expectation, or LOLE). The New York State Reliability Council requires that the number be less than 1 day in 10 years. Changes in the system that would increase the LOLE to more than 1 day in 10 years would not be acceptable.

It is unusual for a blackout to occur simply because a large number of generators were unexpectedly out of service (the 1965, 1977, and 2003 blackouts were much more complicated). Nevertheless, the LOLE is useful in determining how much extra generation a given area requires. Meeting this standard in the NYCA usually means that the available capacity (the total power of all generators able to be scheduled to serve the load) should exceed the peak load by 18 percent.

Because power can be imported from neighboring areas, the reliability and capacity of both the transmission system and the generation equipment must be included in the analysis. The loss of transmission lines to other areas (notably New England, PJM, or Canada) could have serious consequences on a hot summer day. Relief from other control areas is limited, however, as interarea transmission capacity is about 5 percent of peak load and is decreasing with time. A reliable power system has enough excess installed generating capacity so that the load can be supplied even if some generators are out of service for maintenance or because of unexpected problems, and it has a transmission system that is adequate to transport the power from wherever it is generated (inside or outside the control area) to the customers. The mix of generation normally includes some inexpensive baseload generators that tend to run at a constant output around the clock and serve the minimum (base) load, along with units that respond more rapidly to changes in demand and can follow the peak. Nuclear units are operated as baseload units because they usually have the lowest variable operating costs.

An additional reliability concern is the supply of fuel for generators. The adequacy and diversity of fuel constitute an important issue in operating the system and planning new generation. Heavy reliance on a single fuel source or a single pipeline for natural gas could have serious consequences if this supply were interrupted. The competing demand for natural gas for heating in the winter must also be considered as

most gas-fired power plants in New York operate on interruptible gas-supply contracts, and therefore most are dual-fuel units that can be switched to oil firing. On an annual basis, however, as noted in Chapter 2, dual-fuel units in New York use natural gas for about 82 percent of their annual generation.

Reactive Power

Major power system disturbances have, in one way or another, involved unstable oscillations of electrical quantities. Dynamic changes in power flows, or in system frequency (departures from 60 hertz.), or in voltage reduction are all signs of system instability. Frequency excursions take place when the balance between supply and demand for power is upset. Too much demand produces a lower frequency and too much supply results in a higher frequency. As the power system came apart in August 2003 there were islands with excess generation and islands with too little generation.

There is another kind of power in alternating current systems, associated with the magnetic fields produced by currents flowing in transmission lines, generators, and motors. This power is called *reactive power* and is measured in vars (for volt-ampere reactive).[3] Reactive power represents energy stored in the magnetic field and later released. Motors such as those in air conditioners and refrigerators also require reactive power to function correctly.

Reactive power also is essential for the smooth operation of the transmission grid. It helps hold the voltage to desired levels. Inadequate reactive power leads to a decrease in the voltage of the system in which the shortage exists. For an interconnected system where active power is exactly in balance, the frequency is constant and the same everywhere, and the system is said to be in synchronous operation. Voltage, however, varies from location to location, depending largely on the reactive power balance. If a given load has a large reactive demand, the voltage will be lower at that point than at others. Low voltage can damage equipment and, if low enough, can cause system instability and a voltage collapse. There have been a few voltage collapses solely because of a shortage of reactive power. It is more common that reactive power problems aggravate active power problems in large power system disturbances, as was the case in the August 2003 event (U.S.-Canada Power System Outage Task Force, 2004).

Active power can be transmitted over great distances, while reactive power problems must be solved locally. Generators themselves are an excellent source of reactive power but at some cost. Increasing the reactive output of a generator results in a decrease in the possible active power output and, if not specifically compensated, a loss of income received for real power output. Capacitors can be a second source of reactive power by storing energy in electrostatic fields rather than electromagnetic fields. Capacitors can be fixed or variable in size. Distributed generators—for example, microturbines and synchronous motors—can also supply reactive power, but these units are outside the control of the system operator and cannot necessarily be counted on when needed.

Indian Point is a large supplier of reactive power to the grid in southeastern New York State, capable of providing about 1,000 megavars of reactive power. If it is

[3] Active power, the familiar type of power that keeps light bulbs burning, is measured in watts. Consumers pay for active power (1,000 watts used for an hour is a kilowatt-hour) but usually not for reactive power.

shutdown, that reactive power must be replaced. Insofar as replacement generation is located upstate or even farther away, it becomes even more important to ensure adequate supplies of reactive power. That could be done by installing capacitors at the Indian Point site or in the general area. Generating vars is not expensive, but it is a critical necessity that must be planned for if Indian Point is to be closed.

NYISO projects that, even with Indian Point operating, voltage constraints due to reactive power deficiencies in the Lower Hudson Valley will lower system reliability to unacceptable levels. Consequently, NYISO has solicited market-based and regulated backstop solutions to correct the reliability deficiency.[4]

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[4] See M. Calimano, NYISO solicitation letter to S.V. Lant, R.M. Kessel, E.R. McGrath and J. McMahon, December 22, 2005.

4

Institutional Considerations and Changing Impacts

The previous two chapters identified the demand- and supply-side options for replacing the generating capacity of the Indian Point Energy Center's two operating nuclear reactors. Putting these options into action in planning and administering the New York Control Area (NYCA) electrical system must be done in the context of economic, social, and institutional impacts as well as with regard to the technological opportunities and constraints. This chapter reviews the most significant general, statewide considerations: [1]

- *Financial underpinnings of the electrical supply system* (that is, how the various organizations that generate, transmit, and distribute power underwrite the necessary investments to ensure reliable service) and how that relates to the evolving institutional structure in New York State; and
- *Environmental and other impacts that affect society.*

REGULATION, FINANCE, AND RELIABILITY

Finance and economic considerations will have a profound effect on the choice of options to replace Indian Point, the reliability of the system, and the costs of substituting generation or transmission options for the Indian Point units. Procedures for maintaining the reliability of the New York State system are discussed mainly in Chapter 5. The impact of the replaced costs of the Indian Point units if they are shut down is dictated by the evolving New York State competitive market, and by the socio-economic background in the state. Indian Point's replacement costs to the customer are virtually impossible to project at present, given the electricity market operation and its evolving status. The reasons are summarized in Boxes 4-1 and 4-2, on the cost of replacing Indian Point: "In Theory" and "In Practice." The following section describes some of the details of the New York marketplace.

[1] Specific plant and transmission line siting issues, including costs and environmental constraints, are not discussed here, since they vary so widely throughout the state and are considered beyond the scope of the study.

Box 4-1
The Cost of Replacing Indian Point: In Theory

The cost of replacing Indian Point is substantial because its two operating nuclear reactors, Units 2 and 3, represent 2,000 megawatts (MW) of baseload capacity with relatively low operating costs. In addition, a large capital investment of these units has already been made. To the extent that a replacement strategy includes conventional generating capacity (e.g., using natural gas as a fuel), the incremental cost of building this new capacity will include the capital costs, and in addition, the operating costs will be higher. Under traditional regulation, all of these incremental costs would be passed on directly to customers in New York State. Although someone has to pay for these higher costs, customers may not see major increases in their monthly bills in the new deregulated market in the State. How is this possible? An explanation follows using a simple example of the magnitudes of the costs involved.

Let us assume that the full operating costs of Indian Point are $20 per megawatt-hour (MWh) and that the units operate for a total of 8,000 hours per year. These operating costs would include the nuclear fuel, labor, and capital costs for operations and maintenance (which might require adding a cooling tower in the future), and payments into a sinking fund to cover decommissioning as well as a charge paid to the federal government to cover the cost of disposing of nuclear waste. Since Indian Point has a capacity of 2,000 MW, the total annual cost of operations is $320 million per year (20 x 2,000 x 8,000). The average wholesale price of electricity in New York Control Area Zone H was $80 per MWh in 2005 (when the price of natural gas was substantially higher than historical levels). Consequently, the annual revenue, if all power had been sold in the wholesale market, would be $1,280 million per year (80 x 2,000 x 8,000) and the annual earnings for Entergy Corporation (the plants' owner) would be $960 million per year (1,280 – 320). The situation is more complicated in reality, because Entergy may have long-term contracts to sell some of the power at prices below the current high level in the wholesale market. Nevertheless, these contracts will have to be renewed periodically, and with high prices for natural gas, Indian Point represents a very valuable source of income for Entergy.

To keep the example simple, let us assume that Indian Point is replaced completely by 2,000 MW of combined-cycle capacity using natural gas as a fuel. The operating cost of these units is $60 per MWh, and the annualized capital cost is $120 per kilowatt per year (kW/year). These units will also operate for 8,000 hours per year, and as a result, the capital cost prorated to the annual amount generated corresponds to $15/MWh (120,000/8,000). The total annual cost of generation is $1,200 million per year ([60 + 15] 2,000 x 8,000), and the incremental cost of replacing Indian Point is $880 million per year (1,200 – 320). That is a very large amount of money, but it could be much lower for a number of valid reasons. For example, reducing load by improving the efficiency of appliances is shown in Chapter 2 of this report to be much more cost-effective than building new generating capacity, and the transmission upgrades discussed in Chapter 3 may allow existing units in other locations to generate more power.

Under traditional regulation, all prudent operating costs and capital costs for generation, transmission, and distribution are aggregated to determine the size of the revenue requirement and the corresponding retail rates charged to customers.[1] In a competitive market for generation, the most expensive unit needed to meet the load sets the wholesale price paid to all units that are generating in the market (prices actually vary from location to location owing to congestion on the transmission lines, but this is not an important issue for this example). When an expensive peaking unit sets the price on a hot summer day, the wholesale price paid to generators is much higher than the operating costs of most units. This "extra" income can be used to cover the capital cost of generation.

In theory, the wholesale price in a competitive market should cover all of the operating and capital costs of generation, but, as explained in this chapter and in Appendix E, "Paying for Reliability in Deregulated Electricity Markets," a truly competitive market will not cover the capital cost of a peaking unit unless high prices (scarcity prices) are allowed. However, the total cost of the combined-cycle unit in this example ($75/MWh) is covered by the wholesale price ($80/MWh). Although these results are clearly sensitive to the assumptions made, this specific example shows that it is quite possible in a competitive market to add new generating capacity without increasing the wholesale price. In fact, the simulated market prices in some of the scenarios presented in Chapter 5 are lower when new generating capacity is added. The reason is that the new efficient units displace some generation from existing units that are more expensive to operate, and the more efficient units set the market price more frequently.

Who does pay for the incremental cost of replacing Indian Point in this example, if customers still pay the same wholesale price as before? The main loser in this example is Entergy, because the substantial annual earnings from Indian Point have now been eliminated. Given the many complexities of determining costs, such as the effect of increases in the use of natural gas on the future price of natural gas, it is extremely difficult to measure the true cost to customers of replacing Indian Point. The most important complications about determining this cost are discussed in Box 4-2. The main point of the present example is to show that the current wholesale price of electricity in the New York market may cover a large part of the incremental costs of replacing Indian Point. In a competitive market, the financial consequences for customers are likely to be smaller than the consequences would have been under traditional regulation. There is, however, an important qualification that should be made. The example here and the scenarios presented in Chapter 5 assume that new generating capacity will be built in a timely way before Indian Point is retired. If Indian Point experienced an unscheduled failure and had to be taken off-line in an emergency, the wholesale price would increase substantially. Without Indian Point and without new capacity, more-inefficient units with higher costs would have to be used to meet load. These expensive units would set higher wholesale prices.

[1] In fact, traditional regulation did not apply to Indian Point unit 3, because it was owned by the New York Power Authority, and its power sold in part outside the regulated market.

This section provides background information on the regulatory and financial environment in New York State and on how this environment shapes the incentives for investing in generation and transmission facilities. It also explains why there are growing concerns about the continued reliability of electricity supply, particularly in New York City. Appendix E, "Paying for Reliability in Deregulated Electricity Markets," gives a fuller account of how the regulation of the electric utility industry in New York State has changed and the implications of these changes for reliability.

In response to a number of financial problems, such as the cost of building excess generating capacity in the 1980s, the Federal Energy Regulatory Commission (FERC) supported new legislation in the 1990s to facilitate increased competition in the electric power industry. Competition was introduced initially in the northeastern states and in California, regions that had relatively high prices for electricity under traditional regulation. In 1999, regulators in New York State took the first major step by introducing new markets for electricity (real energy) and ancillary services, such as reserve generating capacity. At the same time, the New York Independent System Operator (NYISO) was established to run these new markets and to control the operation of all power plants in the New York Control Area. Unlike the generation components of

the industry, the transmission and distribution components continued to be regulated by the New York Public Service Commission (NYPSC).

Appendix E explains that the current patterns of spot prices in the NYCA have changed and are now much less volatile, with fewer price spikes than when the market was first introduced in 1999. This change in price behavior has made prices more predictable, but at the same time it has reduced the financial earnings of peaking capacity (generating units that are used only to meet relatively short periods of peak demand and therefore have low capacity factors) relative to those of baseload capacity. The consequences of this type of change in price behavior have been discussed extensively in the regulatory literature. Competitive spot prices will provide enough income to cover the operating cost of peaking capacity but not the capital cost, and as a result, the owners of peaking capacity do not earn enough in the spot market to be financially viable.

Box 4-2
The Cost of Replacing Indian Point: In Practice

Although the cost of building and operating new electric generating capacity to replace some or all of the 2,000 MW at the Indian Point Energy Center would be substantial, it is very difficult to determine what the overall effect would be on the bills paid by customers. The committee's scenarios, presented in Chapter 5, project the basis for the wholesale market prices in different zones. Generally, these prices are higher than the prices in the base case with Indian Point operating, but in some situations they are lower. The explanation for getting lower wholesale prices is that new efficient capacity displaces some of the old inefficient capacity and sets the market price more often.

The pricing mechanism used in all of the scenarios is based on a uniform-price auction assuming that the market is competitive (i.e., that the offers submitted into the auction by generators are equal to the true production costs, and under this specification, it would be extremely unlikely for the market price ever to be set by the low production cost of Indian Point). Assuming that the market is competitive is a reasonably close representation of how the market is actually performing at this time. Hence, the predicted prices in the scenarios provide a consistent way to determine how wholesale prices would be affected in different situations. Higher wholesale prices would result in higher rates charged to customers unless there was an offsetting reduction in the other costs of generation.

The main complication for determining the total cost of generation in the current market structure is that the wholesale price of electricity is only one of the components of the total cost. It would be necessary to determine how the costs of the other components would change to get a complete accounting of the effects of replacing Indian Point. Some of these costs are set by regulators and are subject to change. Consequently, unlike modeling wholesale prices, there is no consistent structure for modeling the other costs and it is virtually impossible to predict how they would change in different scenarios.

The best examples of the other costs of generation are (1) payments for availability in the installed capacity (ICAP) market, and (2) payments for reserve capacity. In addition, the discussion of reliability in this chapter explains why the current structure of markets is still not providing sufficient incentives for new merchant projects. The implication is that investors will have to be paid some form of additional premium above the revenue received from the existing markets if new capacity is going to be built. In the long run, customers will have to pay for all of the additional costs of generation as well as for purchases in the wholesale market.

Information on the performance of the wholesale market is readily available, but information about the other costs of generation is much more limited. Patton (2005, pp. 22-25)

provides a valuable discussion of the performance of the ICAP and reserve markets; Section F and Figure 16 in particular, shows a "net revenue analysis" of the annual net revenue (revenue – production costs) in 2002-2004 for a combined cycle turbine and a combustion turbine in different locations. For generators in New York City, the ICAP market is the primary source of net revenue for combustion turbines (roughly $140,000 per year per MW out of a total net revenue of $160,000 per year per MW in 2004) and a major source for combined-cycle turbines (roughly $140,000 per year per MW out of a total net revenue of $260,000 per year per MW in 2004). The net revenue from the ancillary service markets (e.g., reserve capacity) is small for both types of turbine (roughly $10,000 per year per MW). The net revenues for generators on Long Island are similar to the levels in New York City, but for generators in upstate regions of the state, the net revenue from the ICAP and reserve markets is very small (roughly $25,000 per year per MW).

The discussion above is relevant for assessing the cost to customers of replacing Indian Point because it shows the importance of the location of capacity on the magnitudes of the "other" costs of generation. In New York City and Long Island, customers will eventually have to pay the relatively high wholesale prices for all of their purchases (the annual average prices in 2005 were $83 per megawattt-hour (MWh) and $98/MWh, respectively, compared to prices ranging from $65/MWh to $72/MWh in Zones A through F upstate) and the high other costs of generation for all generating capacity in New York City and Long Island (Zones J and K). New capacity that is built in zones other than J and K will incur relatively low costs in the ICAP and reserve markets but may require a higher premium to make them financially attractive (i.e., because the net revenue from the existing markets will be low). It is beyond the scope of this study to try to determine the net effect of these offsetting factors.

The current regulatory strategy in the ICAP market is to make all generating capacity in a region eligible for capacity payments. Hence, the relatively high prices for capacity in Zones J and K are paid to all installed capacity that have offers accepted in the ICAP auctions for those zones. Nevertheless, it is probable that additional premiums will have to be paid to get new merchant capacity built.

An alternative regulatory strategy is to direct capacity payments to cover the premium for new capacity, and possibly for existing capacity that operates most of the time at a minimum level but is still essential for reliability. This alternative strategy may be a less expensive way to maintain reliability in the long run because making capacity payments to all installed capacity in the current ICAP market places no obligation on existing generators to build new capacity. Once again, there is a lot of uncertainty about how regulators will decide to deal with current concerns about reliability and what the additional costs will be above the price in the wholesale market.

There are various ways to provide additional income to generators, but the current projections of installed generating capacity made by NYISO suggest that the market procedures adopted in the NYCA have not been entirely effective. In particular, installed capacity in the New York City metropolitan area could fall below the level needed to meet industry standards for reliability by 2008 (NYISO, 2005). Regulators had not anticipated this situation only a year ago. The outlook in 2004 indicated that sufficient new generating units had been approved and were expected to be completed in the near future so that standards for reliability in the NYCA would be exceeded for another 10 years. Subsequently, many of the proposed new generating units were delayed indefinitely, owing to the unfavorable market conditions faced by investors.

Given the size and importance of the financial, commercial, and residential sectors in the New York City region, the very high cost of blackouts makes it essential to

maintain a reliable supply of electricity to customers in the region. Evidence from other published studies demonstrates that the value of avoiding a blackout is likely to be many times the typical wholesale price of electricity (Hamachi et al., 2004). In other words, customers are willing to pay a substantial amount to ensure that the supply of electricity is reliable, and the current industry standard of limiting outages to less than 1 day in 10 years, established by the North-American Electric Reliability Council (NERC), is consistent with this high value of reliability. The possibility that reliability in the New York City region will fall below the industry standard by 2008 presents a challenge that regulators will have to address in the near future (NYISO, 2005).

Before new ways are considered to supplement the earnings of generators in the spot market, it is important to identify three assumptions that have been adopted by regulators in the NYCA, which have limited the effectiveness of market forces in maintaining reliability, as explained in Appendix E. These assumptions are consistent with the NYISO planning strategy,[2] and are:

1. That setting minimum levels of installed generating capacity is an acceptable proxy for meeting the NERC standards for reliability in the NYCA;
2. That setting locational requirements for generating capacity in New York City (NYC) and Long Island (LI) is an acceptable way to offset the limitations of the legacy transmission system into the New York City region;[3] and
3. That the political realities in the NYCA make it infeasible to allow high price spikes in the spot market above short-run competitive levels as a way to supplement the earnings of generators.

By accepting the first two assumptions, regulators have reduced the problem of determining how to maintain the reliability of supply to one of simply ensuring that reserve margins for generating capacity in New York City, Long Island, and the NYCA are met. Clearly, this transformation of concerns about the reliability of supply to concerns about minimum levels of generating capacity (generation adequacy) is more likely to be economically efficient when the transmission system is relatively robust and the availability of generating capacity is the main limiting factor. This is no longer the case in the NYCA, given the structure of the legacy transmission system and the size and location of New York City. Nevertheless, regulators have accepted the assumption that meeting locational requirements for generating capacity is an effective strategy for meeting the NERC reliability standards. By focusing on generation adequacy, however, the current regulatory practices followed in the NYCA, using the NYISO planning models adopted in Chapter 5, estimate the required levels of generating capacity. This modeling framework tends to discount the potential value of upgrades to the transmission system as a way to improve the reliability of supply. However, alternative planning models could be adopted that, in principle, would treat generation and transmission in a more integrated way. The development of such models was beyond the scope of this analysis.

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[2] The assumptions follow from NYISO comprehensive reliability planning and the NERC reliability criteria. (NYISO, 2005).

[3] System security planning using the so-called N-1 analysis for generation and transmission failure could be applied as an alternative planning approach.

By adopting the third assumption—that it is desirable to maintain short-run competitive spot prices—regulators have ensured that earnings for some peaking units that are needed for operating reliability will be insufficient to make them financially viable.

Two distinct ways to address the economic problem of funding sufficient capacity are under discussion. The first is to supplement the profits earned in the spot market for all generating units by providing enough additional income from another source to cover the "missing" capital costs. The second is to use targeted contracts, such as Power Purchase Agreements (PPAs), with sufficient generating units to meet reliability standards.

Regulators in the NYCA have chosen the first approach, because they apparently consider that it is economically fair for both the owners of installed generating capacity and potential investors in new capacity. In contrast, contracts with some but not all generators are inherently discriminatory and may distort market behavior. Although the basic rationale for these arguments is consistent with regulatory theory, there is still no guarantee that the approach chosen by regulators for maintaining reliability in the NYCA will be either effective or economically efficient.

In other electricity markets (e.g., Australia), short-term price spikes in the spot market are acceptable to regulators so long as the average spot prices are competitive. Discussions are under way in Texas on adopting a similar approach. The regulatory focus in this type of market is on maintaining long-run competitive prices, rather than short-run competitive prices, and the effect is to make the earnings of generators correspond more closely to the true costs of production, including the capital costs. In the NYCA, however, regulators appear to try to avoid high price spikes in the spot market. Given this restriction, one possible way to recover the missing capital costs for peaking units is through a separate market for generating capacity.

The approach just described that has been proposed by regulators in the three northeastern power pools. At this time, NYISO is the only one of the three to fully implement such a capacity market. There is still a considerable amount of political opposition to the proposal in New England, and there is an ongoing debate about it among stakeholders in the "Pennsylvania Jersey Maryland" (PJM) power pool. To provide a perspective on current conditions in the NYCA, it is important to understand why there is so much controversy about the effectiveness of capacity markets as a way to provide the incentives needed to initiate merchant investments in new generating capacity.

Initially, the Installed Capacity (ICAP) market run by NYISO was simply an auction for availability, designed to ensure that enough installed generating capacity would be available to meet the projected loads in New York City, Long Island, and the NYCA for a few months ahead. In general, this type of ICAP market does provide additional earnings for generators; these earnings may be significant for the continued financial viability of some peaking units. On the one hand, for example, the existence of the ICAP market may result in some units being available instead of unavailable, and it may also delay the retirement of some units. On the other hand, the extra earnings from the ICAP market are really a bonus for other generating units, such as nuclear and hydro units, because these units would be available anyway without the ICAP market. Nevertheless, regulatory theory implies that all generators should be eligible for

participation in the ICAP market, and this issue is not the major source of controversy among regulators.

The main controversy about the ICAP market arises when the objectives of this market are extended to deal with the construction of new generating capacity. The following three limitations of an ICAP market in providing incentives for potential investors are explained more fully in Appendix E:

- The time horizon in an ICAP market does not extend far enough into the future to meet the needs of investors.
- It is unrealistic to place the primary responsibility for maintaining generation adequacy (and by assumption, system reliability) on load serving entities (LSEs).
- There is no legal requirement that any of the additional earnings from an ICAP market be used to build new generating capacity when and where it is needed.

The basic structure of the ICAP market in the NYCA is that regulators have placed a legal obligation on buyers (LSEs) to purchase enough generating capacity to meet their projected load plus a reserve margin before the spot market for electricity clears. (LSEs can also meet some of their own capacity requirements if these sources are certified by NYISO.) The final monthly auction in the ICAP market clears a few days before the month begins. It represents the last chance for LSEs to meet their capacity obligations without paying a substantial penalty

The final monthly ICAP auction includes a specified "demand curve" that is designed to ensure that the market price of capacity is equivalent to the capital cost of a peaking unit if the total supply of capacity in the ICAP auction falls to the minimum amount needed to meet the regulated standards of generation adequacy. The market price will be higher (lower) if the total capacity offered is lower (higher) than the required amount. The basic objective of the current ICAP market is to make the market price of capacity cover the missing capital cost of a peaking unit when the market is economically efficient (i.e., when the total supply of capacity is equal to the amount needed for adequacy).

The financing of new generation and transmission facilities in the NYCA, whether it is needed to accommodate the retirement of existing facilities, the projected growth of load, or the intentional shutdown of Indian Point Units 2 and 3, must be understood in the context of the current hybrid mix of competitive markets and regulatory interventions that has resulted from the restructuring of the electric sector. Proposals to build new generation and transmission facilities are no longer preapproved by the New York Public Service Commission, with the implicit guarantee to investors that all prudent production costs and capital costs will be recovered from customers. Investors face "regulatory risk" due to concerns that current market rules may be changed in the future, as they were after the "energy crisis' of 2000 and 2001 in California as well as competitive risk. Risk increases the financial risk of an investment in new generating capacity, implying that the cost of borrowing capital for investors will be substantially higher than it would be under regulation.

Market forces have been able to maintain adequate levels of generation with relatively little regulatory intervention in Australia, for example, but not in the NYCA. Appendix E explains why the successful efforts of regulators to maintain short-run standards of economic efficiency in the spot market have undermined the financial

viability of generating units that are needed for reliability (i.e., units with low capacity factors). This change in the pattern of spot prices has reduced the earnings of peaking units relative to baseload units and, coupled with the current uncertainty about the future prices of fossil fuels such as natural gas, has led to delays in the construction of new facilities already licensed in the NYCA.

The deteriorating outlook for reliability in the NYCA is best summarized by the drop in projected reserve margins for generating capacity from the forecast made in 2004 to that in 2005. A year ago as of this writing, in 2004, the reserve margin in 2008 was expected to be over 40 percent; however, the 2005 projection for 2008 was less than the 18 percent needed to meet the NERC reliability standards.

Figure 4-1 shows the two projections of reserve margins for the summer peak load in the NYCA that were published by NYISO in 2004 and 2005. The drop in the projected reserve margins shown in the figure was caused by delays in the construction of new generating units that had already received construction licenses. The lists of potential new generating units underlying the two projections of reserve margins in 2004 and 2005 are essentially the same, but the "Proposed In-Service" dates are quite different. In 2004, 2,038 MW were under construction (four units), 3,120 MW were approved (seven units) and 1,605 MW had applications pending (two units) for a total of 6,763 MW. Five of the nine projects (2,430 MW) with applications Approved or Pending had proposed in-service dates no later than 2007. However, although the amount of capacity under construction was still 2,038 MW in 2005, none of the other nine projects had proposed in-service dates, and under current market conditions, there is no guarantee that any of these generating units will actually be built.[44]

The current concern about meeting the levels of generation adequacy needed to maintain reliability in the NYCA coincides with two important changes in regulatory procedures and responsibilities. First, a new Comprehensive Reliability Planning Process (CRPP) was implemented by NYISO in 2005; the new forecasted reserve margins for 2005 shown in Figure 4-1 were produced for the CRPP. The second regulatory change is that the Energy Policy Act of 2005 has given the FERC stronger oversight responsibilities for maintaining reliability standards for all users of the bulk power system in the United States. Under this legislation, the FERC is permitted to pass these responsibilities to a single Electric Reliability Organization (ERO) that will determine explicit reliability standards and also have the authority to enforce them.

[4] The time frame for deciding on alternatives is not known. However, NYISO is sufficiently concerned about the delays or cancellation of new generation capacity to have requested proposals for alternative solutions for addressing electricity supply, especially into the New York areas. For example, letter of M. Calimano, to chief executives of transmission companies, dated March 6, 2006.

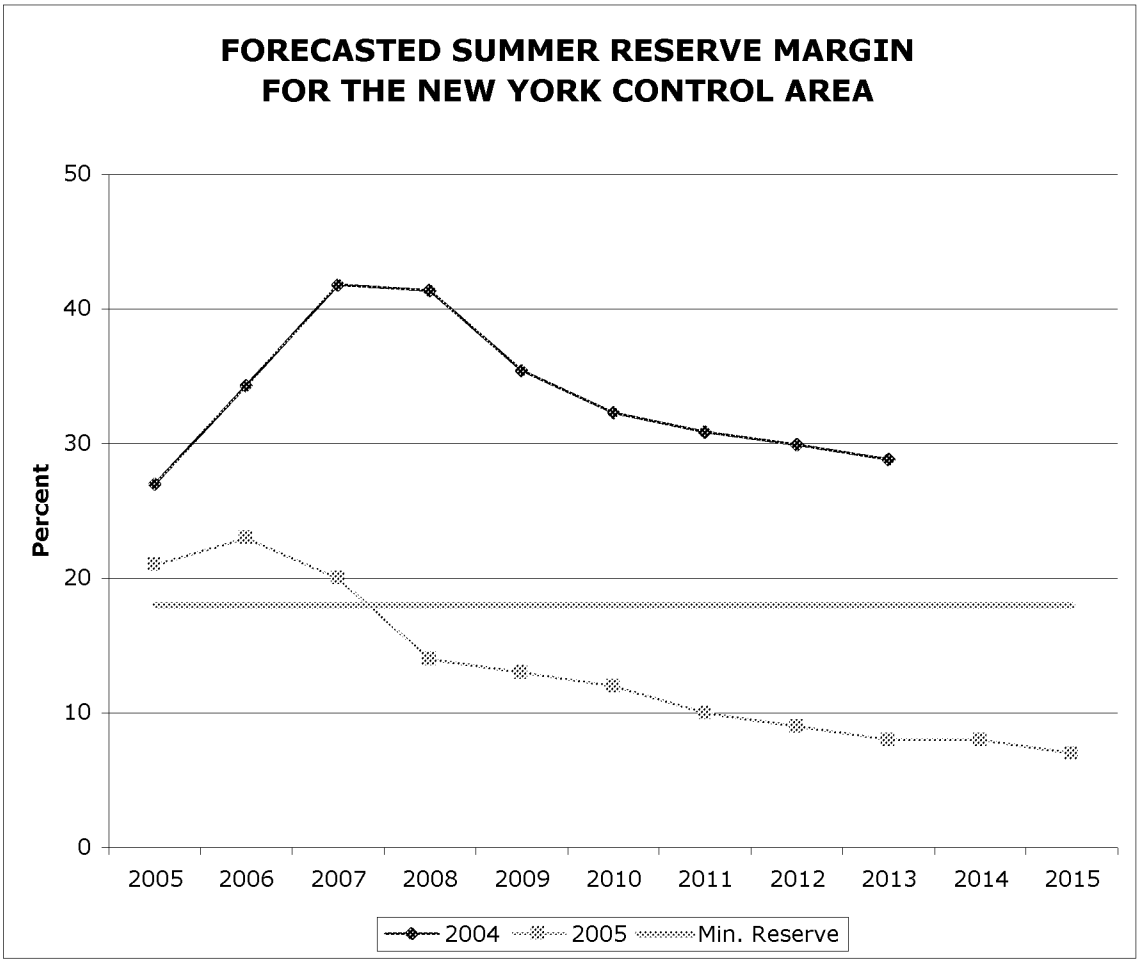

FIGURE 4-1: Projections made by NYISO in 2004 and 2005: summer reserve margin for generating capacity in the New York Control Area.
SOURCES: Projections made in 2004 from NYISO (2004), Table V-2; those made in 2005 from NYISO (2005), Table 7.2.1.

When uncertainty about the retirement dates of existing generating units in the NYCA is combined with uncertainty about whether new generating units will be built, the task of ensuring that there will be enough installed generating capacity to meet reliability standards is very challenging. Nevertheless, reliability standards must be met because the cost of blackouts in a dense urban area like New York City is so high. Although the importance of maintaining reliability has been recognized in the implementation of the CRPP and the Energy Policy Act of 2005, it is still too early to know exactly how regulators will meet their new responsibilities and use their new authority. Nevertheless, it is clear that the objective of meeting reliability standards is a high priority at both the state and federal levels, as it should be.

The current pessimistic outlook for maintaining reliability standards in the NYCA also poses a challenge for this committee. Although the committee is convinced that regulators should place the highest priority on maintaining reliability, the committee's responsibilities do not include making specific recommendations about how this should be done. Since the current projections of installed generating capacity fall short of the minimum levels needed for generation adequacy, the first step in evaluating alternatives to Indian Point is to specify a new scenario that does meet reliability standards with Indian Point operating. The assumptions used to specify this scenario are discussed in detail in Chapter 5 of this report.

The Permitting Process with Article X

The committee is aware that New York State will face a formidable task in constructing sufficient power plants to satisfy the continued load growth being experienced in the state and to replace old power plants that are to be retired for various reasons. Early retirement of Indian Point would add to those problems, whichever options are selected. A business-as-usual approach is unlikely to achieve the additional capacity that would be required. The siting of new major electric generating facilities would be facilitated if the State of New York reauthorized Public Service Law Article X, which expired on January 1, 2003.[5]

Article X had centralized the process of environmental permitting for electric power plants and provided for a firm, finite schedule for the approval or denial of environmental permits, limiting the risks of delay. This approach grew in importance with the restructuring of the electric power sector. Before restructuring, the monopoly franchise utility would propose a project based on the need to meet local loads, and the appropriate regulatory body (e.g., the NYPSC) approved or denied the proposal. In this approach, additional costs imposed on the utility company by environmental regulatory requirements or delays could be (and usually were) passed on to ratepayers. Now, the costs and risks of power plant development fall to private developers, who seek to be compensated in the marketplace—which may be intolerant of any additional expenses due to delays or other contingencies.

While it was in force, Article X set forth a review process for consideration of applications to construct and operate electric generating facilities of 80 MW or more. An approval would result in the applicants' being granted a Certificate of Environmental Compatibility and Public Need, which is required before the construction of such a facility.

Most of the review under Article X is conducted by two examiners, one from the New York Department of Public Service and one from the New York Department of Environmental Conservation (NYDEC). Numerous opportunities for public involvement in hearings and other proceedings existed, and the applicants were required to pay fees that interveners could use, with permission of the examiners. Municipalities and individuals within a 5-mile radius of the proposed facilities were granted routine intervener status.

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[5] For additional information, see http://www.dps.state.ny.us/articlex_process.html. Accessed January 2006.

Within a year of receipt of the application, the Board on Electric Generating Siting and the Environment was required to make a decision. This board consisted of the chair of the New York Public Service Commission, the chair of the New York State Energy Research and Development Authority (NYSERDA), the commissioners of NYDEC, the New York Department of Health, and the New York Department of Economic Development, plus two public members who reside near the proposed facility and are appointed by the governor.

For example, in 2000 the Board granted the Athens Generating Station a certificate (Board on Electric Generating Siting and the Environment, 2000). Topics that the board considered included the legality of the application and review process, regional and local aquatic impacts (including erosion control and deposition of pollutants), the visibility of the plant and stacks to the public (especially from historic sites), the visibility of the proposed cooling-tower plume, air quality, terrestrial biology, chemical storage and waste management, impacts on agricultural lands, noise, traffic, land use (including wetlands mitigation), public interest concerns (including the enhancement of competition, alternative sites, electrical interconnection, and local taxes), and the status of required permits. During the process, many interveners participated; they and the applicant agreed to many changes in plant design, some of which were fairly expensive. Important changes included shorter stacks, the use of dry cooling, the use of state-of-the-art emissions controls, and payments to mitigate various impacts. The board also imposed several conditions on the applicant in its approval.

Since the expiration of Article X, electric generating project developers must obtain all of the appropriate local and state permits and approvals, and must undergo environmental review subject to the State Environmental Quality Review Act (Article 8 of the Environmental Conservation Law). Project developers may also obtain a Certificate of Public Convenience and Necessity, based on the traditional approach to adding electric generating capacity. New York's Governor George Pataki and several state legislators have proposed new laws to replace Article X, but there is none currently in place.

Industry groups (e.g., the Business Council of New York State) have promoted a new siting law, while some advocacy groups (e.g., the New York Public Interest Research Group) have expressed concerns. One specific concern is about whether or not the local community must give its permission for a new plant. Under Article X, municipalities could participate in the process, but the final decision was made by the board.

If action is taken to reauthorize Article X, the following issues, among others, could be considered:

- The addition of modifications and measures to Article X's procedural requirements that would enable the siting board to streamline its review when interested parties, including affected communities groups, had reached a consensus as to the specific issues presented by an Article X application.
- The appropriateness of developing specific procedures with respect to the expansion, modification, or repowering of existing major generating facilities.

In addition, the committee suggests consideration of the reauthorization of Article 6 of New York's energy law, for statewide energy planning, that expired on January 1, 2003.[6] In addition to statutory modifications, the following administrative steps might be taken:

- The Energy Planning Board could meet annually to coordinate the development and implementation of energy-related strategies and policies, receive reports from the agencies' staffs on the compliance of major energy suppliers with its information filing requirements, and receive summary reports on the information filed.
- The information-filing regulations of the Energy Planning Board could be modified to recognize new entrants into the energy marketplace and the need for pertinent energy-related information and data.

SOCIAL CONCERNS

The social concerns considered here are environmental impacts, energy security, and indirect socio-economic factors, including impacts on the affected communities. The concerns can have a significant affect on what sort of facilities can replace Indian Point and where they can be built.

Environmental Regulation

All energy technologies have environmental impacts. Replacement technologies discussed in Chapters 2 and 3 include efficiency and distributed generation,[7] natural gas-fired turbines, and, potentially, coal-fired generation (any new coal plants are likely to be upstate or out of state, with long-distance transmission). Replacing the Indian Point nuclear power generators with a different type of electricity supply may reduce some environmental effects but may increase others. In contrast, energy-efficient technologies reduce the need for both capacity (megawatts) and energy (megawatt-hours) and thus tend to reduce environmental impacts (unless their manufacture, recycling, or disposal is problematic).

In New York as elsewhere in the United States, a complex set of regulations and permit requirements are in place to manage these effects and to ensure that they impose a minimal burden on the public and the environment. Environmental effects of nuclear power plants associated with plant construction, fuel production, and disposal of radioactive waste, have been evaluated extensively elsewhere (e.g., McFarlane, 2001; NRC, 2001 on spent fuel disposal) and are outside the scope of this study. In normal

[6] Article 6 concerns the organization and functions of the state Energy Planning Board.

[7] On-grid renewable generation options were also considered, but the committee determined that they were not competitive in the timescale of the study.

operation, nuclear power plants such as those at Indian Point emit very little air pollution. Large releases of radionuclides might occur as the result of an accident or attack (Farrell, 2004b), but that potential has a relatively low probability. Indian Point does have a significant impact on the Hudson River, as discussed in the subsection below, on "Water Use."

The most significant pollutants from natural gas combined cycle plants, the most likely fossil-fueled generation replacement for Indian Point, are nitrogen oxides, NO and NO_2 (designated as NO_x), and, to a much lesser extent, carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter (PM) (e.g., Barboza et al., 2000). However, emissions of all of these pollutants are sufficiently low from gas turbines or can be controlled sufficiently well so that it is quite feasible to obtain air quality permits which guarantee plant operation that protects human health and the environment (U.S. EPA, 1997). Carbon dioxide emissions, currently not regulated, are discussed below.

The effect of possible replacements for the Indian Point reactors on a broader size range of particulate matter (PM_{10}) emissions is likely to be small because of (1) permitting requirements that will require low emission rates and a tall stack to control local effects, and (2) emission-reduction offset requirements that will yield a net decrease in regional emissions of PM_{10}. For the more important emissions of the smaller particulate matter (called $PM_{2.5}$), the effect on mass emissions is largely determined by SO_2 and NO_x emissions, which, on a regional basis, will be unaffected owing to the emissions caps imposed on the electric power sector for these pollutants.

Three important pollutants from power plants, including coal fired units, are or will be controlled by cap-and-trade programs: NO_x, sulfur dioxide (SO_2), and mercury (Hg), (U.S. Congress, 1990; Farrell, 2004a).

Both NO_x and SO_2 can have *direct* negative effects on human health, and so are "criteria pollutants," with their own standards under the federal Clean Air Act. Southeastern New York (and, in fact, the entire country) has attained healthful air quality for NO_x and SO_2 and is classified as "in attainment" of the National Ambient Air Quality Standards (NAAQS) for these pollutants. Nitrogen oxides and SO_2 contribute *indirectly* to two other criteria pollutants, ozone (O_3) and particulate matter. The former is produced in the atmosphere through photochemical reactions of NO_x and VOCs. The latter involves nitrate and sulfate formation from oxidation of the two gases in the air forming condensable material as PM. Measured O_3 and $PM_{2.5}$ concentrations in various cities have resulted in local nonattainment of the NAAQS for these pollutants, including citites in some parts of southeastern New York. The nonattainment designation requires the state to provide plans for achieving attainment, which in turn requires reductions in NO_x and SO_2 concentrations well below levels otherwise required. These requirements affect choices of power plant technology using fossil fuels.

The attainment of the NAAQS for NO_x (as NO_2) and SO_2 has been achieved locally through the use of cleaner fuels, improved combustion technologies, and combustion by-products emitted well above ground level, to disburse and dilute remaining emissions. As with PM and CO, the regulatory process to approve new power plants involves atmospheric modeling to set emissions limitations and stack heights in order to help ensure that there are no local health impacts from the expected NO_x and SO_2 emissions. A new power plant would also be required to offset its emissions and retire

emission "credits" equal to 30 percent of those emissions, creating a net reduction in regional NO_x and SO_2 emissions.

Nitrogen oxides and SO_2 contribute not only to local issues, but also to larger-scale (regional) environmental problems of tropospheric ozone, fine particulate matter ($PM_{2.5}$), acidification of sensitive ecosystems, and (in the case of NO_x) eutrophication (Regens, 1993; Chameides et al., 1994; Jaworski et al., 1997; Tucker,1998; Solomon et al., 1999; U.S. EPA, 2000; Mauzerall and Wang, 2001; Streets et al., 2001; Farrell and Keating, 2002; Creilson et al., 2003). In order to manage these regional problems, additional controls for NO_x and SO_2 are superimposed on controls designed to ensure local air quality. These regional air-quality-related problems result from aerometric phenomena that occur over several hundred kilometers and can take several days to complete. Therefore, projecting the impact of potential fossil-fueled replacements for Indian Point requires placing them into a context of regional changes in emissions, not simply the localized changes near new power plants or urban settings.

In the United States, SO_2 and NO_x emissions from large electric generators are regulated by a "cap-and-trade" system; this type of regulation has been proposed for Hg as well (Farrell, 2004a). Current regulations for SO_2 and NO_x are contained in the Clean Air Interstate Rule (CAIR), which was published in its final form in March 2005 and will be implemented fully by 2020 (U.S. EPA, 2005).[8]

The CAIR will lower SO_2 emissions from the electric power sector across a 28-state region (including New York) by about 65 percent and NO_x emissions by about 50 percent. However, the CAIR imposes an annual cap on NO_x emissions, while the key problem in the northeastern states is summertime ozone and fine particulate formation. Some analyses suggest that the annual cap in the CAIR may not be sufficient to maintain current summer air quality in the New York area, and that an additional, seasonal NO_x control program may be required (Palmer et al., 2005).

The Clean Air Mercury Rule (CAMR) is still under review. Even without it, Hg emissions are expected to decline as a co-benefit of the more stringent controls on SO_2 and NO_x emissions.

In considering a potential replacement of the Indian Point reactors with fossil-fuel generation, the key feature of cap-and-trade systems is that emissions are limited in absolute magnitude and do not respond to changes in the amount of electricity generated, or in the technologies used. While increased generation at an existing power plant may lead to additional emissions at that facility, such increased generation would not be allowed if new emission controls are added to the plant, as is happening (and has been happening for over a decade) across the nation. Even if no new control technologies are added, under a cap-and-trade system additional emissions at one plant (including a new one) must be compensated for by reduced emissions from another plant. This trade-off would result in no net change in regional emission. The SO_2 and NO_x cap-and-trade programs are designed to solve such regional (not local) problems. These requirements are added to protect local air quality. Under the federal Clean Air Act amendments of

[8] See www.epa.gov/interstateairquality. Accessed November 2005.

1990, the air quality standards that these policies are designed to achieve must protect human health with an adequate margin of safety.

Thus, if the Indian Point plants are replaced by gas- or coal-fired generators, total emissions of SO_2, NO_x, and Hg will not change (assuming that the CAMR or a more restrictive cap is put in place), and should not significantly affect human health. Instead, the spatial patterns of emissions may change slightly, and the cost of controlling emissions will increase slightly.

Local air quality in the immediate vicinity of power plants is controlled separately by environmental regulations (as discussed above). These regulations set limits on rates of emissions and require the use of tall exhaust stacks to ensure that pollutants are diluted sufficiently to avoid negative health impacts in the communities immediately surrounding the facilities under expected meteorological conditions (Davis et al., 2000; Goodfellow, 2000).

Most cap-and-trade systems, such as the one that controls SO_2 emissions, include "antibacksliding" provisions that prevent facilities from violating local air quality regulations through the use of emissions trading. Nonetheless, because the emissions of specific sources are not directly controlled by cap-and-trade programs, concerns have been raised about the possibility of "hotspots," areas of greater air pollution (or air pollution that is not lowered sufficiently) in the vicinity of some sources (Nash and Revesz, 2001). However, there is little evidence of hotspots having occurred in SO_2 and NO_x cap-and-trade programs (Farrell, 2004a; U.S. EPA, 2004). Nevertheless, local effects of emissions of toxics under a cap-and-trade program has been found to be a cause for concern (Chinn, 1999). Thus, it is reasonable to be concerned about the possibility of negative effects of Hg emissions if a coal-fired power plant replaces the Indian Point plants. However, the difficulty of finding an adequate site and of delivering coal in sufficient quantities to a location near New York City makes such an outcome unlikely in the short term (to 2015) examined in this study.

There is scientific consensus (with few dissenting opinions) that rising concentrations of greenhouse gases (GHGs) in the atmosphere have already caused perceptible changes in climate and will lead to further climate change in the future (Intergovernmental Panel on Climate Change, 2001). The impact of climate change may be significant for water resources, agriculture, ecosystems, and the incidence of catastrophic weather systems (Malmqvist and Rundle, 2002; Hayhoe et al., 2004). The most important anthropogenic GHG is carbon dioxide (CO_2), and the most important source of CO_2 is the combustion of fossil fuel.

Avoiding serious climate change impacts will require deep cuts in global CO_2 emissions. Deep cuts in return will require significant changes from current practices in energy supply and demand, because fossil fuels dominate global energy use (Hoffert et al., 1998). As a non-fossil fuel source of energy, nuclear power may grow in importance in the future. Replacement of the Indian Point Energy Center with fossil-fueled generation could increase CO_2 emissions, the opposite of the direction necessary to avoid climate change.

There is currently no regulatory framework in the United States for controlling GHG emissions, but on December 20, 2005, Governor Pataki signed the Regional Greenhouse Gas Initiative (RGGI) Memorandum of Understanding, which committed New York State to proposing a cap-and-trade program to limit GHG emissions from the

electric power sector starting in 2009. Six other states were part of this agreement: Connecticut, Delaware, Maine, New Hampshire, New Jersey, and Vermont. Fossil-fueled replacements for the Indian Point plant would emit CO_2 and would be subject to this regulation.

Costs of Emissions from New Fossil Power Plants

An upper-bound estimate of the cost of obtaining pollutant-emission allowances to cover annual emissions is calculated assuming two technologies that could be adopted as replacements for the Indian Point units up to 2018 and perhaps beyond. These are the natural gas combined-cycle (NGCC) and coal-based integrated gasification combined cycle (IGCC), with the latter serving as a proxy for advanced pulverized coal with state-of-the-art emission-control technologies. The amount of energy required is assumed to be the amount produced by the two Indian Point units operating at 90 percent capacity factor for one year, which is about 17 million MWh. Assuming 80 percent capacity factors for the fossil-fueled plants, a total capacity of about 2,430 MW would be required.

For purposes of evaluation, nominally representative emission rate data are taken from the observed performance of Sithe Independence and Polk Stations, as given in the U.S. Environmental Protection Agency's (EPA) database, e-grid. Two scenarios are considered: in one, CAIR and CAMR are implemented but there is no GHG emission control; the other is identical except that the RGGI baseline policy package is also implemented. Emission allowance prices for these two scenarios are taken from the September 2005 RGGI analysis (Table 4-1). The price of CO_2 allowances in the latter scenario is $1 per ton. While this is lower than the amount estimated in other policies, including that of the European Union, it nevertheless is consistent with current projections for the Northeast. Below are considered the consequences of a range of CO_2 charges, ranging from $1 per ton of CO_2 removed to $25 per ton of CO_2 removed.

TABLE 4-1 Estimated Costs ($/ton) Future Emission Allowance Prices from a Variety of Sources

Study	Description	NO_x ($/ton)	SO_2 ($/ton)	Hg ($/lb.)	CO_2 ($/ton)
Energy Information Administration (2001), Table 4	50%-75% reductions in SO_2, NO_x, and Hg	1,108-2,825	719 -1,737	$21,119 - $85,225	N.A.
Palmer, Burtraw and Shin (2005, Table 14)	CAIR, CAMR and seasonal NO_X cap	1,042	0 -1,347	$35,760	N.A.
Regional Greenhouse Gas Initiative (RGGI)[a]	Baseline: CAIR and CAMR	1,710	1,268	$21,730	N.A.
Regional Greenhouse Gas Initiative (RGGI)	Reference: CAIR, CAMR, constant CO_2 emissions 2009-2014	1,713	1,267	$21,670	$1

[a] RGGI prices are based on the September 2005 analysis. See http://www.rggi.org/documents.htm. Accessed November 2005.
NOTE: N.A., not available. Abbreviations are defined in Appendix B.

The results are shown in Tables 4-2 and 4-3. The projected upper bound for the policy with GHG controls is only about $60 million per year, using the RGGI baseline price for CO_2 allowances. However, many other studies have suggested that higher prices for CO_2 allowances are likely. Holding the other allowance prices constant, adjusting CO_2 allowance prices to $10 per ton yields total annual allowance costs for NGCC of about $72 million and for IGCC of about $210 million. At $25 per ton of CO_2, these costs become about $175 million for NGCC and $450 million for IGCC.

Given the uncertainties in fuel prices, policies, and technologies, it is reasonable to expect that the cost of air emission allowances for fossil-fueled replacements for the Indian Point units would vary from a few million to ten million dollars per year if there is no GHG policy, and from ten million to possibly several hundred million dollars per year if a GHG policy is imposed.[9]

[9] Higher levels of costs would encourage energy efficiency investments or replacements that emit less carbon, thus reducing the total cost.

TABLE 4-2 Annual Costs for Allowances to Replace Indian Point Generation, Without CO_2 Control (Regional Greenhouse Gas Initiative Baseline Scenario, No CO_2 Control)

Type of plant	Nuclear Plant	Natural Gas Combined-Cycle Plant	Coal Integrated gasification combined cycle
Capacity (MW)	2,158	2,428	2,428
Capacity factor	0.9	0.8	0.8
Generation (MWh)	17,013,672	17,013,672	17,013,672
NO_x rate (lb/MWh)	0	0.134	0.719
NO_x emissions (tons)	0	1,140	6,116
NO_x allowance cost (cost per ton $1,710)	$0	$1,949,256	$10,459,070
SO_2 rate (lb/MWh)	0	0.025	1.55
SO_2 emissions (tons)	0	213	13,186
SO_2 allowance cost (cost per ton $1,268)	$0	$269,667	$16,719,335
Hg rate (lb/GWh)	0	0	0.0397
Hg emissions (lb)	0	0	675
Hg allowance cost (cost per lb $21,730)	$0	$0	$14,667,493
Total emission allowance cost	$0	$2,218,923	$41,845,898

NOTES: Allowance prices based on September 2005 analysis of the Regional Greenhouse Gas Initiative. See http://www.rggi.org/documents.htm. Accessed November 2005. Abbreviations are defined in Appendix B.

TABLE 4-3: Annual Costs for Allowances to Replace Indian Point Generation with CO_2 Control (Regional Greenhouse Gas Initiative Reference Scenario)

Type of Plant	Nuclear Plant	Natural Gas Combined-Cycle Plant	Coal Integrated Gasification Combined-Cycle Plant
Capacity (MW)	2,158	2,428	2,428
Capacity factor	0.9	0.8	0.8
Generation (MWh)	17,013,672	17,013,672	17,013,672
NO_x rate (lb/MWh)	0	0.134	0.719
NO_x emissions (tons)	0	1,140	6,116
NO_x allowance cost (cost per ton $1,713)	$0	$1,952,676	$10,477,419
SO_2 rate (lb/MWh)	0	0.025	1.55
SO_2 emissions (tons)	0	213	13,186
SO_2 allowance cost (cost per ton $1,267)	$0	$269,454	$16,706,150
Hg rate (lb/GWh)	0	0	0.0397
Hg emissions (lb)	0	0	675
Hg allowance cost (cost per lb $21,670)	$0	$0	$14,626,993
CO_2 rate (lb/MWh)	0	828	1,959
CO_2 emissions (tons)	0	7,043,660	16,664,892
CO_2 allowance cost (cost per ton $1)	$0	$7,043,660	$16,664,892
Total emission allowance cost	$0	$9,265,790	$58,475,454

NOTES: Allowance prices based on September 2005 analysis of the Regional Greenhouse Gas Initiative. See http://www.rggi.org/documents.htm. Accessed November 2005. Abbreviations are defined in Appendix B.

Water Use

The Indian Point Energy Center is located on the eastern shore of the Hudson River and uses three intake structures to withdraw approximately 2.5 billion gallons of water per day for cooling the reactor units in once-through heat exchangers; the water is returned to the river somewhat warmer (NYDEC, 2003, p. 8). Under the federal Clean Water Act, discharges of heat to water bodies are considered pollution and are regulated by NYDEC. In addition, the cooling-water intake systems at Indian Point contribute to significant mortality of aquatic organisms in the Hudson River estuary. For this reason the cooling-water intake system is also subject to regulation under the Clean Water Act and state regulations. These regulations require that the location, design, construction and capacity of the cooling-water intake system must reflect the best technology available (BTA) for minimizing adverse environmental impacts.

In 2003, NYDEC issued a draft State Pollutant Discharge Elimination System (SPDES) permit for Indian Point that required immediate and long-term steps to reduce the adverse impacts on the Hudson River estuary.[10] The short-term steps include mandatory outage periods, reduced intake during certain periods, continued operation of fish-impingement mitigation measures, the payment of $25 million to a Hudson River Estuary Restoration Fund, and the conduct of various studies. In the long term, NYDEC staff has determined that closed-cycle cooling is the best technology available to minimize environmental impacts of the Indian Point facility. However, the implementation of the very large, expensive modification is contingent on approval of the U.S. Nuclear Regulatory Commission (USNRC) and extension of the USNRC operating license for Indian Point and so is not yet certain.

Alternatives to Indian Point would likely also be required to use closed-cycle or "dry cooling" technologies that use little water. This type of cooling technology was required of the new Athens Generating Station up the Hudson River (Board on Electric Generating Siting and Environment, 2000). Small-scale generators (used for distributed generation and combined heat and power) use air cooling and thus have no significant water use.

Overall, potential replacements for Indian Point would have less impact on the Hudson River than Indian Point currently does. However, if Indian Point adds closed-cycle cooling, its impact would be reduced also.

