Electricity Assessment: Resources and Markets

New York State Energy Plan 2009

December 2009

1 Overview

This Assessment identifies New York's electricity needs and evaluates the State's ability to meet those needs over the 10-year planning horizon. This Assessment provides a descriptive overview of New York's electricity system, including the structure and function of the regulatory framework and markets designed to produce and deliver electricity. It also discusses the aging state of electric system infrastructure and the upward pressure on rates that will result from related capital expenditures required to maintain system safety and reliability. Electricity system modeling was performed to assist with this Assessment by projecting future trends in capacity needs, generation mix, fuel diversity, net imports of electricity, electricity market prices, emissions, loss of load expectations