Environmental Justice

Equity and aesthetic concerns about the impacts of electric power plants (and all energy infrastructure) are often called matters of environmental justice, which is typically defined as the fair treatment of all people, regardless of race or income with respect to environmental issues. Ensuring environmental justice has been a matter of policy for the federal government for more than a decade, and in 2004 the U.S. Nuclear Regulatory Commission reaffirmed its commitment to this goal. In practice this means that "while the NRC [Nuclear Regulatory Commission] is committed to the general goals of E.O. 12898, it will strive to meet those goals through its normal and traditional NEPA

[10] Available at http://www.dec.state.ny.us/website/dcs/eisanddp/IndianPointSPDES.pdf. Access November 2005.

[National Environmental Policy Act of 1969] review process." (President of the United States; 1994; USNRC, 2004).

As a concept rooted in ideas of rights and fairness, not science and technology, environmental justice concerns are very different from the other types of issues discussed in this section. In addition, environmental justice concerns associated with energy can include a wide array of issues, because many people find electric power plants and transmission towers ugly and undesirable to live or work near. For this reason, there are often concerns that new power plants or power lines will lower property values. By contrast, some communities might welcome a new power plant because of the jobs and tax revenues it would bring.

Everyone uses electricity, and it must be generated somewhere and delivered in some way. Why should one community accept a power plant or transmission line when that facility will serve another community? This problem can create tensions among communities or between residents of different states. Indian Point serves Westchester County and New York City. Once the power goes onto the grid, it is indistinguishable from all other power sources, but Indian Point is basically a local plant for Westchester County and New York City. In fact, it is essentially the only generating plant in Westchester County. New York City is required to generate 80 percent of its power, but Westchester County currently has no local generation requirement. As noted elsewhere in this report, if Indian Point is closed, it will have to be replaced at least in part with new generating capacity. If these are not local plants, then all of Westchester County's power would have to be imported, impacting other communities that might object to new facilities being imposed on them.

This problem has been exacerbated by the transition from the traditional model of a regulated monopoly franchise in the electric power sector toward a model of a competitive generation market with monopoly franchise distribution utilities and a transmission system owned by various firms, but coordinated by an independent system operator. In this new framework, the traditional concepts applied to proposed power plants—including estimating the public interest in granting construction permits against the need for new generation to meet local loads—no longer fits. Instead, plants are built to be competitive in the marketplace, as embodied in the New York State Energy Plan, which describes competition as being in the public interest, as discussed earlier in this chapter.[11]

As discussed in Chapter 1, safety is a primary concern for many people living near Indian Point. They feel threatened by the plant and want it closed. This committee has not assessed the vulnerability of Indian Point. It defers to other experts to analyze whether those risks are real or negligible. What this committee can say is that the socio-economic, environmental, and environmental-justice impacts of replacing Indian Point are significant, although not universally negative. The committee also notes that safety risks of the plant would not be eliminated until the spent fuel pool is emptied, which may be many years after the plant is closed. Storage of the spent nuclear fuel, presumably on-site, may involve costs that will be born by the current owner, or by negotiated settlement with the state or federal authorities. Policy makers must balance the risks of continued operation against the impacts inherent in closing the plant.

[11] See http://www.nyserda.org/Energy_Information/energy_state_plan.asp

Energy Security

Historically, access, availability, and affordability have dominated public policy and the design of energy systems. The costs of existing security measures have been implicitly divided between energy users, suppliers, and the government. Today, the security of energy infrastructures against deliberate attack has become a growing concern. Therefore, the context within which energy is supplied and used has evolved well past the paradigm that has led to the current physical energy infrastructure and associated institutional arrangements.

Concerns about deliberate attacks on the energy infrastructure have highlighted many critical questions to which no ready answers exist. For example: How much and what kind of security for energy infrastructure do we want and who will pay for it? Current government efforts directed at critical infrastructure protection tend to ignore this issue entirely, focusing on preventing attacks and protecting whatever energy infrastructure the private sector creates. These decisions are being made implicitly for decades, favoring certain risk-creating technologies over others (Farrell, 2004b).

Many different approaches are likely to be necessary to achieve desired levels of energy-infrastructure security. Routine security and emergency planning have obvious roles, and some features seem to inherently enhance system security, including decentralization, diversity, and redundancy. Other features, such as the utilization of specific energy sources and energy-efficiency measures, seem to have mixed effects. In particular, some renewable energy technologies can be deployed more securely than can fossil-fuel and nuclear technologies; others cannot.

Socio-Economic Factors Including Indirect Costs to the Public

The direct-cost projections, as exemplified in the scenarios discussed in Chapter 5, depend on the generation choices to replace the 2,000-MW baseload of Indian Point, the location of the generation, modifications in transmission and distribution, the timing of any projected changes and the load growth in the New York area. Each of the options considered has certain costs associated with it in addition to the direct costs of replacement capacity and environmental protection. These likely will be borne by the public, either through arrangements with the state, or through changes in the electricity rates in southern New York, although the indirect costs do not appear directly on the customer's electricity bill. At least three kinds of potential indirect, or hidden, costs are associated with replacing the power from Indian Point:

- *The economic value of the plant and its associated property.* Entergy Corporation might have to be reimbursed if the Indian Point reactors are shut down prior to their end of licenses (including the period of extended operation if they are re-licensed).
- *Higher natural gas costs to all users because of increased demand from the electric power sector.* Natural gas is likely to be the main fuel for replacement generating capacity, and unless new supplies are created, constraints are likely to be experienced.

- *Changes in employment opportunities and the tax base and the loss of local services associated with the Indian Point plant.* These costs (or potential benefits, e.g., if the Indian Point plant site is converted to other economic uses) would be borne mainly by Westchester County.

The committee was unable to assess these costs, but they could be significant relative to the direct replacement costs, depending on the arrangements for the possible closure of Indian Point.

Additional sociopolitical issues to be faced by the New York communities are less tangible than are projected costs or regulation. However, there are factors that need to be taken into account, which may constrain or severely limit the options for replacing Indian Point, and may affect the communities in the next 20 to 30 years. These factors include the following:

- Public attitudes toward siting power plants and transmission lines (aesthetics and the not-in-my-backyard, or NIMBY, phenomenon);
- The willingness of the public to invest in energy-efficiency measures;
- Attitudes toward advanced nuclear power plants as an option that would help maintain electric energy fuel-source diversity and minimize CO_2 emissions;
- Growth and development in southern New York, requiring major decisions on resource management and infrastructure, including energy, social services, primary and secondary education, and so on; and
- Attitudes of the state government regarding the regulation of the energy sector and its approach to permitting new facilities in the state.

Accounting for these factors will influence the choices of technological options discussed or summarized in Chapters 2 and 3 in ways that are beyond the scope of this study. However, implicitly these factors, along with others discussed in this chapter, tend to reinforce the focus on the short-term options of natural-gas-supplied generation and added transmission in southern New York State as key to a replacement strategy for Indian Point.

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5

Analysis of Options for Meeting Electrical Demand

The retirement of the 2 operating reactors at Indian Point in the 2008-2015 time frame could have significant consequences to the reliable supply of electricity in the Metropolitan New York City area unless appropriate compensation is supplied. This chapter discusses the impacts that potential replacements could have on reliability, costs, and other factors.

These replacements are analyzed in the context of the current evolution of the New York electric system (the New York Control Area, or NYCA) and the regulatory system that oversees it. Until recently, the future of the NYCA was viewed with relative complacency—growth was modest, and more than enough generating plants had been proposed by developers to handle that growth. Subsequently, however, some of these plants have been canceled or deferred indefinitely. As discussed in Chapter 4, projections now show potential shortfalls as early as 2008, even without the retirement of Indian Point. Other projections, using less conservative assumptions, still predict that new capacity will be needed by 2010.

Replacing Indian Point would be likely to involve a portfolio of the options discussed in Chapters 2 and 3 including:

- Energy efficiency (EE);
- Demand-side management (DSM) and distributed generation (DG);
- Fuller utilization of existing generation and transmission, and deferred plant retirements;
- New generation; and
- New transmission.

The committee did not model the actions and policy initiatives that would be required to implement the supply and demand options considered here. The early-shutdown cases in particular would require some strong measures to be implemented immediately.

Different portfolios are possible, emphasizing different options. Exactly which ones would be implemented and where would make a big difference in how well the system would operate. In this chapter, example scenarios are adopted to illustrate options that could provide alternatives to the Indian Point units should they be retired.

THE NYISO STARTING POINT

The New York Independent System Operator (NYISO) recently completed the 2005 Reliability Needs Assessment (RNA; NYISO 2005a) and the companion analysis Comprehensive Reliability Planning Process (CRPP; NYISO 2005b). Box 5-1 briefly reviews the criteria for reliability used in the analysis. The RNA includes all generation and transmission projects currently under construction in the NYCA (2,530 MW); retirements of existing capacity currently announced (2,260 MW); and the projected electrical load through 2015. The NYISO process is described in more detail in Appendix

F-1. Peak load and known NYCA resources listed by NYISO for the period under study are shown in Table 5-1.

To quantify the magnitude of the needed correction, NYISO analyzed the system adding assumed capacity where needed until adequate reliability was achieved. The Base Case in the NYISO reports is a result of analyses showing that NYCA system reliability would be determined by voltage constraints in the system due to reactive power deficiencies in the Lower Hudson Valley (LHV). In that situation, reliability falls below requirements by 2008, and an additional 500 MW would be required then, increasing to 1,750 MW by 2010.

Box 5-1
Reliability Criteria

System operators generally use 2 main criteria for ensuring reliability: reserve margin and loss of load expectation (LOLE). Reserve margin is simply the difference between the generating capacity available to serve an area minus the expected peak demand divided by the peak demand. It is measured in percent. NYISO plans for NYCA to keep a reserve margin of at least 18 percent.

LOLE is more complicated but more meaningful. It measures the predicted frequency, in days per year, that the bulk power system will not meet the expected demand for electricity in one or more zones in New York State, even if only for a short time. Equipment failures in the power system (i.e., generators and the high-voltage transmission grid together) can force part of the load on the bulk power transmission system to be involuntarily disconnected. LOLE does not include the more frequent cause of blackouts for customers that are associated with failures of the local distribution system due, for example, to falling tree limbs and ice storms.

The North American Electric Reliability Council (NERC) recommends a reliability standard of LOLE less than 0.1, and this standard has been adopted for the region by the Northeast Power Coordinating Council (NPCC), and in turn by the New York State Reliability Council (NYSRC). In other words, there must be sufficient generation and transmission capability in the system that a failure to serve load somewhere in the bulk power system would be expected not more than on one day in ten years. The LOLE criterion is central to the discussion of reliability in this chapter. See also Chapter 1 for a discussion of reliability.

NYISO also projects that *if* essential reactive power corrections were made in the Lower Hudson Valley, thermal transmission constraints would then control, and less generating capacity (250 MW beginning in 2009, increasing to 1,250 MW by 2010) would be required to meet NYCA reliability criteria. NYISO projected the scenario with thermal constraints controlling to 2015 (but not the Base Case) when 2,250 MW would be needed. All of these projections are based on Indian Point remaining in service (NYISO 2005a).

NYISO has solicited proposed market-based or regulated solutions from participants and stakeholders in the NYCA market. The solicitations provide that, "Proposed solutions may take the form of large generating projects, small generation projects including distributed generation, demand-side programs, transmission projects,

market rule changes, operating procedure changes, and other actions and projects that meet the identified reliability needs (NYISO 2005c)."

Figure 5-1 shows NYISO's projected LOLEs for the base case and the thermal constraint case (the top and bottom lines). It also shows two other analyses: if load increases faster than expected, and if power is constrained from flowing from upstate New York through New England and back to southeast New York. Both these assumptions adversely affect reliability to a significant extent compared to the thermal constraint case. All the analyses show that LOLE will violate the criteria limit of 0.1 in the 2008-2010 timeframe.

FIGURE 5-1: NYISO Reliability Projections

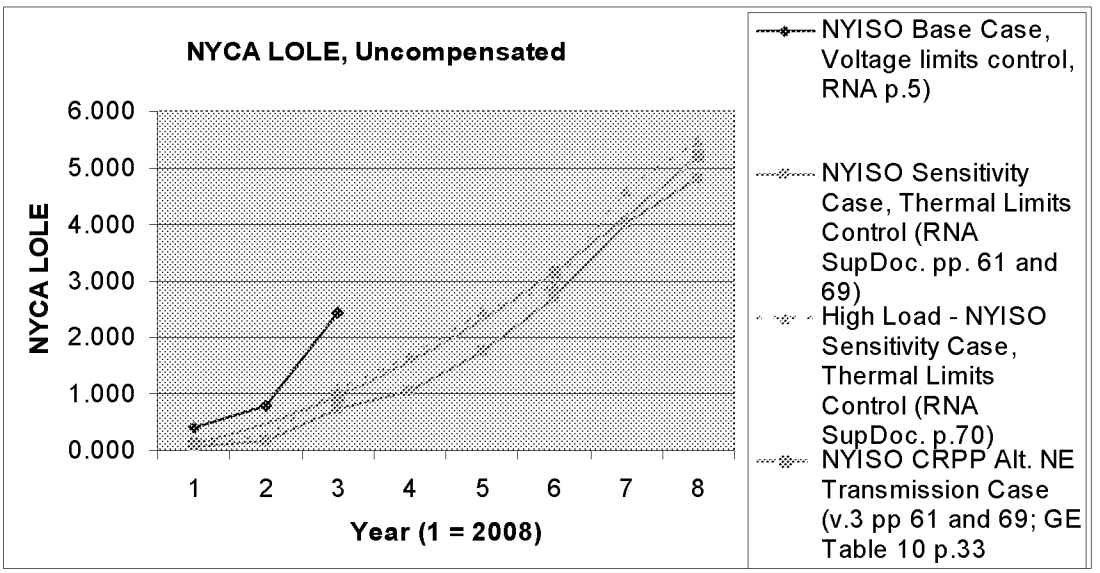

TABLE 5-1 NYISO Base Case Peak Load and Known NYCA Resources

	2008	2010	2013	2015	
Peak load (MW)	33,330	34,200	35,180	35,670	
Resources (MW)	39,759	39,766	39,766	39,766	
Reserve margin[1] %	19	16	13	12	
Reserve margin[2] %	14	12	8	7	(Figure 4-1)

[1] For the calculation of reserve margin and loss-of-load expectation (LOLE), NYISO adjusted installed NYCA generating capacity downward for contracted sale of hydropower outside NYCA and for wind power (because wind cannot be counted on during peak demand). "Resources" include the adjusted NYCA generating capacity plus Special Case Resources (SCR, 975 MW) and Unforced Delivery Rights (UDR, 990 MW). SCRs are agreements between NYISO and large electricity consumers (e.g., industrial companies) which will reduce load at NYISO's order. This is one of the emergency steps available to NYISO to avert outages. UDR corresponds to the two high-voltage direct current (HVDC) cables into Long Island, the Cross Sound Cable from New England (330 MW) and the Neptune Cable from New Jersey (660 MW scheduled for 2007). It is power that is expected to be available and is thus included by NYISO for planning purposes.

[2] The reserve margin plotted in Figure 4-1, in Chapter 4 of this report, does not include the 1,965 MW of SCR and UDR. Including these in Figure 4-1 would raise the plotted reserve margin in 2008 from 14 percent to 19 percent.

SOURCE: NYISO, 2005 b. page 39

THE COMMITTEE'S REFERENCE CASE

The committee adopted a Reference Case (with Indian Point still operating), similar to the NYISO sensitivity case with thermal transmission limits controlling.[1] The Reference Case includes two assumptions that differ from the NYISO case: (1) it includes constraints on the flow of power from upstate New York through New England and back to southeast New York, an assumption that NYISO did not apply in its final RNA/CRPP; and (2) it used actual, though inactive proposals for generating stations for additional capacity to meet demand rather than NYISO's standard 250 MW plants located wherever they were needed. The committee used these as illustrative capacity additions to demonstrate the changes required to meet or exceed the LOLE requirements for balancing the electrical system. While there is no assurance that these projects will be built, presumably the developers wouldn't have proceeded as far as they did without a reasonable expectation that the sites were viable, fuel and transmission access would be available, and all permits attainable (several have been permitted under Article X).[2] In addition, one generic plant was included with 580 MW. Other options could be selected along with alternative timing, but the additions identified serve to illustrate the kinds of response envisaged for Indian Point replacement. The generating capacity changes assumed (beyond the 2530 MW of generation and transmission expected to be completed before 2008) are shown in Table 5-2.

To assist the committee with the analysis, General Electric International, Inc., (GE) was retained to run its proprietary models, MARS[3] and MAPS™,[4] of the New York State and Northeast region electric systems. The MARS model (Box 5-2) is one of the principal tools used to assess NYCA system reliability. The MAPS model allows a preliminary assessment of the impact of each option studied on NYCA system operations and economics.[5] Reliability was analyzed only for 2008, 2010, 2013, and 2015, the years that the Indian Point reactors were hypothesized to be closed.

The goal of the reliability simulations was to determine the additional resources that would be required to meet reliability standards. Generating capacity was added until LOLE met the requirement of 0.1, and the NYCA reserve margin is 18 percent.[6]

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[1] The committee believes that the essential corrections to reactive power would most likely be made in a timely manner, and that thermal transmission constraints would ultimately dictate system reliability and thus the additional compensatory resources required.

[2] The committee does not endorse any of these projects, nor did it analyze the financial viability of any of them; they are simply assumed to be in the generating fleet when needed in the reliability calculation. None of them are under construction. Several of them have been, or may be, canceled, although other generating companies might acquire the sites and reactivate the projects.

[3] GE's MARS: Multi-Area Reliability Simulation. See http://www.gepower.com/prod_serv/products/utility_software/en/downloads/10320.pdf

[4] GE's MAPS™: Multi-Area Production Simulation. See http://www.gepower.com/prod_serv/products/utility_software/enge_mars.htm

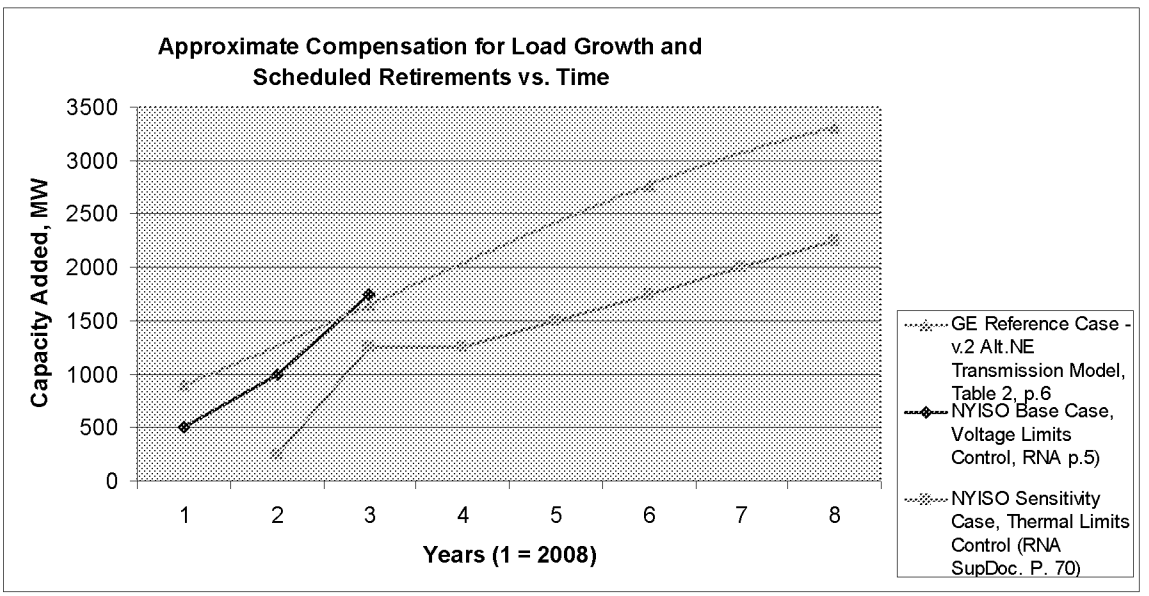
[5] In identifying initial reliability needs, NYISO does not conduct an economic evaluation of resources needed.

[6] The problem is considerably more complex than this. Iterative adjustments of resources assumed are needed, and the parameters to which the model is sensitive also interact with one other.

The results of the MARS analyses are shown in Figure 5-2 in comparison with NYISO's two main cases. With the committee's Reference Case assumptions, 3,300 MW are needed by 2015 to maintain reliability (LOLE<0.1). LOLE is well below 0.1 days per year in 2008 and 2010, slightly exceeding 0.1 in both 2013 and 2015.[7] Details of this analysis, along with those of the scenarios below, are in Appendix F-2.

The different results (about 1 gigawatt (GW) difference in resources needed by 2015) of the generally similar analyses by NYISO and the committee illustrate the sensitivity of the reliability analysis—and thus the additional resources needed—to differences in initial system conditions assumed. The main differences are with transmission constraints and geographic distribution of additional generating capacity.[8] The committee believes that these two cases approximately encompass the range of additional resources needed. Appendix F discusses the differences between the analyses.

FIGURE 5-2: Approximate Additional Resources Needed



[7] In several of the committee's analyses, the rate of adding additional resources was not optimized, resulting in instances of overcompensation; projected LOLEs are thus unnecessarily low in the years prior to 2015. In further analyses, this assumption could be corrected.

[8] Other differences in initial assumptions are estimated roughly to account for < 200 MW of the 1 GW total.

TABLE 5-2 Additional Generating Capacity Assumed in Reference Case

Project	Capacity (MW)	NYCA Zone[b]	On-Line Date
SCS Astoria Energy	500	J	Jan 08
Caithness	383	K	Jan 08
Long Island Wind	15[a]	K	Jan 08
Bowline Point	750	G	Jan 10
Wawayanda	540	G	Jan 13
Generic Combined Cycle	580	H	Jan 13
Reliant Astoria I	367	J	Jan 15
Reliant Astoria II	173	J	Jan 15
Total Power	3308		

[a] FPL Energy has proposed a 150 MW wind energy project off the south shore of Long Island. Wind is an intermittent power producer, and only a small fraction of rated capacity may be available during peak load . The committee used 15 MW for this project in its reliability analysis. NYISO did not use any of the 47 MW of existing NYCA wind capacity its reliability analyses.
[b] See Figure 1-2 in Chapter 1 of this report for a map of the NYCA zones.
SOURCE: NRC (as shown in Hinkle et al., 2005)

BOX 5-2
Multi-Area Reliability Simulation (MARS) Model

GE's MARS simulation software is the same system reliability screening tool approved by NYSRC and used by NYISO in its CRPP/RNA studies. MARS uses Monte Carlo simulation of the electrical generation and transmission system of the New York Control Area (NYCA) interconnected with the four contiguous electrical power systems in the northeast United States and eastern Canada.

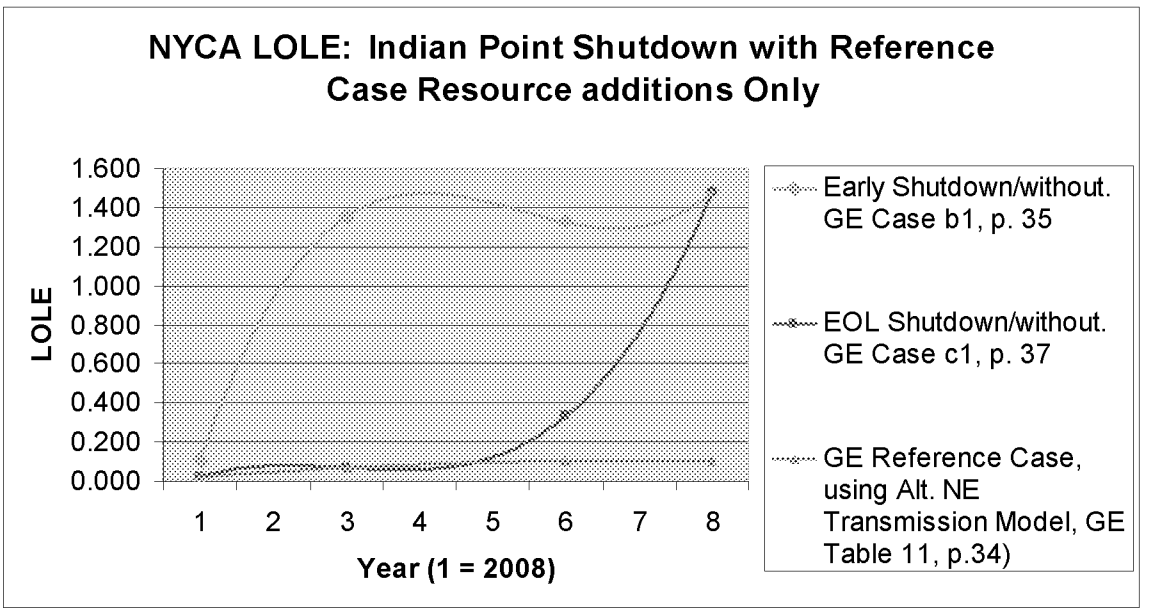
MARS is a "transportation" model, sometimes referred to as a "bubble and stick" model, connecting generation and loads in the grid. That is, it connects the sources and sinks of power with direct-current-like flows.

REPLACEMENT SCENARIOS

With the Reference Case defined, the committee examined several cases with Indian Point closing. First, it looked at simply closing Indian Point, either in 2008/2010 (Case b1), or at the end of current license (EOL) in 2013/2015 (Case c1) with no measures to compensate for the 2000 MW capacity reduction.[9] As expected, the LOLE in both cases increased to unacceptable levels for these cases, as summarized in Figure 5-3 below.

[9] Note that the license for Indian Point Unit 2 expires on September 28, 2013, and that for Unit 3 on December 12, 2015. Both could still be operating through the summer peak of their last year. In particular, the absence of Unit 3 wouldn't seriously affect reliability until the summer of 2016. However, because of the lack of a database for 2016, it was not possible to extend the analysis past 2015, so the reactors were assumed to close in January 2013 and 2015 in order to capture the impact on peak-demand reliability. In reality, an additional year would be available for replacement.

FIGURE 5-3 Impact on NYCA Reliability (LOLE) of Shutting Down Indian Point without Additional Resources beyond the Reference Case



The committee then analyzed cases with additional replacement resources, representing possible solutions that might arise out of NYISO's solicitation process to restore or maintain system reliability. The goal was to determine how much compensation would be necessary to maintain reliability within criteria. All these cases included additional, aggressive programs to improve efficiency of electricity use and stronger demand-side measures to reduce peak demand. For most of them, peak demand was reduced by 300 MW in 2008, 650 in 2010, 800 in 2013, and a total of 850 MW[10] in 2015.

Additional supply was assumed to come from the proposed TransGas Energy project (1,100 MW, which wasn't needed in the Reference Case) in Brooklyn. Several of the Reference Case projects were accelerated as shown in Table 5-3 for Cases b2 (early retirement) and Case c2 (end-of-license retirement).

[10] Energy Efficiency measures (575 MW) and Demand Side Management measures (300 MW) by 2015 contribute in different ways to peak reduction, The net effect of these assumptions in the model is 850 MW reduction in peak load, not the 875 MW sum.

TABLE 5-3 Capacity Additions Assumed for Cases b2 and c2

Project	Capacity MW	NYCA Zone	Case b2 On-Line[b]	Case c2 On-Line[b]
SCS Astoria Energy	500	J	2008	2008
Caithness	383	K	2008	2008
Long Island Wind	15[a]	K	2008	2008
Bowline Point	750	G	2010	2010
Wawayanda	540	G	2010	2010
Generic Combined Cycle	580	H	2013	2013
Reliant Astoria I	367	J	2008	2010
Reliant Astoria II	173	J	2008	2011
TransGas Energy	1100	J	2010	2015
Total Power	4408			

[a] See note b in Table 5-2.
[b] All additions were assumed to come on line in January of the year listed.
SOURCE: NRC (as shown in Hinkle et al., 2005)

The committee explored the consequences of additional scenarios, but in less detail, only looking at 2015. These included:

1. A 1,000 MW north-south HVDC transmission line running from the Marcy substation (near Utica in Zone E) to Rock Tavern (in Zone G, south of the current transmission bottlenecks) was assumed to be operational in 2012. Cases b3 and c3 represent the early retirement and end-of-license (EOL) retirement of the Indian Point units with this HVDC cable resource in place. The inference drawn from the results is that with such a north-south transmission option, using excess power upstate and from out of state, the potential generating resource needed downstate might be reduced from 1,100 MW to 300 MW.

2. Higher market penetration of energy efficiency and demand-side management, Cases b4 and c4, for early and EOL shutdown scenarios, respectively. This scenario included 1,200 MW of energy efficiency and 800 MW of DSM load-reduction measures for a net 1,950 MW reduction of peak load by 2015, mainly in the New York City area. Demand would continue to grow, but at a low rate (390 MW growth compared with 2340 MW without the EE/DSM measures). No additional capacity beyond the Reference Case would be necessary, as the additional EE and DSM measures would compensate for Indian Point. EE/DSM measures of this magnitude would require significant, aggressive early attention by the New York State government and a high fraction of all electricity users.

3. Sensitivity to higher fuel prices. The systems modeled were the same as in the earlier scenarios, so reliability analysis was not necessary. The committee included this analysis to estimate the approximate economic impact of higher fuel prices. The price projections used in other scenarios are lower than recent prices, and it seems plausible that gas and oil prices could remain much higher.

Table 5-4 summarizes the assumed additions to resources for the various scenarios, based on achieving or exceeding the LOLE requirements. Details of the assumptions and timing of additions of illustrative resources are in Appendix F-2.

RESULTS OF RELIABILITY ANALYSES

Table 5-5 summarizes the reliability results of the cases run showing the resulting LOLEs after compensation. Results for the Reference Case and the main cases of early and end-of-license shutdown of Indian Point are shown graphically in Figures 5-4 and 5-5, which also provide a comparison to the NYISO Base and Sensitivity Cases. Figure 5-6 shows the projected reserve margin for Case c2 (EOL shutdown of Indian Point), allowing comparison to reserve margin projections in Figure 4-1 and the impact of differing compensation.

TABLE 5-4 Summary of Illustrative Resources Assumed To Maintain NYCA Reliability

	2008	2010	2013	2015
NYCA Peak Load, MW	33,330	34,200	35,180	35,670
NYCA Firm Capacity, MW	37,794	37,801	37,801	37,801
Total Resources with 975 MW SCR and 990 MW UDR	39,759	39,766	39,766	39,766
NYISO Additional Capacity Required for Reliability, Cumulative. *Thermal Limits Controlling. MW*	*0*	*1,250*	*1,750*	*2,250*
COMMITTEE SCENARIOS				
REFERENCE CASE, Cumulative Additional generating capacity assumed to meet or exceed load growth and scheduled retirements, Indian Point continues in service, MW	900	1650	2770	3310
EARLY SHUTDOWN + COMPENSATION, Case b2, Cumulative Generation Added Above Reference Case, MW	540	2180	1640	1100
Total Generation Added, MW	1440	3830	4410	4410
Cumulative Peak Load Reduction By EE/DSM Measures, MW	300	650	800	850
Total Compensation for Scenario, MW	1740	4480	5210	5260
EOL SHUTDOWN + COMPENSATION, Case c2, Cumulative Generation Added Above Reference Case, MW	0	900	540	1100
Total Generation Added, MW	900	2550	3310	4410
Cumulative Peak Load Reduction By EE/DSM Measures, MW	300	650	800	850
Total Compensation for Scenario, MW	1200	3200	4110	5260

▼ Additional Scenarios

COMPENSATION INCLUDING 1000 MW HVDC LINE Cases b3 AND c3, Cumulative Generation Added above Reference Case, MW				300
Total Generation Added, MW				3600
Cumulative Peak Load Reduction By EE/DSM Measures, MW				850
COMPENSATION INCLUDING HIGH EE/DSM MEASURES, Cases b4 and c4, Cumulative Generation Added above Reference Case, MW				0
Total Generation Added, MW				3300
Cumulative Peak Load Reduction By EE/DSM Measures, MW				2000

SOURCE: NRC (as shown in Hinkle et al., 2005)

TABLE 5-5 Results of Reliability Analyses [1]

	2008	2010	2013	2015
NYISO 2008 CRPP/RNA Data: Table 7.3.1 *Firm Resources only*				
NYCA Reserve Margin %	*19*	*16*	*13*	*11*
NYCA LOLE	*0.073*	*0.752*	*2.692*	*4.816*
For Comparison: GE-Calculated NYCA LOLE with Thermal Limits Controlling and Alternate NE Transmission Constraints	*0.122*	*0.966*	*3.164*	*5.210*
NYISO Compensation Case, *with Additional Capacity as in Table 5-4. Thermal Limits Controlling*				
Estimated NYCA Reserve Margin %	*19*	*20*	*18*	*18*
Resulting NYCA LOLE	*0.073*	*0.068*	*NA*	*NA*
COMMITTEE SCENARIOS				
REFERENCE CASE				
NYCA Reserve Margin %	22	21	21	21
Resulting NYCA LOLE	0.021	0.069	0.104	0.102
EARLY SHUTDOWN, REFERENCE CASE ADDITIONS ONLY, Case b1				
NYCA Reserve Margin %	20	16	16	16
Resulting NYCA LOLE	0.104	1.352	1.323	1.48
EARLY SHUTDOWN with COMPENSATION, Case b2				
NYCA Reserve Margin %	22	24	23	22
Resulting NYCA LOLE	0.023	0.011	0.032	0.101
EOL SHUTDOWN, REFERENCE CASE COMPENSATION ONLY, Case c1				
NYCA Reserve Margin %	22	21	19	16
Resulting NYCA LOLE	0.021	0.069	0.333	1.48
EOL SHUTDOWN with COMPENSATION, Case c2,				
NYCA Reserve Margin %	18	21	18	17
Resulting NYCA LOLE	0.013	0.006	0.036	0.101
▼ Additional Sensitivity Analyses				
COMPENSATION INCLUDING 1000 MW HVDC LINE in 2012, Cases b3 AND c3				
NYCA Reserve Margin %				19
Resulting NYCA LOLE				0.098
COMPENSATION INCLUDING HIGH EE/DSM MEASURES, Cases b4 and c4				
NYCA Reserve Margin %				22
Resulting NYCA LOLE	-	-	-	0.082

Note: All Reserve Margin and LOLE results include SCR and UDR as defined in Table 5-1.

SOURCE: NRC (as shown in Hinkle et al., 2005)

FIGURE 5-4 Capacity assumed to meet load growth and compensate for retiring Indian Point

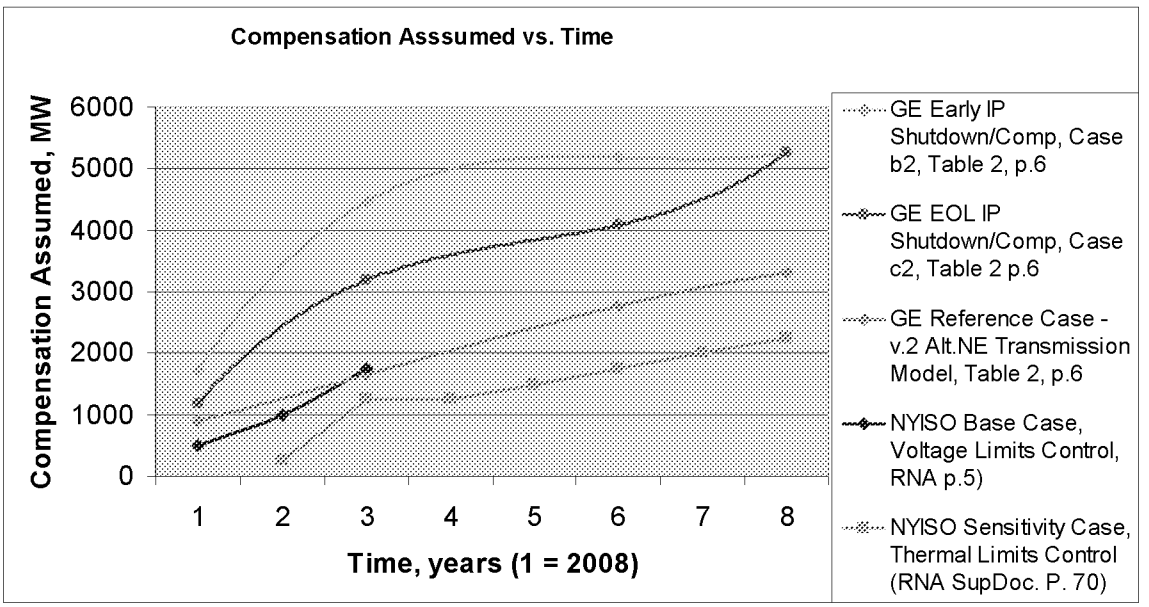


FIGURE 5-5: Loss of load expectation after compensation

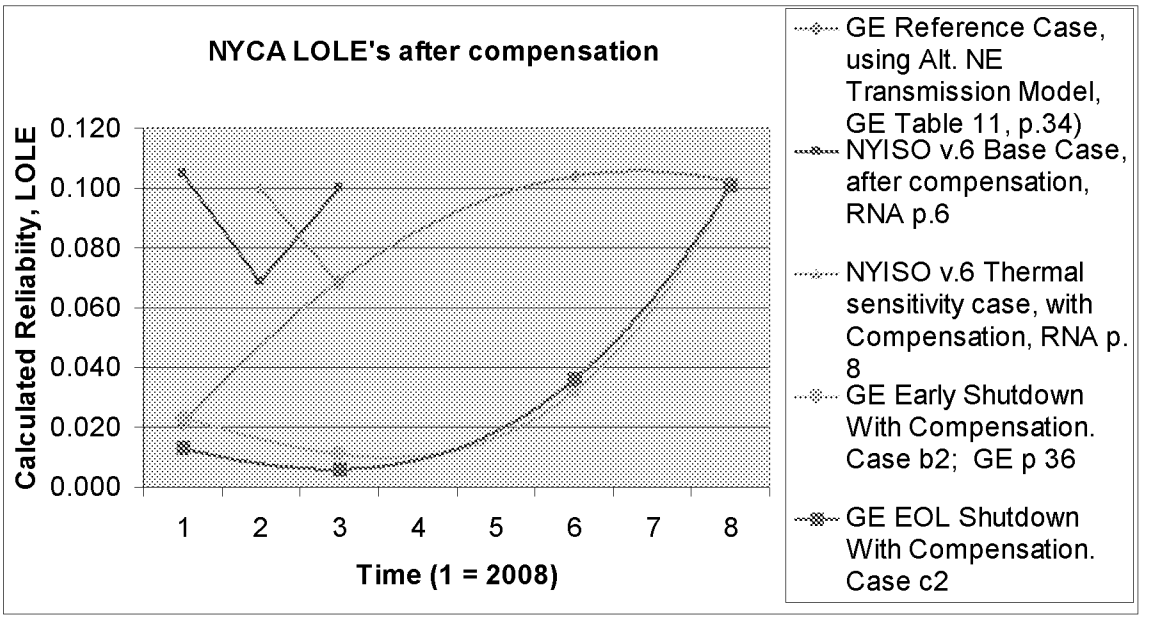
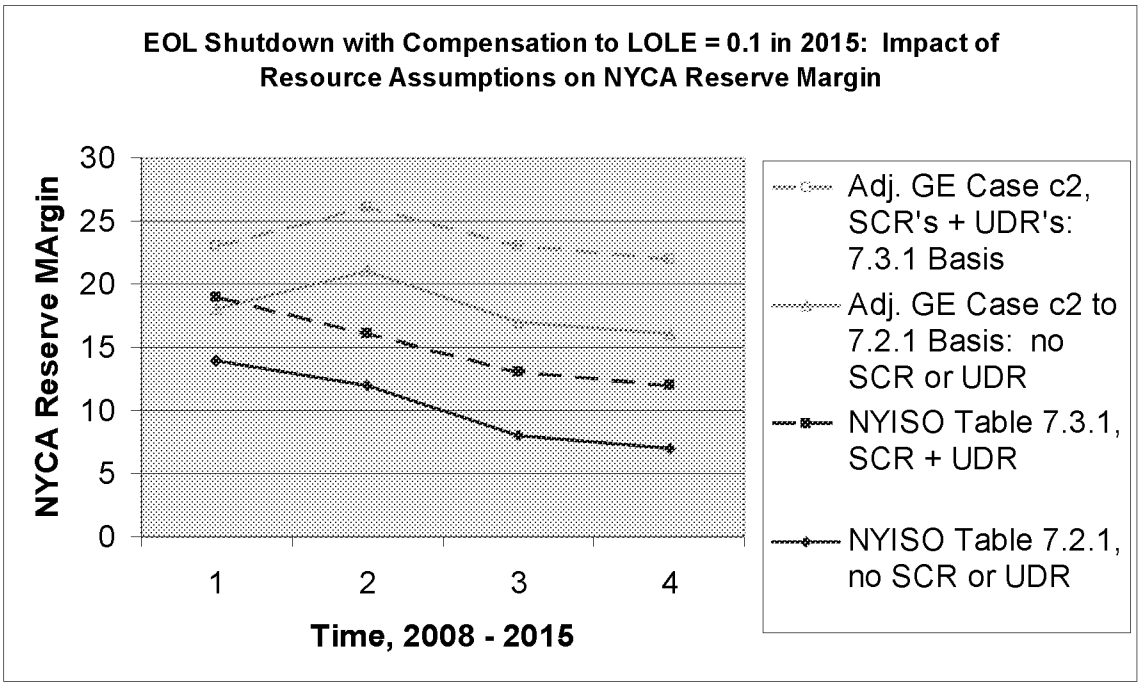


FIGURE 5-6: Projected Reserve Margin for EOL Shutdown of Indian Point with Compensation (Case c2)



If Indian Point is closed, roughly 2000 MW of additional resources would be needed beyond that needed for the Reference Case. As shown in Table 5-4, the early shutdown scenario (b2) requires about 4,500 MW of additional resources (total new capacity plus peak load reduction) to be available by 2010 to meet load growth, retirements of other units, and retirement of Indian Point.[11] Of this amount, about 650 MW could result from improved efficiency and demand-side management. Constructing the proposed 600 MW Cross-Hudson Cable Project, presently suspended, and extending the operation of the 880 MW Poletti 1 plant through 2010, for example, would help. Another possibility would be to extend the operation of one of the Indian Point units beyond 2010, until sufficient generation capacity could be installed in the NYCA.

In Cases b3 and c3, the added north-south HVDC transmission line was counted as a 1000 MW resource, but the availability of sufficient generating capacity upstate was not examined in detail. As discussed in Chapter 3, the supplemental generation could come from a combination of sources, including existing or new generation upstate, or imports from Canada, all of which require additional analysis beyond the scope of this study.

This assumed HVDC line would reduce the need for new capacity in the New York City area by about 800 MW. The impact of the line on reliability would be even more substantial if (1) it would extend all the way into New York City (Zone J) and (2) if it would be backed by dedicated generating capacity. If these two conditions could be met, the transmission line would then also be counted as a resource contributing to the

[11] The data on reserve margins and Figure 5-5 show the degree to which the illustrative resource additions result in overcompensation in the early years until 2013 and 2015. The schedule for adding compensation might therefore be extended in the early years.

locational margin reserve (LMR) requirement that Zone J's generation capacity be at least 80 percent of peak load. This HVDC line would then be analogous to the Neptune Cable now under construction, which will meet both criteria for Long Island and therefore contribute to Zone K's LMR requirement of 98 percent.

The high levels of EE and DSM in Cases b4 and c4 would be advantageous in meeting reliability criteria, while reducing the additional generating resources required for load requirements with the retirement of the Indian Point units. Reducing demand growth by 1 MW would mean avoiding the need to build 1.18 MW to meet the NYCA reserve margin requirement. Even so, replacing the 2000 MW from Indian Point would require reducing peak load by 1,700 MW by 2015, a very ambitious goal. The technical potential is there, and current programs are having considerable success, but progress comes in small increments that must be implemented by many people. It should be noted that the results of such programs are harder to verify than the contribution of a new generating capacity.

Corrections to reactive power are also required. The capital cost of static VAR compensation (SVC) is in the range of $50 per kilovar kVAR, and that of a synchronous condenser about $35/kVAR (O'Neill, 2004).[12] Equipment to replace the reactive power that Indian Point is capable of supplying would cost on the order of $30 to $45 million. In comparison, the capital cost of a 1,000 MW power plant is on the order of $1 billion. Since the cost of correcting reactive power is relatively low, the committee infers that timely local corrections to reactive power would be made.

OPERATIONAL AND ECONOMIC IMPACTS

The committee estimated the impact of closing Indian Point with the GE MAPS model for the scenarios that met reliability criteria in the MARS modeling. The NYISO Case with thermal limits controlling in 2008 is the benchmark for comparing projected operational and economic impacts on the: (1) diversity of the mix of fuels used to generate electricity, (2) impact on the wholesale price of electricity, and (3) annual variable operating cost (VOC) of producing electricity, important in the industry because it reflects the net effect of changes in both zonal generation and fuel cost (and is the fundamental variable minimized systemwide in the MAPS calculations). In addition, a brief sensitivity analysis was conducted to help understand the impact that differing fuel costs would have on the cost of electricity.

Analytical Considerations

Neighboring regions (New England and part of the Pennsylvania Jersey Maryland [PJM] control area) were included in the analysis. At the outset, the committee recognized that MAPS, itself dependent on the approximate results from the MARS model analyses, would provide mainly an approximate picture of economic and cost projections into the future. Part of the MAPS model simulates the current wholesale electricity marketplace in New York State. This market is evolving to take into account aspects of pricing and investment that will differ from the present operation (see Chapter

[12] O'Neill is on the staff of the Federal Energy Regulatory Commission (FERC) but was expressing his own views here.

4). Since the model cannot project such changes, confidence in the MAPS results for wholesale cost change is substantially less than in the reliability calculations of MARS.

Box 5-3 lists the main points of how the MAPS simulation works with MARS and the results produced by the simulation. Details of the modeling are contained in Appendix F-2 and the GE report (Hinkle et al., 2005).

BOX 5-3
Multi-Area Production Simulation Software (MAPS) Model

The MAPS model assesses the operational and economic characteristics of the entire interconnected region. MAPS models the electrical system in greater detail than MARS does, and is based on an economic commitment and dispatch model, also examining the flow on each transmission line for every hour of the simulation, recognizing both normal and operating reliability-related constraints. MAPS dispatches generating units in the system to meet the zonal electrical-generation requirements of a specific scenario being modeled, considering any transmission constraints. MAPS then calculates the annual variable operating cost (AVOC) of producing electricity systemwide and iterates, adjusting the dispatch of units in the system, starting with lowest variable operating cost first, to determine the minimum annual regional systemwide variable operating cost. The variable cost of producing electricity is dominated by fuel costs, but it also includes variable operational and maintenance costs, unit start-up cost (say, going from a cold start and ramping up to full electrical output), and the variable cost of emission credits consumed, where required. MAPS does not explicitly consider fixed costs, which would include capital charges; in this work, MAPS was not used to mimic the bidding strategy for bids into the wholesale market submitted by generators of electricity. Instead, pricing was equal to the variable cost of the marginal bidder, which is the theoretical limit to which economic theory drives the clearing price of a commodity in a perfectly competitive market.

Having established the minimum systemwide AVOC, MAPS then provides the corresponding wholesale price of electricity, airborne emissions, and the mix of fuels used in generating electricity for each pricing zone in the system

Generation resources added to maintain reliability are inputs to the model, using MARS results as a base. MAPS does not assess the financial attractiveness of adding that capacity. It assumes that the resource is there, calculates its variable operating cost, and "dispatches" it in rank order of the variable operating cost for that resource, as capacity is aggregated to meet the then-current demand for electricity in the wholesale market.

Iterative use of both the MARS reliability simulations in conjunction with the MAPS simulations for the different scenarios thus provides a basis, with some caveats, for comparing both reliability and trends of operating and economic impacts among the illustrative scenarios posed by the committee.

GE's MARS and MAPS are well-accepted screening methodologies despite their many limitations. Some additional caveats are necessary in considering some limitations in the models and databases used, and thus the utility of comparisons of results for the various scenarios.

Since MAPS calculates a systemwide minimum operating cost of producing electricity, which in turn is dominated by fuel costs, the fuel prices assumed dominate the

economic outputs. Fuel-cost volatility presents a significant uncertainty in interpreting the MAPS results. For the basic calculations, MAPS used a reference 2008 cost of natural gas of $5.1 per million British thermal units ($5.1/MMBtu), decreasing to $4.2/MMBtu by 2015 (both in nominal cost, or dollars-of-the-year).[13] For comparison, the U.S. Department of Energy's Energy Information Administration (DOE/EIA) reports that natural gas prices paid by electric power producers in New York State was in the range of $7.3 and $9.3/MMBtu in August 2005 (before the price increases resulting from the damage caused by Hurricane Katrina).

To assess the impact of higher fuel prices, a sensitivity study was made using a 2008 natural gas price of $7.8/MMBtu (decreasing to $7.0 by 2015). Although gas prices have dropped some in recent months, the committee recommends focusing on this case unless increased imports of liquefied natural gas are seen as likely. Clearly, more in-depth study of gas prices and their consequences is needed.

The MAPS model of the scenarios adds considerable new NYCA generation based on modern, efficient gas-fired combined-cycle units, which require less natural gas than simple-cycle gas turbines for the same power produced. Consequently application of these units results in lower system variable operating costs. However, no comparable assumption is made in the MAPS database for adjacent areas. This tends to lower the impact on the wholesale price of retiring Indian Point and would tend to project reduced imports of electricity from the adjacent areas in favor of increased, lower variable cost generation in the NYCA.

In evaluating the results of the MAPS analyses, readers should understand that the assumptions made tend to underestimate the projections on future wholesale prices of electricity. Therefore, the focus should be on major trends and percentage changes rather than on the absolute value of projected wholesale price of electricity. Similarly, the wholesale price of electricity modeled does not represent the final cost to consumers. Among other things, it does not include transmission and distribution costs or all of the costs for recovery of the cost of new capacity, either generation or transmission, which ultimately will, most likely, be borne by the consumer.

Fuel Diversity: Impact on NYCA Reliance on Natural Gas for Generating Electricity

Diversity of fuels used in generation is a security criterion to avoid excessive reliance on a single fuel. Generation in urban environments with minimal pollution is another criterion. New York State has benefited from ample fuel diversity in the past, and flexibility has been maintained using many gas-fired plants with dual-fuel units that can burn oil.

For the new generating capacity assumed in this study, the committee focused on natural gas in high-efficiency combined-cycle units. Natural-gas-fired generators have been the dominant choice nationwide since the mid-1980s, but that may not be strategically prudent for the next decade.

[13] Base case data set, Quarter 1 2005, published by Platts, a Division of McGraw-Hill Companies. See http://www.platts.com/Analytic%20Solutions/BaseCase/index.xml

Table 5-6 compares the diversity of fuels used to generate electricity in the NYCA and the Northeast region for 2005 and 2008. Gas consumption for generating electricity is expected to increase 25 percent from 2005 to 2008. In addition, the regional shifts in fuel diversity are significant. There has been a recent reduction in the use of both oil and coal in the NYCA. In the Northeast region as a whole, the use of oil has declined, but the use of coal evidently is increasing. Finally, the projections for the Reference Case are about the same as for the Benchmark and are directionally correct in that the Reference Case adds about 1 GW of gas-based capacity and increases the change from 2005 by about another 2 percent. Further detail is shown in Appendix F-2.

TABLE 5-6 Benchmark of the Consumption of Natural Gas, Coal and Oil for 2005 and 2008
Annual Fuel Consumption in Trillion Btu

	2005		Benchmark CRPP Thermal Case in 2008		Reference Case in 2008	
	NYCA	Northeast	NYCA	Northeast	NYCA	Northeast
Natural gas	308	804	385	1,031	392	1,032
Oil	103	132	47	59	32	44
Coal	249	2,242	218	2,344	218	2,343
Percent Change from 2005						
Natural Gas	-	-	25.1	28.1	27.3	28.3
Oil	-	-	-53.7	-54.8	-68.1	-66.3
Coal	-	-	-12.4	4.5	-12.5	4.5
Percent Change from Benchmark 2008 NYISO Base Case						
Natural Gas			-	-	1.8	0.1
Oil			-	-	-31.1	-25.4
Coal			-	-	-0.1	0.0

SOURCE: Derived from Hinkle et al, 2005, plus additional personal communication with Gene Hinkle, December 2005.

Table 5-7 summarizes the projected increase of NYCA reliance on natural gas for the main options scenarios considered in this study. The table gives the percentage of NYCA reliance on natural gas for generating electricity and the impact of higher assumed fuel prices.

TABLE 5-7: Projected Impact on Electrical Generation Based on Natural Gas for 2008 to 2015, with Sensitivity to Fuel Price

	Reference Fuel Price: NYCA Natural Gas Prices: 2008@$5.11/MMBtu; 2015@$4.24/MMBtu				Higher Fuel Price: NYCA Natural Gas Prices: 2008@$7.69/MMBtu; 2015@$7.03/MMBtu			
	2008	2010	2013	2015	2008	2010	2013	2015
Percent gas in: 2003: 20% 2005: 28%								
Benchmark NYISO CRPP Thermal Case in 2008	34							
Reference Case	36	38	43	44	34			
Early Shutdown with Compensation, b2	40	48	53	53	38	47	49	50
E-O-L-Shutdown with Compensation, c2	35	39	47	53	33	37	44	50
Early Shutdown with Higher EE/DSM, b4				51				
E-O-L-Shutdown with Higher EE/DSM, c4				51				

SOURCE: Derived from Hinkle et al, 2005.

The MAPS projections show that reliance on natural gas would increase from 34 percent in 2008 to 44 percent in 2015 just to meet load growth and replace the capacity of units currently scheduled for retirements (the Reference Case). The projected reliance on natural gas increases to 53 percent by 2015 if Indian Point is shut down and capacity shortfall is compensated for principally by adding gas-fired units. Higher penetration of EE/DSM measures tends to reduce gas requirements, but only by about 2 percentage points. One might expect that the High EE/DSM case would lie closer to the Reference Case, but the committee was not able to investigate this further. Higher natural gas price shifts generation to other fuels, but not much, according to the MAPS projections, as the reliance on natural gas decreased only by about 3 percentage points.

In sum, the compensatory actions evaluated would significantly reduce diversity in the mix of fuels used for electrical generation in New York State. Basing compensating resources upstate on fuel other than natural gas could lessen the reliance on natural gas, but to meet NYCA reliability criteria, that option would also require additional transmission capacity to bring power south of the congested UPNY/SENY interface. Greater than 50 percent reliance on gas presents a strategic issue. In addition, it is not clear from where the additional gas will be coming. New sources, such as imported liquefied natural gas, and new transmission pipelines are likely to be required. A coal plant might be completed upstate by 2016 (the first peak demand period after the second Indian Point reactor reaches its current EOL would be in the summer of 2016), but planning would have to start soon. Otherwise, there are few supply alternatives to gas. Considerable analysis and planning are required to develop the optimum path forward in the common interest.

Projected Impact on the Wholesale Price of Electricity

The options selected to compensate for an Indian Point shutdown would affect the operating costs for power generation. This change in turn will influence the wholesale price of electricity. Table 5-8 gives the results of the MAPS-projected impact on wholesale prices of electricity in the NYCA and New York City. It is also important to recognize that other costs of producing, transmitting, and distributing electricity will ultimately be passed through, directly or indirectly, to the consumer.

TABLE 5-8: MAPS- Projected Impact on Electricity Wholesale Price

Higher Fuel Prices Sensitivity Cases

		2008	2010	2013	2015
Case	Area	$/MWh	$/MWh	$/MWh	$/MWh
Benchmark of 2008 NYISO Thermal Case, Lower fuel cost		**46.28**			
Reference Case in Year Noted	NYCA	61	58	57	59
	Zone J	73	69	66	67
Early Shutdown With Compensation, Case b2	NYCA	63	62	60	66
	Zone J	77	75	71	79
End-of-License Shutdown With Compensation, Case c2	NYCA	60	53	58	66
	Zone J	72	60	68	79

Reference Case Natural Gas Prices

		2008	2010	2013	2015
		$/MWh	$/MWh	$/MWh	$/MWh
Benchmark of 2008 NYISO Thermal Limits Case	NYCA	46.28			
	Zone J	56			
Reference Case in Year Noted	NYCA	44	42	37	39
	Zone J	51	49	42	43
Early Shutdown, Case b2	NYCA	45	44	40	43
	Zone J	54	53	47	51
End-of-License Shutdown, Case c2	NYCA	43	38	38	43
	Zone J	51	43	44	51
Shutdown with HVDC Line, Cases b3 and c3	NYCA				41
	Zone J				47
Shutdown with High EE/DSM, Cases b4 and c4	NYCA				43
	Zone J				49

SOURCE: Derived from Hinkle et al, 2005.

As noted earlier, the committee has been unable to estimate future costs to the consumer accurately. The trends and estimated changes should be viewed as approximate. Since this is an important topic of particular importance to the consumer, additional investigation is required, including that into the evolving market structure in

New York.[14] For the Reference Case results with the higher-fuel-price assumption (more likely considering the situation today) NYCA wholesale prices are projected to remain in the range of $57 to $61/MWh between 2008 and 2015.[15] Zone J prices are consistently higher, ranging from $73/MWh to $66/MWh. If Indian Point is retired, MAPS calculates that wholesale prices by 2015 would be about $66/MWh in the NYCA and $79/MWh in New York City.

For the lower fuel prices, (lower by one third in 2008 and lower by 40 percent in 2015) the yearly average wholesale price of electricity in all of NYCA for 2008 is projected at about $46/MWh for the Benchmark 2008 NYISO Thermal Limits case. As in the present market, there is a strong difference among zones, as the data in Appendix F-2 show in detail. The wholesale price is in the range $51/MWh to $53/MWh in Zones I, J, and K, but reaches $61/MWh in Zone H.

Some general observations include:

- Adding substantial efficient capacity based on low-cost gas tends to lower wholesale prices in meeting load growth and scheduled retirements in both NYCA and Zone J (always substantially higher price than the NYCA). One should also recall that the unoptimized cases with compensation added more low-cost generation than needed (or is likely to be built) in the early years. Such overcompensation leads to predictions of lower wholesale prices than would result from a more realistic level construction that just maintained reliability at an LOLE of 0.1.

- The early-shutdown scenario gives up a bit of that reduction, but not much until 2010 when Indian Point Unit 2 would be shut down.

- The HVDC case suggests the potential cost benefit of needing 800 MW less of new downstate capacity, by bringing south lower-cost electricity from upstate (assumed, arguably, to exist without new capacity upstate). It also should be noted that this case is not directly comparable to other cases, as the cost of the HVDC line would have to be passed through to the consumer in some manner, but not via the wholesale price market. The inference might still be that if no new generation is needed upstate specifically to supply the HVDC line, a lower wholesale price might well

[14] Indian Point Unit 2 was out of service for some time in 2000, as the new market was emerging and before later measures were introduced to mitigate wholesale price spikes. The NYISO Market Adviser, David Patton, analyzed the impact on wholesale prices due to the outage [Patton, 2001]. During off-peak months the estimated impact on state-wide wholesale prices of loss of that one unit varied from 3 to 13 percent. For summer months in the eastern part of the state, the estimated impact was as much as 30 percent. Though the market structure has changed somewhat, the impact of loss of two units could be substantial. Care should also be taken to distinguish between whole prices and cost to the consumer which also includes cost of delivery to the consumer. The Westchester Public Issues Institute, citing a NYPSC study, estimated that a 20 percent increase in wholesale price of electricity would translate to about a 9 percent increase in cost to the consumer. [Westchester Public Issues Institute, 2002]

[15] Wholesale prices are generally quoted in $/MWh. To convert $/MWh to ¢/kWh, divide by 10. Thus $57/MWh is 5.7¢/kWh. Recall that these are wholesale prices. Retail prices are higher.

prevail downstate, but considerable analysis would be required to verify that.

- The impact of high EE/DSM penetration has only a 2 percentage point impact on wholesale price by 2015 relative to the cases with assumed EE/DSM penetration of 875 MW. This seems to be counterintuitive, and further evaluation is warranted, as this also relates to the overall incentive to invest in EE/DSM measures. In any event it is also important to note that the ultimate cost to the consumer may be lower with EE/DSM measures, as consumers use less electricity.

An estimate of the net change in the wholesale price solely due to shutting down Indian Point, after compensating for load growth and scheduled retirements, can be obtained from GE's calculations by subtracting from the Reference Case the wholesale price estimates for the various scenarios considered. For example, by 2015 with the higher fuel prices used, the increase in wholesale price might increase $7/MWh for all of the NYCA and increase $13/MWh in New York City. For the lower-fuel-cost cases, the impact for NYCA might be $2 – 4/MWh, and double that for New York City. However, the committee urges great caution in interpreting these numbers, since (1) the difference between two uncertain numbers is doubly uncertain; (2) it unrealistically takes shutting down Indian Point out of the context of the overall reliability situation facing New York today; (3) it allows the inference that shutting down Indian Point's 2 GW at EOL would also be compensated for by adding additional low-cost, gas-based generation; and (4) the several caveats noted earlier on the committee's low confidence in the MAPS-projected wholesale prices (based on the current LBMP wholesale market), which are believed to be too low.

Impact on the Annual Variable Cost of Producing Electricity

The systemwide AVOC that MAPS minimizes depends principally on the annual generation in the systemwide region under consideration and the prices of fuel there.[16] Table 5-9 gives part of the output results, providing a picture of the impacts on the AVOC for the NYCA and New York City (Zone J) in 2008 and 2015 and the sensitivity to fuel prices for the limited cases run. Values listed are the percentage changes from the Benchmark.

[16] As noted earlier, current variability in fuel prices, with bias toward higher prices than modeled, indicates that the AVOC values from the MAPS modeling are likely to be highly uncertain.

TABLE 5-9 Projected Impact on Variable Operating Cost

	REFERENCE FUEL PRICES				HIGHER FUEL PRICES			
	2008 NYCA Gas at $5.11 /MMBtu		2015 NYCA Gas at $4.24 /MMBtu		2008 NYCA Gas at $7.69 /MMBTU		2015 NYCA Gas at $7.03 /MMBTU	
	NYCA	Zone J	NYCA	Zone J	NYCA	Zone J	NYCA	Zone J
Case	(%)	(%)	(%)	(%)	(%)	(%)	(%)	(%)
Reference Case	-1	-2	5	-8	29	42	48	44
Early Shutdown, Case b2	6	17	21	40	40	70	77	117
EOL Shutdown, Case c2	-2	-3	21	40	27	40	77	117
Early Shutdown, Including N-S HVDC Line in 2012, Case b3	-	-	12	8	-	-	-	-
EOL Shutdown, Including N-S HVDC Line in 2012, Case c3	-	-	12	8	-	-	-	-
Early Shutdown, Including High EE/DSM Measures by 2015, Case b4	-	-	13	14	-	-	-	-
EOL Shutdown, Including High EE/DSM Measures by 2015, Case c4	-	-	13	14	-	-	-	-

SOURCE: Derived from Hinkle et al, 2005.

The data for the Reference Case in 2008 using the lower fuel prices show that AVOC initially decreases slightly, because fuel prices are low and low-cost generation is being added based on high-efficiency, natural-gas-fired units. But early shutdown of Indian Point changes this result because additional gas-based generation is added, and it has a higher variable operating cost than Indian Point, the lowest-variable-cost producer in the generating fleet—aside from hydropower. By 2015 the impact on AVOC is 21 percent higher for the NYCA and 40 percent higher for New York City. Generators of electricity there have substantially higher variable costs to cover.

The data in Table 5-9 show large impacts on AVOCs, especially in Zone J. The key points to note include:

1. The impact of higher fuel prices is large for the entire NYCA, and especially for Zone J, with percentage increases over the Benchmark ranging from 27 to 70 percent for 2008 and from 44 to 117 percent for 2015, with the higher percentages applying to New York City. (Note that the higher-fuel-price assumptions correspond to a 50 percent increase of the 2008 price of natural gas.)
2. The annual variable operating cost in Zone J increases by 17 to 40 percent from 2008 to 2015, both relative to the Benchmark, for the Early Shutdown with Compensation scenario, because of the added capacity in Zone J.
3. Delaying the shutdown of Indian Point units until EOL shows a net early reduction in Zone J (up until 2015) because additions to capacity come later, and in the early years the impact of the use of more efficient units dominates total additions to capacity.
4. Addition of the HVDC line into Rock Tavern (Zone G) reduces the change in Zone J, as expected, as does greater penetration of EE/DSM measures. For Zone J in 2015, the combined net impact on AVOC is reduced to the range of 8 to 14 percent increase over the Benchmark. The impact of this magnitude warrants further detailed study.

More complete data in Appendix F-2 also show that the impact on AVOC in the various pricing zones differs significantly, with large percentage changes in some instances, as MAPS adjusts the electricity dispatch of various generating units to find the minimum systemwide cost. Changes of this magnitude may influence different generators of electricity substantially and could present operating and risk management challenges, such as reliable access to fuels, and substantial shifts as new low-cost capacity is added.

Detailed results summarized in Appendix F-2 suggest an increase in AVOCs of about 10 percent for the entire Northeast region from 2008 to 2015. But this raises another caution to consider regarding the initial MAPS runs presented here and the complexity of the economic factors. The MAPS results suggest a significant, perhaps controversial, impact on regional AVOC beyond meeting load growth and compensatory actions from shutting down Indian Point. This inference might, however, only be an artifact of the calculations because of the assumptions used in the MAPS studies. Substantial gas-fired combined-cycle capacity with high efficiency is added to the NYCA over the period in question. This new capacity could be expected to displace more expensive generation there, even older gas-fired units having lower efficiency (after compensating for the shutdown of Indian Point). However, as just one example of complexity, no comparable assumption of adding more modern gas fired combined cycle

capacity for the New England region went into the initial MAPS model run by GE. This approach distorts the likely pattern of new generating sources that would likely emerge.

Sensitivity to Higher Fuel Prices

For the fuel-price sensitivity cases, the price assumptions used in MAPS differ in the following ways. For the assumed lower fuel prices, the natural gas price is 5 to 7 percent higher in PJM and New England than in NYISO; coal is 16 to 28 percent higher in New England than in either NYISO or PJM; residual oil and distillate have the same price in all three regions.[17] For the higher-fuel-price assumptions, fuel prices are the same in all regions, except that gas is 2 percent higher and coal is 16 to 23 percent higher in New England. In addition, the changes from lower fuel prices to the higher fuel prices assume that the NYISO gas price is 50 percent higher in 2008 and 66 percent higher in 2015. The coal price is the same as in the lower set of prices; the price of residual oil rises 50 percent and 63 percent in 2008 and 2015, respectively; and distillate fuel price goes up 38 percent and 35 percent in 2008 and 2015, respectively.

Since MAPS estimates the minimum systemwide AVOCs, these assumptions, in moving from the lower prices to the higher fuel prices, will tend to: (1) slightly favor gas-based generation in NYISO over that in either New England or PJM; (2) favor coal-based generation in NYISO over coal-based generation in New England; (3) favor coal-based generation slightly more in the high-fuel cases; (4) be neutral regarding gas-based generation relative to residual oil-based generation; or (5) favor distillate-based generation, relatively, except that distillate fuel is always 58 to 65 percent more costly than natural gas, so distillate-based generation penetrates only slightly in the MAPS analyses.

In evaluating the results of the MAPS analyses, it should be remembered that trends and percentage changes (rather that the absolute values of the calculated wholesale price of electricity) are mainly of interest.

COMPARING THE RESULTS WITH CRITERIA

Chapter 1 listed six criteria adopted by the committee. This section compares the results of the committee's scenario analysis with those criteria.

1. *Will the combination of demand and supply options provide adequate energy to replace Indian Point?*

A portfolio of additional supply and demand-reduction options can be identified to replace Indian Point, but they must be added to the capacity required to meet load growth and to offset generating plant retirements. The committee estimates that even if Indian Point is not retired, New York State will need about 1.2 to 1.7 GW in 2010, and 2.2 to 3.3 GW in 2015, from projects that are not already under construction. The additional 2 GW required if Indian Point were to be closed could be met by some suitable

[17] Base case data set, Quarter 1 2005, published by Platts, a Division of McGraw-Hill Companies. See http://www.platts.com/Analytic%20Solutions/BaseCase/index.xml

combination of new generation in the New York City area, efficiency improvements and demand-side management, and new transmission capability from upstate.

Most of the approximately 5 GW that would be need by 2015 probably would come from new generating capacity relying at least initially on natural gas as a fuel. Energy efficiency and demand-side management have great potential, and could replace at least 800 MW of the energy produced by Indian Point, and possibly much more. The new North-South transmission line analyzed by the committee also could reduce the additional generating capacity needed downstate by about 800 MW. The committee notes that critically required corrections to reactive power would have to be made locally in a timely manner, since losing the reactive power from Indian Point would only compound the projected deficiency in the Lower Hudson Valley identified by NYISO.

2. *Will the generation and transmission system be adequate to deliver the energy reliably to end users?*

Identifying the generation and transmission system capability that must be provided to replace Indian Point is much easier than determining whether it actually would get built when needed. All these measures will take time to implement and several factors may converge to make it even more difficult. As discussed in Chapter 4, the committee questions whether the present market mechanisms are adequate to attract the capital investment required for the roughly 5 GW of new capacity and transmission corrections that would be needed by 2015. In addition, the lack of a state program, such as the former Article X, to expedite siting and licensing is likely to discourage new projects. A concerted, well managed and coordinated effort would be required to replace Indian Point by 2015. Replacement in the 2008-2010 timeframe would be considerably more difficult, probably requiring extraordinary emergency-like measures to achieve.

3. *How will the new combination of demand and supply options compare with Indian Point in terms of security of fuel supply for new generation?*

While the details of security comparisons are beyond the scope of this study (and would depend on the exact set of options selected), it is possible that the NYCA would be vulnerable to potential natural gas shortages. Adding several GW of electrical capacity (including projects currently under construction) based mainly on natural gas supply would increase NYCA reliance on gas-based generation from 20 percent in 2003 to over 50 percent by 2015. The present gas supply and transmission capacity is inadequate to meet such future demand. In so far as additional gas is supplied by imported LNG, another energy security issue is introduced. Adding electrical capacity upstate based on other fuels will require additional electrical transmission capacity to serve downstate load centers, and transmission systems are inherently vulnerable to some extent. On the other hand, distributed generation has some security advantages over large generating stations. Continued vigilance at the Indian Point site for stored spent nuclear fuel will be necessary whether or not it is closed.

4. *How will economic costs, especially to the consumer, compare to continued operation of Indian Point?*

The Indian Point power plant produces baseload electricity as a low-cost wholesale provider in southern New York York. While the present "regulated competition" wholesale market depends on many factors, the projected wholesale cost

without the Indian Point units, based on analysis of variable operating costs only, will tend to rise. The strongest influence on wholesale costs is fuel costs. The current volatility of natural gas prices and the structure of the wholesale market make it difficult and uncertain to project costs in 2015. In any event, it is unlikely that replacing the low-cost producer would do anything other than raise the ultimate cost of electricity to consumers.

Investors must be attracted back to the NYCA for new projects, but providing for adequate return on new capital investment will tend to increase projected wholesale prices. Costs also will increase indirectly because replacement power will increase demand for natural gas, require investment in new gas transmission infrastructure, and require expenditure for emissions permits.

5. *How will environmental emissions and other impacts compare to continued operation of Indian Point?*

Since the air emissions of New York power plants currently involve emission caps already in place, new sources would have to purchase emission rights. Thus, most pollutants would be little changed. The main change expected would be an increase in carbon dioxide (CO_2, the most important greenhouse gas) from substituting fossil fuel for nuclear fuel. If the regional plans for reducing or capping CO_2 emissions are implemented, local CO_2 increases will likely be offset with an emissions credit market. Water quality will be improved by retiring Indian Point, but much the same advantage could be achieved if the plant switches to cooling towers from the current once-through cooling.

6. *What will be the impacts on local communities from closing Indian Point and replacing it with the hypothesized options?*

Community impacts will be mixed, depending on the choice of replacements and their locations. There would likely be potentially significant disruption in the tax base and supporting business income to Westchester and surrounding counties. A loss of employment of skilled workers would be associated with the plant's retirement. The costs of electricity are likely to rise with changes in the electrical system infrastructure in southern New York State. Projections of all of these impacts are difficult to estimate without additional information. On the other hand, while the committee has not studied these factors, some benefits may occur. For example, upstate communities might benefit if replacement power plants are built there. The Indian Point site could also be used for new industrial facilities that could replace the jobs and tax benefits of the nuclear station.

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Appendices

The appendices provide information on this project and additional details and background information for material in the report.

Appendix A, *Committee Biographical Information*, includes brief biographies of all the committee members.

Appendix B, *Acronyms*, identifies the acronyms in the report.

Appendix C, *Presentations and Committee Meetings*, lists all the meetings the committee held and the presenters who supplies information at the public meetings.

Appendix D, *Supply Technologies*, provides additional details and background information on the generating and transmission options discussed in Chapter 3.

Appendix E, *Paying for Reliability in Deregulated Markets*, provides the information from which the first section of Chapter 4, *Regulation, Finance, and Reliability*, was extracted.

Appendix F, *Background for the System Reliability and Cost Analysis*, describes the process by which the New York Independent System Operator assures reliability, and the details of the committee's analysis of future scenarios, as discussed in Chapter 5.

Appendix G, *Demand Side Measures*, documents the efficiency and demand reduction technologies discussed in Chapter 2.

Appendices D, E, F, and G were prepared by individual committee members or subgroups.

Appendix A

COMMITTEE BIOGRAPHICAL INFORMATION

Lawrence T. Papay (NAE), ***chair,*** is currently a consultant with a variety of clients in electric power and other energy areas. Previously he held positions including senior vice president for the Integrated Solutions Sector, Science Applications International Corporation,; and senior vice president and general manager of Bechtel Technology and Consulting. He also held several positions at Southern California Edison, including senior vice president, vice president, general superintendent, and director of research and development (R&D), with responsibilities for areas including bulk power generation, system planning, nuclear power, environmental operations, and development of the organization and plans for the company's R&D efforts. Dr. Papay's professional affiliations have included the Electric Power Research Institute (EPRI) Research Advisory Committee, the Atomic Industrial Forum, the U.S. Department of Energy Energy Research Advisory Board, and the Renewable Energy Institute. He is a member of the National Academy of Engineering and the National Science Foundation's Industrial Panel on Science and Technology. His expertise and knowledge range across a wide variety of electric system technologies, from production, to transmission and distribution, utility management and systems, and end-use technologies. He received a B.S. degree in physics from Fordham University, and S.M. and Sc.D. degrees in Nuclear Engineering from the Massachusetts Institute of Technology (MIT.)

Dan E. Arvizu is the director and chief executive of the National Renewable Energy Laboratory. He was formerly a senior vice president and chief technology officer for the Federal and Industrial Client Groups of CH2M Hill Companies, Ltd., and before that, as a vice president and director of the Energy and Industrial Systems Business Group. Prior to working at CH2M Hill, Dr. Arvizu worked at Sandia National Laboratories—as director, Materials and Process Sciences Center; director, Advanced Energy Technology and Policy Center; and director, Technology Transfer Center. Dr. Arvizu was also a member of the technical staff, Customer Switching Systems, Bell Telephone Laboratories. He has experience as an executive in managing a business profit and loss, and in corporate technology commercialization as well as extensive experience in materials science applications for nuclear weapons and energy systems, and in the development of renewable energy systems, including solar thermal, photovoltaic, and concentrating solar collectors. He has been recognized for excellence in the management of technology transfer and renewable energy R&D programs. In 2004, Dr. Arvizu was appointed by President Bush to serve on the National Science Board. He received the 1996 Hispanic Engineer's National Achievement Award for Executive Excellence and has served on a number of advisory groups, including the Commercialization Advisory Board for the Solar II Central Receiver Pilot Plant. He served on the National Research Council (NRC) Committee on Programmatic Review of the Office of Power Technologies. He received his B.S. degree from New Mexico State University and his M.S. and Ph.D. degrees from Stanford University, all in mechanical engineering.

Jan Beyea is chief scientist, Consulting in the Public Interest, and is a consultant to the National Audubon Society. He consults on nuclear physics and other energy/environmental topics for numerous local, national, and international organizations. He has been chief scientist and vice president, National Audubon Society, and has held positions at the Center for Energy and Environmental Studies, Princeton University, Holy Cross College, and Columbia University. He has served as a member of numerous advisory committees and panels including the National Research Council (NRC) Board on Energy and Environmental Systems; the NRC Energy Engineering Board; the NRC Committee on Alternative Energy R&D Strategies; the NRC Committee to Review DOE's Fine Particulates Research Plan; the Secretary of Energy's Advisory Board, Task Force on Economic Modeling; and the policy committee of the Recycling Advisory Council. Dr. Beyea has been an advisor to various studies of the U.S. Congress Office of Technology Assessment. He has expertise in energy technologies and associated environmental and health concerns and has written numerous articles on the environment and energy. He received a B.A. from Amherst College and a Ph.D. in Physics from Columbia University.

Peter Bradford advises and teaches restructuring and energy policy in the United States and abroad. He has been a visiting lecturer in energy policy and environmental protection at Yale University and has taught utility law at the Vermont Law School, where he is currently teaching a course on nuclear power and public policy. He is also affiliated with the Regulatory Assistance Project, which provides assistance to state and federal regulatory commissions regarding energy regulatory policy and environmental protection. Mr. Bradford was a member of the US Nuclear Regulatory Commission (1977-82). He has served on panels advising the European Bank for Reconstruction and Development on how best to replace the remaining Chernobyl nuclear plants in Ukraine and advising the Austrian Institute for Risk Reduction on regulatory issues associated with opening the Mochovce Nuclear Plant in Slovakia. He chaired the New York State Public Service Commission and the Maine Public Utilities Commission, and was also briefly Maine's Public Advocate. Mr. Bradford has written extensively on energy regulatory and energy security issues. He is a graduate of Yale University and the Yale Law School.

Marilyn Brown is the Interim Director of the Engineering Science and Technology Division at Oak Ridge National Laboratory (ORNL). During her 22 years at ORNL, Dr. Brown has researched the impacts of policies and programs aimed at advancing the market entry of sustainable energy technologies and has led several energy technology and policy scenario studies. Prior to serving at ORNL, she was a tenured associate professor in the Department of Geography at the University of Illinois, Urbana-Champaign, where she conducted research on the diffusion of energy innovations. She has authored more than 140 publications and has been an expert witness in hearings before committees of both the U.S. Senate and the House of Representatives. She has received awards for her research from the American Council for an Energy-Efficient Economy, the Association of American Geographers, the Technology Transfer Society, and the Association of Women in Science. A recent study that she co-led (Scenarios for a Clean Energy Future) was the subject of two Senate hearings, has been cited

in proposed federal legislation, and has had a significant role in international climate change debates. Dr. Brown serves on the boards of directors of several energy, engineering, and environmental organizations (including the Alliance to Save Energy and the American Council for an Energy Efficient Economy) and she serves on the editorial board of the *Journal of Technology Transfer*. She is also a member of the National Commission on Energy Policy. She has a Ph.D. in geography from Ohio State University and a masters degree in resource planning from the University of Massachusetts. She is also a certified energy manager.

Alexander E. Farrell is assistant professor in the Energy and Resources Group at the University of California, Berkeley. He is working on characterizing environmental impacts of energy production and transformation, especially air pollution and greenhouse gases, and in the economic, political, and other social aspects of energy systems with reduced environmental impacts. Previously, Dr. Farrell had been adjunct assistant professor in the Department of Engineering and Public Policy at Carnegie-Mellon University and executive director of the Carnegie-Mellon Electricity Industry Center. He had been a research fellow at the John F. Kennedy School of Government and at the Wharton Risk Management and Decision Processes Center, University of Pennsylvania. He also was an engineer at Air Products and Chemicals, Inc., and served as a nuclear submarine officer in the U.S. Navy. He has a B.S. degree in systems engineering from the U.S. Naval Academy and a Ph.D. in energy management and policy from the University of Pennsylvania.

Samuel M. Fleming is currently a consultant. His prior positions include executive assistant to the executive vice president for strategic planning and technology commercialization of Bechtel BWXT Idaho, LLC; senior program manager in the Operations Department of Bechtel Technology and Consulting; commercial development manager and program manager for Bechtel R&D's Cargoscan™ program; manager of the Advanced Processes Department in Bechtel R&D; project operations manager for renewable energy and fuels technologies in Bechtel R&D; manager, Process Technology Department, Bechtel R&D; manager of advanced technology planning, Fluor Engineers, Inc.: and director of technology, the Badger Company, Inc. Dr. Fleming's expertise spans a wide range in advanced technology and engineering development, economic evaluation of technologies, and project management. He has worked on various types of technology development, including advanced fuel and gas conversion, nuclear, solar, wind, geothermal, drilling, biotechnology, cargo detection, superconducting magnetic storage, and gas pipelines. He has a B.S. (Pennsylvania State University), S.M. (MIT.), and Sc.D. (MIT) in chemical engineering.

George M. Hidy is principal of Envair/Aerochem. He is the retired Alabama Industries Professor of Environmental Engineering at the University of Alabama, where he was also adjunct professor of environmental health science in the School of Public Health. From 1987 to 1994, he was technical vice president of the Electric Power Research Institute, where he managed the Environmental Division and was a member of the Management Council. From 1984 to 1987, he was president of the Desert Research Institute of the University of Nevada. He has held a variety of other scientific positions in universities

and industry and has made significant contributions to research on the environmental impacts of energy use, including work on atmospheric diffusion and mass transfer, aerosol dynamics, and chemistry. He is the author of many articles and books on these and related topics. Dr. Hidy received a B.S. in chemistry and chemical engineering from Columbia University, an M.S.E. in chemical engineering from Princeton University, and a D.Eng. in chemical engineering from the Johns Hopkins University.

James R Katzer, **(NAE)** was manager of strategic planning and program analysis for ExxonMobil Research and Engineering Company, where he was responsible for primary technology-planning and analysis activities and for future-focused technology-planning activities. Prior to that he was vice president, technology, Mobil Oil Corporation, with primary responsibilities for ensuring Mobil's overall technical health, developing forward- looking technology scenarios, identifying and analyzing technology and environmental developments and trends, guiding Mobil's long-term directions on the basis of strategic technical drivers, and identifying future threats and opportunities and recommending strategies to deal with them. Dr. Katzer joined the Central Research Laboratory of the Mobil Oil Corporation in 1981, later becoming manager of process research and technical service and vice president of planning and finance for Mobil Research and Development Corporation. Before joining Mobil he was a professor on the chemical engineering faculty at the University of Delaware and the first director of the Center for Catalytic Science and Technology there. Dr. Katzer has more than 80 publications in technical journals, holds several patents, and co-authored and edited several books. He received a B.S. degree from Iowa State and a Ph.D. in chemical engineering from MIT.

Parker D. Mathusa is a member of the Board of Directors—Research Scientist, New York State Energy Research and Development Authority (NYSERDA). Formerly he was program director, Energy Resources, Transportation and Environmental Research Program, NYSERDA, where he was responsible for establishing research programs and policies required to develop new energy technologies and environmental mitigation measures that could contribute to New York State's energy supply needs, with a focus on renewable energy resources, advanced transportation technologies, and environmental products. Dr. Mathusa's previous positions include service as chief, Utility Research and Demand Management, New York State Public Service Commission, in which he developed a comprehensive R&D program for electric and gas utilities, and engineering positions at Yankee Atomic Electric Company and Bechtel Corporation. He has been involved in the evaluation of a number of emerging energy technologies and associated environmental mitigation measures, including fuel cells, hybrid electric vehicles, and photovoltaic systems, and has published numerous assessments of energy technologies. He has served on numerous advisory panels including federal and state advisory groups. He has a B.S. in physics from the State University of New York, at-Albany, and an M.S. in engineering management from Northeastern University.

Timothy Mount is Professor of Applied Economics and Management at Cornell University. His research and teaching interests include econometric modeling and policy analysis relating to the use of fuels and electricity, and to their environmental

consequences (acid rain, smog, and global warming). Professor Mount is currently conducting research on the restructuring of markets for electricity and the implications for (1) price behavior in auctions for electricity, (2) the rates charged to customers, and (3) investment decisions for maintaining system adequacy. He has spent sabbaticals at the University of New South Wales, Australia, and the London School of Economics and the University of Manchester, United Kingdom. He has a B.S. from Wye College, University of London and a Ph.D. from the University of California, Berkeley.

Francis J. Murray, Jr. is an energy and environmental consultant, providing strategic policy and market-development guidance on energy and environmental issues for private sector clients. His previous positions include consultant to the Office of Assistant Secretary for Policy and International Affairs, DOE; chairman of NYSERDA, and commissioner of energy in the NY State Energy Office; deputy secretary and assistant secretary to the Governor for energy and environment; and senior. legislative counsel/legislative counsel in the New York State Office of Federal Affairs. His experience includes the development and implementation of major energy and environmental initiatives and programs for New York State, including the development of a comprehensive, integrated State Energy Plan that integrated state energy, environmental and economic development policies in the early 1990s, and policy analysis for the federal government. on electric reliability and appliance efficiency standards. He was an environmental policy fellow at the Institute of Ecosystems, Millbrook, New York (1999-2000); director, Scenic Hudson, Inc. (1994-2000); director, the Environmentors Project (Washington, D.C., 1994-2000); and founding member of the Hudson River Greenway Communities Council (1992–1996). He has a B.S.F.S. from the Georgetown University School of Foreign Service and a J.D. degree from the Georgetown University Law Center.

D. Louis Peoples is president and founder of Nyack Management Company, a business consulting and turnaround firm. Formerly chief exectutive officer of Orange and Rockland Utilities in New York State. While at Orange and Rockland, he was a leader in the deregulation of electric power, serving as chairman of the New York Power Pool and of the Transition Steering Committee to form the New York Independent System Operator. Earlier, he was executive vice president of Madison Gas and Electric Company, senior vice president of RCG/Hagler, Bailly, a consulting company, and Vice President of Bechtel Management Consulting Services. Mr. Peoples has also been corporate controller of McGraw Edison Company, director of nuclear licensing at Commonwealth Edison, and training manager at Vermont Yankee Nuclear Power Corporation. He served in the nuclear submarine service in the U.S. Navy. He received a B.S.M.E. from Stanford University and an M.B.A. from Harvard Business School. He is a certified public accountant and a registered professional engineer.

William F. Quinn is founder and president of Argos Utilities LLC. Formerly he was president of Shaw Transmission and Distribution Services, Inc., part of The Shaw Group, where he had responsibility for strategic planning, business development, and the financial viability of the transmission and distribution subsidiaries. Mr. Quinn also sits on the Board of Directors of Hydro Power Solutions LLC, a joint venture company owned equally by The

Shaw Groupand Hydro Quebec LTD of Montreal. He also managed The Shaw Group's, Structured Transaction Group, where his duties included managing mergers and acquisitions teams, overseeing project development activities, and evaluating investment options. Prior to joining The Shaw Group Inc., Mr. Quinn was responsible for management of the Pacific Gas and Electric (PG&E) National Energy Group's power-asset-development business in North America. Among other projects there, Mr. Quinn directed the 1,200 MW Athens Generating Project, New York's first merchant generating facility and one of the largest gas-fired power plants in the United States. Prior to joining PG&E,he incorporated Meridian Power Corporation, where he was responsible for the marketing, development, financing, and construction of power-generating projects. While at Energy Management, Inc., Mr. Quinn developed several biomass and gas-fired cogeneration projects. He also was Project Engineer for Badger America, Inc. He has a B.S. in mechanical engineering from the University of Massachusetts and did graduate studies in business administration at Harvard University. He is a registered professional engineer.

Dan W. Reicher is president, New Energy Capital Corporation. He served recently as executive vice president of Northern Power Systems, the nation's oldest renewable energy company. From 1997 to 2001, Mr. Reicher was Assistant Secretary of Energy for Energy Efficiency and Renewable Energy at the U.S. Department of Energy as Assistant Secretary, he directed annually more than $1 billion in investments in renewable energy, distributed generation, and energy-efficiency research, development and deployment. Prior to that position, Mr. Reicher held other senior management posts in DOE and was also a senior attorney at the Natural Resources Defense Council. He was also co-chair of the U.S. Biomass Research and Development Board, a member of the U.S. delegation to the Climate Change Negotiations, and a member of the board of the government-industry Partnership for a New Generation of Vehicles. Mr. Reicher is also currently co-chair of the advisory board of the American Council on Renewable Energy and a member of the boards of Burrill and Company's Biomaterials and Bioprocessing Venture Fund, the American Council for an Energy Efficient Economy, and the Keystone Center's Energy Program. He has more than 20 years of experience in energy technology, policy and finance. He holds a B.A. from Dartmouth College and a J.D. from Stanford Law School

John A. Tillinghast, NAE, is president of Tillinghast Technology Interests, Inc. Early in his career from 1949 to 1979, he held a number of positions at American Electric Power (AEP) Service Corporation, including executive vice president, engineering and construction, and vice chairman of the board in charge of engineering and construction. Positions that he held subsequent to his employment at AEP include senior vice president and senior technical officer overseeing research and development at technology, Wheelabrator-Frye, Inc.; senior vice president, technology, Signal Advanced Technology Group, The Signal Companies, Inc; and senior vice president, Science Applications International Corporation. His experience and knowledge span a variety of areas, including steam turbines; nuclear energy systems; magnetohydrodynamic power plants; fossil energy power plants; transmission and distribution (T&D) systems; engineering, construction and operation of electric power production and T&D facilities; restructuring of the utility industry; alternative energy projects; cogeneration including small gas turbines; geothermal plants; life extension of utility facilities; and power

marketing. He has served on a number of National Research Council units, including as chairman of the Energy Engineering Board and as a member of the Commission on Engineering and Technical Systems. He is a a Fellow of the American Society of Mechanical Engineers. He has a B.S. and M.S. in mechanical engineering from Columbia University.

James S. Thorp, **NAE**, is the Hugh P. and Ethel C. Kelly Professor of Electrical and Computer Engineering and head of the Department of Electrical and Computer Engineering at Virginia Polytechnic Institute and State University.. Previously he had been the Charles N. Mellowes Professor in Engineering at Cornell University and director of the Cornell School of Electrical and Computer Engineering. He had also been a faculty intern at the American Electric Power Service Corporation, an Overseas Fellow, Churchill College, Cambridge University, and an Alfred P. Sloan Foundation National Scholar. Dr. Thorp is a Fellow of the Institute of Electrical and Electronics Engineers (IEEE) and is the Editor of the *IEEE Transactions on Power Delivery* for protection systems. Dr. Thorp received the 2001 Power Engineering Society Career Service award. He was a member of the International Advisory Board of the Department of Electrical and Electronic Engineering, Hong Kong University, and a member of the Iowa State Electrical and Computer Engineering External Advisory Board. He has written more than 100 journal articles and many book chapters. He obtained a B.E.E. and Ph. D. from Cornell University

Appendix B

ACRONYMS

AC	alternating current
AMP	Automatic Mitigation Procedures
BWR	boiling water reactor
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	combined cycle
CDW	construction and demolition waste
CHP	combined heat and power
CIPP	Commercial and Industrial Performance Program
CO_2	carbon dioxide
ConEd	Consolidated Edison
CPU	computer processing unit
CRPP	Comprehensive Reliability Planning Process
CSP	curtailment service provider
CT	combustion turbine
DC	direct current
DER	distributed energy resource
DG	distributed generation
DOE	Department of Energy
DR	demand response
DSM	demand-side management
EE	energy efficiency
EESP	Energy Efficiency Service Provider
EIA	Energy Information Administration
EOL	end of license
ERO	Electric Reliability Organization
ESP	electrostatic precipitator
ETP	Enabling Technologies Program
FERC	Federal Energy Regulatory Commission
FF	fabric filters
FGD	flue-gas desulfurization
FO2	No. 2 (distillate oil)
FO6	No. 6 (residual oil)
GAP	Gap Analysis Program (U.S. Geological Survey)
GE	General Electric International
GHG	greenhouse gas
HHV	higher heating value
Hg	mercury
HVAC	heating, ventilating, and air conditioning
HVDC	high-voltage direct current
IC	internal combustion

ICAP	installed capacity
IGCC	integrated gasification combined cycle
IP2	Indian Point Unit 2
IP3	Indian Point Unit 3
IPP	independent power producer
IRM	installed reserve margin
ISO-NE	independent system operator-New England
IOU	investor owned utility
LBMP	locational-based marginal pricing
LBNL	Lawrence Berkeley National Laboratory
LED	light-emitting diode
LHV	Lower Hudson Valley
LICAP	locational installed capacity
LIPA	Long Island Power Authority
LMR	locational margin reserve
LNG	liquefied natural gas
LOLE	loss-of-load expectation
LSE	load serving entity
MAAC	Mid-Atlantic Area Council (reliability council)
MAPS	Multi-Area Production Simulation
MARS	Multi-Area Reliability Simulation
MDEA	methyl diethanol amine
MIT	Massachusetts Institute of Technology
MSW	municipal solid waste
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NG	natural gas
NGCC	natural gas combined cycle
NO_x	nitrogen oxide
NPCC	Northeast Power Coordinating Council;
NRC	National Research Council
NREL	National Renewable Energy Laboratory
NYCA	New York Control Area
NYDEC	New York Department of Environmental Conservation
NYISO	New York Independent System Operator
NYMex	New York Mercantile Exchange
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
NYSRC	New York State Reliability Council
O&M	operation and maintenance
PC	pulverized coal
PJM	Pennsylvania Jersey Maryland (regional transmission organization)
PLRP	Peak Load Reduction Program
PM	particulate matter
PPA	Power Purchase Agreement

PSEG	Public Service Electric and Gas
PUC	public utility commission
PV	photovoltaic, photovoltaics
PWR	pressurized water reactor
RGGI	Regional Greenhouse Gas Initiative
RMR	Reliability-Must-Run
RNA	Reliability Needs Assessment
ROS	rest of state
RPS	Renewable Portfolio Standard
SBC	Systems Benefit Charge
SCR	Special Case Resource; selective catalytic reduction
SO_2	sulfur dioxide
SO_x	sulfur oxide
SPDES	State Pollutant Discharge Elimination System
SVC	satic VAR cmpensation
TO	transmission owner
UDR	Unforced Delivery Rights (transmission capacity)
UPNY-SENY	Upstate New York-Southeast New York transmission interface
USNRC	U.S. Nuclear Regulatory Commission
VOC	volatile organic compound; variable operating cost
VOLL	value of lost load
WESP	wet electrostatic precipitators

Appendix C

PRESENTATIONS AND COMMITTEE MEETINGS

1. COMMITTEE MEETING, THE NATIONAL ACADEMIES, WASHINGTON, D.C., JANUARY 18-19, 2005

Congressional Expectations for the Study
Beth Tritter, Office of Congresswoman Nita M. Lowey, Representative from New York's 18th District

Department of Energy Perspectives: Indian Point Energy Alternatives Study
Philip Overholt, U.S. Department of Energy

Transmission Considerations for the Replacement of Indian Point Generation with Alternate Sources
John Kucek, Oak Ridge National Laboratory

Energy Efficiency and Renewable Energy—Resource Potential in New York State: Summary of Potential Analysis Prepared for the New York State Energy Research and Development Authority (NYSERDA)
Lawrence Pakenas, NYSERDA, and John Plunkett, Optimal Energy, Inc.

Indian Point: What Could Wind Contribute?
Randall Swisher, American Wind Energy Association

Natural Gas Use in Eastern New York: Can the Indian Point Nuclear Facility be Replaced by Gas-Fired Power Generation?
Harry Vidas, Energy and Environmental Analysis, Inc.

2. COMMITTEE MEETING, CROWNE PLAZA HOTEL, WHITE PLAINS, NEW YORK, MARCH 14-16, 2005

Northeast Power Coordinating Council (NPCC) Reliability Criteria, Guides, and Procedures
Philip Fedora, Northeast Power Coordinating Council

New York Power Generation Development Overview
Bill Quinn, Argos Utilities, LLC

ICF Power Market Analysis Capabilities
Juanita Haydel, ICF Consulting

Entergy's Views
Mike Kansler, Entergy Nuclear Northeast

Building Transmission Lines
Steve Mitnick Conjunction LLC

New York State Department of Public Service
Howard Tarler, New York State Department of Public Service

Westchester County Government Views
The Honorable Andrew J. Spano, Office of the Westchester County Executive

Westchester County Legislature Views
The Honorable Michael B. Kaplowitz, Westchester County Board of Legislators

Alternatives to Indian Point
Bruce Biewald, Synapse Energy Economics, Inc; Alex Matthiessen, Riverkeeper; and Fred Zalcman, Pace Law School Energy Project

New York Independent System Operator Views
Garry Brown, New York Independent System Operator (NYISO)

Con Edison Views
Michael Forte, Con Edison

Financing New Electric Generation
Carl Seligson, Economic and Strategic Consultant

3. COMMITTEE MEETING, THE NATIONAL ACADEMIES, WASHINGTON, D.C., MAY 31-JUNE 1, 2005

Integrated Gasification Combined Cycle (IGCC)
N.Z. Shilling, GE

New York State Public Benefits Energy Efficiency Programs
Paul A. DeCotis, New York State Energy Research and Development Authority

4. SITE VISIT, SCHENECTADY, NEW YORK, JULY 25-26, 2005

5. CLOSED COMMITTEE MEETING, THE NATIONAL ACADEMIES, OCTOBER 17-18, 2005

6. CLOSED COMMITTEE MEETING, THE NATIONAL ACADEMIES, NOVEMBER 21-22, 2005

Appendix D

SUPPLY TECHNOLOGIES

This appendix provides additional details and background information related to the 18 potential alternative supply technologies, examined in Chapter 3, "Generation and Transmission Options". Appendix D contains the following:

- *Appendix D-1, "Cost Estimates for Electric Generation Technologies"*—Table D-1-1 summarizes estimated total costs and the later tables detail the key cost elements for each of the technologies examined by the committee.
- *Appendix D-2, "Zonal Energy and Seasonal Capacity"*—Table D-2-1 provides a summary, and the remaining tables which present data for summer and winter capacity (MW) and energy production (GWh) by fuel and other data on the New York Control Area (NYCA).
- *Appendix D-3, "Electric Generation from Natural Gas in Zones H Through K"*—This appendix contains tabular data on power generation from natural gas in the New York City area in 2003 and 2004, indicating the oil products used in the overall production of electricity from gas turbines in the New York City area.
- *Appendix D-4, "Proposed Northeast Pipeline Projects"*—A map of the northeastern states shows proposed natural gas pipelines.
- *Appendix D-5, "Coal Technologies"*—Committee member James R. Katzer presents a discussion of the coal-based technologies that the committee considered and evaluated with respect to operating costs, including the technology (integrated gasification, combined cycle [IGCC]) that will be most appropriate for the capture of carbon dioxide. The appendix explores the issue of emissions control for coal plants.
- *Appendix D-6, "Generation Technologies—Wind and Biomass"*—Dan Arvizu of the Department of Energy's National Renewable Energy Laboratory (NREL) summarizes an analysis performed by NREL to evaluate the potential of wind energy and biomass resources as sources of electricity for the New York City region. Issues associated with the expanding use of wind in New York State are discussed.
- *Appendix D-7, "Distributed Photovoltaics to Offset Demand for Electricity"*—Dan Arvizu summarizes an NREL analysis that evaluated the potential of distributed photovoltaics (PV) for the New York City region. Also included are a summary of New York State's current policies related to PV technology and an accelerated PV-deployment scenario for New York State through 2020.

APPENDIX D-1

COST ESTIMATES FOR ELECTRIC GENERATION TECHNOLOGIES

Parker Mathusa[1]
Erin Hogan

TABLE D-1-1 Summary Cost Estimates: Total Cost of Electricity (in 2003 U.S. dollars per kilowatt-hour) for Generating Technologies Examined by the Committee

	Costs estimated by:		
Technology	EIA [a]	University of Chicago [b]	MIT [c]
Municipal solid waste landfill gas	0.0352		
Scrubbed coal, new (pulverized)	0.0382	0.0357	0.0447
Fluidized-bed coal		0.0358	
Pulverized coal, supercritical		0.0376	
Integrated coal gasification combined cycle (IGCC)	0.0400	0.0346	
Advanced nuclear	0.0422	0.0433	0.0711
Advanced gas combined cycle	0.0412	0.0354	0.0416
Conventional gas combined cycle	0.0435		
Wind 100 MW	0.0566		
Advanced combustion turbine	0.0532		
IGCC with carbon sequestration	0.0595		
Wind 50 MW	0.0598		
Conventional combustion turbine	0.0582		
Advanced combined cycle with carbon sequestration	0.0641		
Biomass	0.0721		
Distributed generation, base	0.0501		
Distributed generation, peak	0.0452		
Wind 10 MW	0.0991		
Photovoltaic	0.2545		
Solar thermal	0.3028		

NOTES: EIA: Energy Information Administration, MIT: Massachusetts Institute of Technology.
Data exclude regional multipliers for capital, variable operation and maintenance (O&M), and fixed O&M. New York costs would be higher. Data exclude delivery costs. Data reflect fuel prices that are New York state-specific, see last table in this series. Cost reflect units of different sizes; while some technologies have lower costs than others, the total capacity of the lower-cost generation technology may be limited—for example, a 500-MW municipal solid waste landfill gas project is unlikely. MIT calculations assumed a 10-year term; consequently, estimated costs are higher.
[a] For EIA data, see Table D-1-3 in this appendix, column "Total Cost of Energy ($/kWh)." *Annual Energy Outlook 2005*, Basis of Assumptions, Table 38. The 0.6 rule was applied to the wind 10-MW and 100-MW units using 50 MW as the base reference. Solar thermal costs exclude the 10 percent investment tax credit.
[b] For University of Chicago data, see Table D-1-5 in this appendix.
[c] For MIT data, see Table D-1-2 in this appendix.

TABLE D-1-2 Cost Components for Electricity Generation Technologies

Source	Capital Costs ($/kWh)	O&M Costs ($/kWh)	Fuel Costs ($/kWh)	Cost of Electricity without Regional Multipliers ($/kWh)
Natural Gas Combined Cycle				
Chicago Report	$0.0088	$0.0030	$0.0236	$0.0354
MIT (moderate gas $)	NR	NR	NR	$0.0416
EIA (Advance CC)	$0.0083	$0.0031	$0.0298	$0.0412
Natural Gas Aeroderivative Turbine				
Chicago Report/MIT	NR	NR	NR	NR
EIA (Advanced CT)	$0.0056	$0.0040	$0.0406	$0.0501
Pulverized Coal Steam				
Chicago Report	$0.0167	$0.0077	$0.0113	$0.0357
MIT	NR	NR	NR	$0.0447
EIA (scrubbed coal new)	$0.0209	$0.0069	$0.0122	$0.0382
Pulverized Coal Supercritical				
Chicago Report	$0.0179	$0.0085	$0.0113	$0.0376
MIT/EIA	NR	NR	NR	NR
Fluidized-Bed Coal				
Chicago Report	$0.0179	$0.0059	$0.0120	$0.0358
MIT	NR	NR	NR	NR
EIA (scrubbed coal new)	$0.0181	$0.0071	$0.0130	$0.0382
Integrated Coal Gasification Combined Cycle				
Chicago Report	$0.0199	$0.0052	$0.0094	$0.0346
MIT	NR	NR	NR	NR
EIA	$0.0209	$0.0069	$0.0122	$0.0400
Biomass				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.0284	$0.0094	$0.0219	$0.0598
Municipal Solid Waste				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.0223	$0.0128	$0.0000	$0.0352
Wind 10 MW				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.0896	$0.0095	$0.0000	$0.0991
Wind 50 MW				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.0471	$0.0095	$0.0000	$0.0566

Wind 100 MW				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.0357	$0.0095	$0.0000	$0.0452
NREL w/o Tax Credit	$0.037 to $0.057	$0.003 to 0.009	$0.0000	$0.04 to $0.06
NREL w Tax Credit	$0.022 to $0.047	$0.003 to 0.009	$0.0000	$0.025 to $0.05
Offshore Wind 500 MW				
NREL	$0.045 or more	$0.0150	$0.0000	$0.06 or more
Solar				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.2646	$0.0382	$0.0000	$0.3028
Photovoltaic				
Chicago Report/MIT	NR	NR	NR	NR
EIA	$0.2496	$0.0049	$0.0000	$0.2545
NREL-Current (2004) Low	$0.20	$0.03	$0.00	$0.23
NREL-Current (2004) High	$0.32	$0.06	$0.00	$0.38
NREL-Projected (2015) Low	$0.11	$0.01	$0.00	$0.12
NREL-Projected (2015) High	$0.18	$0.02	$0.00	$0.20
New Next-Generation Nuclear				
Chicago Report	$0.0238	$0.0152	$0.0042	$0.0433
MIT	NR	NR	NR	$0.0711
EIA	$0.0292	$0.0081	$0.0050	$0.0422

NOTES:

Other abbreviations are defined in Appendix B.
EIA and Chicago reports capital costs are overnight costs only.
Delivery costs are not included.
Capital costs assumed 100-percent debt with a 20-year term at 10 percent.
MIT report assumed a 10 year term; consequently costs are higher.
All costs are in 2003 U.S. dollars.
Adjustment to fuel costs may change relative cost of electricity.
NREL wind costs noted that Canadian wind/hydro would add $0.002/kWh to $0.006/kWh to the cost of pure wind alone.

SOURCES: Assumptions to the Annual Energy Outlook 2005, Energy Information Administration, 2005. MIT Study on the future of Nuclear Power, An Interdisciplinary MIT Study, 2003. The Economic Future of Nuclear Power, A Study Conducted at the University of Chicago, August 2004.

TABLE D-1-3 Energy Information Administration National Average Cost Estimates (2003 dollars)

	Total Cost[1]						Capacity			Financing (20 year term at 10%/year)			
Plant Type[2]	**Annual Cost (million $)**	**Capital Cost ($/kwh)**	**Opera-ting Costs ($/kwh)**	**Fuel Costs ($/kwh)**	**Total Cost of Electricity ($/kwh)**	**Delivery Cost ($/kwh)[3]**	**Assumed Capacity (MW)**	**Capa-city Factor**	**Hours Oper-ated per Year**	**Overnight Costs w/contin-gencies ($/kw)[1,2]**	**Capital Cost (million $)**	**Annual Payment (million $)**	**Payment ($/kwh)**
MSW Landfill Gas	$8.3	$0.0223	$0.0128	$0.0000	$0.0352	$0.0852	30	0.90	7884	$1,500	$45.0	$5.3	$0.0223
Scrubbed Coal New	$180.8	$0.0181	$0.0071	$0.0130	$0.0382	$0.0882	600	0.90	7884	$1,213	$727.8	$85.5	$0.0181
Integrated Coal Gasification Combined Cycle (IGCC)	$173.5	$0.0209	$0.0069	$0.0122	$0.0400	$0.0900	550	0.90	7884	$1,402	$771.1	$90.6	$0.0209
Advanced Nuclear	$332.8	$0.0292	$0.0081	$0.0050	$0.0422	$0.0922	1,000	0.90	7884	$1,957	$1,957.0	$229.9	$0.0292
Advanced Gas Combined Cycle	$130.1	$0.0083	$0.0031	$0.0298	$0.0412	$0.0912	400	0.90	7884	$558	$223.2	$26.2	$0.0083
Conventional Gas Combined Cycle	$85.7	$0.0084	$0.0032	$0.0318	$0.0435	$0.0935	250	0.90	7884	$567	$141.8	$16.7	$0.0084
Wind 100 MW[5]	$12.8	$0.0357	$0.0095	$0.0000	$0.0452	$0.0952	100	0.32	2829	$859	$85.9	$10.1	$0.0357
Advanced Combustion Turbine	$90.9	$0.0056	$0.0040	$0.0406	$0.0501	$0.1001	230	0.90	7884	$374	$86.0	$10.1	$0.0056
IGCC with Carbon Sequestration	$159.4	$0.0299	$0.0090	$0.0143	$0.0532	$0.1032	380	0.90	7884	$2,006	$762.3	$89.5	$0.0299
Wind 50 MW	$8.0	$0.0471	$0.0095	$0.0000	$0.0566	$0.1066	50	0.32	2829	$1,134	$56.7	6.7	$0.0471
Conventional Combustion Turbine	$73.4	$0.0059	$0.0045	$0.0478	$0.0582	$0.1082	160	0.90	7884	$395	$63.2	$7.4	$0.0059
Advanced CC with Carbon Sequestration	$187.6	$0.0166	$0.0048	$0.0381	$0.0595	$0.1095	400	0.90	7884	$1,114	$445.6	$52.3	$0.0166
Biomass	$34.8	$0.0284	$0.0094	$0.0219	$0.0598	$0.1098	80	0.83	7271	$1,757	$140.6	$16.5	$0.0284
Distributed Generation Base	$1.0	$0.0120	$0.0081	$0.0440	$0.0641	$0.1141	2	0.90	7884	$807	$1.6	$0.2	$0.0120
Distributed Generation Peak	$0.6	$0.0145	$0.0081	$0.0495	$0.0721	$0.1221	1	0.90	7884	$970	$1.0	$0.1	$0.0145
Wind 10 MW[5]	$2.8	$0.0896	$0.0095	$0.0000	$0.0991	$0.1491	10	0.32	2829	$2,159	$21.6	$2.5	$0.0896
Photovoltaic	$2.7	$0.2496	$0.0049	$0.0000	$0.2545	$0.3045	5	0.24	2102	$4,467	$22.3	$2.6	$0.2496
Solar Thermal[6]	$39.8	$0.2646	$0.0382	$0.0000	$0.3028	$0.3528	100	0.15	1314	$2,960	$296.0	$34.8	$0.2646

Notes:

1. Excludes regional multipliers.
2. Annual Energy Outlook 2005, Basis of Assumptions Table 38.
3. Assumed $0.05/kwh delivery cost excluding line losses.
4. Fuel prices are New York specific.
5. Applied the 0.6 rule using 50 MW as the base reference.
6. Capital costs are without the 10 percent investment tax credit.

TABLE D-1-3 (Continued) Energy Information Administration National Average Cost Estimates (2003 dollars)

	Variable O&M		Fixed O&M			Fuel Cost			
Plant Type[2]	($/kwh)[2]	Annual (Million)	($/kw)[2]	($/kwh)	Annual O&M (millions $)	Fuel Cost ($/mmBTU)[4]	Heat Rate (BTU/kwh)[2]	Fuel Cost ($/kwh)	Fuel Cost (million $/yr)
MSW Landfill Gas	$0.0000	$2.4	$101.07	$0.0128	$3.0	$0.00	13,648	$0.0000	$0
Scrubbed Coal New	$0.0041	$19.2	$24.36	$0.0031	$14.6	$1.47	8,844	$0.0130	$61.5
Integrated Coal Gasification Combined Cycle (IGCC)	$0.0026	$11.2	$34.21	$0.0043	$18.8	$1.47	8,309	$0.0122	$53.0
Advanced Nuclear	$0.0004	$3.5	$60.06	$0.0076	$60.1		10,400	$0.0050	$39.4
Advanced Gas Combined Cycle	$0.0018	$5.6	$10.35	$0.0013	$4.1	$4.42	6,752	$0.0298	$94.1
Conventional Gas Combined Cycle	$0.0018	$3.6	$11.04	$0.0014	$2.8	$4.42	7,196	$0.0318	$62.7
Wind 100 MW[5]	$0.0000	$0	$26.81	$0.0095	$2.7	$0.00	10,280	$0.0000	$0
Advanced Combustion Turbine	$0.0028	$5.1	$9.31	$0.0012	$2.1	$4.42	9,183	$0.0406	$73.6
IGCC with Carbon Sequestration	$0.0039	$11.8	$40.26	$0.0051	$15.3	$1.47	9,713	$0.0143	$42.8
Wind 50 MW	$0.0000	$0	$26.81	$0.0095	$1.3	$0.00	10,280	$0.0000	$0
Conventional Combustion Turbine	$0.0032	$4.0	$10.72	$0.0014	$1.7	$4.42	10,817	$0.0478	$60.3
Advanced CC with Carbon Sequestration	$0.0026	$8.2	$17.60	$0.0022	$7.0	$4.42	8,613	$0.0381	$120.1
Biomass	$0.0030	$1.7	$47.18	$0.0065	$3.8	$2.46	8,911	$0.0219	$12.8
Distributed Generation Base	$0.0063	$0.1	$14.18	$0.0018	$0.03	$4.42	9,950	$0.0440	$0.7
Distributed Generation Peak	$0.0063	$0	$14.18	$0.0018	$0.01	$4.42	11,200	$0.0495	$0.4
Wind 10 MW[5]	$0.0000	$0	$26.81	$0.0095	$0.3	$0.00	10,280	$0.0000	$0
Photovoltaic	$0.0000	$0	$10.34	$0.0049	$0.05	$0.00	10,280	$0.0000	$0
Solar Thermal[6]	$0.0000	$0	$50.23	$0.0382	$5.0	$0.00	10,280	$0.0000	$0

TABLE D-1-4 Energy Information Administration Regional Cost Estimates (2003 dollars)

	Total Cost[1]						Capacity			Financing (20 year term at 10%/year)			
Plant Type[2]	Annual Cost $million	Capital Cost ($/kwh)	Operating Costs ($/kwh)	Fuel Costs ($/kwh)	Total Cost of Electricity ($/kwh)	Delivery Cost ($/kwh)[3]	Capa-city (MW)	Capa-city Factor	Hours Operated per Year	Overnight Costs ($/kw)[1,2]	Capital Cost ($) millions	Annual Payment ($million)	Payment ($/kwh)
MSW Landfill Gas	$11.1	$0.0340	$0.0128	$0.0000	$0.0468	$0.0968	30	0.90	7884	$2,280	$68.4	$8.0	$0.0340
Scrubbed Coal New	$225.3	$0.0275	$0.0071	$0.0130	$0.0476	$0.0976	600	0.90	7884	$1,844	$1,106.2	$129.0	$0.0275
Integrated Coal Gasification Combined Cycle (IGCC)	$220.6	$0.0317	$0.0069	$0.0122	$0.0509	$0.1009	550	0.90	7884	$2,131	$1,172.1	$137.7	$0.0317
Distributed Generation Base	$0.5	$0.0257	$0.0034	$0.0000	$0.0291	$0.0791	2	0.90	7884	$1,724	$3.5	$0.4	$0.0257
Distributed Generation Peak	$0.3	$0.0339	$0.0034	$0.0000	$0.0373	$0.0873	1	0.90	7884	$2,274	$2.3	$0.3	$0.0339
Advanced Gas Combined Cycle	$143.7	$0.0126	$0.0031	$0.0298	$0.0456	$0.0956	400	0.90	7884	$848	$339.3	$39.8	$0.0126
Wind 10 MW[5]	$1.3	$0.0376	$0.0095	$0.0000	$0.0471	$0.0971	10	0.32	2829	$905	$9.1	$1.1	$0.0376
Conventional Gas Combined Cycle	$94.4	$0.0128	$0.0032	$0.0318	$0.0479	$0.0979	250	0.90	7884	$862	$215.5	$25.3	$0.0128
Advanced Nuclear	$452.3	$0.0443	$0.0081	$0.0050	$0.0574	$0.1074	1,000	0.90	7884	$2,975	$2,974.6	$349.4	$0.0443
Advanced Combustion Turbine	$111.1	$0.0089	$0.0045	$0.0478	$0.0613	$0.1113	230	0.90	7884	$600	$138.1	$16.2	$0.0089
IGCC with Carbon Sequestration	$205.9	$0.0454	$0.0090	$0.0143	$0.0687	$0.1187	380	0.90	7884	$3,049	$1,158.7	$136.1	$0.0454
Wind 100 MW[5]	$19.9	$0.0236	$0.0061	$0.0406	$0.0703	$0.1203	100	0.32	2829	$568	$56.8	$6.7	$0.0236
Advanced CC with Carbon Sequestration	$221.9	$0.0183	$0.0081	$0.0440	$0.0704	$0.1204	400	0.90	7884	$1,227	$490.7	$57.6	$0.0183
Conventional Combustion Turbine	$89.1	$0.0398	$0.0089	$0.0219	$0.0707	$0.1207	160	0.90	7884	$2,671	$427.3	$50.2	$0.0398
Biomass	$47.4	$0.0238	$0.0083	$0.0495	$0.0816	$0.1316	80	0.83	7271	$1,474	$118.0	$13.9	$0.0238
Wind 50 MW	$16.6	$0.0703	$0.0088	$0.0381	$0.1172	$0.1672	50	0.32	2829	$1,693	$84.7	$9.9	$0.0703
Photovoltaic	$4.0	$0.3793	$0.0049	$0.0000	$0.3843	$0.4343	5	0.24	2102	$6,790	$33.9	$4.0	$0.3793
Solar Thermal[6]	$57.9	$0.4022	$0.0382	$0.0000	$0.4404	$0.4904	100	0.15	1314	$4,499	$449.9	$52.8	$0.4022

Notes:
1. Includes a regional multiplier for capital costs only to account for higher construction costs in New York. The regional multiplier of 1.52 based on RGGI modeling assumptions. An additional regional multiplier for the variable and fixed O&M would be needed to reflect the higher costs in New York.

2. Annual Energy Outlook 2005, Basis of Assumptions Table 38

3. Assumed $0.05/kwh delivery cost excluding line losses

4. Fuel prices are New York specific.

5. Applied the 0.6 rule using 50 MW as the base reference

6. Capital costs shown are before the 10 percent investment tax credit is applied

TABLE D-1-4 (Continued) Energy Information Administration Regional Cost Estimates (2003 dollars)

	Variable O&M		Fixed O&M			Fuel Cost			
Plant Type[2]	($/kwh)[2]	Annual ($million)	($/kw)[2]	($/kwh)	Annual O&M ($million)	Fuel Cost ($/mmBTU)[4]	Heat Rate (BTU/kwh)[2]	Fuel Cost ($/kwh)	Fuel Cost (million $/yr)
MSW Landfill Gas	$0.0000	$2.4	$101.07	$0.0128	$3,032,100	$0.00	13,648	$0.0000	$0
Scrubbed Coal New	$0.0041	$19.2	$24.36	$0.0031	$14,616,000	$1.47	8,844	$0.0130	$61.6
Integrated Coal Gasification Combined Cycle (IGCC)	$0.0026	$11.2	$34.21	$0.0043	$18,815,500	$1.47	8,309	$0.0122	$53.0
Distributed Generation Base	$0.0000	$0	$26.81	$0.0034	$53,620	$0.00	10,280	$0.0000	$0
Distributed Generation Peak	$0.0000	$0	$26.81	$0.0034	$26,810	$0.00	10,280	$0.0000	$0
Advanced Gas Combined Cycle	$0.0018	$5.6	$10.35	$0.0013	$4,140,000	$4.42	6,752	$0.0298	$94.1
Wind 10 MW[5]	$0.0000	$0	$26.81	$0.0095	$268,100	$0.00	10,280	$0.0000	$0
Conventional Gas Combined Cycle	$0.0018	$3.6	$11.04	$0.0014	$2,760,000	$4.42	7,196	$0.0318	$62.7
Advanced Nuclear	$0.0004	$3.5	$60.06	$0.0076	$60,060,000	$0.00	10,400	$0.0050	$39.4
Advanced Combustion Turbine	$0.0032	$5.7	$10.72	$0.0014	$2,465,600	$4.42	10,817	$0.0478	$86.7
IGCC with Carbon Sequestration	$0.0039	$11.8	$40.26	$0.0051	$15,298,800	$1.47	9,713	$0.0143	$42.8
Wind 100 MW[5]	$0.0028	$0.8	$9.31	$0.0033	$931,000	$4.42	9,183	$0.0406	$11.5
Advanced CC with Carbon Sequestration	$0.0063	$19.9	$14.18	$0.0018	$5,672,000	$4.42	9,950	$0.0440	$138.7
Conventional Combustion Turbine	$0.0030	$3.7	$47.18	$0.0060	$7,548,800	$2.46	8,911	$0.0219	$27.7
Biomass	$0.0063	$3.7	$14.18	$0.0020	$1,134,400	$4.42	11,200	$0.0495	$28.8
Wind 50 MW	$0.0026	$0.4	$17.60	$0.0062	$880,000	$4.42	8,613	$0.0381	$5.4
Photovoltaic	$0.0000	$0	$10.34	$0.0049	$51,700	$0.00	10,280	$0.00	$0
Solar Thermal[6]	$0.0000	$0	$50.23	$0.0382	$5,023,000	$0.00	10,280	$0.00	$0

TABLE D-1-5a University of Chicago National Average Cost Estimates (2003 dollars)

Plant Type	Total Cost[1]						Capacity			
	Annual Cost ($/yr)	Capital Cost ($/kWh)	Operating Costs ($/kWh)	Fuel Costs ($/kWh)	Total Cost of Electricity ($/kWh)	Delivery Cost ($/kWh)[2]	Assumed Capacity (MW)	Assumed Capacity (kW)	Capacity Factor	Hours Operated per Year
Integrated Coal Gasification Combined Cycle	$136,251,949	$0.0199	$0.0052	$0.0094	$0.0346	$0.0846	500	500,000	0.90	7884
Natural Gas Combined Cycle	$139,350,109	$0.0088	$0.0030	$0.0236	$0.0354	$0.0854	500	500,000	0.90	7884
Pulverized Coal Steam	$140,577,240	$0.0167	$0.0077	$0.0113	$0.0357	$0.0857	500	500,000	0.90	7884
Fluid Bed Coal	$141,076,995	$0.0179	$0.0059	$0.0120	$0.0358	$0.0858	500	500,000	0.90	7884
Pulverized Coal Supercritical	$148,369,695	$0.0179	$0.0085	$0.0113	$0.0376	$0.0876	500	500,000	0.90	7884
Nuclear Advanced Boiler Water Reactor	$341,200,360	$0.0238	$0.0152	$0.0042	$0.0433	$0.0933	1,000	1,000,000	0.90	7884

Plant Type	Financing						Total O&M		Fuel Cost	
	Capital Costs ($/kw)[1]	Capital Cost ($)	Term	Interest	Annual Payment ($/yr)	Payment ($/kwh)	($/kwh)	($/yr)	Fuel Cost ($/kwh)	Fuel Cost ($/yr)
Integrated Coal Gasification Combined Cycle	$1,338	$669,000,000	20	10%	$78,580,489	$0.0199	$0.0052	$20,458,980	$0.0094	$37,212,480
Natural Gas Combined Cycle	$590	$295,000,000	20	10%	$34,650,589	$0.0088	$0.0030	$11,668,320	$0.0236	$93,031,200
Pulverized Coal Steam	$1,119	$559,500,000	20	10%	$65,718,660	$0.0167	$0.0077	$30,471,660	$0.0113	$44,386,920
Fluid Bed Coal	$1,200	$600,000,000	20	10%	$70,475,775	$0.0179	$0.0059	$23,139,540	$0.0120	$47,461,680
Pulverized Coal Supercritical	$1,200	$600,000,000	20	10%	$70,475,775	$0.0179	$0.0085	$33,507,000	$0.0113	$44,386,920
Nuclear Advanced Boiler Water Reactor	$1,600	$1,600,000,000	20	10%	$187,935,400	$0.0238	$0.0152	$120,073,320	$0.0042	$33,191,640

NOTES: Excludes regional multipliers. Assumes $0.05/kWh delivery cost, excluding line losses

TABLE D-1-5b University of Chicago Regional Cost Estimates (2003 dollars)

Plant Type	Total Cost[1]						Capacity			
	Annual Cost ($/yr)	Capital Cost ($/kWh)	Operating Costs ($/kWh)	Fuel Costs ($/kWh)	Total Cost of Electricity ($/kWh)	Delivery Cost ($/kWh)[2]	Assumed Capacity (MW)	Assumed Capacity (kW)	Capacity Factor	Hours Operated per Year
Natural Gas Combined Cycle	$157,368,416	$0.0134	$0.0030	$0.0236	$0.0399	$0.0899	500	500,000	0.90	7884
Pulverized Coal Steam	$174,750,943	$0.0253	$0.0077	$0.0113	$0.0443	$0.0943	500	500,000	0.90	7884
Integrated Coal Gasification Combined Cycle	$177,113,803	$0.0303	$0.0052	$0.0094	$0.0449	$0.0949	500	500,000	0.90	7884
Fluid Bed Coal	$177,724,398	$0.0272	$0.0059	$0.0120	$0.0451	$0.0951	500	500,000	0.90	7884
Pulverized Coal Supercritical	$185,017,098	$0.0272	$0.0085	$0.0113	$0.0469	$0.0969	500	500,000	0.90	7884
Nuclear Advanced Boiler Water Reactor	$438,926,767	$0.0362	$0.0152	$0.0042	$0.0557	$0.1057	1,000	1,000,000	0.90	7884

Plant Type	Financing						Total O&M		Fuel Cost	
	Capital Costs ($/kW)[1]	Capital Cost ($)	Term	Inte-rest	Annual Payment ($/yr)	Payment ($/kWh)	($/kWh)	($/yr)	Fuel Cost ($/kWh)	Fuel Cost ($/yr)
Natural Gas Combined Cycle	$897	$448,400,000	20	10%	$52,668,896	$0.0134	$0.0030	$11,668,320	$0.0236	$93,031,200
Pulverized Coal Steam	$1,701	$850,440,000	20	10%	$99,892,363	$0.0253	$0.0077	$30,471,660	$0.0113	$44,386,920
Integrated Coal Gasification Combined Cycle	$2,034	$1,016,880,000	20	10%	$119,442,343	$0.0303	$0.0052	$20,458,980	$0.0094	$37,212,480
Fluid Bed Coal	$1,824	$912,000,000	20	10%	$107,123,178	$0.0272	$0.0059	$23,139,540	$0.0120	$47,461,680
Pulverized Coal Supercritical	$1,824	$912,000,000	20	10%	$107,123,178	$0.0272	$0.0085	$33,507,000	$0.0113	$44,386,920
Nuclear Advanced Boiler Water Reactor	$2,432	$2,432,000,000	20	10%	$285,661,807	$0.0362	$0.0152	$120,073,320	$0.0042	$33,191,640

NOTES: Includes a regional multiplier for capital costs only to account for higher construction costs in New York; the regional multiplier is 1.52, based on RGGI modeling assumptions; an additional regional multiplier for the variable and fixed O&M would be needed to reflect the higher costs in New York. Assumes $0.05/kWh delivery cost excluding line losses.

TABLE D-1-6 University of Chicago Regional Cost Estimates for the New York Control Area (2003 dollars)

Plant Type	Total Cost[1]						Capacity			
	Annual Cost ($/yr)	Capital Cost ($/kwh)	Operating Costs ($/kwh)	Fuel Costs ($/kwh)	Total Cost of Electricity ($/kwh)	Delivery Cost ($/kwh)[2]	Assumed Capacity (MW)	Assumed Capacity (kW)	Capacity Factor	Hours Operated per Year
Natural Gas Combined Cycle	$157,368,416	$0.0134	$0.0030	$0.0236	$0.0399	$0.0899	500	500,000	0.90	7884
Pulverized Coal Steam	$174,750,943	$0.0253	$0.0077	$0.0113	$0.0443	$0.0943	500	500,000	0.90	7884
Integrated Coal Gasification Combined Cycle	$177,113,803	$0.0303	$0.0052	$0.0094	$0.0449	$0.0949	500	500,000	0.90	7884
Fluid Bed Coal	$177,724,398	$0.0272	$0.0059	$0.0120	$0.0451	$0.0951	500	500,000	0.90	7884
Pulverized Coal Supercritical	$185,017,098	$0.0272	$0.0085	$0.0113	$0.0469	$0.0969	500	500,000	0.90	7884
Nuclear Advanced Boiler Water Reactor	$438,926,767	$0.0362	$0.0152	$0.0042	$0.0557	$0.1057	1,000	1,000,000	0.90	7884

Plant Type	Financing						Total O&M		Fuel Cost	
	Capital Costs ($/kW)[1]	Capital Cost ($)	Term	Interest	Annual Payment ($/yr)	Payment ($/kwh)	($/kWh)	($/yr)	Fuel Cost ($/kWh)	Fuel Cost ($/yr)
Natural Gas Combined Cycle	$897	$448,400,000	20	10%	$52,668,896	$0.0134	$0.0030	$11,668,320	$0.0236	$93,031,200
Pulverized Coal Steam	$1,701	$850,440,000	20	10%	$99,892,363	$0.0253	$0.0077	$30,471,660	$0.0113	$44,386,920
Integrated Coal Gasification Combined Cycle	$2,034	$1,016,880,000	20	10%	$119,442,343	$0.0303	$0.0052	$20,458,980	$0.0094	$37,212,480
Fluid Bed Coal	$1,824	$912,000,000	20	10%	$107,123,178	$0.0272	$0.0059	$23,139,540	$0.0120	$47,461,680
Pulverized Coal Supercritical	$1,824	$912,000,000	20	10%	$107,123,178	$0.0272	$0.0085	$33,507,000	$0.0113	$44,386,920
Nuclear Advanced Boiler Water Reactor	$2,432	$2,432,000,000	20	10%	$285,661,807	$0.0362	$0.0152	$120,073,320	$0.0042	$33,191,640

NOTES: Includes a regional multiplier for capital costs only to account for higher construction costs in New York. The regional multiplier of 1.52 based on RGGI modeling assumptions. An additional regional multiplier for the variable and fixed O&M would be needed to reflect the higher costs in New York. Assumed $0.05/kwh delivery cost excluding line losses

TABLE D-1-7 New York City Fuel Prices
($/MMBTU)

Fuel Prices	2004 Prices	2004 Prices in 2003$
Coal 1% S	$1.50	$1.47
Natural Gas	$4.50	$4.42
MSW	-$2.50	-$2.46
Biomass	$2.50	$2.46

NOTE: Fuel prices are New York specific and were provided by New York State Energy Research and Development Authority. Negative price for MSW is from avoidance of otherwise necessary disposal fees.

APPENDIX D-2

Parker Mathusa
Erin Hogan

ZONAL ENERGY AND SEASONAL CAPACITY IN NEW YORK STATE, 2004 AND 2005

TABLE D-2-1 Summary of Summer and Winter Capacity, Energy Production, and Energy Requirements in the New York Control Area, by Zone

Zone [a]	Summer Capacity (MW)			Winter Capacity (MW)			Energy (GWh)			Energy Requirements (GWh)			Energy Production/Demand Index		
	2004	2005	% Δ	2004	2005	% Δ	2004	2005	% Δ	2004	2005 [2]	% Δ	2004	2005	% Δ
A	5,216	5,083	-2.55%	5,314	5,212	-1.93%	26,963	32,080	18.98%	15,942	16,106	1.03%	1.69	1.99	17.77%
B	950	950	-0.07%	971	972	0.05%	5,738	6,258	9.07%	9,719	9,911	1.98%	0.59	0.63	6.95%
C	6,651	6,617	-0.51%	6,859	6,884	0.36%	29,821	27,263	-8.58%	16,794	16,830	0.21%	1.78	1.62	-8.77%
D	1,268	1,262	-0.50%	1,182	1,277	8.08%	8,505	9,153	7.62%	5,912	5,782	-2.20%	1.44	1.58	10.04%
E	886	871	-1.74%	947	946	-0.11%	3,165	1,404	-55.63%	6,950	7,044	1.35%	0.46	0.20	-56.22%
F	3,608	3,111	-13.78%	3,720	3,535	-4.97%	7,726	8,508	10.12%	11,115	11,161	0.41%	0.70	0.76	9.67%
G	3,501	3,421	-2.28%	3,575	3,512	-1.77%	9,327	9,213	-1.22%	10,452	10,640	1.80%	0.89	0.87	-2.96%
H	2,079	2,069	-0.46%	2,102	2,100	-0.06%	16,297	16,638	2.10%	2,219	2,276	2.57%	7.34	7.31	-0.46%
I	3.5	2.9	-17.24%	3	3	-3.25%	4	8	107.93%	6,121	6,184	1.03%	0.00	0.00	105.81%
J	8,894	8,981	0.99%	9,455	9,705	2.65%	20,352	21,821	7.22%	50,829	52,073	2.45%	0.40	0.42	4.66%
K	5,054	5,180	2.48%	5,375	5,509	2.49%	15,565	14,822	-4.78%	21,960	22,203	1.11%	0.71	0.67	-5.82%
Statewide	38,111	37,548	-1.48%	39,504	39,655	0.38%	143,463	147,169	2.58%	158,014	160,210	1.39%	0.91	0.92	1.18%

[a] The New York Control Area's load zones are A, West; B, Genesee; C, Central; D, North; E, Mohawk Valley; F, Capital; G, Hudson Valley; H, Millwood; I, Dunwoodie; J, New York City; and K, Long Island.
SOURCE: NYISO 2005

TABLE D-2-2 Summer Zonal Capacity, by Fuel, 2004 and 2005

			Dual-Fuel Summer Capacity (MW)					Single-Fuel Summer Capacity (MW)												
		Total (MW)						Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kerosene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone		Zonal Winter Capa-city	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	2004	5,216	201					1,988	309.4	1				5	2,672		39			0.03
	2005	5,083	193					1,902	307.8	1				5	2,636		38			0.03
	%Δ	-2.55%	-3.84%					-4.35%	-0.51%	0.00%				3.85%	-1.34%		-4.06%			0.00%
B	2004	950						240	132	14				2	58			498		6.7
	2005	950						238	133	14				2	57			499		6.7
	%Δ	-0.07%						-0.83%	0.99%	0.00%				0.00%	-1.62%			0.20%		0.00%
C	2004	6,651	1,043					678	442	8	1,667			17	122		34	2,611		30
	2005	6,617	1,038					677	432	8	1,649			17	122		33	2,610		30
	%Δ	-0.51%	-0.42%					-0.19%	-2.13%	0.00%	-1.06%			-0.51%	0.60%		-2.07%	-0.04%		0.00%
D	2004	1,268							320.9	2					927				18	
	2005	1,262							320.6	2					922				18	
	%Δ	-0.50%							-0.09%	0.00%					-0.64%				-0.55%	
E	2004	886						52	333						471				20	9.9
	2005	871						52	329						460				20	9.9
	%Δ	-1.74%						0.00%	-1.44%						-2.30%				1.00%	0.00%
F	2004	3,608	405	356					1,363						1,470		13		0.5	0
	2005	3,111	398						1,227					2	1,472		12		0.5	0
	%Δ	-13.78%	-1.78%						-10.01%						0.18%		-12.3%		0.00%	0.00%
G	2004	3,501	17	2,525	92		727			5			15.6	6	105		9			0
	2005	3,421	16	2,446	91		728			5			15.6	6	105		8			0
	%Δ	-2.28%	-3.53%	-3.13	-1.95%		0.15%			0.00%			0.00%	0.00%	0.67%		-4.65%			0.00%
H	2004	2,079								47							52	1,981		
	2005	2,069								47							52	1,971		
	%Δ	-0.46%								0.00%							0.97%	-0.50%		
I	2004	3													3	0.48	0.2			
	2005	3												0.2	2	0.48				
	%Δ	-17.24%													-21.4%	0.00%				
J	2004	8,894	285	5,253	1,181				1,321	669			186							
	2005	8,981	513	5,181	1,186				1,318	667			117							
	%Δ	0.99%	80.18%	-1.37	0.42%				-0.20%	-0.31%			-36.99%							
K	2004	5,054	567	2,420					805	1,126				6		18	114			
	2005	5,180	579	2,442					920	1,113				5			121			
	%Δ	2.48%	2.26%	0.88					14.39%	-1.17%				-9.09%			6.43%			
NYCA	2004	38,111	2,516	10,555	1,273	0	727	2,958	5,026	1,871	1,667	0	202	36	5,827	18	260	5,090	39	47
	2005	37,548	2,737	10,069	1,276	0	728	2,869	4,988	1,856	1,649	0	133	37	5,777	0	264	5,080	39	47
	%Δ	-1.48%	8.78%	-4.60	0.24%		0.15%	-3.03%	-0.76%	-0.82%	-1.06%		-34.13%	4.28%	-0.86%	-97.4%	1.25%	-0.20%	0.26%	0.00%

NOTE: For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005

TABLE D-2-3 Winter Zonal Capacity, by Fuel, 2004 and 2005

		Total	Dual-Fuel Winter Capacity (MW)					Single Fuel Winter Capacity (MW)												
								Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kero-sene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone		Zonal Winter Capa-city	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	2004	5,314	215					2,039	342.8	1				6	2,672		40			0.03
	2005	5,212	217					1,937	337.4	1				6	2,674		40			0.03
	%Δ	-1.93%	1.07%					-5.01%	-1.56%	0.00%				-1.79%	0.07%		1.77%			0.00%
B	2004	971						250	141	16				2	58			498		6.7
	2005	972						245	143	18				2	58			499		6.7
	%Δ	0.05%						-2.00%	1.92%	12.50%				0.00%	0.21%			0.14%		0.00%
C	2004	6,859	1,184					675	482	8	1,675			18	125		33	2,630		30
	2005	6,884	1,191					673	489	8	1,689			17	123		33	2,629		30
	%Δ	0.36%	0.62%					-0.16%	1.49%	0.00%	0.83%			-1.44%	-1.6%		0.68%	-0.03%		0.00%
D	2004	1,182							330.7	2					831				18	
	2005	1,277							331.2	2					927				18	
	%Δ	8.08%							0.15%	0.00%					11.4%				-0.6%	
E	2004	947						52	373						492				20	9.4
	2005	946						53	365						497				20	11.1
	%Δ	-0.11%						2.89%	-2.28%						0.85%				0.50%	18.2%
F	2004	3,720	444	383					1,392						1,487		13		0.5	0.02
	2005	3,535	458						1,545					2	1,517		12		0.5	0.02
	%Δ	-4.97%	3.08%						11.00%						2.07%		-12.03%		0.00%	0.00%
G	2004	3,575	23	2,565	111		730			5			22.4	6	104		8			0
	2005	3,512	22	2,504	112		731			5			17.7	6	105		8			0
	%Δ	-1.77%	-2.61%	-2.37%	1.54%		0.12%			0.00%			-22.%	0.00%	0.86%		-4.76%			0.00%
H	2004	2,102								64							51	1,987		
	2005	2,100								64							52	1,985		
	%Δ	-0.06%								0.00%							1.96%	-0.11%		
I	2004	3													2	0.48	0.2			
	2005	3												0.2	2	0.48				
	%Δ	-3.25%													-4.2%	0.00%				
J	2004	9,455	324	5,280	1,436				1,385	833			197							
	2005	9,705	580	5,256	1,463				1,394	876			137							
	%Δ	2.65%	79.00%	-0.45%	1.82%				0.67%	5.18%			-31.%							
K	2004	5,375	665	2,312					906	1,374				6			112			
	2005	5,509	674	2,355					980	1,382				6			112			
	%Δ	2.49%	1.29%	1.84%					8.24%	0.59%				0.00%			-0.18%			
NYCA	2004	39,504	2,855	10,540	1,547	0	730	3,015	5,352	2,302	1,675	0	220	37	5,772	0	257	5,115	39	46
	2005	39,655	3,142	10,115	1,575	0	731	2,909	5,586	2,355	1,689	0	155	39	5,903	0	257	5,113	39	48
	%Δ	0.38%	10.06%	-4.03%	1.80%		0.12%	-3.54%	4.37%	2.31%	0.83%		-30%	4.09%	2.26%	0.00%	-0.19%	-0.04%	0.00%	3.68%

NOTE: For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005

TABLE D-2-4 Annual Energy Production, by Fuel, 2004 and 2005

		Dual-Fuel Energy (GWH)						Single-Fuel Energy (GWH)												
Zone		Total Zonal Energy	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kero-sene KER	Methane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	2004	26,963	1,249					12,531	507.0					51	12,355		270			
	2005	32,080	1,214					12,775	484.1					45	17,316		245			
	%Δ	18.98%	-2.75%					1.94%	-4.52%					-11.02%	40.15%		-8.96%			
B	2004	5,738						1,423	201	1				17	216			3,863		15.6
	2005	6,258						1,545	134	1				16	239			4,308		14.3
	%Δ	9.07%						8.60%	-33.27%	-56.42%				-2.19%	10.46%			11.51%		-8.3%
C	2004	29,821	2,664					4,600	261		395			118	653		228	20,833		69
	2005	27,263	1,854					3,967	243		407			144	276		236	20,057		79
	%Δ	-8.58%	-30.4%					-13.78%	-6.82%		2.99%			22.12%	-57.77%		3.64%	-3.72%		14.1%
D	2004	8,505							1989.9						6,417				98	
	2005	9,153							1938.1						7,108				107	
	%Δ	7.62%							-2.60%						10.77%				9.03%	
E	2004	3,165						340	221						2,491				94	18.8
	2005	1,404						420	148						714				104	19.4
	%Δ	-55.6%						23.39%	-33.25%						-71.34%				10.4%	2.72%
F	2004	7,726	3,024	102					1,019						3,491		91			
	2005	8,508	3,021						2,958					14	2,129		77			
	%Δ	10.12%	-0.08%						190.25%						-39.%		-15.09%			
G	2004	9,327	135	4,447	8		4,312						2.4		381		43			
	2005	9,213	136	4,833	1		3,830						0.2		363		49			
	%Δ	-1.22%	1.10%	8.70%	-81.9%		-11.%						-90.%		-4.68%		14.44%			
H	2004	16,297															382	15,915		
	2005	16,638															378	16,260		
	%Δ	2.10%															-1.02%	2.17%		
I	2004	4													4					
	2005	8													8					
	%Δ	107.9%													107.93%					
J	2004	20,352	2,094	12,249	418				5,466	107			19							
	2005	21,821	3,295	12,750	554				5,060	119			43							
	%Δ	7.22%	57.37%	4.08%	32.71%				-7.44%	12.09%			132.%							
K	2004	15,565	2,009	10,507					1,474	664				19			892			
	2005	14,822	2,020	10,099					1,421	369				16			897			
	%Δ	-4.78%	0.52%	-3.89%					-3.58%	-44.49%				-16.75%			0.64%			
NYCA	2004	143463	11,175	27,305	425	0	4,312	18,895	11,140	772	395	0	21	205	26,008	0	1,905	40,610	192	103
	2005	147169	11,541	27,990	556	0	3,830	18,706	12,386	489	407	0	43	236	28,153	0	1,883	40,626	211	112
	%Δ	2.58%	3.28%	2.51%	30.60%		-11.%	-1.00%	11.19%	-36.70%	2.99%		106.%	15.13%	8.25%		-1.13%	0.04%	9.71%	8.63%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005

TABLE D-2-5 Summary of New York Control Area Generation Facilities' Energy Production by Fuel Type as of January 1, 2005

		Dual-Fuel Energy (GWh)					Single-Fuel Energy (GWh)												
Zone	Total Zonal Energy	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kero-sene KER	Meth-ane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	32,080	1,214					12,775	484.1					45	17,316		245			
B	6,258						1,545	134	1				16	239			4,308		14
C	27,263	1,854					3,967	243		407			144	276		236	20,057		79
D	9,153							1938.1						7,108				107	
E	1,404						420	148						714				104	19
F	8,508	3,021	309					2,958					14	2,129		77			
G	9,213	136	4,833	1		3,830						0.2		363		49			
H	16,638															378	16,260		
I	8													8					
J	21,821	3,295	12,750	554				5,060	119			43							
K	14,822	2,020	10,099					1,421	369				16		0	897			
NYCA	147,169	11,541	27,990	556	0	3,830	18,706	12,386	489	407	0	43	236	28,153	0	1,883	40,626	211	112

		Dual-Fuel Energy (%)					Single-Fuel Energy (%)												
Zone	Total Zonal Energy	NG/ FO2	NG/FO 6	NG/KE R	NG/JF	NG/BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kero-sene KER	Meth-ane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	21.8%	3.8%					39.8%	1.5%					0.1%	54.0%		0.8%			
B	4.3%						24.7%	2.1%	0.0%				0.3%	3.8%			68.8%		0.2%
C	18.5%	6.8%					14.5%	0.9%		1.5%			0.5%	1.0%		0.9%	73.6%		0.3%
D	6.2%							21.2%						77.7%				1.2%	
E	1.0%						29.9%	10.5%						50.8%				7.4%	1.4%
F	5.8%	35.5%	3.6%					34.8%					0.2%	25.0%		0.9%			
G	6.3%	1.5%	52.5%	0.0%		41.6%						0.0%		3.9%		0.5%			
H	11.3%															2.3%	97.7%		
I	0.01%													100.0%					
J	14.8%	15.1%	58.4%	2.5%				23.2%	0.5%			0.2%							
K	10.1%	13.6%	68.1%					9.6%	2.5%				0.1%		0.0%	6.1%			
NYCA	100.0%	7.8%	19.0%	0.4%	0.0%	2.6%	12.7%	8.4%	0.3%	0.3%	0.0%	0.0%	0.2%	19.1%	0.0%	1.3%	27.6%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

TABLE D-2-6 Summary of New York Control Area Generation Facilities' Winter Capacity, by Fuel Type, as of January 1, 2005

	Total	Dual-Fuel Winter Capacity (MW)					Single-Fuel Winter Capacity (MW)												
							Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kero-sene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Zonal Winter Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	5,212	217					1,937	337.4	1				6	2,674		40			0
B	972						245	143	18				2	58			499		6.7
C	6,884	1,191					673	489	8	1,689			17	123		33	2,629		30
D	1,277							331.2	2					927				18	
E	946						53	365						497				20	11.1
F	3,535	458						1,545					2	1,517		12		0.5	0
G	3,512	22	2,504	112		731			5			17.7	6	105		8			0
H	2,100								64							52	1,985		
I	3												0	2	0				
J	9,705	580	5,256	1,463				1,394	876			137							
K	5,509	674	2,355					980	1,382				6			112			
NYCA	39,655	3,142	10,115	1,575	0	731	2,909	5,586	2,355	1,689	0	155	39	5,903	0	257	5,113	39	48

	Total	Dual-Fuel Winter Capacity (%)					Single Fuel Winter Capacity (%)												
							Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kero-sene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Zonal Winter Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG /JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	13.1%	4.2%					37.2%	6.5%	0.0%				0.1%	51.3%		0.8%			0.0%
B	2.5%						25.2%	14.7%	1.9%				0.2%	6.0%			51.3%		0.7%
C	17.4%	17.3%					9.8%	7.1%	0.1%	24.5%			0.3%	1.8%		0.5%	38.2%		0.4%
D	3.2%							25.9%	0.1%					72.5%				1.4%	
E	2.4%						5.6%	38.6%						52.5%				2.1%	1.2%
F	8.9%	13.0%						43.7%					0.0%	42.9%		0.3%		0.0%	0.0%
G	8.9%	0.6%	71.3%	3.2%		20.8%			0.1%			0.5%	0.2%	3.0%		0.2%			0.0%
H	5.3%								3.0%							2.5%	94.5%		
I	0.01%												6.7%	77.2%	16.1%				
J	24.5%	6.0%	54.2%	15.1%				14.4%	9.0%			1.4%							
K	13.9%	12.2%	42.7%					17.8%	25.1%				0.1%			2.0%			
State Total	100.0%	7.9%	25.5%	4.0%	0.0%	1.8%	7.3%	14.1%	5.9%	4.3%	0.0%	0.4%	0.1%	14.9%	0.0%	0.6%	12.9%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

TABLE D-2-7 Summary of New York Control Area Generation Facilities' Summer Capacity, by Fuel Type, as of January 1, 2005

		Dual-Fuel Summer Capacity (MW)					Single-Fuel Summer Capacity (MW)												
Zone	Total Zonal Summer Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kero-sene KER	Methane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	5,083	193					1,902	307.8	1				5	2,636		38			0.03
B	950						238	133	14				2	57			499		6.7
C	6,617	1,038					677	432	8	1,649			17	122		33	2,610		30
D	1,262							320.6	2					922				18	
E	871						52	329						460				20	9.9
F	3,111	398						1,227					2	1,472		12		0.5	0
G	3,421	16	2,446	91		728			5			15.6	6	105		8			0
H	2,069								47							52	1,971		
I	3												0	2	0				
J	8,981	513	5,181	1,186				1,318	667			117							
K	5,180	579	2,442					920	1,113				5			121			
NYCA	37,548	2,737	10,069	1,276	0	728	2,869	4,988	1,856	1,649	0	133	37	5,777	0	264	5,080	39	47

		Dual Fuel Summer Capacity (%)					Single Fuel Summer Capacity (%)												
Zone	Total Zonal Summer Capacity	NG/F O2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kero-sene KER	Methane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	13.5%	3.8%					37.4%	6.1%	0.0%				0.1%	51.9%		0.7%			0.0%
B	2.5%						25.1%	14.0%	1.5%				0.2%	6.0%			52.5%		0.7%
C	17.6%	15.7%					10.2%	6.5%	0.1%	24.9%			0.3%	1.8%		0.5%	39.4%		0.5%
D	3.4%							25.4%	0.1%					73.0%				1.4%	
E	2.3%						6.0%	37.7%						52.8%				2.3%	1.1%
F	8.3%	12.8%						39.4%					0.1%	47.3%		0.4%		0.0%	0.0%
G	9.1%	0.5%	71.5%	2.6%		21.3%			0.1%			0.5%	0.2%	3.1%		0.2%			0.0%
H	5.5%								2.2%							2.5%	95.2%		
I	0.01%												6.9%	76.4%	16.7%				
J	23.9%	5.7%	57.7%	13.2%				14.7%	7.4%			1.3%							
K	13.8%	11.2%	47.1%					17.8%	21.5%				0.1%			2.3%			
NYCA	100.0%	7.3%	26.8%	3.4%	0.0%	1.9%	7.6%	13.3%	4.9%	4.4%	0.0%	0.4%	0.1%	15.4%	0.0%	0.7%	13.5%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

TABLE D-2-8 Summary of New York Control Area Generation Facilities' Energy, by Fuel Type, as of January 1, 2004

		Dual-Fuel Energy (GWh)					Single-Fuel Energy (GWh)												
							Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kerosene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Total Zonal Energy	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	26,963	1,249					12,531	507					51	12,355		270			
B	5,738						1,423	201	1				17	216			3,863		16
C	29,821	2,664					4,600	261		395			118	653		228	20,833		69
D	8,505							1989.9						6,417				98	
E	3,165						340	221						2,491				94	19
F	7,726	3,024	102					1,019						3,491		91			
G	9,327	135	4,447	8		4,312						2		381		43			
H	16,297															382	15,915		
I	4													4					
J	20,352	2,094	12,249	418				5,466	107			19							
K	15,565	2,009	10,507					1,474	664				19			892			
NYCA	143,463	11,175	27,305	425	0	4,312	18,895	11,140	772	395	0	21	205	26,008	0	1,905	40,610	192	103

		Dual-Fuel Energy (%)					Single Fuel Energy (%)												
							Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kerosene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Total Zonal Energy	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	18.8%	4.6%					46.5%	1.9%					0.2%	45.8%		1.0%			
B	4.0%						24.8%	3.5%	0.0%				0.3%	3.8%			67.3%		0.3%
C	20.8%	8.9%					15.4%	0.9%		1.3%			0.4%	2.2%		0.8%	69.9%		0.2%
D	5.9%							23.4%						75.4%				1.2%	
E	2.2%						10.7%	7.0%						78.7%				3.0%	0.6%
F	5.4%	39.1%	1.3%					13.2%						45.2%		1.2%			
G	6.5%	1.4%	47.7%	0.1%		46.2%						0.0%		4.1%		0.5%			
H	11.4%															2.3%	97.7%		
I	0.00%													100.0%					
J	14.2%	10.3%	60.2%	2.1%				26.9%	0.5%			0.1%							
K	10.8%	12.9%	67.5%					9.5%	4.3%				0.1%			5.7%			
NYCA	100.0%	7.8%	19.0%	0.3%	0.0%	3.0%	13.2%	7.8%	0.5%	0.3%	0.0%	0.0%	0.1%	18.1%	0.0%	1.3%	28.3%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

TABLE D-2-9 Summary of New York Control Area Generation Facilities' Winter Capacity, by Fuel Type, as of January 1, 2004

		Dual Fuel Winter Capacity (MW)					Single Fuel Winter Capacity (MW)												
	Total						Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kerosene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Zonal Winter Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	5,314	215					2,039	342.8	1				6	2,672		40			0
B	971						250	141	16				2	58			498		6.7
C	6,859	1,184					675	482	8	1,675			18	125		33	2,630		30
D	1,182							330.7	2					831				18	
E	947						52	373						492				20	9.4
F	3,720	444	383					1,392						1,487		13		0.5	0
G	3,575	23	2,565	111		730			5			22.4	6	104		8			0
H	2,102								64							51	1,987		
I	3													2	0	0			
J	9,455	324	5,280	1,436				1,385	833			197							
K	5,375	665	2,312					906	1,374				6			112			
NYCA	39,504	2,855	10,540	1,547	0	730	3,015	5,352	2,302	1,675	0	220	37	5,772	0	257	5,115	39	46

		Dual Fuel Winter Capacity					Single Fuel Winter Capacity												
	Total						Coal	Natural Gas	No. 2	No. 6	Jet Fuel	Kerosene	Methane	Water	Other	Refuse	Uranium	Wood	Wind
Zone	Zonal Winter Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	BIT	NG	FO2	FO6	JF	KER	MTE	WAT	OT	REF	UR	WD	WND
A	13.5%	4.0%					38.4%	6.4%	0.0%				0.1%	50.3%		0.7%			0.0%
B	2.5%						25.7%	14.5%	1.6%				0.2%	5.9%			51.3%		0.7%
C	17.4%	17.3%					9.8%	7.0%	0.1%	24.4%			0.3%	1.8%		0.5%	38.3%		0.4%
D	3.0%							28.0%	0.1%					70.3%				1.5%	
E	2.4%						5.5%	39.4%						52.0%				2.1%	1.0%
F	9.4%	11.9%	10.3%					37.4%						40.0%		0.4%		0.0%	0.0%
G	9.0%	0.6%	71.8%	3.1%		20.4%			0.1%			0.6%	0.2%	2.9%		0.2%			0.0%
H	5.3%								3.0%							2.4%	94.5%		
I	0.01%													77.9%	15.6%	6.5%			
J	23.9%	3.4%	55.8%	15.2%				14.6%	8.8%			2.1%							
K	13.6%	12.4%	43.0%					16.8%	25.6%				0.1%			2.1%			
NYCA	100.0%	7.2%	26.7%	3.9%	0.0%	1.8%	7.6%	13.5%	5.8%	4.2%	0.0%	0.6%	0.1%	14.6%	0.0%	0.7%	12.9%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

TABLE D-2-10 Summary of New York Control Area Generation Facilities' Summer Capacity, by Fuel Type, as of January 1, 2004

		Dual Fuel Summer Capacity (MW)					Single Fuel Summer Capacity (MW)												
Zone	Total Zonal Summer Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kerosene KER	Methane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	5,216	201					1,988	309.4	1				5	2,672		39			0.03
B	950						240	132	14				2	58			498		6.7
C	6,651	1,043					678	442	8	1,667			17	122		34	2,611		30
D	1,268							320.9	2					927				18	
E	886						52	333						471				20	9.9
F	3,608	405	356					1,363						1,470		13		0.5	0
G	3,501	17	2,525	92		727			5			15.6	6	105		9			0
H	2,079								47							52	1,981		
I	3													3	0	0			
J	8,894	285	5,253	1,181				1,321	669			186							
K	5,054	567	2,420					805	1,126				6		18	114			
NYCA	38,111	2,516	10,555	1,273	0	727	2,958	5,026	1,871	1,667	0	202	36	5,827	18	260	5,090	39	47

		Dual Fuel Summer Capacity					Single Fuel Summer Capacity												
Zone	Total Zonal Summer Capacity	NG/ FO2	NG/ FO6	NG/ KER	NG/ JF	NG/ BIT	Coal BIT	Natural Gas NG	No. 2 FO2	No. 6 FO6	Jet Fuel JF	Kerosene KER	Methane MTE	Water WAT	Other OT	Refuse REF	Uranium UR	Wood WD	Wind WND
A	13.7%	3.8%					38.1%	5.9%	0.0%				0.1%	51.2%		0.8%			0.0%
B	2.5%						25.3%	13.9%	1.5%				0.2%	6.1%			52.4%		0.7%
C	17.5%	15.7%					10.2%	6.6%	0.1%	25.1%			0.3%	1.8%		0.5%	39.3%		0.5%
D	3.3%							25.3%	0.1%					73.1%				1.4%	
E	2.3%						5.9%	37.6%						53.1%				2.3%	1.1%
F	9.5%	11.2%	9.9%					37.8%						40.7%		0.4%		0.0%	0.0%
G	9.2%	0.5%	72.1%	2.6%		20.8%			0.1%			0.4%	0.2%	3.0%		0.2%			0.0%
H	5.5%								2.2%							2.5%	95.3%		
I	0.01%													80.5%	13.8%	5.7%			
J	23.3%	3.2%	59.1%	13.3%				14.9%	7.5%			2.1%							
K	13.3%	11.2%	47.9%					15.9%	22.3%				0.1%		0.4%	2.2%			
NYCA	100.0%	6.6%	27.7%	3.3%	0.0%	1.9%	7.8%	13.2%	4.9%	4.4%	0.0%	0.5%	0.1%	15.3%	0.0%	0.7%	13.4%	0.1%	0.1%

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO 2005.

APPENDIX D-3

ENERGY GENERATED IN 2003 FROM NATURAL GAS UNITS

IN ZONES H THROUGH K

Parker Mathusa
Erin Hogan

TABLE D-3-1 Natural Gas Consumption for Electricity in Zones H Through K, 2003

Fuel Type	Total Gigawatt-hours Produced in 2003	Percent of Capacity Using NG	Estimated GWH Generated with NG	Estimated Heat Rate Btu/kWh	Estimated NG Consumed (million Btu per year)	Estimated NG Consumed (thousand cubic feet per year)	Estimated Daily Consumption (billion cubic feet per day)
NG/FO2	4,103	80	3,282	10,500	34,465,200	33,625	0.09
NG/FO6	22,756	80	18,205	9,500	172,945,600	168,727	0.46
NG/KER	418	80	334	14,500	4,848,800	4,731	0.01
NG	6,940	100	6,940	8,500	58,990,000	57,551	0.16
Total	34,217		28,762		271,249,600	264,634	0.73

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO, 2005.

TABLE D-3-2 Natural Gas Consumption for Electricity in Zones H Through K, 2004

Fuel Type	Total Gigawatt-hours Produced in 2004	Percent of Capacity Using NG	Estimated GWH Generated with NG	Estimated Heat Rate Btu/kWh	Estimated NG Consumed (million Btu per year)	Estimated NG Consumed (thousand cubic feet per year)	Estimated Daily Consumption (billion cubic feet per day)
NG/FO2	5,315	80	4,252	10,500	44,646,000	43,557	0.12
NG/FO6	22,849	80	18,279	9,500	173,652,400	169,417	0.46
NG/KER	554	80	443	14,500	6,426,400	6,270	0.02
NG	6,481	100	6,481	8,500	55,088,500	53,745	0.15
Total	35,199		29,455		279,813,300	272,989	0.75

NOTE: See Table D-2-1, footnote *a*, for zone names. For definitions of acronyms in "Dual-Fuel" column heads, see "Single-Fuel" column heads.
SOURCE: NYISO, 2005.

TABLE D-3-3 Estimated Natural Gas Consumption of a 2,000 MW Combined-Cycle Unit with a 95 Percent Capacity Factor

Fuel Type	Total Gigawatt-hours Produced	Percent of Capacity Using NG	Estimated GWH Generated with NG	Estimated Heat Rate Btu/kWh	Estimated NG Consumed (millions of Btu)	Estimated NG Consumed (thousands of cubic feet)	Estimated Daily Consumption (billions of cubic feet per day)
NG	16,644	100	16,644	7,000	116,508,000	113,666	0.31

APPENDIX D-4

PROPOSED PIPELINE PROJECTS

IN THE NORTHEAST OF THE UNITED STATES

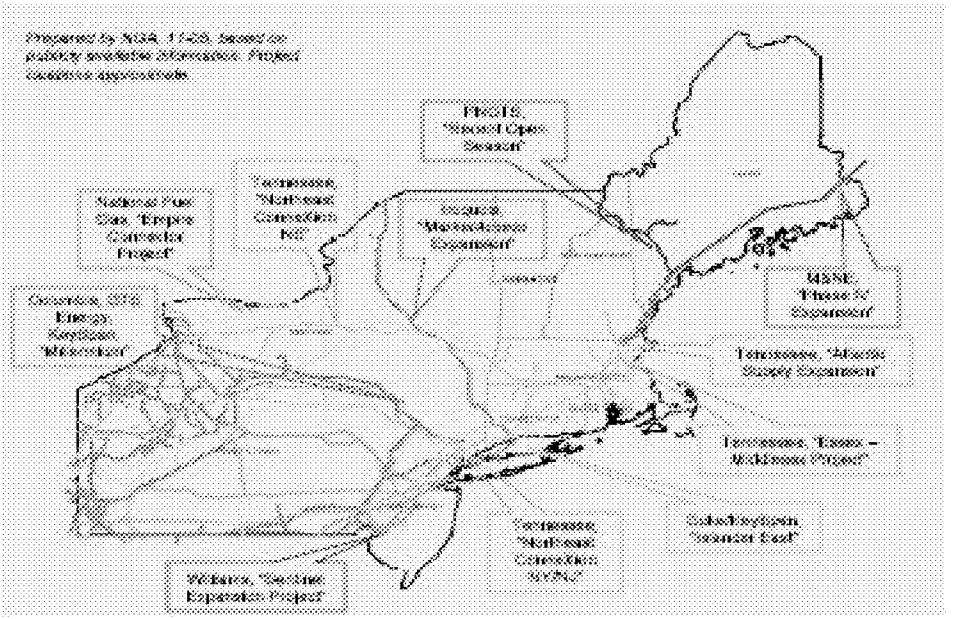

FIGURE D-4-1 Proposed Northeast Pipeline Projects
SOURCE: Northeast Gas Association. Available at http://www.northeastgas.org/pdf/pipe_enhance1105.pdf. Accessed February 2006.
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APPENDIX D-5

COAL TECHNOLOGIES

James R. Katzer[1]

Coal was used to produce 51 percent of the electricity generated in the United States in 2004. Domestic coal reserves are far greater than those of oil or natural gas, and costs for using coal to generate electricity are much lower than for oil and natural gas. Thus, coal promises to continue its position as the primary fuel for power generation for the foreseeable future. Pennsylvania, West Virginia, and other states have large resources of coal that could be delivered to New York relatively inexpensively.

Coal can contain high concentrations of ash and substantial amounts of sulfur, in addition to other toxic elements. It thus has the potential for high emissions, but appropriate control technology can reduce these emissions to a very low level.

Large coal-fired power plants are expensive to build and require substantial infrastructure for the delivery and storage of coal and the removal of ash and other captured pollutants. A much larger area is required for a coal plant than for a natural gas combined-cycle (NGCC) plant. Thus, coal plants require careful site selection and design. Even then, their impact on the environment and local communities can be greater than that of nuclear plants.

Pulverized coal combustion is the primary technology used to generate electricity from coal. Flue–gas-treatment technology to control emissions on new coal plants is very effective in reducing criteria emissions to very low levels. Plant generating efficiency can range from about 35 percent to as high as 43 percent for ultrasupercritical steam technology.

Fluidized-bed technology is another approach to coal combustion which, compared with pulverized coal combustion, offers much broader operating flexibility with respect to coal type. It also allows the combustion of a range of other materials mixed with the coal, such as the co-firing of biomass, wood wastes, and so on. Efficiency and emissions control are similar to that of pulverized coal.

Integrated gasification combined cycle (IGCC) involves gasification of coal to produce synthesis gas, cleaning the syngas, and then burning it in a combustion turbine. The power generation block for an IGCC plant is similar to that of a NGCC plant. The syngas-burning combustion turbine is connected to a generator; the steam raised from cooling the turbine exhaust powers a steam turbine. Typical generating efficiency is about 39 percent. The technology is commercial but issues of operability and availability need further resolution. With IGCC, emissions, including mercury and other toxics can be extremely low (unlike the case of pulverized coal with current technology), because the gases are all fully contained at high pressure. Coal ash from the IGCC process is fused and exits as a much less-leachable solid than fly ash. IGCC also allows for co-firing with biomass. Gasification provides for the most effective route to the capture of carbon dioxide for sequestration, and IGCC is projected to produce the lowest cost power from any technology with carbon dioxide capture.

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[1] James R. Katzer is a member of the committee and a former manager of strategic planning and program analysis at ExxonMobil Corporation.

Whereas coal-fired power plants produce the lowest cost power (without carbon dioxide capture), the requirements for large sites and extensive infrastructure limit the potential for the New York City area. In addition, air emissions and other environmental and community issues are likely to create considerable opposition to them in heavily populated areas. High capital costs and uncertainty of success in construction are likely to discourage investors. Nevertheless, the potential, particularly of the advanced IGCC technology, is so great that coal should be considered an option, at least for New York's upstate regions. The remainder of Appendix D-5 explores emissions control, probably the most contentious issue for coal plants.

Emissions Control for Pulverized Coal (PC) Combustion Units

Typical flue-gas-cleaning configurations for coal-fired power plants are shown in Figure D-5-1. U. S. emissions data are typically given in terms of energy input—for example, pounds per million British thermal units (Btu) and are thus independent of generating efficiency. This does not drive generating efficiency, as would an emissions limit based on output, such as pounds per megawatt (electric)-hour (MWe-h). Emissions below are presented in milligrams per cubic meter ($mg/Nm^{3)}$. The pulverized coal (PC) emissions are typically for supercritical PC units that are operating at about 39 percent (higher heating value [HHV]). Those for IGCC are for a unit that has 38 to 40 percent efficiency (HHV).

Figure D-5-2 shows how emissions of SO_x and NO_x are likely to continue to decline for many years, despite growing electricity generation. Figure D-5-3 compares the emissions potential for various technologies. Table D-5-1 lists the cost of electricity with various levels of emissions control.

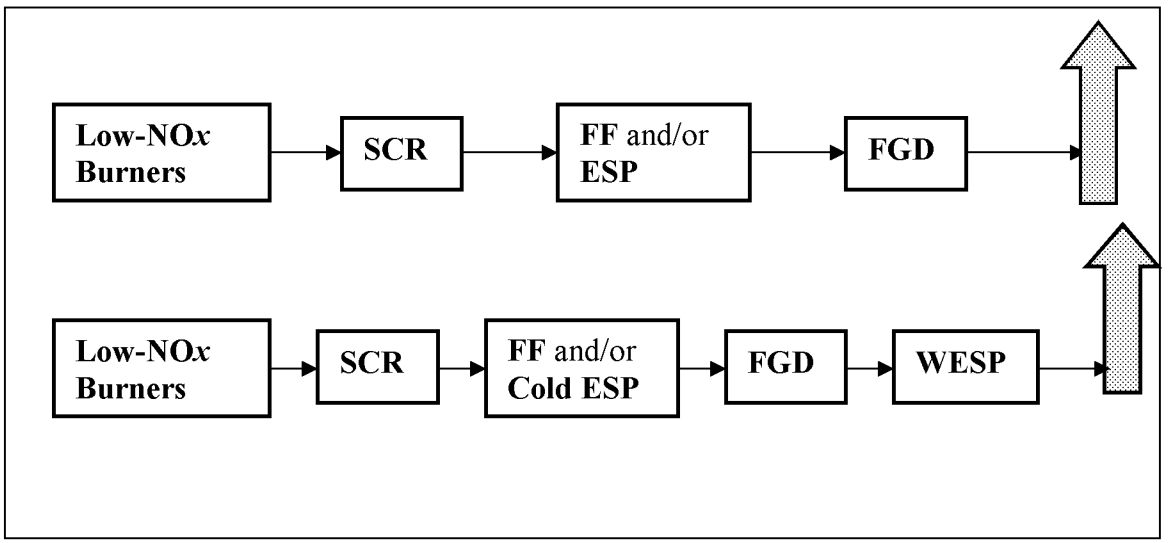


FIGURE D-5-1 Emissions Control Options for Coal-fired Generation
Note: NO_x:,oxides of nitrogen; SCR: selective catalytic reduction; FF: fabric filter; ESP: electrostatic precipitation; FGD: flue-gas desulfurization; WESP: wet ESP.

Particulate Control

Particulate control is typically accomplished with electrostatic precipitators (ESP) or fabric filters. ESPs or fabric filters are installed on all U.S. PC units and routinely achieve >99 percent particulate removal. Greater particulate control is possible with enhanced performance units or with the addition of wet ESP (WESP) after flue-gas desulfurization (FGD) (Oskarsson et al, 1997), (as illustrated in the second set of technologies in Figure D-5-1. The addition of wet ESP is beginning to become standard U.S. practice for new units to control condensable PM and should achieve emissions levels less than 5 mg/Nm^3 at 6 percent O_2. Typical emissions for modern, efficient, U.S. PC units are 15 to 20 mg/Nm^3. New units in Japan are achieving 5 mg/Nm^3 (PowerClean, 2004). Level of control is affected by coal type, sulfur content, and ash properties.

SO_x Control

Partial flue-gas desulfurization (FGD) is accomplished by dry injection of limestone into the duct work just behind the air preheater for 50-70 percent removal, with recovery of the solids in the ESP. Wet flue gas desulfurization (wet lime scrubbing), can achieve 95 percent SO_x removal without additives and 99+ percent SO_x removal with additives (Oskarrson et al., 1997; "Emissions Performance of PC Units," personal communication from ALSTOM, Windsor, Connecticut). Wet flue gas desulfurization has the greatest share of the market in the U.S., is well proven, and is commercially established. Typical U.S. commercial performance is 150 to 170 mg/Nm^3 at 6 percent O_2,[2] because this is what their permits require. Recently permitted units have much lower limits, and still lower emissions levels can be expected as permit levels are further reduced. The technology has not reached its limit of control. The best PC units in the U.S. burning high-sulfur bituminous coal are achieving demonstrated performance of less than 0.04 lb SO_2/MM Btu or 40

[2] When input based standards are given such as lb/MMBtu are, mg/Nm^3,or ppmv are compared, the respective degree of dilution of the flue gas needs to be specified in terms of flue gas O_2 concentration. All values here are given for 6 percent O_2 which is the international standard; boiler emission standards in the U.S. are typically given for 3 percent O_2.

mg/Nm^3 ("Emissions Performance of PC Units," personal communication from ALSTOM, Windsor, Connecticut); those in Japan operate below 75 mg/Nm^3. The wet sludge from the FGD unit must be disposed of safely.

NO_x Control

Low-NO_x combustion technologies, which are very low cost, are always used and give up to a 50 percent reduction from non-controlled combustion. The most effective, but also, the most expensive, technology is selective catalytic reduction (SCR), which can achieve >90 percent NO_x reduction over inlet concentration. Selective non-catalytic reduction falls between these two in effectiveness and cost. Today, SCR is the technology of choice to meet very low NO_x levels. Typical U.S. commercial emissions control performance is 65 to 90 mg/N m^3. The best PC units in the U.S. are achieving demonstrated performance of 0.03 lb NO_x/MM Btu or 30 mg/Nm^3 on sub-bituminous coal and 60 mg/Nm^3 on bituminous coal. The Parish plant, burning Powder River Basin coal, is achieving 0.03 lbs/MMBtu, which is 30 mg/Nm^3. The best PC units in Japan are achieving 30 to 50 mg/Nm^3 at 6 percent O_2.

Mercury Control

Mercury in the flue gas is in the elemental and oxidized forms, both in the vapor, and as mercury that has reacted with the fly ash. This third form of emissions is removed with the fly ash, resulting in 10 to 30 percent removal for bituminous coals, but less than 10 percent for sub-bituminous coals and lignite. The oxidized form is effectively removed by wet FGD scrubbing, resulting in 40-60 percent removal for bituminous coals and less than 30-40 percent removal for sub-bituminous coals and lignite. For low-sulfur sub-bituminous coals and particularly lignite most of the mercury is in the elemental form, which is not removed by wet FGD scrubbing. SCR for NO_x control can convert up to 60 percent of the elemental mercury to the oxidized form which is removed by FGD (EPA, 2005). Additional mercury removal can be achieved with activated carbon injection and an added fiber filter to collect the carbon. This technique can achieve 85-95 percent removal of the mercury. Commercial short-duration tests with powdered, activated carbon injection have shown removal rates around 90 percent for bituminous coals but lower for sub-bituminous coals (EPA, 2005). Research and development are currently evaluating improved technology that could reduce costs and improve effectiveness. The general consensus in the industry is that improved technology will change this picture significantly within the next few years.

Emissions Control for Integrated Gasification Combined Cycle Technology

IGCC has inherent advantages for emissions control because the cleanup occurs in the syngas which is contained at high pressure, and contaminants have high partial pressures. Thus, removal can be more effective and economical than cleaning up large volumes of low-pressure flue gas.

Particulate Control

The coal ash is primarily converted to a fused slag which is about 50 percent less in volume and is less leachable than fly ash; as such, it can be more easily disposed of safely. Particulate emissions from existing IGCC units vary from 1 to 8 lb/MWe-h. Most of these emissions come from the cooling towers and not from the turbine exhaust and as such are probably characteristic of

any generating unit with large cooling towers. This means that particulate emissions in the stack gas are below about 1 mg/Nm^3.

SO_x Control

Commercial processes such as MDEA and Selexol can remove more than 99 percent of the sulfur so that the syngas has a concentration of sulfur compounds that is less than 5 parts per million by volume (ppmv). The Rectisol process, which is more expensive, can reduce the SO_x concentration to less than 0.1 ppmv (Korens, 2002). SO_2 emissions of 0.15 lb/MWe-h, or 5.7 mg/Nm^3 (2 ppm) have been demonstrated at the ELCOGAS plant in Puertollano, Spain (Thompson, 2005), and at the new IGCC plant in Japan. Recovered sulfur can be converted to elemental sulfur or sulfuric acid.

NO_x Control

NO_x emissions from IGCC are similar to those from a natural-gas-fired combined-cycle plant. Dilution of syngas with nitrogen and water is used to reduce flame temperature and to lower NO_x formation to below 15 ppm. Further reduction to single digit levels is achievable with SCR. NO_x emissions of 4.2 mg/Nm^3 (2 ppm) NO_x (at 15 percentO_2) have been demonstrated commercially in the new IGCC unit in Japan.

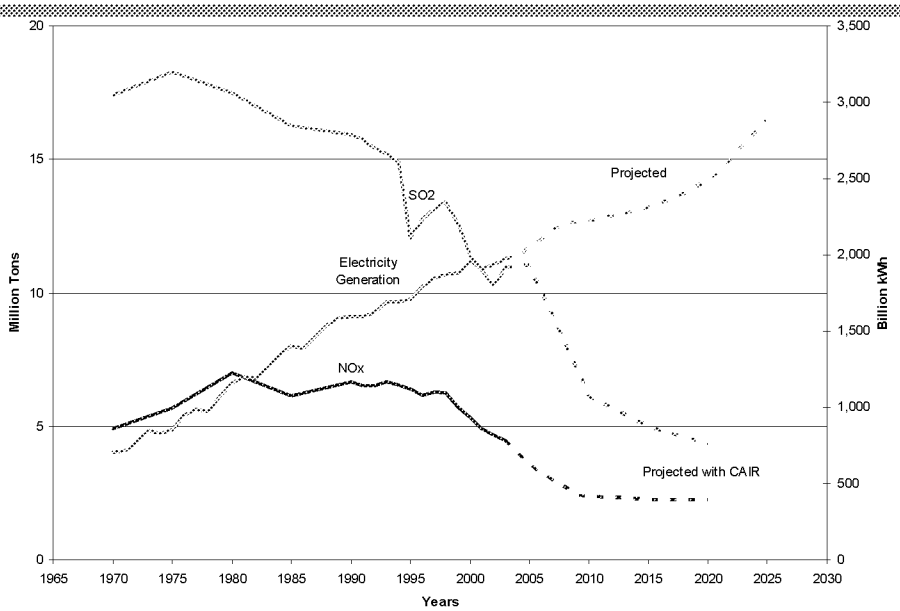
Mercury Control

Commercial technology for mercury removal in carbon beds is available. For natural gas processing 99.9 percent removal has been demonstrated, as has 95 percent removal from syngas (Parsons, 2002). Mercury and other toxics that are also co-captured in carbon beds produce a very small volume of material, which must be handled as a hazardous waste. Carbon capture will likely inhibit re-release into the environment.

Water Usage

PC and IGCC technologies both use significant quantities of water, and treatment and recycling are increasingly important issues. IGCC uses 20 to 50 percent less water than do PC plants. Wastewater treatment technology has been demonstrated for both technologies. Proven water treatment technology is available to handle the water effluents from each technology.

U.S. Emissions from Fossil Power Generation



2005 Clean Air Interstate Rule and Mercury Rule Caps for 2015:
SO2 = 2.5 million tons; NOx = 1.3 million tons, Mercury = 15 tons

FIGURE D-5-2 Past and projected U.S. Emissions from Fossil Power Generation, 1965 to 2030

FIGURE D-5-3. Types of Power Plant

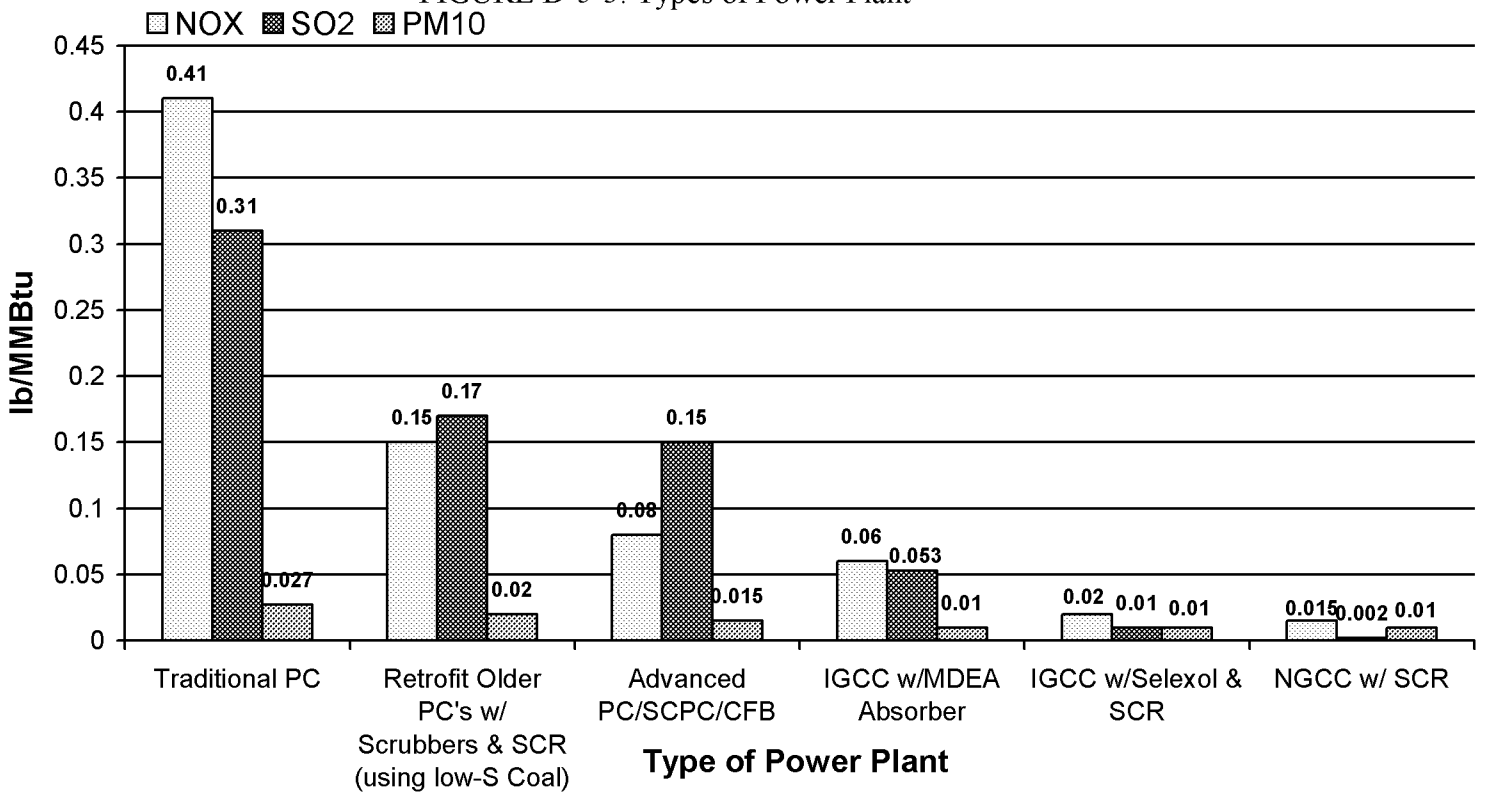


TABLE D-5-1 Electricity Cost from Coal with Emissions Controls

Level of Emissions Control		Cost of Electricity, cents/kWe-h
PC generation without SO_x or NO_x Controls, but with ESP for particulates		4.08
Today's PC unit with SO_x and NO_x Controls		4.75
2015 PC unit, tighter SO_x, NO_x and Mercury		4.97

SOURCE:

APPENDIX D-6:

GENERATION TECHNOLOGIES—WIND AND BIOMASS

Dan Arvizu[3]

This paper summarizes an analysis performed by NREL under my direction and supervision to evaluate the potential of wind energy and biomass resources to generate electricity to meet the future energy needs in the area currently supplied by the Indian Point Nuclear Power Plant near New York City. This analysis discusses the potential for three sources of wind energy and several sources of biomass, and the underlying assumptions and issues related to the projections of potential.

Some important observations include the following:

- The technical potentials (market size constrained only by the ability of technology to meet customer need and not by economics or other considerations) for both wind and biomass are very substantial, on the order of 9-10 GW in the Indian Point service area.
- The achievable potentials for both are significantly less than the technical potential, on the order of 3 GW in 2014, but still substantial enough to replace the Indian Point capacity by that time.
- Wind systems can be placed in the Hudson Valley right now, and, to a small extent, in the rural areas (northeast) of Long Island, within ten miles of a transmission corridor.
- Offshore wind could meet most of the Indian Point load by 2014. Canadian wind and hydro are reasonable options to explore in the meantime.
- Biomass in the form of municipal solid waste could provide half of the Indian Point capacity in 2014.
- Studies should continue to resolve wind-related issues such as transmission, dispatchability, siting and permitting, and biomass-related issues such as public perception, improved technology costs, and tipping fees.

Table D-6-1 summarizes quantitatively the potential impact of wind and biomass resources on the Indian Point service area, both in terms of technical potential and achievable potential.

[3] Dan Arvizu is a member of the committee and the director and chief executive of the National Renewable Energy Laboratory.

TABLE D-6-1 Estimate of Potential Impact of Renewable Generation Technologies on Indian Point Service Area

9/12/2005

Technical Potential - Wind and Biomass

	Today		2009		2014	
	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)
Wind Onshore	2,294	5,310	2,294	5,310	2,294	5,310
Wind Offshore	5,200	17,082	5,200	17,082	5,200	17,082
Biomass	1,502	10,560	1,502	10,560	2,233	15,680
TOTAL	**8,996**	**32,952**	**8,996**	**32,952**	**9,727**	**38,072**

Achievable Potential - Wind and Biomass

	Today		2009		2014	
	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)
Wind Onshore	0	0	229	531	459	1,062
Wind Offshore	0	0	300	986	1,800	5,913
Biomass	234	1,640	386	2,705	1,137	7,968
TOTAL	**234**	**1,640**	**915**	**4,222**	**3,396**	**14,943**

SOURCE: NYSERDA 2003.

Wind Contribution

Much relevant work has been done recently and is currently underway regarding wind power in New York. This analysis will outline broad issues and deployment options that could be considered as part of the electrical energy and capacity replacement, with reference to the recent work.

In addition to being renewable, wind power has characteristics that are different than conventional, dispatchable resources. First, the "fuel" source is controlled by nature, resulting in variable power output that is not controlled by the utility schedulers and dispatchers. This has two main implications to consider: a) the capacity credit in the long term and the reliability value of wind to meet peak demand, and b) the impact of wind variability on grid operations in the short term resulting from increased regulation, load following, and unit commitment burdens on other generators.

Second, the "fuel" cannot be transported. The wind turbines must be located in areas of good wind resource, which may or may not have access to existing transmission lines. Therefore, any comprehensive look at wind power potential must factor in questions such as:

- Proximity of wind resources to the existing grid
- Available transmission capacity on existing lines (temporal profiles can be important)
- Potential for upgrading capacity of existing lines and existing corridors

- And finally, costs and siting issues for any necessary new transmission connections

The analysis below broadly discusses three wind-based options, including issues of resource, cost, reliability, and transmission (deliverability). The purpose is to broadly describe what is known, what the quantitative potentials may be, and what remaining issues could be examined to further define the potential.

Option 1: Land-Base, In-State Wind Development

Resources:

- There is adequate raw and developable wind resource in the state to generate the energy equivalent of Indian Point, over and above current state RPS needs.
- In the future, increased hub heights, low wind speed turbine developments, and better wind resource information will likely expand the resource estimate.
- Site-specific permitting issues may remain, and could be impacted by local and state policy.

Costs:

- Generally, land-based bus bar wind costs are in the 3-7 cent/kWh range (not including the federal ten-year 1.8c/kWh Production Tax Credit, which currently applies to projects on-line by 12/31/05).
- Costs are expected to continue to incrementally decline due to increased efficiency, taller towers and manufacturing volume. (However, it should be noted that near-term costs have increased slightly due to the euro exchange rate, cost of steel, and other temporary factors.)
- Further examination of the details of the GE/NYSERDA wind integration and the Regional Greenhouse Gas Initiative work would likely yield specific site-based cost/supply curves.
- Additional grid operating costs have been found to be in the 0.2-0.5 cent/kWh range for a variety of US utilities and up to 20 percent penetration by nameplate.
- Operating costs were considered in the GE/NYSERDA study, but these additional costs were not reported separately from total costs. Little regulation impact and no impact on reserve requirements were found. Scheduling impacts were identified, and improvements in forecasting could bring costs down.
- Specific operational costs for higher wind generation scenarios are unknown, but the study framework and methods exist.
- For the GE 3300 MW wind scenario, the increase in system costs was projected to range between $582 million and $762 million for renewable projects. It is expected to be offset by approximately $362 million in wholesale energy cost reductions as New York reduces its reliance upon fossil fuels.

Transmission

- The GE study examined load-flow impacts of a 3300 MW wind generation scenario for RPS compliance and found no significant upgrade needs.
- Grid stability was found to be generally enhanced by the installation of new turbine technology incorporating power electronics and fault ride-through capability.
- Much of the land-based resource is located upstate, on the wrong side of the bottlenecks near Indian Point.
- Likely, significant upstate wind additions for Indian Point replacement would require some grid reinforcement. Specific needs are speculative, but the study methods and data are known.
- Generally, transmission costs, including new lines, are an order of magnitude lower than generation costs.
- Transmission permitting and construction times are in the 10-year time frame. Wind plants can come on line in 1-3 years total. Grid operators in TX and CA are examining innovative solutions to this mismatch.
- Due to resource variability, the potential exists for average line utilization factors to be low on lines serving primarily wind generation.
- Temporal line loading profiles could be examined to determine if increased wind energy could flow on existing lines with limited curtailment during critical times.

Reliability

- Effective load carrying capability studies in the GE/NYSERDA study show low values, averaging 10 percent, therefore a land-based wind-only replacement of the peak load capability of Indian Point is not feasible.
- Other opportunities could be examined to complement the energy–dominated value of wind with other generators, including:
    - Hydro: In-state resources of around 4.5 GW have an average utilization factor of around 50 percent, indicating a water-limited resource. If other flow regulations (environmental, recreation, etc.) allow, water could be retained for peak demand needs as a result of wind energy meeting off-peak and shoulder needs.
    - Simple Cycle fast ramp generators: Simulations show an economic advantage for new, low-capital-cost gas generation run for very minimal peak hours in conjunction with wind as an optimum solution (saving expensive gas, but getting reliability benefit). These "super peakers" can also be located optimally on the transmission system.
    - Other electric storage systems could potentially help: pumped hydro, and compressed air being the most economical. Longer term, a transition to plug-in hybrid vehicles could expand wind electricity markets and also provide grid storage support.

Option 2: Off Shore Wind Development

Resources

- Shallow water resources (up to 20 m depth) exceed 5 GW potential for class 5 and above for Long Island. Deeper water resources (20-40 m depth) off Long Island exceed 40 GW potential.
- Permitting issues for federal waters (> 3 miles) are in flux, but the Long Island Power Authority is currently negotiating with a developer for a 160-MW development within the state water boundaries.
- Visual and other concerns seem to be much less off Long Island than those associated with the Cape Wind project in Massachusetts.
- Technologies for deeper water are under development, including deep water floating and tethered concepts. Great amounts of resources exist in these waters.

Costs

- Off-shore capital cost estimates begin at $1500/kW (roughly 50 percent more than on-shore) and go up. European experience is relevant up to about 30 m depth. Higher, steadier wind speeds increase energy production, but O&M costs are generally higher. Current levelized cost is around 6 c/kWh at best.
- Costs are expected to decline significantly, perhaps to less than 4 cents in shallow water, in the next decade.
- Grid-operating cost additions would be expected to be similar to on-shore, with the possible caution that limited data from Horns Rev in Europe shows some higher ramp rates than on-shore.

Transmission

- Off-shore is generally envisioned as being deployed near load centers. Some on-shore reinforcement may be needed, and an off-shore cable is needed. However, costs should be lower and siting difficulties should be minimal compared to on-shore transmission expansion.
- The Long-Island off shore resource is on the load side of the transmission bottlenecks around Indian Point, further alleviating transmission concerns.

Reliability

- The GE study found an effective load carrying capability (capacity factor) of 30 percent for Long Island off-shore resources. This is promising compared to on-shore.
- Further study of great lakes resources would be necessary to quantify possible diversity benefits of multiple off-shore locations.
- All the generator synergistic and storage options discussed in on-shore could apply here, but needs might be a factor of three less per MW of wind.

Option 3: Imported Canadian Wind, firmed with Canadian Hydro

Resources

- Canadian wind and hydro resources appear vast; further examination is needed.

- Hydro Quebec imports some energy into NY already, and is willing to look at more, including wind/hydro blends.
- There is some reluctance to promote additional large Canadian Hydro for U.S. demand due to environmental and native population concerns.

Costs
- Wind power costs should be similar to the U.S. land -based resources.
- Operating cost additions from hydro are not well characterized, but should be minimal
- Bonneville Power in the United States has offered a shaping and firming product for wind that delivers a schedulable, flat block of equivalent wind power for an additional 0.6 cents/kWh. Recent discussions indicate this price is well over actual cost and the price may drop as the utility gets more experience with the service.
- Canadian hydro seems to be much less constrained by other river criteria than in the United States, so costs of variability mitigation would be expected to be much lower.

Transmission
- Studies of the capability of existing lines for importing additional power from Canada should be available, but were not researched.
- At 2 GW levels, DC options become advantageous for new long lines. This could be considered for direct connection to and near-equivalent replacement of Indian Point. Hydro firming could essentially base-load the wind and levelize the transmission line loading at near full capacity.

Reliability
- Hydro firming will essentially turn the wind into a base-load resource with equivalent reliability to Indian Point.
- Options for shaping the energy to fit the full peaking and load following needs could also be examined, with some incremental impact on transmission due to lower average loading factors and/or higher line capacity needs.

Quantitative Estimates for Wind

Estimates of wind resources in New York electric zones G, H, I, J, and K are presented in Table D-6-2. These zones are south of the major transmission bottlenecks from up-state New York generation to the New York City load. Therefore, adding wind generation in these zones is not likely to require significant upgrade or additional transmission line construction. This analysis used a high-resolution wind map produced for NYSERDA by AWS Truewind in 2000. Higher resolution data should now be available, and the analysis should be repeated.

As noted above, GE Energy and AWS Truewind Solutions have recently completed a look at integrating 3300 MW of additional wind spread around the NY grid, finding no need for significant transmission upgrades or reliability issues. In selecting locations for the 3300 MW, GE identified 10 GW of likely wind locations. Much of that wind

generation was postulated in upstate areas. For comparison purposes, the last column in the table below shows how much of the 10 GW scenario is in each of the generation zones in question.

The numbers presented below assume 5 MW per square kilometer of windy land. Values are net after subtracting environmental exclusions defined as all national Park Service, Fish and Wildlife, other specially designated federal lands such as wilderness areas, monuments, etc., all highly protected as determined by land stewardship data from the Gap Analysis Program (GAP) of the U.S. Geological Survey, and half of the second highest GAP land stewardship category, remaining U.S. Forest Service, and Department of Defense land. No other land use exclusions were subtracted.

TABLE D-6-2 Quantitative Estimates of Wind Potential In Indian Point Zones

Zone	Complete wind resource, after environmental exclusions; Power Class 3, 4, 5 and above	Resource within 10 miles of existing transmission Power Class 3, 4, 5 and above	Postulated possible development (out of 10 GW total) in GE NYSERDA Renewable Portfolio Standard study
Zone G	528, 129, 90	436, 110, 84	154 MW
Zone H	0, 0, 0	0, 0, 0	0
Zone I	0, 0, 0	0, 0, 0	0
Zone J	0, 0, 0	0, 0, 0	0
Zone K	2116, 431, 73 (onshore) Over 5200 MW of offshore class 5 and better wind is located in water less than 20 m deep	1482, 177, 5 (onshore)	600 MW (offshore within state 3 mile limit)

Notes: The wind resource potential is essentially constant with time, so the numbers can be used over the complete 2007-2015 study time frame. Between-turbine spacing to prevent excessive induced downwind turbulence is normally computed as a multiple of rotor diameter. In this assessment we have assumed a turbine density of 5 MW per square kilometer, independent of turbine size. Energy output per unit of nameplate capacity is expected to increase slightly over the time period due to incremental improvement in machine efficiency and higher average wind speeds resulting from increasing tower height. Because of increased energy delivery, there may be a corresponding incremental increase in reliability (capacity credit) values.
SOURCE: NRC

As shown, there is some potential for wind in the immediate vicinity of Indian Point. Most of the wind potential in Zone G is close to existing transmission corridors. However, Zones H, I, and J are some of the least windy areas of the state. Long Island shows significant on and offshore wind resource potential. Note again that offshore wind power peak times show a much better match to peak electric load demand as measured by Effective Load Carrying Capability (reliability based capacity credit) than on-shore resources. The operational, reliability, and transmission impacts of wind as a potential part of Indian Point replacement is best examined with detailed grid simulation. This will provide much better data on least cost solutions that may incorporate significant amounts of wind outside the zones tabulated above.

Wind-Related Policy Options

- On a $/MWhr basis, wind is likely to be a low cost, in-state option in 2007-2015, so broad state economic subsidy policy drivers may not be necessary.

- It is likely that near- to mid-term world wide markets for wind hardware will be supply limited. Manufacturing incentives may help build up supply capability, and help state economic development as well.
- Wind is primarily an energy, not capacity source, so that system reliability issues are important. The GE tools called MARS (multi-area reliability simulator) and MAPS (multi-area production simulator) are a good framework for the grid issues to be examined. GE could examine scenarios that include reliability synergies of possible benefit to wind, including:
    - In-state hydro dispatch modifications
    - Canadian hydro contract modifications to provide additional ancillary services (indications are they have dispatch flexibility)
    - Options for additional Canadian hydro (it appears current Day Ahead and Real Time Hydro Quebec imports are bounded at about 1500 MW, so additional transmission may be needed)
    - Examination of competitive market structures that would motivate other resources to provide additional ancillary service levels
    - Examination of transportation market modifications (plug hybrids and hydrogen) that would decrease the need for grid ancillary services imposed by wind
- Grid-level issues like transmission and operational issues for increased wind deployment should continue to be examined, through public funded mechanisms like NYSERDA or through allowing NYISO or others to recover appropriate costs from ratepayers.
- Siting and permitting issues for both land-based and off-shore wind plants should be addressed, including proactive examination of potential wildlife issues.
- Transmission costs are not large adders to generation costs. It is almost always cheaper to build transmission to a better wind resource than to use lower-class, closer wind. Transmission planning, siting, cost recovery, and construction issues need to be examined to reduce uncertainty and shorten the in-service timelines, if new transmission is necessary to serve wind.
-

Biomass Contribution

Primary Source

There have been extensive studies of the renewable biomass potential in NY. Information summarized in this analysis has been gleaned from the NYSERDA report *Energy Efficiency and Renewable Energy Resource Development Potential in New York State - Final Report* dated August 2003. (Prepared by Optimal Energy Inc, ACEEE, Vermont Energy Investment Corporation and Christine T. Donovan Associates.)

Geographical Basis

The zones of interest in the NYSERDA report are G, H, I, J, and K. Since biomass is generally assigned on a county basis, the relevant counties are (again working Northwest to Southeast): Delaware, Ulster, Green, Columbia, Sullivan, Dutchess, Orange, Putnam, Rockland, Westchester (location of Indian Point), Richmond, Nassau, and Suffolk. The

report also has time horizons of 2007, 2012, and 2022.

Background on Biomass Availability

The regions other than Delaware, Sullivan, and Ulster are increasingly heavily populated as one goes from NW to SE. Thus six of the existing 10 waste-to-energy facilities are in this region. These six already generate 68 percent of the total 2.15 TWh generated in 2000. The region's net capacity is 156 MW.

Urban residues are a huge resource, but are not viewed as "clean" from the NY-RPS definition. Public acceptance is low and to comply with Federal, State and local regulations, the cost of the facilities has reached over 8,000 $/ kW[4]. Thus even with a tipping fee, there is presently a lower cost alternative in burial of the wastes out of state.

The report assumes continuing use of Mass Burn technology. For the regions defined above, the capacity would be unchanged until 2012 when the report proposes 76 MW additional located in NYC. By 2022 a further 166 MW would be added, also in NYC.

Cleaner biomass resources include: mill residues (from primary and secondary wood processing); silviculture residues; site and land conversion residues; wood harvest; yard trimmings; construction and demolition wood(C&D); pallets; agricultural residues; bio-energy crops; animal and avian "manure," and wastewater methane.

Supply curve: Ideally the availability of these resources could be combined with the potential technologies to derive a supply curve - GWh vs cost. The current data is not adequate to do this at the regional scale. Statewide the sum of these resources amounts to 0.24 quad in 2003, and 0.4 quad in 2022, with the increase primarily due to a large energy crop contribution. In the regions identified for the Hudson valley to Long Island, the resource base is primarily urban residues (ranging from MSW to C&D wood) in the timeframe to 2012. After 2012 additional energy crop biomass could be developed. For this region the assumption is that the 2012 availability would about 0.015 quad. Upstate NY has a far higher potential due to forest and agricultural potentials.

Table D-1-3 assumes two biomass prices - biomass (e.g wood chips from forestry operations) at $2.50 /$10^6$ Btu, and MSW at -$2.50 /$10^6$ Btu. The negative cost reflects a tipping fee. A reasonable blended price for the urban residue generation in the zones considered would be $1.00 /$10^6$ Btu (2002). More detailed study would be needed to arrive at a more precise estimate of the proportions of material with a significant tipping fee, and those for which transportation would be a larger factor.

Technical potential: Applying these resources to the load zones G, J, and K, the 2003 technical potential would be 203 MW generating 1.423 TWh (capacity factor is 7000 h/y,

[4] While the report quotes $8,000/kw, a modern mass burn facility of 2000 tons per day mass capacity would have a rated capacity of 80 MW, the maximum allowed by law, and would cost about $150,000 to $200,000 per ton of daily capacity. These industry-recognized data (unpublished) give a maximum estimated cost of $5,000 per kW.

heat rate 10,500 Btu/kWh, i.e. 32 percent efficient). The technical potential in 2022 would be 295 MW, with the main part of the growth being in the Hudson Valley (zone G).

Technologies

There are three technologies in the NYSERDA report: CHP, co-fire, and gasification. Assumptions in the report are for CHP to grow statewide, mainly in the pulp and paper sector. However, in the regions of interest, there would be a zero contribution of CHP.

Co-fire would be possible in the Hudson valley. However, this is not an incremental generation of net power as the biomass displaces coal in an existing facility. Approximately 100 MW of the potential 203 MW would be in cofiring in the report.

Gasification in the study would be applied to low-cost construction and demolition debris more or less at the point of generation in NYC (zone J) with approximately 100 MW capacity.

Conclusion from the 2003 Report

The near term potential in the region is about 200 MW with an 80 percent annual capacity factor. With attention to energy crops in the Hudson valley this could increase to 300 MW. A further increment could come from the urban residue stream but would require a change in technology to overcome public resistance and very high investment cost barriers.

Economics: Assuming that gasification was to be used for all biopower applications (i.e. no CHP or co-firing contribution), the economic parameters assumed include an investment level (2002) of 1700 $/kW, and a fuel cost of about 1 $/GJ. This fuel cost is a blended price from very low cost C&D material to some forest residues at 2.50 $/GJ. The proposed technology is based on an IC engine technology with a medium-heating-value gasifier system. The scale would be in the range of 20 MW - 40 MW with a heat rate of 35 percent (9000 Btu kWh^{-1}). The fleet of gasification IC engine units would be between 5 and 12 depending on size. Modularity is assumed as well as a series production of units to achieve the investment cost proposed.

Cost per kWh: Using the same financial assumptions as in Appendix D-1 above, the busbar cost before distribution would be 0.045 $/kWh.

An Alternative View

Table D-6-3 contains both technical potential data and an estimate of achievable potential that exceeds the values proposed on the basis of the Energy Efficiency and Renewable Energy Resource Development Potential in New York State - Final report dated August 2003. Similar cost and performance of the biomass-to-electric technologies are assumed in the report and Table D-6-3, such that the technical potential is the same. The

differences in achievable potential result from valid differences in optimism about economics, technology, and non-monetary barriers.

The New York State report was constrained by an economic assumption framework for a period up to about 2001. This is essentially a business-as-usual framework that did not assume the loss of the nuclear capacity, nor the recent rapid changes in fossil energy prices (coal, oil and gas), nor the more aggressive renewable energy framework of State RPS and increased Federal and State incentives. Thus, for MSW/CDW shown in Table 3, the difference between 398 MW in 2022 in the report, and the achievable potential of 1096 MW for 2014, represents the difference between a very conservative forecast and one in which many of the non-monetary barriers, and some of the cost barriers, are reduced.

The disparity can only be resolved by a more substantial analysis in which there is a region-wide supply curve for biomass electricity generation at specific locations based on GIS supply and demand analysis.

TABLE D-6-3 Biomass Potential Applicable to Indian Point

Table 3. Biomass Potentials for the Indian Point Region

Achievable Potential

	Today	2009		2014	
	Capacity (MW)	Capacity (MW)	Generation TWh	Capacity (MW)	Generation TWh
MSW/CDW	233.8	365	2.56	1096	7.68
Biogas (Sewage)		20	0.16	41	0.32
Total Biomass		386	2.72	1137	8.00

Technical Potential

	Today	2009		2014	
	Capacity (MW)	Capacity (MW)	Generation TWh	Capacity (MW)	Generation TWh
MSW/CDW		1461	10.24	2192	15.36
Biogas		41	0.32	41	0.32
Total Biomass		1502	10.56	2233	15.68

1) Counties in Region - Bronx, Kings, New York, Queens, Richmond, Columbia, Delaware, Dutchess, Greene, Nassau, Orange, Putnam, Rockland, Suffolk, Sullivan, Ulster, Weschester
2) Population data - New York State Data Center, http://www.nylovebiz.com/nysdc/data_economic.asp (Aug 10, 2005)
3) MSW Per capita generation - National average from Biocycle, Apr 2004, v45, n4, p22 (1.31 ton/percapita/per annum). This number includes C&D wood.
4) Biogas = 1 ft/percapita/day @640 Btu/ft^3 Roberts and Hagen, UC Davis, 1978
5) Existing Capacity, Renewable Electric Plant Information System, NREL, 2002 data
6) Assumption - For solid feeds: 80% capacity factor, 20% efficiency in 2009, 30% efficiency in 2014
7) Assumption - For For biogas 35% efficiency, 80% Capcity Factor
8) Did not factor in population growth for this version
9) Existing Generation is for 2004, estimated from EIA Form 906

Supporting Discussion for Biomass Potential Table

Technical Potential

The amount of capacity or power which is possible by using a technology or practice in all applications in which it could technically be adopted, without consideration of its costs.

Assumptions

Counties in Region – The counties are Bronx, Kings, New York, Queens, Richmond, Columbia, Delaware, Dutchess, Greene, Nassau, Orange, Putnam, Rockland, Suffolk, Sullivan, Ulster, Westchester

1. Population Data: 2004 estimate from the New York State Data Center (http://www.nylovbiz.com/nysdc/data_economic.asp, August 10, 2005). Population growth was not factored into the 2009 and 2014 estimates, but can be in future updates.
2. 1.31 tons MSW per capita per year. This was the national average generation from Biocycle, Apr 2004, v45, n4, p22 (individual states not given). The number may include construction and demolition wood. Since then the actual Biocycle survey ("The State of Garbage in America," Biocycle, January 2004) was obtained. The New York estimate is 1.29 tons /per capita /year. Since the value is close the original estimate was not corrected.
3. The existing capacity estimate was taken from the Renewable Plant Information System (REPIS), NREL, 2002 data. The data are on a state and regional basis. Existing biogas generation (primarily landfill gas) was not included.
4. Existing generation was taken from the EIA Form 906/920 using 2004 data. http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html, (August 10, 2005). Form 906 gives capacity and generation information for all power plants in the United States. Form 906 was not used for capacity since not all data entries include a reported capacity.
5. Assumed basis is higher heating value.
6. Biomass potential was based on Oak Ridge National Laboratory, *Biomass Feedstock Availability in the United States, State Level Data*, 1999.
7. Sewage biogas was estimated using 1 ft^3/per capita/per day with a heat content of 640 Btu/day based on an old reference: Roberts, E.B, and R.M. Hagen, "Guidelines for the estimation of total energy requirements of municipal wastewater treatment alternatives," A report to the California State Water Control Board, University of California Davis, 1977.
8. MSW heating value (5000) Btu/lb (dry) was taken from Niessen, W. R.; Marks, C. H.; Sommerlad, R. E. (1996). Evaluation of Gasification and Novel Thermal Processes for the Treatment of Municipal Solid Waste. 196 pp.; NREL Report No. TP-430-21612. Values used for wood and Ag residues/energy crops were 8,000 and 7,500 Btu lb dry, respectively.
9. Efficiency and capacity assumptions
    a. Biogas – 35 percent efficiency (IC engine), 80 percent capacity factor
    b. Solid feeds

i. 20 percent efficiency (mass burn or stoker grate), 80 percent capacity factor from Bain, R. L., W. P. Amos, M. Downing, and R. L. Perlack (2003). "Biopower Technical Assessment: State of the Industry and the Technology," National Renewable Energy Laboratory, Golden, CO, NREL/TP-510-33123, Jan.
ii. 30 percent efficiency (gasification), 80 percent capacity factor from Niessen, W. R.; Marks, C. H.; Sommerlad, R. E. (1996). Evaluation of Gasification and Novel Thermal Processes for the Treatment of Municipal Solid Waste. 196 pp.; NREL Report No. TP-430-21612.

Calculation Procedure

1. Biomass
   a. Generation estimated by multiplying resource by heating value, converting to kW thermal, and multiplying by assumed efficiency to obtain kWh electric
   b. The capacity factor was used to estimate capacity: MWh divided by hours per year divided by capacity factor.
2. MSW/CDW and Biogas
   a. Generation estimated by multiplying population estimate (both regional and state) by per capita generation, multiplying by heating value, converting to kWh thermal, and multiplying by assumed efficiency to obtain kWh electric.
   b. The capacity factor was used to estimate capacity: MWh divided by hours per year divided by capacity factor.

Market Potential

1. Technical Potential
   a. Assumes 100 percent utilization of estimated feedstock
   b. In 2009, the assumption is that the process will be mass burn or stoker grate for solid feeds
   c. In 2014, the assumption is that the process will be gasification for solid feeds.
   d. IC engines at constant efficiency assumed for biogas.
   e. Although cofiring is by far the least expensive option for electricity generation, it does not increase capacity, i.e., considered fuel substitution and was not included.
2. Achievable Potential
   a. For Biomass and MSW/CDW
      i. A RPS and a Section 45 tax credit are assumed as market intervention factors.
      ii. A Section 45 type credit (value not estimated) is extended to CHP systems heat production to encourage maximum process efficiency.
      iii. A 25 percent penetration is assumed in 2009
      iv. With the use of higher efficiency, lower emissions, and lower cost gasification technologies the penetration rate is increased to 50 percent in 2014
      v. For energy crops a low penetration is assumed, 5 percent in 2009 and 10 percent in 2014. The value is greater that zero to recognize the

progress made in dedicated crops (willow) by projects such as the Salix project.

b. Since biogas (sewage) is already being generated, and because the generation of electricity should give lower emissions than flaring a high penetration should occur. Fifty percent is assumed in 2009, and 100 percent in 2014.

APPENDIX D-7:

DISTRIBUTED PHOTOVOLTAICS TO OFFSET DEMAND FOR ELECTRICITY

Dan Arvizu[5]

This appendix summarizes an analysis performed by NREL under my direction and supervision to evaluate the potential of distributed photovoltaics (PV) to offset the future electricity generation and capacity needs in the area currently supplied by the Indian Point Nuclear Power Plant near New York City. This analysis provides an overview of PV markets, an analysis of the potential for PV to help replace the electricity capacity and generation from the Indian Point nuclear power station in New York State, a summary of New York's current policies related to PV technology, and an accelerated PV deployment scenario for New York through 2020.

Some important observations include:

- The technical potential for rooftop PV in New York is very large – on the order of 35-40 GW State wide, and 18-20 GW in the Hudson Valley, NYC and Long Island control areas. Reaching this potential will require time to scale up the market infrastructure and production capacity for PV.
- Given that PV is a distributed generation technology it competes against retail, not wholesale electricity rates.
- Given that PV is a distributed generation technology *and* that its production profile is highly coincident with peak demand it can contribute significantly to grid stability, reliability and security. Thus from a planning perspective PV should be valued at a rate higher than the average retail rate.
- The cost of PV generated electricity is expected to decline considerably over the next decade, falling from a current cost of 20-40 cents/kWh, to a projected cost 10-20 cents/kWh by 2015.
- Given that Indian Point is a ~2GW base load plant, operating roughly 95 percent of the time, it would be very difficult for PV alone to replace all of the generation from Indian Point during the next 5-10 years.
- By pursuing a strategy that would combine PV with other technologies, such as efficiency, wind, hydro, and storage, PV should be able to replace 15-20 percent of the generation of Indian Point and 80-90 percent of the capacity of Indian Point during peak periods during by 2020.

[5] Dan Arvizu is a member of the committee and the director and chief executive of the National Renewable Energy Laboratory.

Under an aggressive but plausible accelerated PV deployment scenario, roughly 50 MW of PV systems could be installed in New York by 2009 (generating roughly 80 GWh of electricity), and 470 MW of PV systems could be installed in New York by 2014 (generating 700 GWh of electricity) (see Table D-7-1). This level of PV installations in 2014 could offset about 30 percent of Indian Point's capacity during peak periods and about 4 percent of Indian Point's annual electricity output. In addition, under the accelerated scenario about 1 GW of PV systems could be installed in New York by 2016, generating 1,500 GWh of electricity (offsetting about 40-50 percent of Indian Point's capacity during peak periods and 9 percent of Indian Point's annual electricity output). Realizing this accelerated scenario would require making a clear long-term commitment, in terms of both policies and resource, to expanding New York's existing PV programs. Perhaps more importantly such an initiative would establish a self-sustaining PV market in New York resulting in an additional 1 GW of PV being installed in New York by 2020, generating 3,000 GWh of electricity (offsetting about 80-90 percent of Indian Point's capacity during peak periods and 18 percent of Indian Point's annual electricity output), without any public subsidies between 2016 and 2020.

TABLE D-7-1. Estimated Distributed Photovoltaics in the Indian Point Service Area in the Accelerated Deployment Scenario

	2005	2009	2014	2016	2020
Installed PV Capacity (MW)	2	56	470	1,000	2,000
Generation Offset by PV(GWh)	3	84	700	1,500	3,000

SOURCE: Derived from NYSERDA 2003.

Key PV Markets

During the past decade the global PV market has been experiencing explosive growth. For example, during the past 5 years (1999-2004), the average annual growth rate of the global PV industry has been 42 percent. As shown in Figure 1, the fastest growing PV market segments during this period were the grid-connected residential and grid-connected commercial segments. Such rapid growth has created tremendous excitement about PV technology around the world within governments (EC 2004), industry (SEIA 2004, NEDO 2004, EPIA 2004) and the investment community (CLSA 2004). As shown in Figure 1, during 2004 the global PV industry passed the 1GW mark in annual installations. At this point in time the global PV industry is truly beginning to move into large-scale production.

The rapid growth in the global PV market during the past decade, shown in Figure D-7-1, was driven largely by government subsidy programs, in particular in Japan, Germany, and a few States within the U.S. (including California and New York). Over the coming decades, as costs continue to decline and subsidies are phased out, industry analysts expect that the distributed grid-connected residential and grid-connected commercial markets will continue to expand rapidly and will become self sustaining. Thus the grid-connected residential and commercial markets have emerged as key markets for developing and expanding the use of PV technology, and are the logical place for New York State to focus its market development efforts over the next decade.

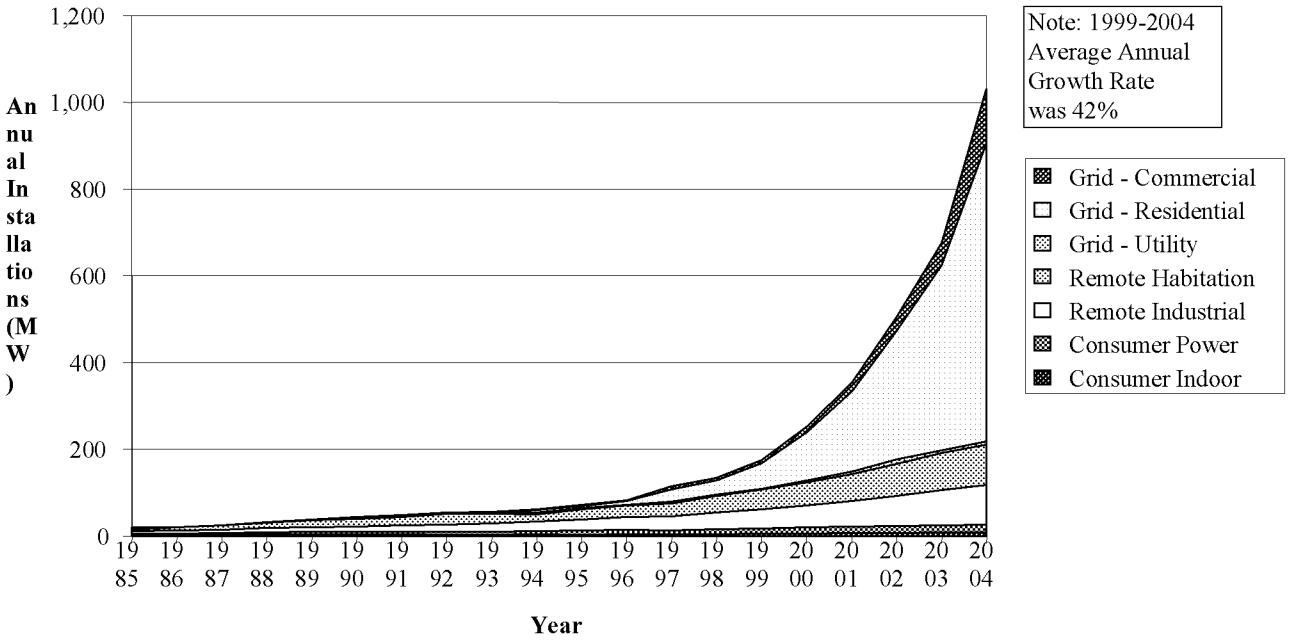


FIGURE D-7-1. Global PV Market Evolution by Market Segment
SOURCE: Strategies Unlimited (2005)

Technical Potential and Value of PV in New York State

The technical potential for grid-connected residential and commercial PV in New York State is very large – estimates of the rooftop technical potential in 2025 are on the order of 35GW to 40GW (NYSERDA 2001; Navigant 2004). If one considers only the Hudson Valley, NYC and Long Island control areas, then the rooftop technical potential is on the order of 18-20GW (NYSERDA 2001; Navigant 2004). This technical potential is enough to generate 27,000 GWh of electricity per year compared to the 16,700 GWh currently produced at Indian Point Units 1 and 2.

Expanding the market towards this technical potential, however, will require time to develop both the market infrastructure and production capacity for PV. As noted above, global PV production exceeded 1GW in 2004. Given that Indian Point's capacity is ~2 GW with a capacity factor of ~95 percent, and that PV in New York State has a capacity factor of ~17 percent, replacing the equivalent of Indian Point's generation with PV alone would require an installed PV capacity of >10GW in New York State. Thus it would be unrealistic to expect New York State to be able to fully replace the generation from Indian Point with PV alone during the next 5 to 10 years.

In thinking about the potential contribution PV could make towards replacing Indian Point, it is important to emphasis the technology's best attributes, i.e., PV can provide high-value peak-time power in a distributed fashion and with zero environmental

emissions. The ability to install PV in a distributed fashion combined with its production profile enable PV to contribute significantly to grid stability, reliability and security (Perez et al. 2004b). Thus it would make sense to pursue a strategy that combines PV with energy conservation, other generation technologies (such as hydro and wind) and storage (e.g, a combination of pumped storage, compressed air energy storage, a variety of end-use storage technologies, etc). Such a strategy would be designed to draw on the strengths of each of its components. For example, using hydro as a buffer for PV might be an attractive option. While major hydro facilities within New York State, such as Niagara Falls and Robert Moses (7 GW total) have limited buffers, it might be possible to use PV in combination with imported Canadian Hydro. This strategy would utilize PV generation combined with a limited amount of local energy storage to displace expensive on-peak demand, i.e., when transmission is likely to be constrained and the market clearing price is high, and import Canadian Hydro to meet off-peak demand, i.e., when transmission is available and the market clearing price is low.

With such a strategy PV might be able to realistically replace 15-20 percent of the generation of Indian Point and 80-90 percent of the capacity of Indian Point during peak periods by 2020 (the strategy as a whole would replace a much larger fraction of the generation from Indian Point). This strategy could be implemented starting in relatively small increments, installing 10s of MW during the first couple of years and increasing installations to about 200MW per year by 2015, resulting in a total installed PV capacity of ~2 GW by 2020 (as illustrated in the accelerated PV deployment scenario discussed below). Reaching such a goal could probably be achieved through a declining subsidy program that would enable the PV industry and market infrastructure to grow in New York State, and enable regulators and policymakers to learn about how PV interacts with the grid in a controlled fashion.

Overview of PV Current and Projected Cost Through 2015

An overview of the current and projected cost through 2015 for PV technology is shown in Table 2. As discussed above the two key markets for PV are assumed to be distributed residential systems and distributed commercial systems, thus the high/low ranges are based on current and projected costs in these two market segments. As shown in the table, the current levelized cost of energy is roughly 20-40 cents/kWh, and the projected levelized cost of energy in 2015 is roughly 10-20 cents/kWh.

It is important to note that the costs shown in Table 2 are to the end-user, i.e., they should be compared to retail rather than wholesale electricity rates. In addition, since the production from PV is highly coincident with peak demand in New York,[6] a strong argument can be made for valuing PV in a planning context at a rate higher than the average retail rate in New York. For example, Perez et al. (2004a) used average NYISO day ahead hourly wholesale price of electricity data in the NYC-metro and Long Island

[6] Letendre et al. (2003) analyzed data on the day ahead hourly wholesale price of electricity from NYISO from the summer of 2002, combined with satellite derived solar resource data, and found that the average PV availability for all 32 peak power price days in the summer of 2002 was 79%. In other words, on average in the NYISO control area, distributed PV systems would have been operating at roughly 80 percent of their ideal output during the days when power prices spiked above 20 cents/kWh in the wholesale market.

regions during 2002 to estimate the solar- weighted wholesale price, i.e., weighted by PV output. Using this detailed data they concluded that combining PV with a limited amount of load management (to enable PV to claim a capacity value close to 100 percent) would have increased the value (i.e., the system-wide cost savings) of residential PV during 2002 from 15 cents/kWh (the average retail rate) to 21.3 cents/kWh in NYC and from 12 cents/kWh (the average retail rate) to 20.3 cents/kWh on Long-Island. As shown in Table D-7-2, if PV system owners could capture this value through interconnection rules, rate-structures, etc., then PV technology could become a rapidly expanding and self-sustaining industry in New York State during the next decade.

TABLE D-7-2. Current and Projected Distributed PV Cost (all estimates are $2005)

	Current (2004)		Projected (2015)	
	Low	High	Low	High
Capital Cost ($/W)	6	8	3.5	4.5
O&M Cost (cents/kWh)	3	6	1	2
DC-AC Conversion Eff. (%)	93	91	95	95
Fuel Cost (cents/kWh)	n.a.			
Levelized Cost of Electricity (cents/kWh)	23	38	12	20
Availability	17% CF, i.e., daylight hours only (without storage).			
Reliability	Very reliable, can help reduce stress on grid.			
Environmental Considerations	Clean, quiet and easy to site.			
Site Retrofit Potential	Limited: Requires ~ 100 sq. ft/kW ➔ could install ~50MW using ~50% of the Indian Point site.			
Other issues	Very large technical potential, but will require time to penetrate market/develop market infrastructure.			

NOTES: LCOE calculation assumes system is financed over the 30-year life of system.
Low estimates are based on a commercial system with: 17 percent capacity factor, 10 percent federal investment tax credit, federal accelerated depreciation, and 7 percent real (after tax) discount rate. High estimates are based on a residential system with: 17 percent capacity factor and 4 percent real (after tax) interest rate.
O&M costs are dominated by inverter replacement cost. Current inverters lifetimes are 5-7 years, with expected lifetimes rising to 10-15 years over the next decade.
SOURCE: Based on data and projections in DOE (2004), Margolis and Wood (2004), and SEIA (2004).

Current Policies for PV in New York

New York has a fairly aggressive set of policies aimed at encouraging the adoption of PV technology. A detailed list of existing policies is provided in Table D-7-3. As shown in the table, New York has put in place a combination of tax exemptions and credits, loan subsidies, rebates (administered by LIPA and NYSERDA), and standard interconnection and net metering rules. Only New Jersey has created a more comprehensive set of incentives for residents and businesses to install PV in the northeast.

TABLE D-7-3. Current PV Related Policies in New York State

Incentive	Description
Sales Tax Exemption (R)	100% Sales tax exemption
Property Tax Exemption (C, I, R, A)	15 year tax exemption for all solar improvements
Personal Tax Credit (R)	25% tax credit for PV (<10kW) & SHW, capped at $5,000
State Loan Program (C, I, R, A, G)	$20,000 - $1 million loan for 10 years at 4% - 6.5% below the lender rate for PV and SHW
State Rebate Program (C, I, R, A, G)	$4 - $4.50 / W (<50kW) up to 60% of total installed costs. IOU customers only
Municipal Utility Rebate Program (C, R, G)	$4 - $5 /W (<10kW). LIPA customers only.
Interconnection Standards (C, I, R, A)	Standard Agreement for PV requires additional insurance and an external disconnect. Up to 2 MW max.
Net Metering Standards (R, A)	All utilities must credit customer monthly at the retail rate for PV systems under 10kW

C = Commercial R = Residential I = Industrial A = Agricultural G = Government
Incentive data available at DSIRE.org 08/2005.

As shown in Table D-7-3, New York has an existing rebate or "buy down" program. The main program, administered by NYSERDA, is called New York Energy Smart and includes customers with all the major IOUs. New York Energy Smart provides customers who purchase and install PV systems with a $4/W rebate. This incentive in combination with state tax credits and exemptions has resulted in the installation of over 1.5MW as of summer 2005. The program currently has $12 million allocated to its PV incentive program, of which about $6.5 million has been reserved as installer/customer incentives. The remaining funding should take the program through 2006.

LIPA, the public utility serving Long Island, also has an existing PV incentive program called the Solar Pioneer Program. LIPA launched the Solar Pioneer Program in 1999 and offered customers a substantial rebate. The rebate's budget is tied into LIPA's five-year Clean Energy Initiative with a funding level totaling $37 million annually

(covering multiple technologies). The Clean Energy Initiative is expected to receive funding through 2008. To date, 511 rebates have been disbursed for PV systems totaling more than 2.63 MW installed on Long Island. LIPA's rebate is currently set at $4/W.

While the existing rebate programs are functioning well and expect to be fully subscribed this year, what is missing in New York is a clear long-term commitment of resources at the scale required to grow the PV industry in New York rapidly. Given New York's relatively high electricity prices – the average residential electricity price in New York was 14.3 cents/kWh in 2003 (EIA 2005) – and reasonably good solar resources, with a long-term commitment of sufficient resources New York should be able to accelerate the growth of PV substantially over the next decade.

An Accelerated PV Deployment Scenario for New York

The fact that the existing buy-down programs are well subscribed indicates that they are buying down the price of PV systems into a range that makes them economically attractive to consumers. Given that current installed system prices are about $8/W in New York, with a $4/W buy-down, the final cost to the consumer is about $4/W. If financed over the life of the system (30 years) at a 6 percent interest rate (~4 percent real interest rate after tax benefits) the levelized cost of energy from such a PV system would about 13.5 cents/kWh. With an average residential electricity price above 14 cents/kWh in New York, combined with attractive net metering rules, it is not surprising that this investment would look reasonable to many consumers.

While such an investment might look attractive to consumers it is of little value if consumers can not find reputable installers. Here is where having a clear long-term policy commitment plays a critical role. Setting up a new business (getting certified, training staff, etc.) requires a substantial investment of resources. Entrepreneurs need to believe they will be able to recoup this investment over time. Policy uncertainty, in this context, creates a substantial barrier to building a viable local PV distribution, installation and maintenance industry.

This accelerated scenario is modeled on the successful Japanese program which provided a declining subsidy to residential PV systems over the past decade, expanding residential PV installations in Japan from roughly 2 MW in 1994 to 800 MW in 2004 (Ikki 2005). The history of the Japanese residential PV subsidy program during the past decade has provided proof that making such a long-term commitment to building the market infrastructure for PV can result in a self-sustaining industry. The average price of residential PV systems installed in Japan in 2004 was $6.2/W, i.e., about 25 percent lower than in New York. This cost differential is a reflection of the difference between a well functioning and emerging market for PV systems. PV modules and inverters are commodities whose prices are largely driven by international markets; however, labor and balance of system cost (which typically account for 30-40 percent of total system cost) are driven by local policies and market development.

Figure D-7-2 shows an accelerated market development path for New York. This scenario is not a model result, but an estimate of what New York could achieve under the following assumptions:

- The cost projection is in line with what the DOE Solar Energy Technology Program and the U.S. PV industry believe will be achieved over the next 10-15 years in the U.S. (DOE 2004 and SEIA 2004) – in other words it is an aggressive but plausible projection.
- The average annual growth rate was set in five-year intervals as follows: 55 percent between 2006 and 2010, 40 percent between 2011 and 2015, and 5 percent between 2016 and 2020. These rates are below the rates achieved in the Japanese program.
- A declining subsidy is implemented, set at 50 percent in 2006, declining linearly to 25 percent in 2011, and 0 percent in 2016. The combination of a declining subsidy and declining costs maintains an installed system cost to consumers below $4/W throughout the scenario.
- A clear long-term commitment to growing the PV industry in New York is put in place. The combination of a declining subsidy, declining system costs and rising installations creates a peak program cost of $74 million in 2012.
- Achieving the high growth rates envisioned during the 2006-2015 period will require investing additional resources (on the order of $10 million per year) in programs aimed at helping entrepreneurs establish PV businesses and boosting public awareness of PV in New York.

Additional detail for this scenario is shown in Table D-7-4. This scenario envisions creating a self-sustaining PV market in New York by 2016. Under this scenario about 1 GW of PV systems would be installed in New York by 2016. Achieving this goal would require a total public investment of roughly $500 million (undiscounted) between 2006 and 2015. An additional 1 GW of PV would be installed in New York by 2020 without any public subsidies beyond 2015.

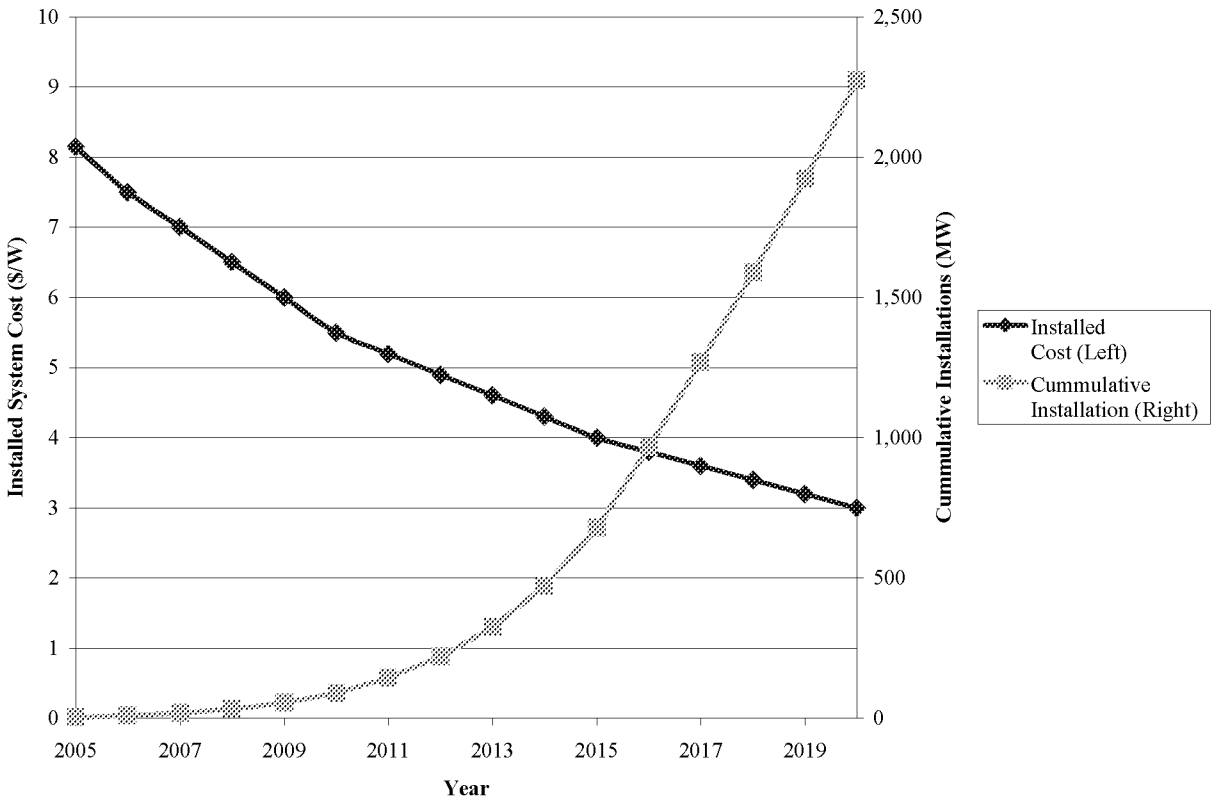


FIGURE D-7-2. An accelerated PV market development path for New York (all estimates are $2005)
SOURCE: NRC

TABLE D-7-4. Accelerated PV Deployment Scenario for New York (all estimates are $2005)

Year	Annual Installa-tions (MW)	Growth Rate (%)	Cumulative Installations (MW)	Installed System Cost ($/W)	Buydown Rate	Effective Buydown ($/W)	Annual State Invest-ment (millions)	Installed System Cost to Consumer ($/W)
2005-actual	*2.0*	*NA*	*4.2*	*8.14*	*52%*	*4.23*	*8.47*	*3.91*
2006	**6.0**	**55%**	**10.2**	**7.50**	**50%**	**3.75**	**22.50**	**3.75**
2007	9.3	55%	19.5	7.00	45%	3.15	29.30	3.85
2008	14.4	55%	33.9	6.50	40%	2.60	37.48	3.90
2009	22.3	55%	56.3	6.00	35%	2.10	46.92	3.90
2010	34.6	55%	90.9	5.50	30%	1.65	57.14	3.85
2011	**53.7**	**40%**	**144.6**	**5.20**	**25%**	**1.30**	**69.78**	**3.90**
2012	75.2	40%	219.7	4.90	20%	0.98	73.65	3.92
2013	105.2	40%	324.9	4.60	15%	0.69	72.60	3.91
2014	147.3	40%	472.2	4.30	10%	0.43	63.34	3.87
2015	206.2	40%	678.4	4.00	5%	0.20	41.24	3.80
2016	**288.7**	**5%**	**967.1**	**3.80**	**0%**	**0.00**	**0.00**	**3.80**
2017	303.1	5%	1,270.3	3.60	0%	0.00	0.00	3.60
2018	318.3	5%	1,588.6	3.40	0%	0.00	0.00	3.40
2019	334.2	5%	1,922.8	3.20	0%	0.00	0.00	3.20
2020	350.9	5%	2,273.7	3.00	0%	0.00	0.00	3.00

SOURCE: NRC

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APPENDIX E

PAYING FOR RELIABILITY IN DEREGULATED MARKETS

Timothy Mount[1]

CONTENTS

THE CHANGING REGULATORY STRUCTURE IN NEW YORK STATE

The problems faced by investors in the process of financing new power plants and transmission lines have changed over time depending on the regulatory structure and the economic climate, and these factors will probably continue to change in the future. Prior to the restructuring of electricity markets, under the system of regulated monopolies, investor-owned utility companies were given a guaranteed rate of return (Potts, 2002), with a potential penalty if their investments were found to be imprudent. Once an expansion plan had been approved by a state public utility commission (PUC), it was relatively straightforward for investors to finance the capacity expansions, even for a capital-intensive project such as a nuclear plant, because the financial risk of an investment was relatively low under regulation. A key factor in determining how many plants were to be built was the utility's forecast of future load and the acceptance of this forecast by the PUC. If the utilities' forecasts of demand were consistently biased in the same direction, utilities could be caught with a deficit of capacity, as happened after World War II, or a surplus of capacity, as happened in the late 1980s (Zadlo et al., 1996).

The rate of growth of demand was consistently high after the post-war shortages, and the total demand doubled every 10 years in the United States until the early 1970s. After the oil embargo in 1973, the growth of demand was and has continued to be much lower than historical levels. Electricity demand grew at a 7.3 percent annual rate from 1960 to 1973, but slowed to 2.5 percent a year from 1973 to 1985 (Geddes 1992). The utility industry was relatively slow to recognize and adopt lower forecasts of demand, and there was an extended public debate about how much the industry's forecasts of demand should be lowered in response to higher prices (Nelson and Peck, 1985. An additional rationalization for building nuclear power plants after the oil embargo was to substitute a domestic source of energy for imported oil. As a result, ambitious construction plans for nuclear power plants were continued in spite of growing

[1] Note: Timothy Mount is a member of the Committee on Alternatives to Indian Point and Professor of Applied Economics and Management at Cornell University.

evidence that the growth of demand would be lower than expected and that these projects would eventually lead to an excess of installed generating capacity (Schuler, 2001).[2]

Since the industry's forecasts of demand had been approved by PUCs, consumers still had to pay for much of the excess capacity when installed capacity got ahead of demand (Zadlo et al., 1996).[3] As a result, there was considerable soul-searching by regulators and criticism by the public about what had gone wrong with the regulatory process. Increases in prices led to further decreases in demand below projections (Zadlo et al., 1996). When the excess capacity and the high cost of new nuclear facilities (Potts, 2002) [4] became apparent in the 1980s, many PUCs held prudency hearings (Geddes 1992), and in some high-profile cases, such as those involving Nine Mile Point Unit 2, near Oswego, New York and Seabrook Nuclear Power Plant in New Hampshire, stockholders were denied the full recovery of capital (Adams, 2005). In total, $19 billion of the accumulated costs of constructing new generating capacity was disallowed according to one estimate (Lyon and Mayo, 2000). Although $19 billion was a small amount compared with the total book value of installed generating capacity, it was still large enough to send a message of dissatisfaction to investors. Since only a fraction of the total cost of building excess generating capacity was charged to stockholders, ratepayers were also adversely affected by paying higher rates; the primary cause of the problem was a failure by the industry and regulators to predict future levels of demand accurately.

The memory of excess generating capacity and unrealistic demand forecasts was part of the rationale for utility restructuring, based on the perception that the investment decisions made by regulated utilities were often economically inefficient (Rebellon, 2002). Regulated monopolies were thought by many people to imply high rates for customers owing to "overbuilding." It was also thought that more competition would lower costs, encourage innovation, and attract new investment (Rebellon, 2002; Anderson, 2004; Higley, 2000; Potts ,2002). [5] [6] In addition, investment decisions in deregulated markets would be decentralized, and as a result, the responsibilities of regulators for selecting a particular forecast of demand and authorizing an expansion plan would be substantially reduced.[7] Supporters of deregulation

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[2] ". . . customers in New York were burdened over the past twenty years to pay for reserve margins as high as forty percent because of incorrect load forecasts" (Schuler, 2001, p.80).

[3] "Changes in the market, such as the oil embargo, resulted in lower growth in peak demand than had been projected. The result was the construction of excess capacity through the late 1980's" (Zadlo et al., 1996).

[4] Considerable debate exists as to why these cost overruns occurred. Some blame undue safety regulation of nuclear plants; some blame utilities delaying completion of facilities to avoid having so much installed capacity that they would trigger prudency hearings; some blame the many different nuclear designs that permeated the U.S. market.

[5] "The primary rationale for electricity restructuring in most countries has been to reap welfare gains by supplanting regulation with competition where it is viable." (Anderson 2004)

6 "Calls by large industries for utility deregulation found a ready chorus in academics, analysts, and politicians who believed that competition could produce lower prices, better service, and more innovation than government regulation. The free-marketeers pointed at other industries that had been deregulated during the 1980s, such as airlines and telecommunications, claiming that deregulation helped lower the cost of airplane tickets and long-distance telephone rates (Public Citizen disputes many of these claims; deregulation helped lower prices for some, but others have seen price increases and reduced service). The free market proponents argued that since deregulation worked for the airlines and telecommunications (which Public Citizen disputes), why not the electric power industry?" (Higley 2000)

[7] "Recent history has created a tremendous disincentive to risk the economic future of the industry on forecasting the right energy production technology and building the correct amount of it to serve future demand." (Zadlo et al. 1996)

argued that market forces could be relied on to ensure that there would be enough installed generating capacity to meet the growth of demand.

Although it was not recognized at the time, the changing economic circumstances in the 1980s had already led most utilities to reduce their level of capital investment. Some analysts attributed the cause of this reduced investment to the "hammer" of the prudency reviews and the resulting regulatory disallowances (Geddes 1992).[8] Other analysts, however, concluded that the primary cause was the existence of excess generating capacity and the economic incentives to shift way from expensive nuclear power plants to less expensive natural gas turbines (Lyon and Mayo, 2000).

In the latter half of the 1970s, high oil prices, restrictions on the use of natural gas by utilities and increasing environmental concerns about the adverse effects of air pollution were among the major reasons that utilities in New York State embraced nuclear power as an alternative to fossil-fuel sources of electricity. When high oil prices and cost overruns for constructing nuclear power plants drove electric rates steadily higher, the New York legislature responded by enacting a law in 1980 that required utilities to buy power from independent power producers (IPP) for 6 ¢/kWh. Unfortunately, this law was enacted just before the price of oil dropped, and after additional supplies of natural gas became available after the oil industry was deregulated. Consequently, the actual cost of generating electricity from natural gas turbines, including the capital cost, was well below 6 ¢/kWh. Nevertheless, forecasters did not anticipate these changes in 1980, and therefore they expected higher prices for oil and natural gas in the 1980s.

The assumption underlying the "six-cent law" was that rising oil prices and the high construction costs of nuclear power plants would soon make 6 ¢/kWh a bargain for the buyers. In fact the opposite happened. Falling fuel prices, technological advances, and successful energy -efficiency investments created a surplus of generation that kept the cost of electricity well below 6 ¢/kWh, and the six-cent law created a substantial subsidy for IPPs and became a source of controversy for the public. The six-cent law was reinterpreted in 1987 to require an IPP to accept 6 ¢/kWh until such time as the front-end subsidy was paid back to customers, but projections indicated that wholesale prices of electricity would be so low that repayment would never occur. The overall outcome of the six-cent law was that thousands of megawatts of new contracts were made to buy electricity from IPPs at above-market prices. Most of this new capacity was built upstate, because construction costs were lower there than they were in the New York City region. The high cost of these contracts resulted in higher rates for customers. In the 1990s, regulators decided that the best strategy was to allow utilities to buy out the IPP contracts and treat the cost of doing this as a lump-sum loss.

Combining the effects of the high construction costs of the new nuclear power plants, the impact of the six-cent law, and the high property taxes in Long Island and New York City, electricity prices in New York State remained among the highest in the country, even though the amount of generation from oil-fired sources diminished to relative insignificance. Large customers in New York State—as in California and other high-cost states—became interested in self-generation and retail access as ways to "bypass" paying the high rates for electricity and, in some cases, as ways to shift production and jobs to regions with lower electricity prices. In

[8] "The lesson of that experience was not lost on electric utility managers. They now fear that the cost of large (and efficient) new generating capacity might not be recovered through the regulatory process. New capacity might be disallowed from the rate base although its costs were justified and prudently incurred." (Geddes 1992).

1994, California became the first state to announce the intention of permitting retail customers to choose their power suppliers. New York State announced its own plan for retail access one year later. This plan started by persuading the utilities to sell their generating capacity to merchant generators prior to the establishment of a new deregulated wholesale market for electricity in 1999.

The perceived failure of the traditional "regulatory compact" that occurred in many countries in the 1970s and 1980s was the primary motivating factor for "deregulating" the electric utility industry. This restructuring took place around the world beginning in the 1980s and accelerated in the 1990s (Anderson, 2004), and it generally involved unbundling assets (i.e., separating the ownership) for the generation, transmission, and distribution segments of the supply system. Customers were no longer restricted to buying electricity from a single utility. In the United States, "As of April 2004, twenty four states and the District of Columbia had enacted legislation or issued regulatory orders to permit retail access to competitive electricity suppliers; more recently, however, seven of these states delayed or suspended their plans for retail access, largely in response to the turmoil in California's market" (Anderson, 2004).

In 1999, when the new wholesale market for electricity started to operate in New York State, the price of natural gas happened to be low. Entrepreneurs saw an opportunity to make money by building efficient combined-cycle turbines that would undercut the costs of older fossil-fuel power plants. Merchant facilities were built without guarantees of a regulatory rate of return and these projects were still able to get financing from financial institutions. Given the economics of the time, merchant plants were expected to earn for investors higher rates of return than the traditional regulated rates. Figure E-1 shows the dramatic increase in the construction of new generating capacity in North America that started in 2000. It looked at that time as though market forces would ensure that the amount of new generating capacity being built would be enough to keep up with the forecasted growth of demand (and the retirement of older power plants).

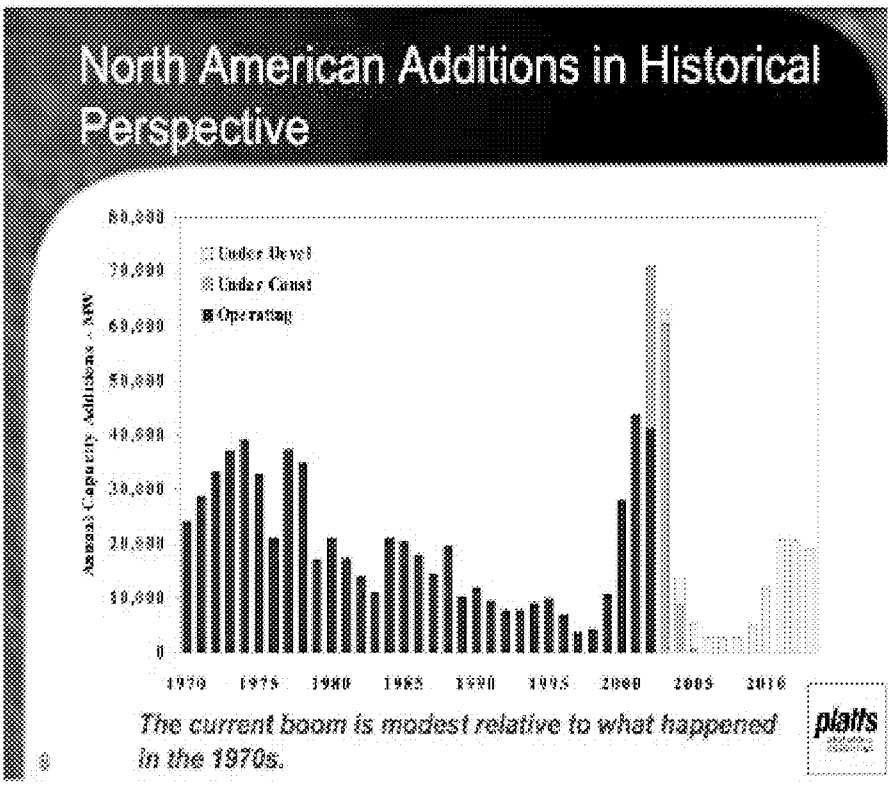

FIGURE E-1. North American additions in historical perspective. The current boom is modest relative to what happened in the 1970s.
SOURCE: Adapted, with permission, from Logan, 2002

However, during the early 2000s, the underlying economic conditions changed. As a result, many merchant projects for natural gas turbines ended up in financial trouble that persists today. By 2003, cancellations of planned facilities accelerated (Horton, 2002), leading to concerns about capacity shortages in the near future (see Figure E-1). New York State is not the only region of the country that is facing the possibility of capacity shortages. All three of the northeastern control areas (New York, New England, and the mid-Atlantic control area known as Pennsylvania Jersey Maryland [PJM]) are now struggling to create effective investment incentives for building new generating capacity. Some policy makers are calling for major changes in the current path of deregulation and less dependence on the merchant development paradigm (Adams, 2005).

Once again, the failure to forecast key economic variables accurately (in this case the prices of natural gas and electricity) has contributed to the financial problems faced by many owners of natural gas turbines. This time, however, the financial consequences of unprofitable merchant projects will be borne by the stockholders rather than by the ratepayers. Higher prices for natural gas in 2005, coupled with relatively low prices for electricity, have led to delays in the construction of new generating capacity in New York State. These delays have arisen in spite of the establishment of a new form of Locational Installed Capacity (LICAP) auction, run by the New York Independent System Operator (NYISO). The major objectives for establishing this new LICAP auction were to supplement the income of generators when shortages of generating capacity are likely to occur, and to provide sufficient incentives to delay the retirement of existing generating capacity and to build new generating capacity.

Today, even with higher natural gas prices, natural gas turbines are still the preferred type of traditional generating capacity for providing an alternative to the nuclear units at New York's Indian Point Energy Center. Although many utilities in the country are now planning to use coal instead of natural gas in new power plants, building a typical coal plant in the New York City region is unlikely to meet state environmental standards and unlikely to get widespread support from the public. Clearly, a nuclear power plant in this region is not a viable alternative.

To summarize, until a year ago most policy makers in New York State believed that market forces could be relied on to build enough new generating capacity to meet future levels of demand. Unfortunately, this level of optimism about market forces is no longer realistic under the present economic conditions. The increased uncertainty that now exists about the financial viability of building new generating capacity in New York State, particularly in the New York City region, makes the task of finding alternatives to Indian Point much more challenging for this Committee on Alternatives to the Indian Point Energy Center for Meeting New York Electric Power Needs. For example, the current projection made by the NYISO of the reserve margin for capacity in New York State falls below the 18 percent level needed to maintain reliability standards by 2008 (NYISO, 2005a). This type of problem is occurring in other parts of the nation, and the North American Electric Reliability Council (NERC) has lowered the forecasts of installed generating capacity in the nation every year since 2002. The current projected summer capacity margin (summer capacity margin = installed capacity - summer peak load) is below 15 percent for the nation in 2008 and continues to decline to 10 percent by 2014, the last year forecasted (NERC, 2005b, Fig. 7, p. 18).

The growing concerns about how to maintain the reliability of the electric supply system in New York State and the nation coincide with major changes in the regulatory structure of the industry. In particular, the Energy Policy Act of 2005 was signed into law in August 2005, giving greater authority over reliability to the Federal Energy Regulatory Commission (FERC). Prior to the enactment of this legislation, FERC was primarily an economic regulator of the wholesale transactions and tariffs on the bulk power system. The main implications of the Energy Policy Act of 2005 are to give FERC the authority to enforce reliability standards by imposing penalties on end users if the standards are violated. In addition, a new organization, the Electric Reliability Organization (ERO), will be given the authority to establish these reliability standards. At this time, it is not clear exactly how this new authority will be implemented by FERC. Nevertheless, these mandatory changes show that maintaining reliability is a major priority of federal policy makers, but state regulators will still have the main responsibility for determining how the new standards will be implemented (i.e., determining how much generating capacity is needed to meet the standard).

The sections below provide a more detailed explanation of the following questions: how regulators determine the amount of generating capacity needed to meet reliability standards, why the current regulatory practices have failed to ensure that future levels of generating capacity will be sufficient to meet these standards, and what can be done, given current circumstances, to meet future levels of demand and maintain the reliability of supply.

DETERMINING AND IMPLEMENTING THE RELIABILITY STANDARDS

In an electric supply system, the performance of the network and the level of reliability are shared by all users of the network. Reliability has the characteristics of a "public" good (e.g.,

all customers benefit from the level of reliability without "consuming" it). In contrast, real energy is a "private" good because the real energy used by one customer is no longer available to other customers. Markets can work well for private goods but tend to undersupply public goods, such as reliability (and over-supply public "bads" such as pollution). The reason this happens is that customers are generally unwilling to pay their fair share of a public good because it is possible to rely on others to provide it (i.e. they are "free riders"). Some form of regulatory intervention is needed to make a market for a public good or a public bad socially efficient.

If a public good or a public bad has a simple quantitative measure that can be assigned to individual entities in a market, it is feasible to internalize the benefit or the cost in a modified market. For example, the emissions of sulfur and nitrogen oxides from a fossil-fuel generator can be measured. Requiring every generator to purchase allowances for the quantities emitted makes pollution another production cost. Regulators determine a cap on the total number of allowances issued in a region, and this cap effectively limits the level of pollution. Independent (decentralized) decisions by individual generators in the market determine the pattern of emissions and the types of control mechanisms that are economically efficient. For example, the choice between purchasing low-sulfur coal and installing a scrubber is left to market forces in a "cap-and-trade" market for emission allowances. Unfortunately, when dealing with the reliability of an electric supply system, it is impractical to measure and assign reliability to individual entities on the network in the same way that emissions can be assigned to individual generators. This is particularly true for transmission lines that are needed to maintain supply when equipment failures occur. NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system (NERC, 2005, p. 10):

> "1. Adequacy—The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> "2. Operating Reliability—The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements."

The desired level of reliability on a network should be specified by a regulatory agency, and under the Energy Policy Act of 2005, FERC will be responsible for enforcing a set of standards for reliability that are established by the ERO. State regulators will continue to be responsible for interpreting the standards to determine how they should be implemented. Before passage of the Energy Policy Act of 2005, the NERC standard of 1 day in 10 years for the loss-of-load expectation (LOLE) was generally accepted by regulators as the appropriate standard for the reliability of the bulk transmission system (i.e., this does not include outages of the local distribution systems caused, for example, by falling tree limbs and ice storms). Nevertheless, it is still very difficult to allocate the responsibilities for maintaining this standard to individual owners of generating and transmission facilities because of the interdependencies that exist among components of a network. This fundamental problem has not stopped regulators from trying to do it.

The basic approach used by state regulators is to assume that setting reserve margins for generating capacity (i.e., setting a standard for "generation adequacy") is an effective proxy for meeting the NERC reliability standard. This new proxy for reliability can now be viewed as the sum of its parts, like emissions from generators, and the task of maintaining reliability can be turned over to market forces once the regulators have set a reserve margin. In practice, it has

been difficult, without regulatory intervention, to maintain a given standard for generation adequacy in many deregulated markets, particularly in the three deregulated markets in the northeast. The underlying reasons for this difficulty are explained in the following sections. The main implication for this study is that even if Indian Point continues to operate at full capacity, there will still be problems with maintaining the reliability of supply that should be addressed immediately by regulators. Ignoring these problems would make it much more difficult to find viable ways to replace the generating capacity at Indian Point and maintain the reliability of supply in the New York City region.

Generation adequacy is clearly a necessary condition for the operating reliability of supply, but it is not a sufficient condition. Treating generation adequacy as the central issue for reliability downplays the importance of transmission services and distributed energy resources (DER) for maintaining the reliability of supply. This issue has been discussed in the NERC (2005) report *Long-Term Reliability Assessment.* In the executive summary of that report, (NERC, op. cit. p. 5) states:

> **"Transmission Systems Will be Operated at or Near Limits More Frequently**. North American transmission systems are expected to meet reliability requirements in the near term. However, as customer demand increases and transmission systems experience increased power transfers, portions of these systems will be operated at or near their reliability limits more of the time. Under these conditions, coincident failures of generating units, transmission lines, or transformers, while improbable, can degrade bulk electric system reliability."

This general conclusion reflects the complicated state of the electric utility industry in North America at this point in time when different regions are in different stages of deregulating the industry. Deregulation implies moving away from the use of a relatively centralized planning process to determine the investments needed in generation and transmission in order to meet reliability standards in a given region and moving towards a more decentralized decision process and a greater reliance on market forces. However, there is a lot of uncertainty in the deregulated markets about the best way to maintain system reliability and provide the right incentives to get new generation and transmission built when and where it is needed. For example, in the New York City region, two out of three recent proposals for new merchant transmission lines have failed to secure financing. In addition, there is a considerable amount of ongoing uncertainty about whether or not some existing generating units will be retired and whether proposed new generating units will actually be built. Most of these decisions have been or will be determined by the financial conditions faced by the owners and the investors and their expectations about the profitability of future sales of electricity in the spot market.

Three issues relating to reliability are discussed in the following three sections. Section D-3 explains why the amount of generating capacity needed to meet adequacy standards in New York City is relatively large. Section 4 shows why the profitability of this capacity from earnings in the spot market is low and therefore why additional sources of income for generators are needed to maintain operating reliability. Section D-5 discusses alternative ways of providing additional income for generators. Section D-6 explains the potential limitations of the current approach adopted in New York State and the pressing need to find a more effective way to finance new generation and transmission capacity.

GENERATING CAPACITY FOR MEETING ADEQUACY STANDARDS IN NEW YORK CITY

New York City's large size, commercial importance, and unique dependence on electricity for transportation implies that unscheduled outages in New York City cause substantial financial losses for electricity customers. As a result, maintaining a high level of reliability for the city has always been, correctly, a major priority for system planners and regulators. This basic objective has not changed in the new deregulated market, but the financial consequences of maintaining reliability are no longer as straightforward as they were when electric utilities were fully regulated. Although financial problems of this type occur in all deregulated markets, the chosen approaches to solving the problems vary substantially from one region to another. Regulators in New York State have adopted a relatively innovative but untested way to address the problem. This approach is discussed in more detail in Section D-4.

The problem of maintaining reliability in New York City is exacerbated by the structure of the legacy transmission system. Since the geographic region supported by the New York Power Pool under regulation corresponded almost exactly with New York State, the supply of electricity to New York City was designed to depend heavily on transmission lines from the north through the Hudson Valley. Transmission links to adjoining power pools in the west/south and east (i.e., PJM and New England) were and continue to be relatively weak. Furthermore, the location of Long Island as an appendage to New York City adds to the concentration of load in the southeastern corner of the New York Control Area (NYCA). If the legacy transmission system had been developed at the regional level rather than at the state level, it is probable that the transmission links between New York City and New Jersey, for example, would be considerably stronger than they are now.

The overall implication of the size and location of New York City in the NYCA is that the New York Independent System Operator (NYISO) has supplemented the standard reliability criterion used by the New York State Reliability Council (NYSRC) to conform to the NERC standard for reliability. The Introduction to the current annual report by the NYSRC summarizes the council's responsibilities as follows (NYSRC, 2005, p. 1):

> "Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the annual statewide Installed Capacity Requirements (ICR) for the New York Control Area (NYCA) consistent with North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC) standards. This report describes an engineering study conducted by the NYSRC for establishing the NYCA required installed reserve margin (IRM) for the period of May 2005 through April 2006 (Year 2005) in compliance with the NYSRC Agreement. The ICR relates to the IRM through the following equation:
>
> ICR = (1 + IRM% / 100) x Forecasted NYCA Peak Load
>
> "The New York Independent System Operator (NYISO) will implement the statewide ICR as determined by the NYSRC — in accordance with the NYSRC Reliability Rules and the "NYISO Installed Capacity" manual. The NYISO translates the required IRM to an 'Unforced Capacity' (UCAP) basis, in accordance with a 2001 NYISO filing to FERC."

In the same report (NYSRC, op. cit. p.3), the reliability criterion is defined as follows:

"The acceptable LOLE reliability level used for establishing NYCA Installed Reserve Margin (IRM) requirements is dictated by the NYSRC Reliability Rules, wherein Rule A-R1 (Statewide Installed Reserve Margin Requirements) states:

> "The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures."

The underlying analysis of reliability in the NYSRC report (NYSRC, 2005, p. 2) is based on:

"a probabilistic approach for determining the NYCA IRM requirements. This technique calculates the probabilities of generating unit outages, in conjunction with load and transmission representations, to determine the days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (MARS) is the primary analytical tool used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA Zones—plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. MARS calculates "Loss of Load Expectation" (LOLE, expressed in days per year), to provide a consistent measure of system reliability."

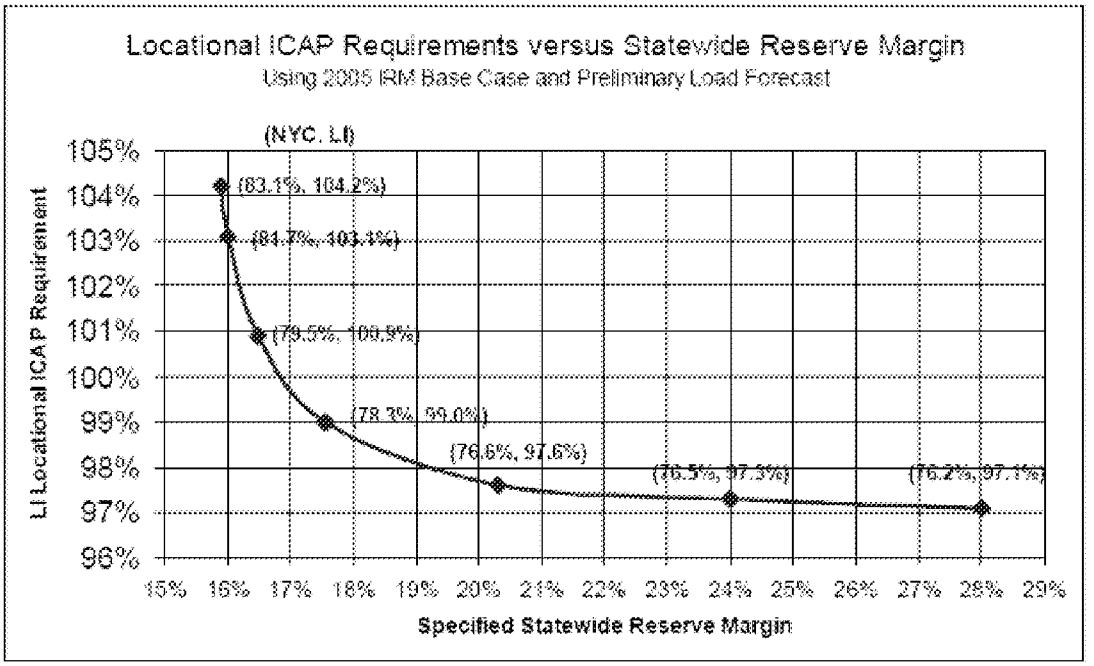

FIGURE E-2 Locational installed capacity requirements for Long Island and New York City for 2005-2006.
SOURCE: Reprinted, with permission, from NYSRC, 2005.

The overall implication of the NYSRC report is to set the statewide installed reserve margin (IRM) for 2005 to 2006 at 17.6 percent (NYSRC, op.cit. p. 2). However, this criterion is found to be sensitive to the levels of installed generating capacity in New York City and Long Island, and as a result, the NYISO does a supplementary analysis to determine the locational installed capacity (ICAP) requirements for these two regions, using the General Electric Multi-Area Reliability Simulation (MARS) model. Figure E- 2 shows that the locational ICAP requirements are very stringent, particularly for Long Island, and it is not practical to meet the NERC standard for LOLE if the ICAP on for Long Island falls below 97 percent of the peak load (NYISO, op.cit. p.8). The required levels of ICAP proposed by the NYISO for 2005/06 are 80 percent of peak load for New York City and 99 percent of peak load for for Long Island (NYISO, 2005, p.10). These requirements are supplements to the NYSRC requirement of 118 percent of peak load for the NYCA, and the capacity implications are summarized in Table E-1 (NYISO, 2005. Pp. 6 and10).

TABLE E-1 Locational ICAP Requirements and Installed Capacity for NYCA in 2005-2006

Locality	Forecasted Peak Load MW	Locational ICAP % of Peak	Required Locational ICAP, MW	Actual ICAP, MW	Actual ICAP % of Peak	Ratio of Actual ICAP to Required
New York City	11,315	80	9,052	9,887	87	1.09
Long Island	5,231	99	5,179	5,318	102	1.03
New York Control Area	31,692	118	37,715	39,647	125	1.05

SOURCE: Derived from NYISO, 2005b.

The capacity requirements in Table E-1 are relatively stringent and imply that 38 percent of the total NYCA generating capacity must be located in New York City and Long Island. However, most of the inexpensive sources of generation in the NYCA (hydro, nuclear and coal) are located upstate. The existing generating units in New York City and Long Island are relatively expensive to operate because they use oil or natural gas as a fuel. As a result, an economically efficient dispatch of generators in the NYCA loads the transmission capacity from upstate to New York City to the maximum allowed, and the capacity factors of the generating units in New York City and Long Island are relatively low. This implies that it may be difficult to maintain the desired level of reliability (i.e., LCAP) because the profitability of sales in the spot market is relatively low for many generating units in New York City and Long Island. The low profitability of these generating units is a major cause of the current uncertainty that exists about the timing of retirements and of new construction of generating units in New York City and Long Island. The issue of profitability of generating units in the New York City and Long Island regions is discussed in more detail in the Section D-4.

THE HIGH COST OF RELIABILITY IN NEW YORK CITY AND LONG ISLAND

Effect of the Capacity Factor of Peaking Units on Cost

The standard rule for defining an economically efficient (competitive) market is that the market price paid by buyers to sellers should be equal to the highest marginal production cost. In a deregulated market for electricity, the competitive price is equal to the "short-run marginal cost" of production, defined as (the fuel cost plus the operating and maintenance cost) of the most expensive generating unit that is dispatched to meet the load in a region (under regulation, this measure corresponds to the system lambda for a merit order dispatch). In reality, most final customers in a deregulated market still pay a fixed price based on a regulated tariff rather than the spot price of electricity in the wholesale market. Generators, on the other hand are paid the spot price (or they are paid through forward contracts that reflect the expectations that traders had about future spot prices when the contracts were executed). Hence, an efficient market price covers the production costs of all units that are dispatched, but additional income to cover capital costs is only earned when the market price is higher than the marginal production cost of a generating unit. Generators that are only needed to meet peak loads on hot summer days are dispatched for relatively few hours in a year (i.e., they have very low "capacity factors"), and the ability of these units to earn sufficient income to cover capital costs is highly dependent on how often high prices above their production costs actually occur.

To understand how the capacity factor of a peaking unit affects the cost, define the average total cost as (production cost plus annualized capital cost)/megawatt-hour (MWh) generated. This definition measures the "long-run marginal production cost" conditional on the number of megawatt-hours generated. The average total cost is highly sensitive to the number of hours that a peaking unit is dispatched, and this relationship is illustrated in the following simple example. The production cost for a representative peaking unit is $60/MWh and the annualized capital cost is $85/kW.[9] Using these component costs of generation, the average total cost can be written:

$$\text{Average total cost} = (60 + 85000/\text{number of hours dispatched})\$/\text{MWh}$$

In Figure E-3, the average total costs for this representative peaking unit are shown in terms of the number of days that the unit is dispatched, assuming that it generates for 16 hours on each one of these days. The costs are shown for a range of 1 to 100 days, and the latter corresponds roughly to being dispatched every day during the summer (equivalent to an annual capacity factor of only 18 percent). The average total costs in Figure E-3 decrease rapidly from over $5,000/MWh for 1 day to $113/MWh for 100 days. However, this latter cost would still be nearly twice as high as the competitive market price ($60/MWh) if this unit was the marginal generator. For peaking units, there is a fundamental inconsistency between the ability of generators to earn a fair rate of return on capital and the existence of economically efficient prices in the spot market. This problem is not new. There are extensive discussions in the regulatory literature about the financial implications of real-time pricing using the system lambda from a merit order dispatch to set the price.

[9] These costs correspond to the values used by David Patton, market monitor for NYISO from Potomac Economics, in recent discussions among regulators and system operators about the adequacy of generation capacity in the NYCA.

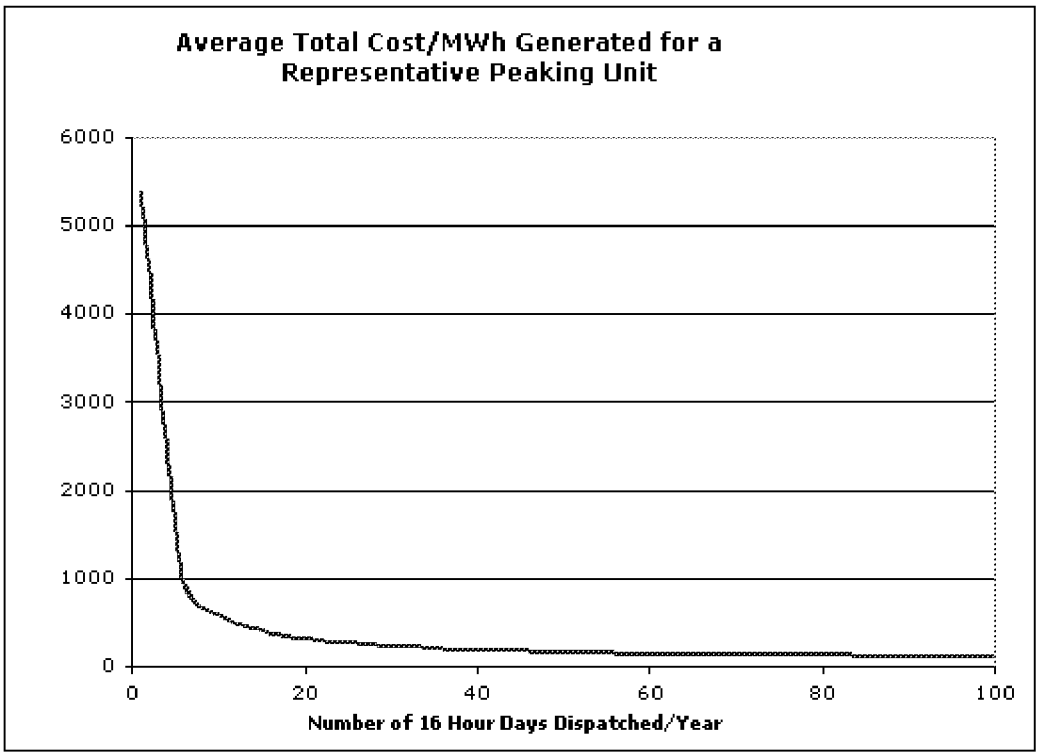

FIGURE E-3: Average total cost of production per megawatt-hour generated for a representative peaking unit.

SOURCE: NRC, derived from values in the text above.

Regulators have followed two very different approaches for dealing with this financial predicament in a deregulated market. One is to focus on the standard goal of short-run economic efficiency in the spot market and to provide some source of supplementary income for generators (the approach advocated in the northeastern states of the United States). The second is to allow high prices to occur (above the marginal production cost) and to focus on long-run economic efficiency by keeping the overall average spot price competitive (the approach followed in Australia and proposed in Texas). In the latter case, the basic rationale is that a few high spot prices will provide sufficient financial incentives to maintain generation adequacy. Experience in the Australian market suggests that this rationale is correct, and average spot prices in Australia are low even though price spikes up to a cap of A$10,000/MWh (US $7500/MWh) can and do occur (NEMMCO, 2005). In contrast, most deregulated markets in the United States set a price cap of $1,000/MWh in the spot market and have introduced ways to mitigate high spot prices, such as the Automatic Mitigation Procedures (AMP) used in the NYCA (NYISO, 2005c).

Before describing the changing behavior of spot prices in the NYCA, the question of whether or not high spot prices are economically justifiable should be addressed. Since most spot prices in the NYCA are well below $100/MWh and the highest marginal production cost for any generating unit is almost certainly less than $200/MWh, is it reasonable to allow prices to go above $5,000/MWh (the total cost of production from peaking capacity that is used for only 16 hours per year, corresponding to 1 day per year in Figure E-3)? The answer is yes, because the value of lost load (VOLL) when an unscheduled outage occurs is very high, particularly for a

large urban complex like New York City. A recent study published by the Lawrence Berkeley National Laboratory (LBNL, 2004) concludes that the total cost of interruptions in electricity supply is $80 billion/year for the nation (LBNL, op. cit. p. xi-xii), and 72 percent of this total is borne by the commercial sector (plus 26 percent by the industrial sector and only 2 percent by the residential sector). The frequency of interruptions is found to be the most important determinant of the cost because the cost of an interruption increases proportionally much less than the length of an interruption, and the cost of relatively short interruptions of only a few minutes is substantial.

The cost estimates in the LBNL (2004) report were developed from an earlier report on customer outage costs (Lawton et al., 2003), prepared for the U.S. Department of Energy's (DOE) Office of Electric Transmission and Distribution. The results in the DOE report are based on a number of surveys of the outage costs for individual customers. For large commercial and industrial customers in different economic sectors, the average costs are reported for 1-hour outages in dollars per peak kilowatt (Lawton et al.., 2003, Table 3-3, p.13). These average costs range from negligible for the construction sector to $168/kW ($168,000/MWh for a 1-hour outage) for the finance, insurance, and real estate sector, and the average cost for all sectors is $20/kW ($20,000/MWh for a 1-hour outage). Although there is much variability in the reported costs of an unscheduled outage, the overall conclusion is that the VOLL is much higher than $5,000/MWh, particularly for the finance, insurance, and real estate sector in New York City. It is interesting to note that the current NERC reliability standard of 1 day in 10 years corresponds to a VOLL of $33,333/MWh (5,000 x 16/2.4, based on the costs shown in Figure E-2) and this value is at the low end of the range of estimated values of VOLL in the DOE report.

The high level of the VOLL does not imply that all loads are equally valuable. Some types of load, such as water pumps and refrigerators, can be cut for short periods of time and cause minimal costs for customers. There are many realistic opportunities for customers to reduce load willingly when prices are high, and the main obstacles to realizing this are the lack of adequate metering and the fact that most customers still pay fixed regulated prices. Clearly, a truly efficient market would include price-responsive load, "smart" appliances, and a wide range of distributed energy resources on microgrids. Nevertheless, the VOLL is still a valid measure for an unscheduled outage, and as a result, having generating units available to meet unexpected contingencies is economically justifiable, even if these units are only dispatched for a few hours each year. The real problem for regulators is how to pay for these generating units with low capacity factors that are needed primarily to maintain operating reliability. This question is discussed in more detail in Section C-5, after presenting a description of the behavior of spot prices in the NYCA after deregulation.

Spot Prices in the New York Control Area After Deregulation

Figure E-4 shows the daily spot prices in New York City after the market was first deregulated in the fall of 1999. The prices in Figure E-4 represent the zonal price for New York City in the balancing (real-time) market at 2:00 p.m. each day. During the first summer after deregulation, a number of price spikes occurred. This type of price behavior provided sufficient financial incentives for investors to initiate the licensing process for a number of new generating units. However, the summer of 2000 was exactly when the deregulated market in California became "dysfunctional" leading eventually to an intervention in the California market by the FERC in the fall. The response of regulators and politicians in the Northeast was to adopt measures to ensure that the problems experienced in California were not repeated in their own

regions. High prices above the marginal production cost were treated as evidence of the exploitation of market power by generators. (This is strictly correct in an economic sense given the standard textbook definition of a competitive market.) For example, the NYISO set a low price cap of $1,000/MWh and eventually introduced Automatic Mitigation Procedures that made it harder for generators to justify submitting high offers above their true production costs into the spot market.

The presence of AMP, together with additional new generating capacity, more participation by loads and other factors have resulted in fewer price spikes occurring after the summers of 2000 and 2001. This is clearly evident in Figure E-4, and the current price behavior in the spot market will probably continue. Although high price volatility is perfectly acceptable in Australia, it is highly unlikely that politicians in the Northeast, unlike Texas, will tolerate price spikes even if they actually result in lower average prices and better operating reliability. For the NYCA, this situation implies that many generating units needed for operating reliability in New York City and Long Island will not earn enough income above production costs to cover their capital costs. Given the current behavior of spot prices, additional financial incentives from other sources will be needed to maintain generation adequacy in the NYCA.

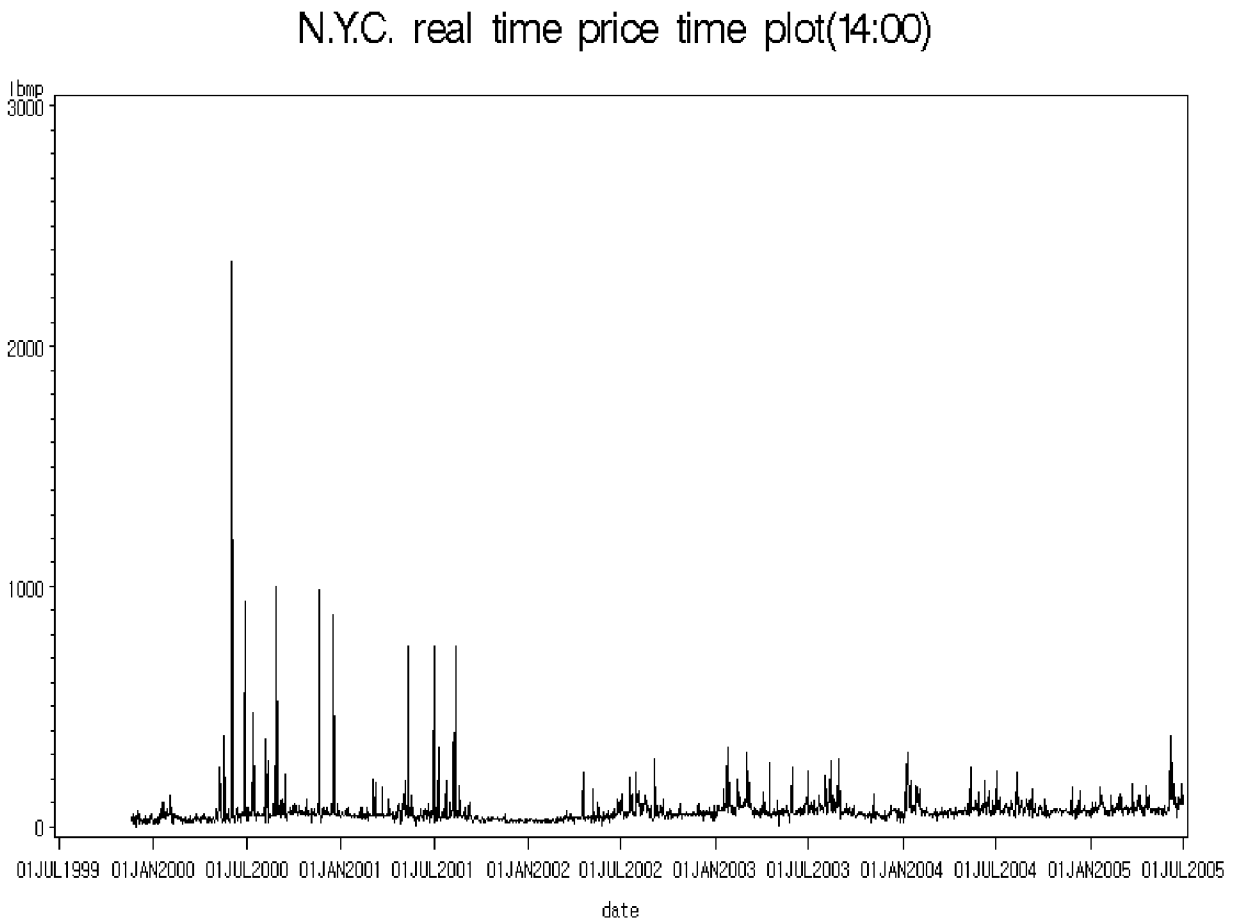

FIGURE E-4 Daily zonal spot prices ($/MWh) , January 2000 to July 2005, for New York City in the balancing (real-time) market at 2:00 p.m.

SOURCE: Derived from NYISO hourly spot prices, www.nyiso.com, accessed November 2005.

Concerns about maintaining generation adequacy are not limited to New York City or the NYCA. This problem is widespread. For example, the NERC Report on Long-Term Reliability Assessment (NERC, 2004, Fig. 7,p. 16) shows that the projected reserve margins published in 2001 for the nation were substantially higher than they had been a year earlier. However, the delays and cancellations in the construction of new generating units have resulted in lower projections published in the 2004 report that are actually lower than the corresponding low values in the 2000 report. The projections of summer capacity margins for 2005 are even lower, and fall below 15 percent by 2008 (NERC, 2004, Fig. 7, p.18).

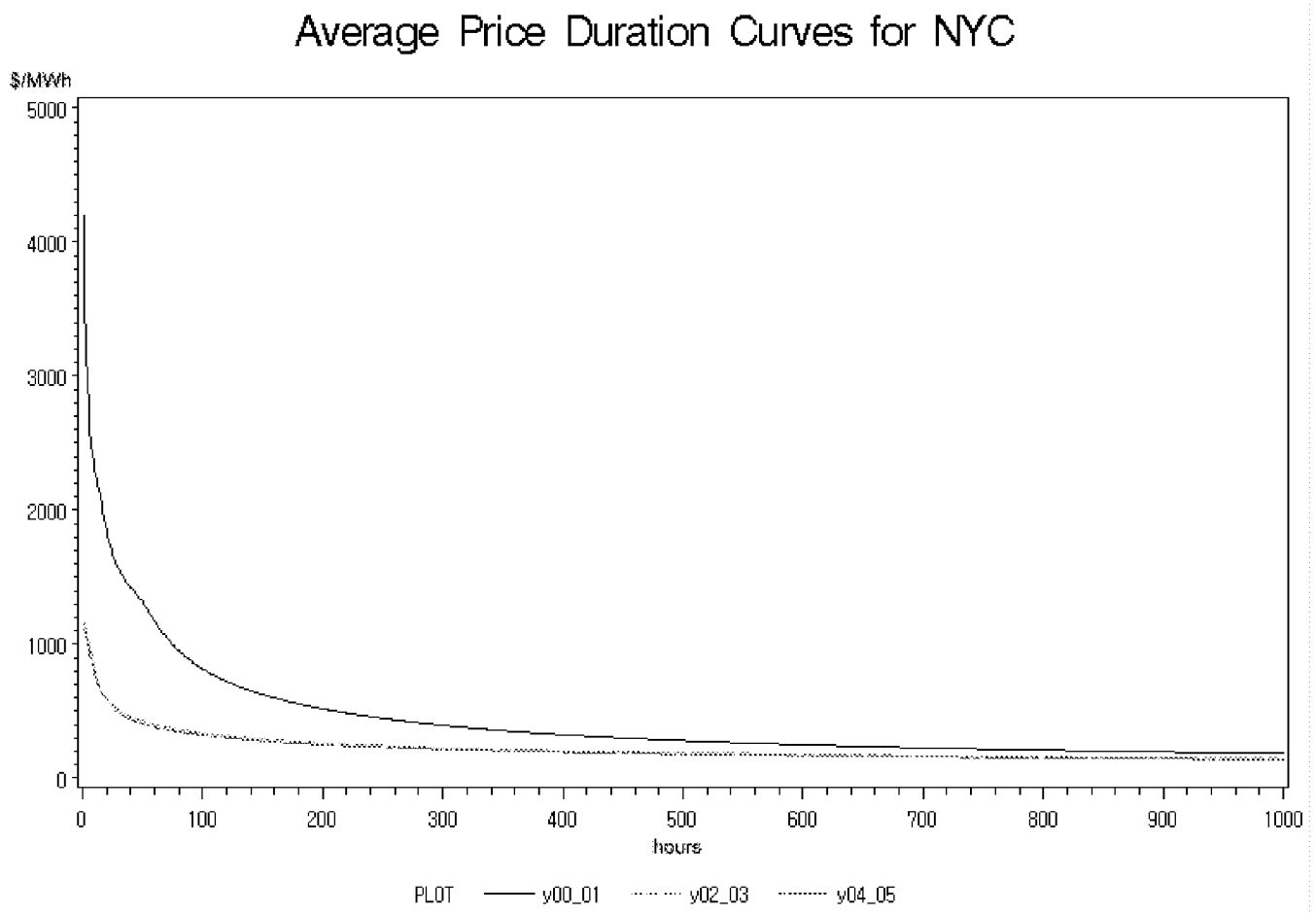

FIGURE E-5 Average price duration curves in the balancing market for May-April in New York City (in dollars per mmegawatt-hour) for 2000-2001, 2002-2003 and 2004-2005).

SOURCE: Derived from NYISO hourly spot prices, www.nyiso.com, accessed November, 2005.

The changing behavior of spot prices experienced by generators in New York City since deregulated wholesale market began is illustrated by the three average price-duration curves

shown in Figure E-5. The three curves are derived from the hourly zonal spot prices in New York City from May to April for 2000-2001, 2002-2003 and 2004-2005, corresponding to the standard time periods used by the NYSRC to determine the annual installed capacity requirements for the NYCA. The two curves for 2002-2003 and 2004-2005 are almost identical and consistently below the curve for 2000-2001 over the truncated range of hours shown in Figure E-5. An important additional point is that the effect of suppressing price spikes after 2000-2001 did not lower the annual average spot price. The annual average spot prices are $57.47/MWh, $59.81/MWh, and $67.96/MWh for 2000-2001, 2002--2003 and 2004-2005, respectively. The lowest average price occurred in 2000-2001, and the average price duration curve for 2000-2001 eventually crosses the other two curves if the horizontal axis is extended beyond 1,000 hours. For example, comparing 2000-2001 and 2004-2005, the two curves cross at 3,042 hours (equivalent to a capacity factor of 35 percent), and for higher capacity factors, the prices are eventually $10/MWh lower in 2000-2001 than they are in 2004-2005. Although there is no guarantee that the relationship between average prices and price spikes will behave this way, there is also no reason to assume that higher or more frequent price spikes must lead to higher average prices.

Each average price-duration curve in Figure E-5 is computed by ranking the hourly spot prices from highest to lowest, and for any given number of hours *N* (the horizontal axis), the corresponding price in dollars per megawatt-hour (vertical axis) measures the average spot price for the *N* hours with the highest prices. In other words, this average price is the average revenue received by a generator from a generating unit in New York City if it was dispatched for the *N* hours with the highest spot prices in a year (note that this definition of a "duration curve" is not the same as the one used to derive a load duration curve, because the latter is simply a ranking of the hourly loads and it does not measure the average load for the *N* hours with the highest loads). For a generator in New York City, each average price-duration curve in Figure E-5 represents the average revenue curve that corresponds to the average total cost curve shown in Figure E-3.

It is clear from a comparison of Figures E-3 and E-5 that the shape of the average price-duration curve in 2000-2001 is much closer than the other two curves are to the shape of the average total cost curve in Figure E-2, particularly when the number of hours is close to zero. (Note that the horizontal axis in Figure E-2 corresponds to a range of 16 to 1,600 hours.) The basic reason for the change after 2000-2001 is that price spikes were higher and more frequent in 2000-2001. For generators in New York City, the revenues received from sales in the spot market in 2000-2001 were far more consistent with their average total costs than they have been in more recent years, when fewer price spikes occurred. To get more insight into the conclusions of this section, it is helpful to look at the annual capacity factors of the major generating units in New York City and Long Island. This information is presented in Table E-2, using 2004 data from the NYISO (2004) and covers roughly half of the generating capacity required in New York City and Long Island to meet reliability standards (see Table E-1).

The power plants shown in Table E-2 all have generating units with a total capacity greater than 80MW, and most of the remaining generating units in New York City and Long Island are small turbines of various types that use natural gas or distillate oil as a fuel. Only 4 of the 13 power plants in Table 2 have capacity factors above 50 percent. The two plants with the highest capacity factors (more than 85 percent) are relatively new combined cycle generators (No. 8 and No. 10), the next highest (No. 11) is a relatively new cogeneration unit with a capacity factor of 74 percent, and the fourth highest (No. 5), with a capacity factor of 55 percent,

is the only traditional steam turbine among the four. With one exception (#6), the other power plants in Table E-2 are relatively old steam turbines and their capacity factors range from 9 percent to 41 percent. The low capacity factors of these plants confirms the fact that the production costs of traditional steam turbines that use natural gas or residual oil are substantially higher than the costs of the combined cycle units (and purchases from upstate).

TABLE E-2 The Capacity Factors in 2003 of Major Generating Units in New York City and Long Island

Name	Zone	Unit and Fuel Type [a]	Summer Capacity (MW)	Generation (GWh)	Capacity Factor (%) [b]
1. Ravenswood ST 01-03	Long Island	ST F06/NG	1,765	4,751	31
2. Barrett ST 01-02	Long Island	ST NG/F06	390	1,336	39
3. Far Rockaway ST 04	Long Island	ST NG/F06	107	264	28
4. Glenwood ST 04-05	Long Island	ST NG	238	545	26
5. Northport 1-4	Long Island	ST NG/F06	1,539	7,507	55
6. Wading River 1-3	Long Island	GT/F02	245	306	14
7. Port Jefferson 3-4	Long Island	ST F06/NG	385	1,399	41
8. Flynn	Long Island	CC NG/F02	136	1,069	89
9. East River 6-7	New York City	ST F06/NG	304	543	20
10. Brooklyn Navy Yard	New York City	CC NG/F02	262	1,983	86
11. Cogen Tech-Linden	New York City	GT/NG	661	4,286	74
12. Poletti 1	New York City	ST F06/NG	882	2,629	34
13. Arthur Kill ST 2-3	New York City	ST NG/F06	860	675	9

[a] ST, steam turbine; CC, combined cycle turbine; GT, combustion turbine; NG, natural gas; F06, residual oil; F02, distillate oil.
[b] Capacity factor = 100 x generation/(365.25 x 24 x summer capacity/1,000).
SOURCE: Derived from NYISO, 2004a, Table III-2)

Since a large number of the installed generating units in New York City and Long Island are relatively old units, with high production costs and low capacity factors, there is a legitimate concern about the continued financial viability of these generating units and whether some of them will be retired in the near future. This concern has been exacerbated by the changes in the behavior of spot prices shown in Figure E-5. Comparing the average price-duration curves in 2004-2005 and 2000-2001, the average price paid to generating units with high capacity factors (>>66 percent) increased by roughly $10/MWh. In contrast, the average price paid to generating units with low capacity factors (<<33 percent) fell dramatically, but these units (or their replacements) are still essential for maintaining the operational reliability of supply in New York City and Long Island. Nevertheless, the VOLL is very high (probably more than 100 times the average spot price), and it is still economically rational from the perspective of society as a whole to maintain a high level of operational reliability and to meet the NERC standards of limiting outages to less than 1 day in 10 years.

The underlying economic problem is that the spot prices in a strictly competitive market are not high enough to cover the total cost of the generating units with low capacity factors that are essential for maintaining operating reliability. In other words, the current financial incentives in a competitive market are insufficient to keep installed generating units with high production costs active in the market or to attract investors to build new generating units to replace them. Although current spot prices in 2004-2005 are probably closer to competitive levels than they were 2000/01, the textbook definition of a competitive market simply ignores the reliability of supply as an issue. The discussion in Section E-5 explains how regulators have addressed this fundamental inconsistency between the market signals from a competitive spot market and the legitimate objective of maintaining operating reliability. In this discussion, it is important to distinguish the differences in the financial needs of the existing generating capacity with high production costs and low capacity factors from the needs of new generating capacity, such as combined-cycle units, with high capacity factors. Both types of capacity can contribute to maintaining operating reliability but their financial needs are not the same, and it is unlikely that a single strategy will be the best solution for solving both problems.

FILLING THE FINANCIAL GAP TO MEET RELIABILITY STANDARDS

Before discussing the alternative ways of supplementing the earnings of generators from the spot market for electricity, it is important to reiterate the three major regulatory assumptions that underlie the need for additional income to maintain operating reliability in the NYCA. First, setting a level of generation adequacy for the NYCA is an acceptable proxy for meeting the NERC standards for reliability (see Section D-2 above). Second, given the limitations of the legacy transmission system, the locational requirements for generation capacity in New York City and Long Island determined by the NYISO are also acceptable proxies for meeting the NERC standards (see Section 3). Third, the political realities in the NYCA make it infeasible to adopt the Australian solution of allowing high price spikes in the spot market above short-run competitive prices (see Section 4). By accepting these assumptions, the very real complications of determining how to plan for and maintain the reliability of supply have been reduced by the regulators to simply ensuring that locational reserve margins for generating capacity in New York City, Long Island, and the NYCA are met.

Clearly, this transformation of concerns about the reliability of supply to concerns about generation adequacy is more likely to be an economically efficient solution when the transmission system is relatively robust and the availability of generating capacity is the main limiting factor. This is no longer the case in the NYCA given the structure of the legacy transmission system and the size and location of New York City. Nevertheless, regulators have accepted the assumption that meeting locational reserve margins in New York City, Long Island, and the NYCA is an effective strategy for meeting the NERC reliability standards. By focusing on generation adequacy, it is likely that the current regulatory practices followed in the NYCA, and the models used to determine the required levels of reserve margins for generating capacity, overlook the potential value of upgrades to the transmission system as a way to improve reliability.

By adopting the three assumptions stated above about reliability, state regulators have limited their primary concerns about the performance of the deregulated market to the dual objectives of maintaining (1) generation adequacy and (2) short-run competitive spot prices. Consequently, it is inevitable that the earnings from some generating units needed for operating reliability will be insufficient to make them financially viable. There are two distinctly different ways of addressing this problem. The first is to "correct" the prices in the spot market for all generating units by providing additional income from another source to cover the "missing" capital costs. The second is to use targeted contracts, such as Power Purchase Agreements (PPAs), to meet reliability standards with some but not all generating units. Regulators in New York State have chosen the first approach. Their basic rationale is that this strategy is consistent with regulatory theory and is economically fair both for the owners of installed generating capacity and for potential investors in new capacity. In contrast, contracts with some but not all generators are inherently discriminatory and may distort market behavior in an adverse way. These arguments are basically correct using standard textbook economics, but this fact still does not guarantee that the approach chosen by state regulators for maintaining reliability in the NYCA will be either effective or economically efficient. The characteristics of a market for electricity are not typical because, unlike storage alternatives for most commodities, the ways of storing electricity economically are very limited. As a result, the beneficial effects of having an inventory to cover shortages in the spot market are also very limited in electricity markets, and in general, the amount of generation must balance the level of load at all times.

Oren (2003) has given a persuasive account of the economic rationale for adopting the strategy chosen by regulators for the NYCA, and his justification is consistent with the analyses of real-time pricing in the regulatory literature. Short-run competitive spot prices imply that only the production costs of peaking units will be covered in the spot market. Consequently, the cost of capital for a peaking unit should be added to the competitive spot price for all generators to get the "correct" price (long-run marginal cost of production). A straightforward solution to this problem is to include an expensive source of energy with no capital costs in the portfolio of supply options. The obvious choice is to treat shedding load as a source of energy that is valued at the VOLL. Since the VOLL is very high, this strategy is equivalent to the Australian solution of allowing high price spikes. Joskow and Tirole (2004) have made the same argument as Oren (2003) in their analysis of how to make deregulated markets work better with fewer non-market interventions by regulators. They conclude that the current form of deregulated market will not lead to merchant investment in new generating capacity because (1) price caps are too low, and (2) most retail customers do not respond to high spot prices because they are still paying fixed regulated rates instead of the real-time spot prices.

If price spikes in the spot market are not politically acceptable, one approach is to cover the missing capital costs for peaking units in a separate market for generating capacity. This is the approach that has been proposed by regulators in the three Northeastern power pools. At this time, the NYISO is the only one of the three to fully implement this type of capacity market. There is still a considerable amount of political opposition to the proposal in New England, and there is an ongoing debate about it among stakeholders in PJM. It is important to understand why there is so much controversy about the effectiveness of a capacity market as a way of providing the incentives needed to initiate merchant investment in new generating capacity.

Initially, the installed capacity (ICAP) auction run by the NYISO was simply a market for availability, designed to ensure that enough installed generating capacity would be available to meet the projected loads in New York City, Long Island, and the NYCA (It should be noted that the Australian market does not have markets for either capacity or reserves because the financial consequences for generators of missing a price spike are so severe if their units are unavailable.) In general, an ICAP auction does provide an additional source of revenue for generators that may be significant for the continued financial viability of some installed generating units with low capacity factors. For example, the existence of the ICAP auction may result in some units being available instead of unavailable, and it may also delay the retirement of some units. However, this extra revenue from the ICAP auction is really a bonus for other generating units, such as nuclear and hydro units, because they would be available anyway without the ICAP auction. Nevertheless, regulatory theory implies that all installed capacity should be eligible for participation in the auction, and this issue is not a major source of controversy among regulators. The controversy arises when the objectives of the ICAP auction are extended to deal with the investment needed for new generating capacity.

There are three major issues of contention about the effectiveness of extending the ICAP auction to new capacity. The first is the difficulty of increasing the time horizon far enough into the future to meet the needs of investors. The second is whether it is appropriate to pass the responsibility for maintaining generation adequacy on to load serving entities (LSEs), and, most importantly, the third is how to ensure that enough revenue is provided in the ICAP auction to make investment in new capacity financially attractive. These issues are discussed after the following description of how regulators expect the augmented capacity market to work in the NYCA.

The economic justification underlying the current structure of the capacity market in the NYCA was established by Reeder (2002), and a detailed description of this market is given in Chapter 5 of the NYISO Installed Capacity Manual" (NYISO, 2004a). The basic structure of the market is that buyers (LSEs) submit bids to buy and generators submit offers to sell into a two-sided auction for generating capacity over a 6-month summer or winter period (a "capability period"). There is no guarantee in this type of auction that the quantity of capacity purchased will be sufficient to meet reliability standards, but regulators have imposed an obligation on the LSEs to purchase enough capacity to meet their load plus a reserve margin before the spot market for energy clears. This can be done through secondary trading in auctions for capacity over 1-month periods (i.e. making it possible to divide a six-month strip into its one-month components) or by bilateral contracts made over-the-counter between an LSE and a generator. LSEs can also meet some of their own capacity requirements if these sources are certified by the NYISO. The final monthly auction is the "spot" market for capacity that clears a few days before the month begins. The spot ICAP auction represents the last chance for LSEs to meet their capacity obligations without paying a penalty.

Initially, the ICAP auction in the NYCA was only designed to deal with the availability of generating capacity for a few months ahead. In contrast, an investor in a new generating unit probably needs to have a forward contract for energy for at least ten years to get adequate financing. Hence, the first issue of contention about ICAP auctions is how to extend the auction further into the future. Although regulators recognized this issue as an important objective, a major limitation is that LSEs are generally reluctant to commit to long-term contracts. The basic concern of LSEs is that it is difficult, given the regulatory push towards retail competition, for an individual LSE to predict how many customers they will have in the future, and therefore, how much capacity they need to purchase. The compromise between the needs of LSEs and generators is to extend the ICAP auction from one to three years into the future. For an investor, the new auction does provide more information about the likely future levels of income from the capacity market, but a decision to build a new generating unit will still depend on getting a forward contract for a longer time period. Given the relatively short time horizon for contracts in the ICAP auction (and in existing forward markets for electricity, such as the New York Mercantile Exchange [NYMEx]), long-term bilateral contracts (i.e. PPAs) will still be needed to get new generating capacity built. Basically, it is unrealistic to expect ICAP auctions to solve the problem of the long time horizon needed for an investment in new generating capacity.

The second issue of contention is the current regulatory strategy of placing the responsibility for maintaining generation adequacy on LSEs. Since generation adequacy in a region is specified in terms of the projected load, the public-good characteristics of reliability are converted implicitly to a criterion based on a private good. Markets and decentralized decision-making can work well for private goods, and as a result, regulators have decided to leave the responsibility for determining how to meet reliability standards, such as generation adequacy, to market forces. This decentralization is similar to the cap-and-trade strategy used in a market for emissions. Regulators set the standards for generation adequacy for each LSE, but the decisions about how to meet these standards are left to the market. LSEs have to purchase enough capacity from generators, or provide it themselves, to meet their capacity obligations.

When levels of installed capacity are low relative to load, it will be harder for LSEs to find generators that are able to contract with them. Consequently, the price of purchasing capacity from generators will increase and may be very high indeed for an LSE that is short of capacity close to real time. Although an LSE is not obligated to have full capacity coverage until the final spot ICAP auction, it may be very risky to wait until the last minute to purchase the capacity needed to meet their capacity obligations. A retailer caught in this predicament might be tempted to drop customers rather than pay the high price required to get full capacity coverage. In this situation, an incumbent utility that still has the regulatory obligation of meeting load would be required to pick up the discarded customers and pay the high price for additional capacity. However, if there really is insufficient installed capacity to meet generation adequacy in the near future, it is unlikely that there would be enough time to build new capacity. Under the Energy Policy Act of 2005, the NYISO would have to shed some load when capacity shortages occur to avoid paying penalties enforced by FERC. In other words, the market signals would come too late to ensure that adequacy standards were met without shedding load. This is a very serious deficiency of the ICAP auction, but regulators have anticipated this problem and introduced a "demand curve" into the capacity auction to address it.

The demand curve is designed to address the third issue of contention and to ensure that the revenue from the ICAP auction is sufficient to make a timely investment in new generating capacity financially viable. The proposed solution originates with the basic deficiency of a

competitive market identified in the regulatory literature. The bids of LSEs in the spot ICAP auction are replaced by a specified demand curve (set by regulators). The spot ICAP auction is not like the balancing market for energy because it includes all existing contracts on the supply-side of the auction. For each location, the demand curve is calibrated to the total capacity requirement for that location, and it ensures that the market price of capacity is equivalent to the capital cost of a peaking unit when the total supply of capacity falls to the amount needed for adequacy. The market price will be higher (lower) if the total capacity offered is lower (higher) than the required amount. There are additional features of the NYCA auction, such as how capacity is measured and whether the demand curve should have a kink in it, but the overall objective is clear. The market price of capacity in the spot ICAP auction should be equivalent to the capital cost of a peaking unit when the market is economically efficient (i.e., the total supply of capacity in the spot ICAP auction is just equal to the capacity needed for adequacy).

Incorporating a demand curve into the spot ICAP auction still does not solve the basic financial problem faced by an investor looking for a long-term contract. To address this problem, the parameters of the demand curves are set for the next 3 years. Even though the actual ICAP auctions are conducted a few months ahead in the same way as before, investors now know that the future ICAP auctions, up to 3 years ahead, will converge to the specified demand curves. In fact, the information provided by the modified ICAP auction is more valuable than this because the economic rationale for setting the demand curve is known. As long as the total capacity supplied in each spot ICAP auction is close to the capacity required for adequacy, a prospective investor will be able to recover the annualized capital cost of a peaking unit from the ICAP auction.

The main weakness of this argument is that it is difficult for anyone to predict future levels of available capacity because some of the capacity requirements may be self-supplied by LSEs and the retirement dates of generating units are considered to be private information in a deregulated market. The overall result of these uncertainties is that the projected levels of future reserve margins published annually by the NYISO in *Power Trends* and *Load and Capacity Data* (NYISO, 2005d) are no longer as accurate as they were under traditional regulation. An investor cannot take the NYISO predictions at face value. Even if the exact specifications of the demand curve in the modified ICAP auction are known, there is still a substantial amount of uncertainty about the future market price of capacity due to the uncertainty about future levels of installed capacity. Although the demand curve does provide more security about the future revenue stream from a capacity market (by reducing the price volatility and mitigating the boom-or-bust cycles that typically occur in an ICAP auction), there is still a lot of risk for investment decisions. For any investor, having a demand curve in the spot ICAP auction does not provide an effective substitute for having a long-term PPA. The demand curve may be an effective way of keeping some generating units with low capacity factors in the energy market, but it is unlikely to be an effective way of getting new generating units built when and where they are needed.

A more pragmatic criticism of the ICAP auction is that the higher payments to generators for capacity do not place any obligations on the generators to build new capacity. When the spot prices are consistent with short-run competitive behavior, generators do need to earn additional income to initiate an investment in new capacity. However, paying this extra income to all generators for installed capacity in the ICAP auction is expensive, and it still does not guarantee that generation adequacy will be maintained. The obvious solution proposed by most critics of ICAP auctions is to issue PPAs when projected future levels of capacity fall short of the required

standards. If this were done, there would be contracts to build capacity when and where it was needed, but it might be necessary to pay the investors a substantial premium above the expected income that could be earned in the energy, reserve, and capacity markets. Issuing a PPA in this way would be no longer a decentralized decision based on market forces. Some regulatory authority must make the initial decision about the size and location of the PPAs. Once this has been done, the responsibility for implementing and paying for the PPAs can be allocated to the LSEs. In essence, the locational-capacity obligations set by regulators for LSEs in the existing ICAP market would be supplemented by obligations for acquiring new capacity when projected levels of installed capacity do not meet the levels of generation adequacy needed to maintain reliability.

Critics of the critics of ICAP auctions argue that issuing PPAs would put the market on a slippery slope back to regulation. When a premium is paid in a PPA, it is equivalent to putting a financial squeeze on the owners of installed capacity. As a result, some generating units may be retired prematurely, increasing the need for new capacity or some form of PPA to keep installed capacity in the market. In other words, once decisions about building new capacity were centralized, many generators would want to get special deals. To avoid an undermining of the implicit fairness of the ICAP auction, it would be necessary for regulators to set rules for determining (1) when to issue PPAs for new capacity and (2) for which installed generating units would be eligible for a PPA. For example, the rules could require initiating PPAs (1) for new capacity when the reserve margin forecasted by the NYISO fell below a specified amount on a specified future date, and (2) for installed capacity when the capacity factor of a unit fell below a specified level and the unit was still needed for reliability. Contracts of this type for Reliability-Must-Run (RMR) units are common in the industry now, and the only real change required would be to specify an explicit set of rules for how and when new PPA or RMR contracts would be authorized by the regulators.

The uncertainty that exists about how reliability standards will be maintained in deregulated markets has contributed to a substantial level of "regulatory risk" faced by investors. Regulatory risk implies that high rates of return on capital will be required for merchant investments in deregulated markets if there is a lack of clarity about existing rules and the possibility of future rule changes. This situation constitutes a major impediment to investment in new capacity that was not present when the rate of return was guaranteed under regulation. For an investor in the NYISO market, having a PPA would be a good substitute for a regulated rate of return if the possibility of a default was minimal. Since the time horizon in the ICAP auction is too short to commit to building new capacity, an investor will still want to have a PPA with some credit-worthy buyer. However, an inherent characteristic of transferring the responsibility for generation adequacy from regulators to decentralized decisions by LSEs would be to require that investors contract with LSEs. The reluctance of most LSEs in the New York Control Area to make long-term contracts justifiable and reflects real uncertainty that they face about future market conditions. Hence, the risk premium for making a PPA with an LSE will be substantial and the resulting cost of capital will be high. Under these conditions, a large part of the regulatory risk is caused by the uncertainty that exists about how defaults will be treated if, for example, a retailer holding a PPA files for bankruptcy.

One way to reduce the regulatory risk of a PPA between an investor and an LSE is to have the contract backed by regulators. This situation is, however, essentially equivalent to having the PPA initiated by the regulators in the first place. To avoid getting too much capacity built, a PPA would have to be certified as necessary for generation adequacy. The decision

about how much new capacity should be built would no longer be left to decentralized market forces. The overall conclusion is that the NYISO ICAP auction does not provide a secure enough source of extra income far enough into the future to meet the needs of investors. In addition, it places no obligations on generators to spend the extra income on building new capacity. The threat that LSEs will have to pay penalties if they fall short of their capacity obligations is unlikely to be effective. As long as spot prices remain at short-run competitive levels in the electricity market, it will be difficult and expensive to get LSEs to bear the financial risk of building new capacity without some form of regulatory backing. The evidence presented in Section E-5 about how standards of generation adequacy are being met in the NYCA suggests that this conclusion is correct. Most of the existing proposals to build new generating units were initiated when price spikes occurred in the energy market (2000-2001) and many of these projects have been postponed now that electricity prices are more competitive.

CURRENT PROSPECTS FOR MAINTAINING GENERATION ADEQUACY IN THE NEW YORK CONTROL AREA

The financing of new generation and transmission facilities in the NYCA—regardless of whether it is needed to accommodate the retirement of existing facilities, the projected growth of load, or the intentional shutdown of Indian Point Units 2 and 3 before the end of their current licenses—must be understood within a broad context associated with the current hybrid mix of competitive markets and regulatory interventions. Under this mix, projects to build new generation and transmission facilities are no longer preapproved by the New York Public Service Commission (NYPSC), nor is there an implicit guarantee to investors that all prudent production costs and capital costs will be recovered from customers. Although market forces have been able to maintain levels of generation adequacy with relatively little regulatory intervention in Australia, for example, this is not the case in the NYCA.

Section E-5 above explains why the successful efforts of regulators to ensure that the spot prices of electricity meet short-run standards of economic efficiency have undermined the financial viability of generating units that are needed for reliability but have low capacity factors. This policy has made the current shape of the price-duration curve much flatter than it was in 2000-2001 (see Figure E-5), and as a result, has reduced the earnings of generating units with low capacity factors (peaking units) relative to units with high capacity factors (baseload units). The flattening of the price-duration curve, coupled with the current uncertainty about the future prices of fossil fuels such as natural gas, has led to delays in the construction of new generating facilities that have already received licenses to build in the NYCA.

Fortunately, the deteriorating outlook for attaining the required levels of generation adequacy for meeting the NERC standards for reliability in the NYCA after 2008 has been recognized in the new Comprehensive Reliability Planning Process (CRPP). This planning process was initiated in 2005, and there is still enough time for regulators to find solutions for meeting reliability standards in the NYCA. However, at this particular time, potential solutions are still being discussed and no specific solution has been chosen. This situation makes the task of this committee more difficult because it is necessary to propose a realistic plan for building new generating facilities to meet reliability standards before the alternatives to Indian Point can be evaluated. A detailed discussion of the scenarios specified by the Committee and the corresponding results are presented in Chapter 5 of this report.

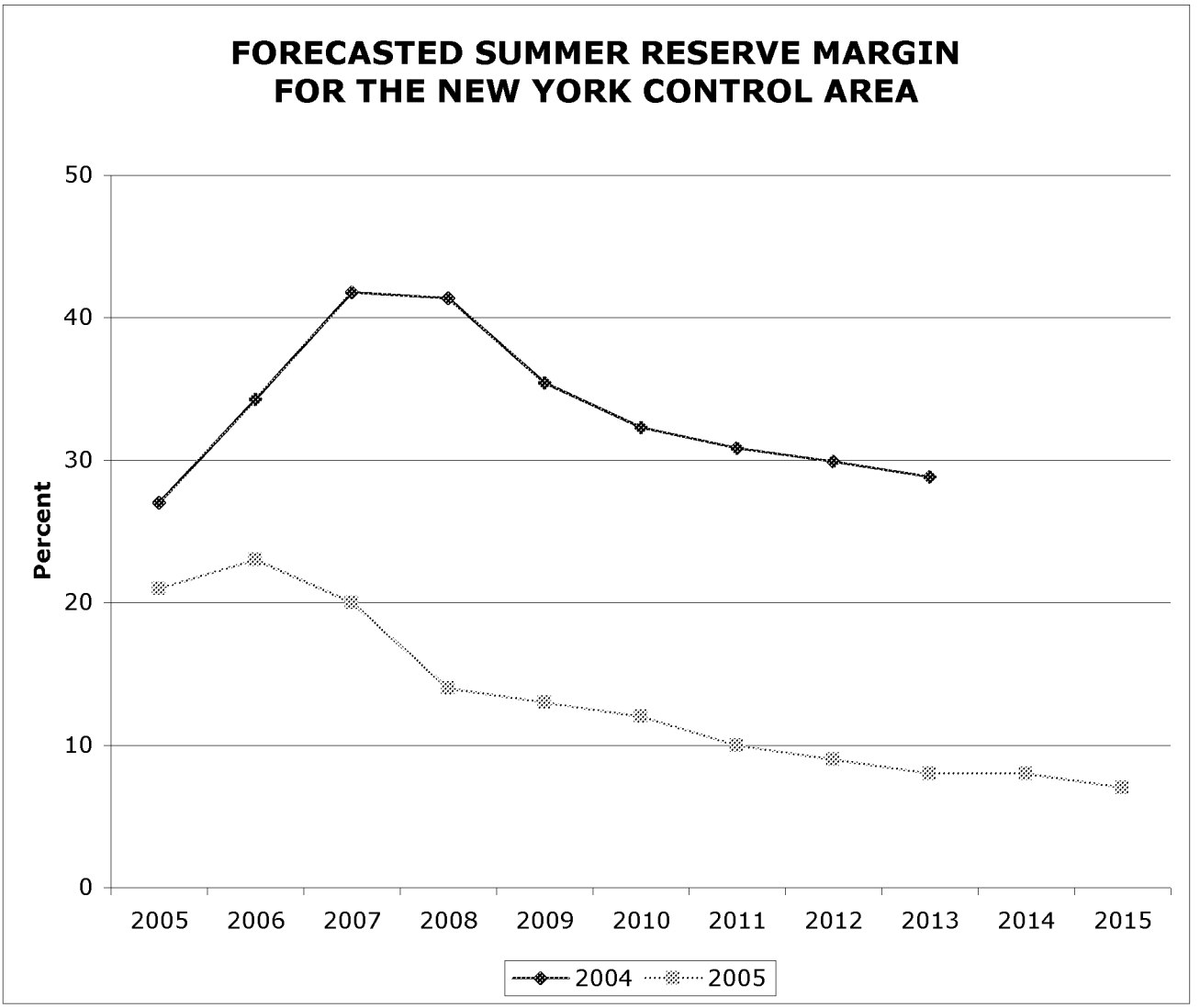

FIGURE E-6 Projections made in 2004 and 2005 of the summer reserve margin for generating capacity in the New York Control Area .
SOURCE: Projections made in 2004 from Table V-2, "Load and Capacity Schedule" " (NYISO, 2004b); those made in 2005 from Table 7.1, "Load and Capacity Table." in NYISO,(2005d).

The change in the outlook for meeting reliability standards in the NYCA is best summarized by the drop in projected reserve margins for generating capacity from the forecast made in 2004 to that in 2005, shown in Figure E-6. NYISO's 2004 report, the reserve margin in 2008 was expected to be over 40 percent, but in the 2005 report, the current projection for 2008 is less than the 18 percent needed to meet the NERC reliability standards.

Generation Projects Subject to Article X Top of the Queue						
Project Name	Owner / Developer	Size (MW)	Connect-ing Utility	Date of NYISO Application	Status of Article X	Proposed In-Service
Bethlehem Energy Center	PSEG Power NY	750	NM-NG	04/27/99	Certified 2/28/02	2005
East River Repowering	Consolidated Edison of NY	358	CONED	08/10/99	Certified 8/30/01	2004
Poletti Expansion	NYPA	500	CONED	04/30/99	Certified 10/2/02	2004
SCS Astoria Energy Phase I	SCS Energy LLC	500	CONED	11/16/99	Certified 11/21/01	2006
Under Construction TOTAL		2,038				
Brookhaven Energy	American National Power	540	LIPA	11/22/99	Certified 08/14/02	2006
Bowline Point Unit 3	Mirant	750	CONED	10/13/99	Certified 3/25/02	?
Spagnoli Road CC Unit	Keyspan Energy, Inc.	250	LIPA	05/17/99	Certified 05/08/03	2006
Wawayanda Energy Center	Calpine Eastern Corporation	540	NYPA	06/10/99	Certified 10/22/02	?
Astoria Repowering Phase I	Reliant Energy	367 net	CONED	07/13/99	Certified 06/25/03	2007
Astoria Repowering Phase II	Reliant Energy	173 net	CONED	08/18/00	Certified 06/25/03	2007
SCS Astoria Energy Phase II	SCS Energy LLC	500	CONED	11/16/99	Certified 11/22/01	?
Approved - TOTAL		3,120				
Empire State Newsprint	Besicorp / Empire State	505	NM - NG	07/14/00	Appl accepted 05/28/02	?
TransGas Energy	TransGas Energy, LLC	1,100	CONED	10/05/01	Appl accepted 8/06/03	2007
Projects with Applications Pending - TOTAL		1,605				
GRAND TOTAL MW Proposed Projects		6,763				
under construction	approved	application pending				

TABLE E-3 New Generating Units Proposed for the NYCA in 2004.
SOURCE: Adapted, with permission, from "NYISO Power Trends 2004" (NYISO, 2004b)

The drop in the projected reserve margins shown in Figure E-6 was caused by delays in the construction of new generating units that had already received construction licenses. The lists of new generating units that correspond to the two projections of reserve margins in Figure E-6 are shown in Tables E-3 and E-4 for 2004 and 2005, respectively. The two lists are essentially the same, but the "Proposed In-Service" dates are quite different. In 2004 (Table #-3) , 2,038 MW were under construction; 3,120 MW were approved, and 1,605 MW had applications pending, for a total of 6,763 MW. In 2005 (Table E-4), the amount of capacity under construction was still 2,038 MW, but none of the other nine projects had proposed in-service dates. In 2004, five of the nine projects had proposed in-service dates no later than 2007, and the dates for the other four units were uncertain. The important implication is that it is no longer realistic under current economic conditions to assume that a generating unit will be built after regulators have approved a license for construction. This was typically not the case under regulation.

Generation Projects Subject to Article X Top of the Queue						
Project Name	Owner/ Developer	Size (MW)	Connecting Utility	Date of NYISO Application	Status of Article X	Proposed In-Service
Bethlehem Energy Center	PSEG Power NY	750	NM-NG	04/27/98	Certified 2/28/02	2005
East River Repowering	Consolidated Edison of NY	288	CONED	06/10/99	Certified 8/30/01	2005
NYPA Project	NYPA	500	CONED	04/30/99	Certified 10/2/02	2005
SCS Astoria Energy Phase I	SCS Energy LLC	500	CONED	11/16/99	Certified 11/21/01	2007
Under Construction - TOTAL		2,038				
Brookhaven Energy	American National Power	540	LIPA	11/23/99	Certified 08/14/02	
Bowline Point Unit 3	Mirant	750	CONED	10/13/98	Certified 3/25/02	
Spagnoli Road CC Unit	Keyspan Energy, Inc.	250	LIPA	05/17/99	Certified 05/09/03	
Wawayanda Energy Center	Calpine Eastern Corporation	540	NYPA	06/10/99	Certified 10/22/02	
Astoria Repowering Phase I	Reliant Energy	387 net	CONED	07/13/99	Certified 06/25/03	
Astoria Repowering Phase II	Reliant Energy	173 net	CONED	08/18/00	Certified 06/25/03	
SCS Astoria Energy Phase II	SCS Energy LLC	500	CONED	11/16/99	Certified 11/22/01	
Empire State Newsprint	Basicorp/Empire State	505	NM-NG	07/14/00	Certified 09/21/04	
Approved - TOTAL		3,625				
TransGas Energy	TransGas Energy, LLC	1,100	CONED	10/05/01	Appl accepted 6/05/03	
Projects with Applications Pending - TOTAL		1,100				
GRAND TOTAL MW Proposed Projects		6,763				
under construction	approved		application pending			

TABLE E-4 New Generating Units Proposed for the NYCA in 2005.
SOURCE: NYISO, 2005d

The importance of reliability has also been recognized in the Energy Policy Act of 2005, and the major effect of this legislation is to give the FERC the overall authority to enforce reliability standards throughout the Eastern and Western Inter-Connections. Although it is still too early to know how this new authority will be implemented by the FERC, it is clear that the threat of paying penalties will be a tangible reason for regulators in New York State to make sure that reliability standards are met. In addition, if the required levels of generation adequacy are not maintained, the possibility that some load will have to be shed to maintain adequate capacity margins will be unpopular with politicians and the public. Hence, it is highly likely that state regulators will deal with the current problem of inadequate generating capacity in the NYCA.

When the uncertainty about the retirement dates of existing generating units is combined with the uncertainty about whether new generating units will be built, the task faced by state regulators, ensuring that there is enough installed generating capacity to meet FERC's reliability standards is very challenging. Nevertheless, reliability standards must be met because, as explained in Section 4 above, the cost of blackouts in a dense urban area like New York City is very high. (The value of lost load is over $10,000/MWh compared with typical spot prices of less than $100/MWh.) It is also clear that the regulatory practices in the NYCA existing prior to

the CRPP and the Energy Policy Act of 2005, were not entirely satisfactory. During public meeting held by this committee, it was unclear what responsibilities the different regulatory organizations had for ensuring that reliability standards in the NYCA are met. Both the New York Public Service Commission and the Northeast Power Coordinating Council (NPCC) are required to confirm that the NYISO's plan for meeting projected levels of load will meet reliability standards. However, the main problem identified by the Indian Point Committee was that there were no standard procedures for determining how deficiencies in a plan would be corrected. According to Michael Forte, Chief Engineer for Planning at Consolidated Edison, addressing the committee, "reliability trumps economics," and in his view a transmission provider such as Consolidated Edison must focus on reliability. However, Howard Tarler (NYPSC) stated that load serving entities and energy service companies are responsible for maintaining the levels of generating adequacy needed for reliability. Until the lower projections of capacity margins were published in the CRPP report in September 2005, it seems that most state regulators believed that the existing regulatory practices were working well and that reliability standards would continue to be met.

Merchant generation and transmission projects are difficult to finance under current economic conditions. According to the Chairman of the NYPSC, "merchant transmission projects are currently experiencing financing difficulties due to uncertainty about cost recovery by non-utility providers." (Flynn 2005). Carl Seligson, a Wall Street financier, made the same point in his presentation of March 15, 2005 to the committee when referring to his "three Rs rule": Risk Requires Return! He also stated that a better way to finance utility projects is to follow the practices currently used in Iowa State.[10] Under this scheme, regulators and investors agree in advance of the construction on an explicit set of rules for recovering costs from each new project. This is a transparent process that reduces the financial risk for investors and lowers capital costs. The process is consistent with issuing a Power Purchase Agreement (PPA) for a new generating facility that has regulatory backing, and could include performance-based rates of return. In contrast, there is a perception among some investors that state regulators in the NYCA may change the rules for a standard PPA that is initiated as a bilateral contract, and in particular, may try to recover "profits" from incumbent utilities holding a PPA for a successful contract but provide no compensation for "losses." To the extent that this perception is correct, the possible asymmetry in the treatment of profits and losses increases the regulatory risk faced by investors.

In summary, getting sufficient financing for the capital-intensive investments in a new generation or transmission facilities needed to maintain the reliability of supply in the NYCA requires state regulators to address the following issues:

- Long-term PPAs and other contracts need a projected revenue-stream that will cover the production costs and support the recovery of the initial capital cost with a reasonable rate of return.
- A regulatory commitment is needed to establish and abide by explicit rules governing long-term PPAs and other contracts.
- Credit-worthy counterparties are needed for investors initiating long-term PPAs and other contracts to build new facilities, or as an alternative, some regulatory backup to deal with defaults on contracts.

[10] All these comments were made at the committee's 2nd meeting March 14-16, 2005.

- Increased regulatory consistency is needed for expediting the siting and licensing of new facilities at the state and local level. (Note that the Article X law, which facilitated this process, expired in 2002. A variation of the Article X law was introduced in the New York State Legislature in 2005 but was never enacted.)
- More emphasis is needed on the importance of upgrading transmission facilities (current regulatory practices and the models used for analysis treat generation adequacy as the main issue for maintaining reliability and do not address transmission adequacy effectively).
- Appropriate roles should be established for the New York Power Authority and the Long Island Power Authority to determine the best way for these authorities to help maintain reliability standards. (These two public authorities control substantial amounts of generation and transmission capacity in New York City and Long Island. In the past, these authorities have been used to intervene in the market by, for example, installing 500 MW of peaking capacity in New York City. These types of decisions are not part of the standard planning process in the NYCA, and as a result, they create an additional source of regulatory risk for investors.)

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Appendix F

BACKGROUND FOR THE SYSTEM RELIABILITY AND COST ANALYSIS

Samuel M. Fleming[1]

Contents

Tables

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[1] Samuel M. Fleming is a member of the Committee on Alternatives to Indian Point for Meeting Energy Needs.

[2] In this Appendix F *ONLY,* the "NYISO Initial Base Case" corresponds to "Base Case" in the Draft NYISO RNA dated 10/25/05. It assumes thermal transmission constraints control, and it employed the "Alternate New England Transmission Constraints" on the assumption that substantial loop flow of power into New England, then back into New York south of the UPNY/SENY interface would be limited. The issue of what transmission constraints are appropriate has been appealed to FERC and NYSRC by upstate power generators. The Committee's studies assumed the use of the "Alt. NE Transmission Constraints," but the Committee obviously takes no position on the merit of the appeals before the regulatory commissions. The NYISO "Base Case" assumed in its Final Report dated 12/21/05 corresponds to voltage constraints controlling, and leads to the requirement to correct reactive power in the Lower Hudson Valley.

APPENDIX F-1

THE NYISO APPROACH

The CRPP recently completed by NYISO represents a major advance in planning. It is a stakeholder process, described along with its criteria, organization, and approval process in the Reliability Needs Assessment (RNA) Support Document (NYISO 2005, pp. 1-6). Below are the main points of the CRPP relating to this committee's charge:

- The reliability of the electrical generation and transmission system in the New York Control Area (NYCA) would be inadequate beginning in 2009 *if*, as is the case historically, thermally constrained transmission limits control transmission.[3] The reliability criterion of loss-of-load-expectation (LOLE) for the NYCA reaches 0.160 by 2009, and thus exceeds the NYSRC criterion of LOLE of 0.1 or less.
- The projected inadequate reliability by 2009 is a consequence of the factors listed below, in spite of new resources of about 2,890 megawatts (MW) coming online between 2005 and 2007 (including the 660 MW Neptune high-voltage direct current (HVDC) cable from the Pennsylvania-Jersey-Maryland-(PJM) Independent System Operator into Long Island). These compounding factors are as follows:
  - Projected load growth in southeastern New York State;
  - Increased electrical demand over the past decade of 5000 MW in SE New York, only one fourth of which was matched by net additions to generating capacity or load reduction downstate,
  - Scheduled retirements by early-2008 of about 2250 MW of generating capacity and changes in neighboring power systems, and, consequently
  - Greater past reliance and higher projected reliance on a complex and aging transmission system.
- The state's transmission system is increasingly characterized by congestion, especially during summer peak loads, at the Upstate New York-Southeast New York (UPNY/SENY) transmission interface, where power generated in northern and western New York state is transmitted toward the high load centers in southeastern New York, especially New York City, Long Island, and, increasingly, Westchester County (NYCA Zones J, K, and I, respectively)—and by the complexity of the transmission system within New York City. Consideration of transmission transfer constraints, particularly at the UPNY/SENY interface (just north of Pleasant Valley, New York), is thus a key aspect of considering the projected reliability of the alternating current (AC) transmission system.
- The New York Power Authority's (NYPA) Poletti Unit 1 (Zone J, 885 MW) represents 39 percent, and Lovett Units 3, 4, and 5 (Zone G, 431 MW)

[3] Thermal limits relate to avoidance of overheating the transmission lines, a condition causing the lines to sag, and in some instances to touch vegetation, causing outages.

represent 19 percent of the scheduled retirements of generating capacity by early 2008. Thus Poletti 1 and the Lovett Station's units together total 1,315 MW and represent 58 percent of the scheduled retirements by mid-2008

- Addition of a corrective resource—an additional 250 MW of generating capacity in New York City (Zone J), beyond NYISO's Initial Base Case—would be needed by 2009 to meet the NYCA LOLE criterion of 0.1. The additional generating capacity needed downstate increases to 1,250 MW by 2010 and to 1,500 MW by 2011.
- Reactive power deficiencies in the Lower Hudson Valley (LHV) mean, however, that voltage-constraint limits[4] in the transmission system, if not corrected, would control the reliability situation, rather than thermal transmission constraints. In this situation, the projected NYCA LOLE reaches 0.395 by 2008, and 2.43 by 2010. The impact *if* voltage constraints were to control—*and if* only adding more generation capacity were to be considered—would therefore be that an additional 500 MW of generating capacity would be needed in New York City (Zone J) by 2008, increasing to 1,750 MW downstate in Zones I thru K by 2010 (unless an additional 1,500 MW were added in Zone J alone by 2010 (see NYISO, 2005).
- The retirements of Lovett Station Units 2, 3, and 4 and Poletti Unit 1 by early 2008 therefore also result in the need in 2008 for a resource to correct reactive power, some 335 megavars (Mvars) of static var compensation (SVC) at Ramapo Substation (southern Zone G). By 2010 some 1000 Mvars of SVC capacity would be needed downstate, 500 Mvars at Ramapo and 500 Mvars at Sprain Brook (southern Zone I). The inadequate NYCA system reliability beginning in 2008 or 2009 exists *without the additional consideration of the hypothetical retirement of Units 2 and 3 of the Indian Point Energy Center* that presently supply 2,138 MW of power and about 1000 Mvar of reactive power downstate.
- A brief scenario analysis describes the impact on NYCA system reliability of the hypothetical early retirement of the Indian Point 2 and 3 units in 2008 and 2010, respectively. In this early-retirement scenario, the LOLE for the NYCA in 2010 is projected to be 3.5 days per year, which is 35 times higher than the NYSRC requirement.[5]

The final NYISO Reliability Needs Assessment report was issued December 21, 2005, the solicitation for market-based solutions was issued December 22, 2005 along with criteria for evaluating the viability of proposed market-based solutions. Responses

[4] Voltage drop in the AC system must be tightly limited to maintain frequency and synchronous operation, and to avoid physical damage both to generating equipment and equipment served as load.

[5] NYISO identified additional system planning issues. These include: (1) Wind and Renewable Additions to meet Renewable Portfolio Standards; (2) Environmental Compliance Issues including NYS Acid Deposition Reduction Program; the Clean Water Act Cooling Water Intake BAT; New Source Review; Clean Air Interstate Rule (CAIR); Clean Air Mercury Rule; Regional Greenhouse Gas Initiative (RGGI); Regional Haze Rule. (3) Generation expansion, (4) Retirement of existing Generation, (5) Transmission Owner Plans, (6) Fuel Availability/Diversity, (7) Impact of New Technologies, (8) Load Forcast Uncertainty, and (9) Neighboring System Plans.

were due February 15, 2006. Proposed solutions are to be evaluated, and decisions will result in issuance of the final NYISO Comprehensive Reliability Plan in July 2006.

Because of the complexity of the generation and transmission system in New York State and its interconnected regions, a reliability analysis is quite elaborate. It is thus important to appreciate the issues addressed, as well as the logic and sequence of the approach to the problem. To anticipate some of the considerations and results discussed below, one should also recognize that while the regions in the Northeast are electrically interconnected, the inter-region power transfer capability is, at present, about five percent of the peak electrical loads of the region. Thus, the ability of surrounding regions to supply power to the NYCA under emergency conditions, while quite important, is still rather limited.

The main elements of the NYISO (2005) study addressed the adequacy of the system to provide reliable power resources, requiring both enough generating capacity and the capability to transmit the power to the load centers. Adequate generation (or additional capacity required, if needed) was addressed first, and then possible limitations of the transmission system that were identified.

First, the NYCA LOLEs up to 2010, for the first five years of a (NYISO) Initial Base Case, are calculated, assuming no transmission system transfer limitations within the NYCA system. This "Free Flow Transmission" case indicates only whether the projected installed generating capacity would be sufficient to satisfy the projected load demand. Next a recalculation is made of the LOLE for the NYCA when the transmission limits internal to NYCA are imposed. This calculation indicates whether the projected NYCA transmission system in the Initial Base Case is adequate to deliver the projected electricity generation to the various load zones within the NYCA. (Generally, power flows west to east in upstate New York, then southeast to New York City and Long Island.)

If the simulated system failed to meet the LOLE criterion of 0.1 days per year for the NYCA, additional combined-cycle generation units with 250 MW capacity were assumed to be added until the LOLE criteria were satisfied. Generally, these natural gas-fired units were assumed to be added to the Zone(s) having too high a LOLE. This calculation showed a minimum additional generating capacity needed to meet the New York State reliability criteria.

A simplified transmission screening study was then carried out. The NYISO then performed a power-flow analysis, focusing only on the voltage and thermal performance of the bulk power transmission system as well as performing a limited transfer analysis of some 16 New York power system interfaces. The objective of this part of the screening analysis was to identify the regions or corridors requiring any significant transmission-system upgrades in order to meet system reliability criteria. In particular, the goal was to determine which transmission reinforcement areas could provide the most system performance benefit, over the broadest range of possible system future conditions. Multiple scenarios representing different possible system conditions (e.g., generation, load, transmission variations) were evaluated.[6]

[6] From NYISO, 2005, p. 35. A comprehensive transmission reliability analysis is far more complex, as discussed in the Draft Report. Such comprehensive reliability analysis considers many more factors, and can include dynamic (time-dependent) simulations. For very complex systems therefore, such comprehensive dynamic transmission analysis requires massive computing power and computer run times,

To account for the effects of "short circuits," a fault duty study was then performed using the ASPEN design code to determine the impact of the 2013 maximum generation scenario on local circuit breakers.[7] Following the analysis of the Initial Base Case, scenarios were simulated using test cases that combine variations in installed generation, load forecasts, transmission system transfer capabilities, and available assistance from neighboring systems. These scenarios were simulated to determine their impact on the reliability of the NYCA system and hence the adequacy of the transmission system.

The Initial Baseline and sensitivity analyses performed by the NYISO also include addition of illustrative and hypothetical "compensatory resources," zone by zone, that might be used to correct projected capacity deficits in each zone of the system and/or to make up for inadequate transmission line capacity or transmission transfer limits at the intertie points. Also included is a screening-level, macro system view that identifies undesirable or unacceptable conditions identified from the modeling and tentative corrective actions.

One such example identified early during the NYISO screening study is large region-to-region flows of electricity, out of upstate New York to New England, with loopback flows of power back to deficit zones in New York, notably the high-load zones of southeastern New York, especially (but not limited to) New York City (Zone J) and Long Island (Zone K). Essentially, the large power loop flow could be corrected by adjusting the transmission transfer limits across the various transmission interties within NYCA. An assumption of "Alternate Transmission Constraints" at the interties within NYCA by NYISO for their study resulted in a proposed, "Modified Transmission System Topology," within NYCA.

This summary of the NYISO approach to the in-state system analysis provided the framework for the committee's study, using the same reliability model. The NYISO results are in NYISO (2005).

APPENDIX F-2

NOTES ON THE MARS-MAPS SIMULATIONS

The committee sought and received in September 2005 substantial then-current draft information from NYISO. The committee also contracted with General Electric International (GE) to run the Multi-Area Reliability Simulation (MARS) program. This model simulates, using a transportation model and Monte Carlo simulation, the electrical generation and transmission system of the New York Control Area (NYCA), interconnected with the four contiguous electrical power systems in the northeastern United States and eastern Canada.

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and thus is considered too expensive for initial screening studies. NYISO notes that some far more sophisticated dynamic analyses *may* be performed annually, while others may be performed only as specific circumstances arise.

[7] From NYISO, 2005, pp 37 – 38.

The MARS software is the same system reliability screening tool approved by NYSRC and used by the NYISO in its Comprehensive Reliability Planning Process (CRPP) and Reliability Needs Assessment (RNA) studies (NYISO, 2005). The databases used by GE and the NYISO for the MARS analysis differed, however, in that the NYISO database contains commercially proprietary data. Other differences are discussed in Chapter 5.

Projecting Impacts on NYCA System Operation and Economics.

In addition to the MARS analyses for system reliability, GE used its Multi-Area Production Simulation (MAPS) program to examine the impacts of the several scenarios on NYCA systemwide operations and economics, as well as the impacts on a portion of the interconnected regional power systems (specifically, part of the PJM system and the ISO-New England (ISO-NE) system). Below are main points of how the MAPS simulation works with MARS, and the results produced by this simulation.

MAPS operates in conjunction with MARS to assess, for systems where MARS projects that reliability criteria are met, the operational and economic characteristics of the entire interconnected system. MARS is a "transportation" model, commonly referred to as a "bubble and stick" model, connecting generation and loads in the grid—that is, connecting with direct-current (DC)-like flows the sources and sinks of power. The MAPS software, however, models the electrical system in greater detail, examining the flow on each transmission line for every hour of the simulation, recognizing both normal and security-related transmission constraints.

MAPS adjusts the operation of each generating unit in the system to meet the electrical generation requirements of the specific scenario being modeled, also considering the transmission constraints noted. MAPS calculates the annual variable operating cost (VOC) of producing electricity systemwide, and iterates, adjusting the operation of each unit in the system, to determine the minimum annual VOC systemwide. The variable cost of producing electricity is dominated by fuel costs, but it also includes variable operation and maintenance (O&M) costs, unit start-up costs (say, going from a cold start and ramping up to full electrical output), and the variable cost of emission credits consumed, where required.[8]

Having established the minimum systemwide annual VOC, MAPS then provides for the Northeast Region, New York Control Area (NYCA) and each pricing (load) zone

[8] Some perspective on how the variable cost of operation relates to the total cost of production of electricity is provided by comparing the contribution of variable and fixed costs of operation. These vary for different kinds of units. A modern, high efficiency, gas fired combined cycle unit having a heat rate as low as 6700 Btu/kWh has a Battery Limits Capital Cost as low as $525/kW installed. The corresponding Non-Fuel Operating Cost is typically $3.30/MWhr. [Hinkle et al, 2005] Numbers reported later for the variable costs of operation—due mainly to the cost of fuel—are of the order of 20 $/MWh. Therefore, in this instance, variable costs represent roughly 85 percent of total operating cost. In New York City, both fuel and capital costs of construction can be markedly higher than in other markets. Project-by-project analysis is required, in any event, which is obviously very closely-held competitive information.
Finally, note with respect to the recovery of the capital cost of new additions to capacity, that NYISO also runs the Installed Capacity Market (ICAP) in New York that is designed to allow generators of electricity to recover part of their capital costs. Consideration is also being given currently to establishing a Capacity Market in New York, as a further evolution of deregulating electricity markets.

in New York (see Figure 1-3 in Chapter 1), the corresponding wholesale price of electricity, airborne emissions, and the mix of fuels used in generating electricity. Iterative use of the MARS reliability simulations in conjunction with MAPS for the different scenarios thus provides a preliminary basis for comparing both reliability and trends of economic impacts among the illustrative scenarios posed by the committee.

Note that the scenario analyses reported here are an early stage of analysis for hypothetical options. Additional analysis, using more sophisticated analytical tools would be required to develop an optimized, defensible plan for Indian Point replacement options. Such an analysis was beyond the scope of the committee's charge.

Perspectives on MARS and MAPS Simulations

Since MAPS minimizes the projected systemwide operating cost of producing electricity, which in turn tends to be dominated by fuel costs, the fuel prices assumed dominate the economic outputs from this model. Consistent with past practice, GE incorporated current data from Platts,[9] which provided a reference 2008 cost of natural gas of $5.1/million Btu (MBtu), decreasing to $4.2/MBtu by 2015 (both in dollars-of-the-year, projected future value).

To assess the impact of higher fuel prices, a brief sensitivity study was made, using a 2008 natural gas price of $7.8/MBtu (decreasing to $7.0 by 2015). In comparison, the Energy Information Administration of the U.S. Department of Energy (EIA) reports natural gas prices to electric power consumers in New York rising from $6 to $7 in 2004 to $7.3 to $9.3/ thousand cubic feet (one thousand cubic feet of natural gas is almost exactly equivalent to one million BTU) through August 2005 (DOE, 2005). The price of natural gas in NYISO is already higher than the high-fuel-price scenario in this case, even before the recent additional gas price volatility introduced by Hurricane Katrina. As noted in the report, the December 21, 2005 spot price of natural gas at Henry Hub (the central point for natural gas futures trading in the United States) was $13.55/MBtu, with a New York City gate premium of $1.11/MBtu (prices have subsequently dropped considerably). The consequences of high gas prices and volatility in the projections have been explored, but the results on cost are believed to be highly uncertain.

In evaluating the results of the MAPS analyses, it is recommended that readers should: (1) appreciate that price assumptions for natural gas are low in comparison with present NYISO prices, even for the "high-fuel-price" cases; (2) look for trends and percentage changes (rather that the absolute values of, say, wholesale price of electricity); and (3) keep in mind the *relative* changes in prices of fuels and the tendencies noted above that are inherent in the assumptions made for the higher fuel price sensitivity cases.

[9] Base case data set, Quarter 1, 2005, published by Platts, a Division of McGraw-Hill Companies. See http://www.platts.com/Analytic%20Solutions/BaseCase/index.xml. Accessed November 2005.

The NYISO Initial Base Case

The generating units incorporated in the NYISO database used for the modeling were used to develop a Baseline case that included the present generation and transmission system, allowing over the next 10 years for known scheduled retirements of generating capacity, and adding the firmly committed generation and transmission additions and upgrades that are projected to occur throughout the study period. The source for the data for the existing system was the MARS database maintained by NYISO staff for use in determining the annual installed reserve requirements (IRM). The electrical load and generation capacity were updated through the 2005-2015 study period based on data from the 2005 load and capacity data report issued by NYISO. Similar reports for the neighboring systems were referenced for updating the data in those regions (NYISO, 2005, p. 35).

For the NYISO (2005) reliability analysis, the NYISO planning staff adopted a somewhat conservative approach, in that only those additions to capacity or transmission were included that (simply stated here) are presently in service, are under construction, or have been certified and are under contract with a credit-worthy entity. For the NYISO Initial Base Case, this translates to the resources that include the following:

- Six new generation projects adding 2,228 MW of new capacity.
- Scheduled retirements of 2,363 MW of generating capacity.[10]
- Twenty-two other *proposed* generation projects totaling some 6,765 MW of proposed capacity are listed in the report. These proposed projects are at various earlier stages of project formation, and thus do not meet the NYISO criteria for inclusion in its Initial Base Case.
- Eleven additions to transmission capacity are included, all rather small with the exception of the Neptune transmission project, connecting the PJM Control Area to Long Island with a DC line of 600 MW capacity. Transmission operator (TO) projects on non-bulk power facilities are included.

The resources also include the existing fleet of generating units in the NYCA and parts of three contiguous areas in the Northeast region. The Initial Base Case for the NYISO is shown in Table F-2-1.

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[10] Retirements in the Initial Base Case do not include either Indian Point Unit 2 or Unit 3, but these possibilities are treated briefly in scenario analyses, subsequent to the NYISO Initial Base Case.

TABLE F-2-1 NYISO Initial Base Case Capacity Details Adopted for the MARS Analysis

Proposed Projects for Inclusion in Study Base Cases - Load Flow									
	In-service Dates	MW Capacity Summer	MW Capacity Winter (**)	Status	CRPS 2010	ATBA 2010	ATRA 2010	CATR 2010	CRPS-15 2015
I. Generation									
A. Additions									
ConEd-East River Repowering	I/S	298		I/S	X	X	X	X	X
NYPA-Poletti Expansion	2006/01	500		UC	X	X	X	X	X
SCS Energy-Astoria Energy	2006/04	500		UC	X	X	X	X	X
PSEG-Bethlehem	2005/07	770	828	UC	X	X	X	X	X
Calpine-Bethpage 3	2005/05	79.9		UC	X	X	X	X	X
Pinelawn-Pinelawn Power 1	2005/05	79.9		UC	X	X	X	X	X
ANP-Brookhaven Enery Center	2009/Q2	560				X	X	X	
SCS Energy-Astoria Energy	2007/Q2	500				X	X	X	
NYC Energy-Kent Ave	2007/06	79.9				X	X	X	
LMA-Lockport II	2007/Q2	79.9				X	X	X	
Calpine-JFK Expansion	2006/06	45				X	X	X	
Reliant-Repowering Phases 1	2010/Q2	535.8	593.7				X	X	
Reliant-Repowering Phases 2	2011/Q3	535.8	593.7				X	X	
SEI-Bowline Point 3 (Mirant)	2008/Q2	750					X	X	
Bay Energy	2007/06	79.9					X	X	
Entergy-Indian Point 2 Uprate	I/S	1078		I/S	X	X	X	X	X
Entergy-Indian Point 3 Uprate	I/S	1080		I/S	X	X	X	X	X
Fortistar-VP	2007/Q2	79.9					X	X	
Fortistar-VAN	2007/Q2	79.9					X	X	
KeySpan-Spagnoli Rd CC	2008-09	250					X	X	
Chautauqua Windpower	2006/11	50					X	X	
Besicorp-Empire State Newsprint	2007/Q2	603	660				X	X	
Flat Rock Windpower	2005/12	198					X	X	
Flat Rock Windpower	2006/12	123.75					X	X	
Calpine-Wawayanda	2008/Q2	500					X	X	
Global Winds-Prattsburgh	2006/10	75					X	X	
ECOGEN-Prattsburgh Wind Farm	2006/07	79					X	X	
Constellation-Ginna Plant Uprate	2006/11	610					X	X	
PSEG Cross Hudson Project	2008	550					X	X	
Liberty Radial Interconnection to NYC	2007/05	400					X	X	
B. Retirements									
NYPA-Poletti 1	2008/02	885.3	885.7		X	X	X	X	X
RG&E-Russell	2007/12	238	245		X	X	X	X	X
ConEd-Waterside 6,8,9	2005/07	167.2	167.8		X	X	X	X	X
PSEG-Albany	2005/02	312.3	364.6		X	X	X	X	X
NRG-Huntley 63,64	2005/11	60.6	96.8		X	X	X	X	X
NRG-Huntley 65,66	2006/11	166.8	170		X	X	X	X	X
Mirant-Lovett 5	2007/06	188.5	189.7		X	X	X	X	X
Mirant-Lovett 3,4	2008/06	242.5	244		X	X	X	X	X
Astoria 2	2010/Q2	175.3	181.3				X	X	
Astoria 3	2011/Q3	361	372.4				X	X	
Hudson Ave. 10	2004/10	65			X	X	X	X	X
II. Transmission									
A. Additions		**Miles**							
PSEG-Bergen (new)-W. 49th St.345kV Cable	2008	7.50					X	X	
AE Neptune PJM –LI DC Line (600 MW)	2007	65.00		UC	X		X	X	X
LIPA-Duffy Convrtr Sta-Newbridge Rd. 345kV	2007/S	1.70		UC	X		X	X	X
LIPA-Newbridge Rd. 345kV-138kV (2-Xfmrs)	2007/S	N/A		UC	X		X	X	X
LIPA-E. Garden City-Newbridge Rd. 138kV	2007/S	4.00		UC	X		X	X	X
LIPA-Ruland Rd.-Newbridge Rd. 138kV	2007/S	9.10		UC	X		X	X	X
Rochester Transmission-Sta. 80 & various	2008/F	N/A		UC	X	X	X	X	X
Liberty Radial Interconnection to NYC-230kV	2007	0.62					X	X	
ConEd-Dunwoodie-Sherman Crk 138kV	2005/W	7.80			X	X	X	X	X
LIPA-Riverhead-Canal(new) 138kV Operation	2005/S	16.40		UC	X	X	X	X	X
LIPA-E. Garden City-Supr.Condr. Sub. 138kV	2006/S	0.38		UC	X	X	X	X	X
LIPA-Northprt-Norwalk Hrbr. 138kV Replcmnt(2)	2006/S	11.00		UC	X	X	X	X	X
ConEd-Mott Havn-Dunwoodie 345kV Rec.(2)	2007/S	9.99			X	X	X	X	X
ConEd-Mott Havn-Rainey 345kV Rec. (2)	2007/S	4.08			X	X	X	X	X
ConEd-Sherman Crk 345kV-138kV (2-Xfmrs)	2007/S	N/A				X	X	X	
ConEd-Sprin Brk-Sherman Crk 345kV	2007/S	10.00				X	X	X	
LIPA- Holtsville GT-Brentwood 138kV (2)	2007/S	12.40		UC	X	X	X	X	X
LIPA-Brentwood-Pilgram 138kV Operation	2007/S	4.60		UC	X	X	X	X	X
LIPA-Sterling-Off Shore Wind Farm 138kV	2008/S	8.00							
O&R-Ramapo-Tallman 138kV Rec.	2007/S	3.24			X	X	X	X	X
O&R-Tallman-Burns 138kV	2007/S	6.08			X	X	X	X	X
LIPA-Riverhead-Canal 138kV	2010/S	16.40				X	X	X	
CHG&E-Hurley Ave-Saugerties 115kV	2011/W	11.11							
CHG&E-Pleasant Valley-Knapps Corners 115kV	2011/W	17.70							
CHG&E-Saugerties-North Catskill 115kV	2012/W	12.25							
Besicorp-Reynolds Rd. 345kV	2007/S	9.00					X	X	
Spagnoli Rd.-Ruland Rd. 138kV	2008/S	1.00					X	X	
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CRPS: Comprehensive Reliability Planning Study
ATBA: Annual Transmission Baseline Assessment
ATRA: Annual Transmission Reliability Assessment
CATR: Comprehensive Area Transmission Review

UC: Under construction
I/S: In-Service

Notes
(**) If Winter ratings are not available, the NYISO will use the summer ratings by default.

Source: NYISO "Comprehensive Reliability Planning Process Supporting Document and Appendices for the Reliability Needs Assessment," December 21, 2005

For the committee's analyses, the units scheduled for retirement that are included in the NYISO Initial Base Case are removed from the database at an appropriate time, and additional generating units are added through time to meet the requirements of each scenario being modeled. Thus, several points should be kept in mind in reviewing results produced by the various MAPS analyses, particularly in the late years of the 10-year study period. First, the presently-known capacity retirements are accounted for, consistent with those in the NYISO Initial Base Case, the last of which is in 2008. But as discussed in Chapter 3 of the present report, and noted by the NYISO, some older units in the present generating fleet may be impacted in the future by new environmental regulations. Thus, some of the existing units may require future addition of emissions-control equipment, or face curtailment of operations, or may even be retired.

No detailed attempt was made to optimize the schedule of illustrative additions to capacity to meet load growth and compensate for scheduled capacity retirements. GE and the committee recognize that in some of the scenarios posed, the LOLE projections are lower than required. This means that the illustrative capacity requirements are assumed to be online earlier than needed. In turn this means that the schedule for additions of new capacity could likely be relaxed somewhat through optimization studies beyond the scope of this committee's charge.

Given the scope of the present study, no attempt was made to adjust the MARS and MAPS databases to account for uncertainty in future changes. Such hypothetical considerations could be modeled and included in another analysis, of course, but the effort required to do is great, and well beyond the scope of this study. [See Footnote 6 and Footnote to Table F-2-2.]

As a consequence, the older generating units in the NYCA that are not presently scheduled for retirement remain in the MAPS database and are considered operable-as-is today in scenarios running through 2015. An obvious caveat in interpreting MAPS results for the 2013-2015 timeframe is that this assumption may not be accurate; and if it is not, some caution should be used in interpreting the MAPS results for the late years. Also, a detailed model of all Northeast regional generating and transmission capacity does not now exist, and is a goal of a regional planning task force. Providing the capability to project to 2015 would be an added challenge if the regional capacity were to be examined.

The scenarios considered in this study add considerable new NYCA generation based on modern gas-fired combined-cycle units that have a low heat rate, thus require less natural gas per megawatt-hour (MWh) produced, and consequently result in lower operating costs. However, no assumption is made in the MAPS database used regarding comparable addition of more fuel-efficient units in adjacent areas in the Northeast region. So, it is assumed implicitly that the generating fleet in the adjacent areas continues to use less fuel-efficient generation well into the future. Thus, even for less efficient gas-fired units, gas consumption is higher per megawatt-hour produced, with a corresponding higher cost of production. Consequently, the new low-cost generation assumed for the NYCA could displace higher-cost generation in other areas. This might tend to lower the price-increase impact of retiring Indian Point, and could reduce imports of electricity from the adjacent areas in favor of increased generation in the NYCA. If so, the total annual variable cost of generation would increase in the NYCA, since total generation in the NYCA increases. Similarly, the generator fuel mix could be influenced, in both NYCA and the adjacent region.

As discussed in Chapter 2, the load growth in New York State over the past 11 years has been south of the UPNY/SENY transmission interface (located north of Pleasant Valley). Further, since 2001, the Lower Hudson Valley (LHV—Zones G, H and I) has experienced the fastest rate of growth, and is projected to experience a high rate of growth (2.38 percent per year) for the period 2004-2015. Load growth in New York City and Long Island is projected to grow substantially more slowly than in past ten years, 1.19 percent for New York City (down from 2.61 percent over the past ten years), and 1.62 percent in Long Island (down from 3.27 percent growth over the past 10 years). Furthermore, greater reliance on the electrical transmission system is reflected in the fact that from 1994 through the summer of 2005, load growth in Southeastern New York State has been about 5,400 MW, while capacity additions there (1,550 MW) and demand reduction (270 MW) sum to only 1,820 MW over the same period. Additions to capacity or load reduction therefore have been only 34 percent of peak load growth over the last 11 years. These changes evidently have been accounted for in the analysis, but they create an uncertainty in the system requirements for future years.

Throughout this study, the committee used Alternative New England Transmission Transfer Limits developed by NYISO (2005). Consequently the committee's projections differ from those recently adopted by NYISO but nevertheless are useful for exploratory analysis and comparisons of scenarios. After consulting GE and NYISO, the committee's estimates of resources need to correct reliability to meet the LOLE standard of 0.1 are slightly higher than NYISO's, perhaps by 200 MW.[11]

Readers therefore should bear in mind that, while comparisons among various illustrative scenarios assumed by the committee are judged to be qualitatively valid, the precise magnitude and timing of compensatory resources required are hypothetical. In addition, the data in graphs and tabulations in the report and this appendix should be considered in terms of two significant figures, and it should be recalled that the timing of additions to capacity is not optimized. Given the exploratory nature of the analysis, it is recommended that readers focus on comparative trends, not on absolute values of price projections.

Perspective on Reactive Power

The use of the thermal-constraint transmission model is, roughly to first order, equivalent to assuming that reactive power corrections would be made in a timely manner in the Lower Hudson Valley. If not, the voltage-constraint model of NYISO would require greater additions to generating capacity—or a correspondingly higher aggregate mix of additional generating capacity, additions to transmission capacity, and/or energy-efficiency and demand-reduction measures.

In the committee's opinion, the essential local corrections to reactive power—on the order of 2,000 Mvar in the Lower Hudson Valley—would most likely be made in a timely manner. Corrections to reactive power are less costly than additions to generation, are often installable at existing substations, and require less lead time because of lower mechanical complexity and ease of permitting. If carried out, the committee expects that correction of the reactive power shortfall would drive the system back toward a situation in which thermal

[11] The Committee saw no need to make the analyses agree perfectly, recognizing they are preliminary. Much refinement and additional analysis will be required to fully understand the implications of retiring Indian Point.

transfer limits control transmission. The committee therefore focused on situations where thermal transmission transfer limits limit system reliability, recognizing that local corrections to reactive power flow also must be made, as NYISO has determined.

The committee did not assess the specifics of the need for corrections to reactive power, but this obviously would be required, particularly in light of the analyses reflected in the NYISO (2005) report. The committee also did not analyze in any detail the cost of corrections to reactive power. There are a number of ways to make such corrections, important technical advances have been made in recent years, and such corrections are presently being made within the NYCA and New York City. O'Neill (2004) provided a recent briefing on some aspects of reactive power in which the capital cost of a Static VAR Compensator (SVC) or a Statcom is stated to be in the range of $50/kvar, and that of a synchronous condenser is about $35/kvar. All three of these devices have fast dynamic response. So as a rough order of magnitude, the capital cost of a 1000 MVAR correction at $50/kvar would be about $50 million. In comparison, capital cost of a 1000 MW power plant, at a cost of order $1,000 per KW installed, is on the order of $1 billion. So as a rough rule of thumb, the cost of correcting 1 Mvar of reactive power is about 5 percent or so of the cost of replacing 1 MW of real power.

It might be possible to use the existing generators at Indian Point Units 2 and 3 as synchronous condensers after retiring the nuclear reactors. As synchronous condensers (see Gerstenkorn, 2004, p. 271) the generators could add reactive power (but not real power) to the transmission system. However, there might be no significant advantage to doing so as the capital cost of a synchronous condenser is about $35/kvar. O'Neill (2004). Replacing the 1,000 Mvar of reactive power supplied by Indian Point Units 2 and 3 with a new synchronous condenser in the area would cost only about $35 million.

Preliminary Screening Analysis

The committee's initial reliability analysis was intended to scope the amount of compensation that would be necessary to replace Indian Point. It is included here (but not in the final GE report to the committee or in Chapter 5) to illustrate how the committee reached its final scenarios. The capacity resource compensation hypothesized in the committee's preliminary screening case included 150 MW of additional energy-efficiency and demand-reduction measures by 2007, added 3,510 MW by 2010, and a total 3,740 MW of new capacity, energy-efficiency, and demand-reduction measures by 2015. As noted, these *illustrative* capacity additions, were limited to proposed generation projects which were not mature enough from a permitting or financing standpoint to meet the NYISO (2005) criteria for inclusion in its Initial Base Case assessment. The committee adjusted the timing of additions somewhat arbitrarily to meet 2010 or 2015 objectives. The additions are illustrative only of capacity that would be required, and no suggestion is made or implied that the "projects" or their timing constitute financially feasible, practical options, or that other projects would not be reactivated, or others proposed later.

In sum, the committee's screening analysis showed first, with the additional compensatory resource capacity assumed, the early-retirement scenario still resulted in an NYCA LOLE of 0.103 in 2010, increasing to 0.585 by 2013. For retirement at the end of current licenses, the NYCA LOLE slightly exceeded the required 0.1 beginning in 2013 as

Indian Point 2 is shut down and reached 1.39 in 2015, when Indian Point 3 is shut down. Thus, the additional capacity compensation assumed in the screening case analysis would not alone accommodate either the early-shutdown or an end-of-license Shutdown of Indian Point Units 2 and 3. The analysis then continued with the Reference Case and following scenarios, as given in Table F-2-9 and following and discussed in Chapter 5.

TABLE F-2-2 2005 Electricity Generation Load and Capacity Representing NYISO Initial Base Case

Category	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Steam Turbine (Oil)	1649	1649	1649	1649	1649	1649	1649	1649	1649	1649	1649
Steam Turbine (Oil & Gas)	9074	9074	9074	8120	8120	8120	8120	8120	8120	8120	8120
Steam Turbine (Gas)	1067	1067	1067	1067	1067	1067	1067	1067	1067	1067	1067
Steam Turbine (Coal)	3597	3597	3242	2830	2830	2830	2830	2830	2830	2830	2830
Steam Turbine (Wood)	39	39	39	39	39	39	39	39	39	39	39
Steam Turbine (Refuse)	264	264	264	264	264	264	264	264	264	264	264
Steam (PWR Nuclear)	2544	2544	2639	2639	2639	2639	2639	2639	2639	2639	2639
Steam (BWR Nuclear)	2610	2610	2610	2610	2610	2610	2610	2610	2610	2610	2610
Pumped Storage Hydro	1409	1409	1409	1409	1409	1409	1409	1409	1409	1409	1409
Internal Combustion	119	119	119	119	119	119	119	119	119	119	119
Conventional Hydro	4488	4488	4488	4488	4488	4488	4488	4488	4488	4488	4488
Combined Cycle	7041	8041	8041	8041	8041	8041	8041	8041	8041	8041	8041
Jet Engine (Oil)	527	527	527	527	527	527	527	527	527	527	527
Jet Engine (Gas & Oil)	173	173	173	173	173	173	173	173	173	173	173
Combustion Turbine (Oil)	1414	1414	1414	1414	1414	1414	1414	1414	1414	1414	1414
Combustion Turbine (Oil & Gas)	1428	1428	1428	1428	1428	1428	1428	1428	1428	1428	1428
Combustion Turbine (Gas)	1284	1284	1284	1284	1284	1284	1284	1284	1284	1284	1284
Wind	47	47	47	47	47	47	47	47	47	47	47
Other	1	1	1	1	1	1	1	1	1	1	1
UDR	330	330	990	990	990	990	990	990	990	990	990
Non UDR	2755	2755	2755	2755	2755	2755	2755	2755	2755	2755	2755
Special Case Resources	975	975	975	975	975	975	975	975	975	975	975
Demand Response Programs	269	269	269	269	269	269	269	269	269	269	269
NYCA Demand	31960	32400	32840	33330	33770	34200	34580	34900	35180	35420	35670
Required Capability	37395	37915	38434	39012	39531	40039	40487	40865	41195	41478	41773
Total NYCA Capability	38772	39772	39512	38146	38146	38146	38146	38146	38146	38146	38146
Reserve Margin	21%	23%	20%	14%	13%	12%	10%	9%	8%	8%	7%

*Capacity based on Summer Capability

NOTES: • NYCA Reserve Margin in this table does not include either Special Case Resources (975 MW of callable demand under NYISO Emergency Operating procedures or Unforced Delivery Rights (UDR, corresponding to two HVDC cables, the Cross Sound Cable (330 MW) and the Neptune Cable (660 MW in and beyond 2007.)

- SOURCE: NYISO (2005).
- The "2006 NYISO Load and Capacity Report" (2006 Gold Book) was issued on 5/3/06 at https://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2006_goldbook_public.pdf
- The 2006 document shows that Peak Load Projections are higher than above. (+3 percent for 2008). NYISO notes *Proposed Net Additions to Resources* of 2244 MW by 2008 with which the present Reserve Margin requirement of 18% would be met through 2010. [Note that 900 MW of these 2244 MW are upstate, and 160 MW of that is wind, so the impact on projected NYCA LOLE is less obvious.]

Tabulated Results of MARS Calculations

Tables F-2-3 through F-2-23 are a compendium of the results from the GE MARS modeling of the various scenarios examined during this study. The tables provide sufficient numerical detail to provide insight into the changes by geographic region, and the compensatory resources introduced, given each of the scenarios adopted by the committee. The comparisons generally should be made relative to the Reference Case assumed by the committee as a baseline for meeting LOLE requirements, meeting load growth and scheduled retirements of capacity (without retiring Indian Point).

TABLE F-2-3 NYISO Initial Base Case—Qualifying Additions to Capacity

Year	Qualifying Additions to Capacity (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	Rest of State	Yearly Total, MW
2005	ConEd East River Repowering (J, 298, in service), Astoria Energy (J, 500), Calpine Bethpage 3 (K, 79.9), Pinelawn Power I (K, 79.9), PSEG Bethlehem (ROS, 770)				798	160	770	1728
2006	NYPA Poletti Expansion (J, 500)				500			500
2007	Neptune HVDC Cable (PJM to K, 600)					600		600
2009								0
2010								0
	TOTALS	0	0	0	1298	760	770	2828

NOTES: (1) New York Control Area Load Zones as shown in Figure 1-3. (2) Neptune Cable is reported later at 660 MW.
SOURCE: Derived from NYISO (2005).

TABLE F-2-4 Committee's Screening Study—Early Shutdown with Assumed Compensation from Planned NYCA Projects and Added Energy Efficiency and Demand-Side Management Measures

Year	Qualifying Additions to Capacity (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	Rest of State	Statewide EE and DSM Measures	Yearly Total, MW	Cumulative Additions Beyond NYISO Initial Base Case	Cumulative Additions from 2005
2005	ConEd East River Repowering (J, 298, in service), Astoria Energy (J, 500), Calpine Bethpage 3 (K, 79.9), Pinelawn Power I (K, 79.9), PSEG Bethlehem (ROS, 770)				798	160	770		1728		
2006	NYPA Poletti Expansion (J, 500)				500				500		
2007	Neptune HVDC Cable (PJM to K, 600)					600		150	750	150	2978
2008	Reliant Astoria Repowering I (J, 367), Reliant Astoria Repowering II (J, 173), SCS Astoria Energy II (J, 500), LIPA Caithness CC (K, 383), LIPA LI Sound Wind (K, 150), EE (100), DSM (50)				1040	533		150	1723	1873	4701
2009									0	1873	4701
2010	Calpine Wawayanda (G, 540), Mirant Bowline Point 3 (G, 750), EE (250), DSM (100)	1290						350	1640	3513	6341
2011									0	3513	6341
2012									0	3513	6341
2013	EE (75), DSM (75)							150	150	3663	6491
2014									0	3663	6491
2015	EE (50), DSM (25)							125	125	3788	6616
	TOTALS	1290	0	0	2338	1293	770	925	6616	3788	6616

NOTE: New York Control Area Load Zones as shown in Figure 1-3.
Source: [Hinkle, et al. Personal Communication, September 2005]

TABLE F-2-5 Committee's Screening Study—End-of-License Shutdown with Assumed Compensation from Planned NYCA Projects and Added Energy Efficiency and Demand Side Management Measures

Year	Qualifying Additions to Capacity (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	Rest of State	Statewide EE and DSM Measures	Yearly Total, MW	Cumulative Additions Beyond NYISO Initial Base Case	Cumulative Additions from 2005
2005	ConEd East River Repowering (J, 298, in service), Astoria Energy (J, 500), Calpine Bethpage 3 (K, 79.9), Pinelawn Power I (K, 79.9), PSEG Bethlehem (ROS, 770)				798	160	770		1728		
2006	NYPA Poletti Expansion (J, 500)				500				500		
2007	Neptune HVDC Cable (PJM to K, 600)					600		150	750	150	2978
2008	SCS Astoria Energy II (J, 500), LIPA Caithness CC (K, 383), LIPA LI Sound Wind (K, 150), EE (100), DSM (50)				500	533		150	1183	1333	4161
2009									0	1333	4161
2010	Astoria Repowering I (J, 367), Calpine Wawayanda (G, 540), Mirant Bowline Point 3 (G, 750), EE (250), DSM (100)	1290			367			350	2007	3340	6168
2011	Astoria Repowering II (J, 173)				173				173	3513	6341
2012									0	3513	6341
2013	EE (75), DSM (75)							150	150	3663	6491
2014									0	3663	6491
2015	EE (50), DSM (25)							75	75	3738	6566
	TOTALS	1290	0	0	2338	1293	770	875	6566	3738	6566

NOTE: New York Control Area Load Zones as shown in Figure 1-3.
Source: [Hinkle, et al. Personal Communication, September 2005]

TABLE F-2-6 NYISO Initial Base Case with Alternate NE Transmission Constraints—Projected NYCA Reliability Loss-of-Load Expectancy (LOLE) and Reserve Margin

NYISO Initial Base Case	LOLE Results			
	2008	2010	2013	2015
AREA-A	0	0	0	0
AREA-B	0	0	0	0
AREA-C	0	0	0	0
AREA-D	0	0	0	0
AREA-E	0	0	0	0
AREA-F	0	0	0.001	0.002
AREA-G	0.001	0.017	0.103	0.291
AREA-H	0.001	0.008	0.017	0.018
AREA-I	0.058	0.617	2.464	4.401
AREA-J	0.095	0.785	2.618	4.473
AREA-K	0.051	0.418	1.888	3.526
NYCA	0.122	0.966	3.164	5.21
NYCA Capacity @ peak	37,039	37,039	37,039	37,039
NYCA Peak Load	33,330	34,200	35,180	35,671
Special Case Resources	975	975	975	975
NYCA Reserve Margin	14%	11%	8%	7%

NOTE: (1) New York Control Area Load Zones as shown in Figure 1-3. (2) LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.

SOURCE: [Hinkle, et al. Personal Communication, September 2005]

TABLE F-2-7 Committee's Screening Study: Impact on Reliability and Reserve Margins of Shutting Down Indian Point Without Adding Compensatory Resources: Comparison of the NYISO Initial Base Case with Early-Shutdown and End-of-Current-License Shutdown Cases

	NYISO Initial Base Case, using Alternate NE Transmission Constraints (Draft v.2 RNA Report)				Early Shutdown: IP2 Shutdown 1/1/08, IP3 Shutdown 1/1/10; No Compensatory Resources Added				End-of-License Shutdown: IP2 Shutdown 1/1/13, IP3 Shutdown 1/1/15; No Compensatory Resources Added			
	Predicted Reliability (LOLE)				Predicted Reliability (LOLE)				Predicted Reliability (LOLE)			
	2008	2010	2013	2015	2008	2010	2013	2015	2008	2010	2013	2015
Zone A	0	0	0	0	0	0	0	0	0	0	0	0
Zone B	0	0	0	0	0	0	0	0	0	0	0	0
Zone C	0	0	0	0	0	0	0	0	0	0	0	0
Zone D	0	0	0	0	0	0	0	0	0	0	0	0
Zone E	0	0	0	0	0	0	0	0	0	0	0	
Zone F	0	0	0.001	0.002	0	0	0.002	0.002	0	0	0.002	0.002
Zone G Hudson Valley	0.001	0.017	0.103	0.291	0.003	0.302	0.876	1.967	0.001	0.017	0.339	1.967
Zone H Millwood	0.001	0.008	0.017	0.018	0.035	5.568	8.913	10.77	0.001	0.008	0.377	10.77
Zone I Dunwoodie	0.058	0.617	2.464	4.401	0.323	5.956	9.582	11.554	0.058	0.617	5.914	11.554
Zone J New York City	0.095	0.785	2.618	4.473	0.292	4.927	7.701	9.742	0.095	0.785	5.071	9.742
Zone K Long Island	0.051	0.418	1.888	3.526	0.226	5.456	8.344	10.528	0.051	0.418	4.595	10.528
NYCA	0.122	0.966	3.164	5.21	0.4	6.338	10.074	12.061	0.122	0.966	6.444	12.061
NYCA Capacity @ Peak	37,039	37,039	37,039	37,039	36,077	36,086	35,086	35,086	37,039	37,039	36,077	35,086
NYCA Peak Load	33,330	34,200	35,180	35,671	33,330	34,200	35,180	35,671	33,330	34,200	35,180	35,671
Special Case Resources	975	975	975	975	975	975	975	975	975	975	975	975
NYCA Reserve Margin	14%	11%	8%	7%	11%	8%	3%	1%	14%	11%	5%	1%

NOTE: IP2, Indian Point Unit 2; IP3, Indian Point Unit 3; see Appendix B for definitions of abbreviations. (2) LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
Source: [Hinkle, et al. Personal Communication, September 2005]

TABLE F-2-8 Committee's Screening Study: Impact on Reliability and Reserve Margins of Shutting Down Indian Point and Adding Compensatory Resources from Announced Projects, Beyond NYISO Initial Base Case (Table F-2-5): Comparison of Early Shutdown and End-of-Current-License Shutdown

	Early Shutdown With Compensatory Resources Added: IP2 Shutdown 1/1/08, IP3 Shutdown 1/1/10				End-of-License Shutdown With Compensatory Resources Added: IP2 Shutdown 1/1/13, IP3 Shutdown 1/1/15			
	Predicted Reliability (LOLE)				Predicted Reliability (LOLE)			
	2008	2010	2013	2015	2008	2010	2013	2015
Zone A	0	0	0	0	0	0	0	0
Zone B	0	0	0	0	0	0	0	0
Zone C	0	0	0	0	0	0	0	0
Zone D	0	0	0	0	0	0	0	0
Zone E	0	0	0	0	0	0	0	
Zone F	0	0	0	0	0	0	0	0
Zone G Hudson Valley	0.001	0	0.002	0.004	0	0	0	0.004
Zone H Millwood	0.005	0.082	0.477	1.192	0	0	0.019	1.192
Zone I Dunwoodie	0.019	0.091	0.533	1.269	0.007	0.002	0.082	1.269
Zone J New York City	0.011	0.053	0.297	0.724	0.009	0.002	0.057	0.724
Zone K Long Island	0.01	0.032	0.267	0.649	0.003	0.001	0.051	0.649
NYCA	0.023	0.103	0.585	1.393	0.013	0.003	0.106	1.393
NYCA Capacity @ Peak	37,650	37,949	37,949	37,949	38,034	39,729	38,940	37,949
NYCA Peak Load	33,039	33,568	34,402	34,820	33,039	33,568	34,402	34,820
Special Case Resources	975	975	975	975	975	975	975	975
NYCA Reserve Margin	17%	16%	13%	12%	18%	21%	16%	12%

NOTE: (1) IP2, Indian Point Unit 2; IP3, Indian Point Unit 3; see Appendix B for definitions of abbreviations. (2) LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
Source: [Hinkle, et al. Personal Communication, September 2005]

TABLE F-2-9 Reference Case: Illustrative Additional Resources beyond the NYISO Initial Base Case to Meet Load Growth and Scheduled Retirements and Assure Reliability Criteria are Met, and Including Reliability Results if Indian Point is Closed without Further Compensation

YEAR	REFERENCE CASE - ILLUSTRATIVE ADDITIONS (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Yearly Gen. Capacity Added	Cumulative Additions Above CRPP Initial Base Case, MW	NYCA LOLE, Reference Case	LOLE for Early Shutdown (2008, 2010) No Further Compensation Case b1	LOLE for EOL Shutdown (2013, 2015) No Further Compensation Case c1
2008	SCS Astoria Energy (J, 500), Caithness (K, 383), Long Island Wind (K, 150 MW)				500	398		898	898	0.021	0.104	0.021
2009								0	898			
2010	Bowline Point (G, 750)	750						750	1648	0.069	1.352	0.069
2011								0	1648			
2012								0	1648			
2013	Wawayanda (G, 540), Generic Combined Cycle (H, 580)	540	580					1120	2768	0.104	1.323	0.333
2014								0	2768			
2015	Reliant Astoria Repower I (J, 367), Reliant Astoria Repower II (J, 173)				540			540	3308	0.102	1.480	1.480
	TOTALS, 2008 - 2015	**1290**	**580**	**0**	**1040**	**398**	**0**	**3308**	**3308**			

Notes: • Wind is credited with 10% availability, or 15 MW. NYISO did not include wind in reliability analyses.
• The Neptune Cable (2007, K, 600 MW) is carried elsewhere in the GE analysis as a UDR. Its capacity has been upgraded to 660 MW in the final NYISO RNA. Also GE uses UDR's in calculating LOLE, but reported Reserve Margins are calculated using Generating Capacity and SDR's (975 MW) only.

SOURCE: Hinkle et al., 2005

TABLE F-2-10 Early Shutdown of Indian Point with Compensatory Resources, Case b2

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Total for year, MW	Capacity Above CRPP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Demand Reduction, MW	Cumulative Resources, Capacity + Load reduction	NYCA LOLE After Compen-sation
2007										100	50			
2008	Reference Case plus Reliant Astoria Repower I&II (J, 540)				1040	398		1438	1438	100	50	291	1729	0.023
2009								0	1438					
2010	Bowline (G, 750), Wawayanda (G, 540), Transgas Energy (J, 1100)	1290			1100			2390	3828	250	100	632	4460	0.011
2011								0	3828					
2012								0	3828					
2013	Generic Combined Cycle (H, 580)		580					580	4408	75	75	778	5186	0.032
2014								0	4408					
2015								0	4408	50	25	850	5258	0.101
	TOTALS	**1290**	**580**	**0**	**2140**	**398**	**0**		**4408**	**575**	**300**			

	NYCA Demand, MW Reference	Case b2	Savings
2008	33,330	33039	291
2010	34200	33568	632
2013	35180	34402	778
2015	35670	34820	850

SOURCE: Hinkle et al., 2005

TABLE F-2-11 End-of-Current-License Shutdown of Indian Point with Compensatory Resources, Case c2

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Total for year, MW	Capacity Above CRRP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Load Reduction	Cumulative Compen-sation, Capacity + Load Reduction, MW	NYCA LOLE After Compen-sation
2007										100	50			
2008	Same as Reference Case				500	398		898	898	100	50	291	1189	0.013
2009									898				898	
2010	Reliant Astoria Repower I (J, 367),Bowline (G, 750), Wawayanda (G, 540)	1290			367			1657	2555	250	100	632	3187	0.006
2011	Reliant Astoria Repower II (J, 173)				173			173	2728				2728	
2012								0	2728				2728	
2013	Generic Combined Cycle (H, 580)		580					580	3308	75	75	778	4086	0.036
2014								0	3308				3308	
2015	Transgas Energy (J, 1100)				1100			1100	4408	50	25	851	5259	0.101
	TOTALS	**1290**	**580**	**0**	**2140**	**398**	**0**		**4408**	**375**	**200**	**851**	**5259**	

NYCA Demand Same as Table F-2-10

SOURCE: Hinkle et al., 2005

TABLE F-2-12 Early Shutdown of Indian Point with HVDC Cable, Case b3

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Yearly Total, MW	Capacity Above CRPP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Demand Reduction MW	Cumulative Resources, Capacity + Load reduction	NYCA LOLE After Compen-sation
2007										100	50			
2008	Reference plus Reliant Astoria Repower (J, 540)				1040	398		1438	1438	100	50	291	1729	
2009								0	1438					
2010	Bowline Point (G, 750), Wawayanda (G, 540), Transgas Energy (J, 300)	1290			300			1590	3028	250	100	632	3660	
2011								0	3028					
2012	1000 MW HVDC Line, Zone E to G	1000						1000	4028					
2013	Generic Combined Cycle (H, 580)		580					580	4608	75	75	778	5386	
2014								0	4608					
2015								0	4608	50	25	850	5458	0.098
	TOTALS	**2290**	**580**	**0**	**1340**	**398**	**0**		**4608**	**575**	**300**			

SOURCE: Hinkle et al., 2005

TABLE F-2-13 End-of-Current-License Shutdown of Indian Point with HVDC Cable, Case c3

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Yearly Total, MW	Capacity Above CRPP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Load Reduction, MW	Cumulative Resources, Capacity + Load reduction	NYCA LOLE After Compen-sation
2007										100	50			
2008	Same as Reference Case				500	398		898	898	100	50	291	1189	
2009								0	0					
2010	Reliant Astoria Repower I (J, 367), Bowline Point (G, 750), Wawayanda (G, 540)	1290			367			1657	1657	250	100	632	2289	
2011	Reliant Astoria Repower II (J, 173)				173			173	1830					
2012	1000 MW HVDC Line, Zone E to Zone G	1000						1000	2830					
2013	Generic Combined Cycle (H, 580)		580					580	3410	75	75	778	4188	
2014								0	3410					
2015	Transgas Energy (J, 300)				300			300	3710	50	25	850	4560	0.098
	TOTALS	**2290**	**580**	**0**	**840**	**0**	**0**		**3710**	**375**	**200**			

SOURCE: Hinkle et al., 2005

TABLE F-2-14 Early Shutdown of Indian Point with Higher Efficiency and Demand-Side Management, Case b4

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Yearly Total, MW	Capacity Above CRPP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Load Reduction due to EE/DSM, MW	Cumulative Resources, Capacity + Load reduction	NYCA LOLE After Compen-sation
2007														
2008	Reference Case plus Reliant Astoria Repower I&II (J, 540)				1040	398		1438	1438					_
2009								0	1438					...
2010	Bowline Point (G, 750), Wayawanda (G, 540)	1290						1290	2728					_
2011								0	2728					_
2012								0	2728					_
2013	Generic Combined Cycle (H, 580)		580					580	3308					_
2014								0	3308					_
2015								0	3308	1200	800			0.082
	TOTALS	**1290**	**580**	**0**	**1040**	**398**	**0**		**3308**	**1200**	**800**	1951	5259	

SOURCE: Hinkle et al., 2005

	NYCA Demand, MW		
	Reference	Case b4	Savings
2008	33,330		
2010	34200		
2013	35180		
2015	35670	33719	1,951

TABLE F-2-15 End-of-Current-License Shutdown of Indian Point with Higher Efficiency and Demand-Side Management, Case c4

YEAR	Capacity Additions (Zone, MW)	Zone G	Zone H	Zone I	Zone J	Zone K	ROS	Yearly Total, MW	Capacity Above CRPP Initial Base Case, MW	Energy Efficiency	Demand Side Manage-ment	Cumulative Peak Load Reduction due to EE/DSM, MW	Cumulative Resources, Capacity + Load reduction	NYCA LOLE After Compen-sation
2007														
2008	Same as Reference Case				500	398		898	898				898	
2009								0	898					
2010	Reliant Astoria Repower I (J, 367), Bowline Point (G, 750), Wayawanda (G, 540)	1290			367			1657	2555				2555	
2011	Reliant Astoria Repower II (J, 173),				173			173	2728					
2012								0	2728					
2013	Generic Combined Cycle (H, 580)		580					580	3308				3308	
2014								0	3308					
2015								0	3308	1200	800	1951	5259	0.082
	TOTALS	**1290**	**580**	**0**	**1040**	**398**	**0**		**3308**	**1200**	**800**	1951	5259	

SOURCE: Hinkle et al., 2005

	NYCA Demand, MW		
	Reference	Case c4	Savings
2008	33,330		
2010	34200		
2013	35180		
2015	35670	33719	1,951

TABLE F-2-16 Early Shutdown without Compensatory Resources beyond the Reference Case—Impact on NYCA Reliability (Loss of Load Expectation) and Reserve Margin, Case b1

	Loss of Load Expectation			
Zone	2008	2010	2013	2015
A	0.000	0.000	0.000	0.000
B	0.000	0.000	0.000	0.000
C	0.000	0.000	0.000	0.000
D	0.000	0.000	0.000	0.000
E	0.000	0.000	0.000	0.000
F	0.000	0.000	0.000	0.000
G	0.002	0.012	0.001	0.008
H	0.013	1.132	1.030	1.217
I	0.083	1.232	1.163	1.325
J	0.071	0.968	1.043	0.974
K	0.041	0.366	0.525	0.820
NYCA	0.104	1.352	1.323	1.480
NYCA Capacity @ peak	37,110	36,869	37,994	38,534
NYCA Peak Load	33,330	34,200	35,180	35,671
Special Case Resources	975	975	975	975
NYCA Reserve Margin	14%	11%	11%	11%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-17 End-Of-Current-License Shutdown without Compensatory Resources beyond the Reference Case—Impact on NYCA Reliability ((Loss of Load Expectation) and Reserve Margin, Case c1

	Loss of Load Expectation			
Zone	2008	2010	2013	2015
A	0.000	0.000	0.000	0.000
B	0.000	0.000	0.000	0.000
C	0.000	0.000	0.000	0.000
D	0.000	0.000	0.000	0.000
E	0.000	0.000	0.000	0.000
F	0.000	0.000	0.000	0.000
G	0.000	0.000	0.000	0.008
H	0.000	0.002	0.039	1.217
I	0.012	0.031	0.217	1.325
J	0.016	0.056	0.354	0.974
K	0.006	0.016	0.124	0.082
NYCA	0.021	0.069	0.333	1.480
NYCA Capacity @ peak	38,072	38,822	38,985	38,534
NYCA Peak Load	33,330	34,200	35,180	35,671
Special Case Resources	975	975	975	975
NYCA Reserve Margin	17%	16%	14%	11%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-18
Committee's Reference Case—Impact on NYCA Reliability Loss of Load Expectation and Reserve Margin

Zone	Loss of Load Expectation			
	2008	2010	2013	2015
A	0	0	0	0
B	0	0	0	0
C	0	0	0	0
D	0	0	0	0
E	0	0	0	0
F	0	0	0	0
G	0	0	0	0
H	0	0.002	0.001	0.002
I	0.012	0.031	0.021	0.033
J	0.016	0.056	0.087	0.067
K	0.006	0.016	0.027	0.051
NYCA	0.021	0.069	0.104	0.102
NYCA Capacity @ peak	38,072	38,822	39,947	40,487
NYCA Peak Load	33,330	34,200	35,180	35,671
Special Case Resources	975	975	975	975
NYCA Reserve Margin	17%	16%	16%	16%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

Table F-2-19
Early Shutdown with Additional Compensatory Resources—Impact on NYCA Reliability and Reserve Margin, Case b2

	Loss of Load Expectation			
Zone	2008	2010	2013	2015
A	0	0	0	0
B	0	0	0	0
C	0	0	0	0
D	0	0	0	0
E	0	0	0	0
F	0	0	0	0
G	0.001	0	0	0.001
H	0.004	0.009	0.02	0.07
I	0.018	0.009	0.024	0.082
J	0.012	0.004	0.011	0.031
K	0.01	0.005	0.022	0.069
NYCA	0.023	0.011	0.032	0.101
NYCA Capacity @ peak	37,650	39,049	39,629	39,629
NYCA Peak Load	33,039	33,568	34,402	34,820
Special Case Resources	975	975	975	975
NYCA Reserve Margin	17%	19%	18%	17%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-20
End-of-Current-License Shutdown with Additional Compensating Resources—Impact on NYCA Reliability and Reserve Margin, Case c2

	Loss of Load Expectation			
Zone	2008	2010	2013	2015
A	0	0	0	0
B	0	0	0	0
C	0	0	0	0
D	0	0	0	0
E	0	0	0	0
F	0	0	0	0
G	0	0	0	0.001
H	0	0	0.007	0.07
I	0.006	0.001	0.023	0.082
J	0.009	0.004	0.02	0.031
K	0.003	0.001	0.019	0.069
NYCA	0.013	0.006	0.036	0.101
NYCA Capacity @ peak	38,072	39,729	39,520	39,629
NYCA Peak Load	33,039	33,568	34,402	34,820
Special Case Resources	975	975	975	975
NYCA Reserve Margin	18%	21%	18%	17%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-21
Additional Compensatory Resources, Including 1,000 MW North-South HVDC Transmission Line—Impact on NYCA Reliability and Reserve Margin, Cases b3 and c3

Zone	Case b3 2015	Case c3 2015
A	0	0
B	0	0
C	0	0
D	0	0
E	0	0
F	0	0
G	0	0
H	0.066	0.066
I	0.084	0.084
J	0.047	0.047
K	0.059	0.059
NYCA	0.098	0.098
NYCA Capacity @ peak	38,829	38,829
NYCA Peak Load	34,820	34,820
Special Case Resources	975	975
NYCA Reserve Margin	14%	14%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-22 Additional Compensatory Resources, Including Higher Energy Efficiency and Demand-Side-Management Penetration—Impact on NYCA Reliability and Reserve Margin, Cases b4 and c4

Zone	Case b4 2015	Case c4 2015
A	0	0
B	0	0
C	0	0
D	0	0
E	0	0
F	0	0
G	0	0
H	0.061	0.061
I	0.072	0.072
J	0.04	0.04
K	0.038	0.038
NYCA	0.082	0.082
NYCA Capacity @ peak	38,529	38,529
NYCA Peak Load	33,719	33,719
Special Case Resources	975	975
NYCA Reserve Margin	17%	17%

Note: LOLE's were calculated using SCR's (975 MW) and UDR's (HVDC Cables - 990 MW). NYCA Reserve Margin reported includes SCR, but not UDR's.
SOURCE: Hinkle et al., 2005

TABLE F-2-23 Projected Impact on the Annual Variable Cost of Operation for the NE Region, NYCA and Zones H to K: All Scenarios , 2008 2105, Including Percentage Change from Benchmark of 2008 NYISO Initial Base Case

	Annual Cost of Operation				Change from 2008 NYISO Initial Base Case			
	2008 ($ millions)	2010 ($ millions)	2013 ($ millions)	2015 ($ millions)	2008 (%)	2010 (%)	2013 (%)	2015 (%)
Benchmark of 2008 NYISO Initial Base Case								
3 Pool	13,169							
NYISO	3,129							
Zone H	97							
Zone I	0							
Zone J	1,094							
Zone K	327							
Reference Case								
3 Pool	13,098	13,269	13,193	14,363	-0.5	0.8	0.2	9.1
NYISO	3,091	3,121	3,056	3,271	-1.2	-0.2	-2.3	4.5
Zone H	97	97	221	224	0.4	0.3	128.2	131.1
Zone I	0	0	0	0				
Zone J	1,072	994	877	1,008	-2.1	-9.1	-19.8	-7.9
Zone K	344	308	274	286	5.1	-5.7	-16.3	-12.5
Early Shutdown with Compensation, Case b2								
3 Pool	13,323	13,685	13,578	14,780	1.2	3.9	3.1	12.2
NYISO	3,301	3,668	3,523	3,783	5.5	17.2	12.6	20.9
Zone H	49	1	131	138	-49.8	-99.2	34.7	41.8
Zone I	0	0	0	0				
Zone J	1,282	1,490	1,383	1,526	17.2	36.2	26.4	39.5
Zone K	367	368	333	368	12.2	12.4	1.8	12.6
End-of-License Shutdown with Compensation, Case c2								
3 Pool	13,054	13,138	13,330	14,780	-0.9	-0.2	1.2	12.2
NYISO	3,058	3,069	3,177	3,783	-2.3	-1.9	1.5	20.9
Zone H	97	97	175	138	0.4	0.3	80.8	41.8
Zone I	0	0	0	0				
Zone J	1,057	928	1,012	1,526	-3.4	-15.2	-7.5	39.5
Zone K	331	254	285	368	1.2	-22.4	-12.9	12.6
Higher Fuel Prices —Reference Case								
3 Pool	16,000	16,125	16,749	18,379	21.5	22.5	27.2	39.6
NYISO	4,039	4,045	4,358	4,636	29.1	29.3	39.3	48.2
Zone H	97	97	292	299	0.4	0.4	201.3	208.0
Zone I	0	0	0	0				
Zone J	1,552	1,402	1,388	1,570	41.8	28.1	26.9	43.6
Zone K	495	459	447	464	51.3	40.4	36.8	41.9

Higher Fuel Prices—Early Shutdown With Compensation

3 Pool	16,366	16,796	17,405	19,132	24.3	27.5	32.2	45.3
NYISO	4,377	4,881	5,096	5,522	39.9	56.0	62.9	76.5
Zone H	49	1	208	221	-49.8	-99.2	114.6	128.1
Zone I	0	0	0	0				
Zone J	1,858	2,090	2,107	2,374	69.9	91.0	92.6	117.0
Zone K	556	560	536	644	70.0	71.3	64.0	96.8

Higher Fuel Prices—End-of-License Shutdown with Compensation

3 Pool	15,934	15,929	17,007	19,132	21.0	21.0	29.1	45.3
NYISO	3,986	3,950	4,598	5,522	27.4	26.2	47.0	76.5
Zone H	97	97	253	221	0.4	0.3	160.7	128.1
Zone I	0	0	0	0				
Zone J	1,531	1,301	1,622	2,374	39.9	18.9	48.2	117.0
Zone K	479	352	467	644	46.6	7.7	42.8	96.8

Early Shutdown with Compensation and HVDC Line, Case b3

3 Pool	13,506	14,701	2.6	11.6
NYISO	3,279	3,500	4.8	11.9
Zone H	129	134	33.1	38.6
Zone I	0	0		
Zone J	1,080	1,186	-1.3	8.4
Zone K	285	320	-12.8	-2.2

EOL Shutdown with Compensation and HVDC Line, Case c3

3 Pool	13,284	14,701	0.9	11.6
NYISO	3,085	3,500	-1.4	11.9
Zone H	173	134	78.5	38.6
Zone I	0	0		
Zone J	919	1,186	-16.0	8.4
Zone K	245	320	-8341.2	-815.3

Early Shutdown with Compensation and High EE/DSM, Case b4

3 Pool	14,650	11.2
NYISO	3,527	12.7
Zone H	135	39.1
Zone I	0	
Zone J	1,242	13.5
Zone K	346	5.7

EOL Shutdown with Compensation, High EE/DSM, Case c4

3 Pool	14,650	11.2
NYISO	3,527	12.7
Zone H	135	39.1
Zone I	0	
Zone J	1,242	13.5
Zone K	346	5.7

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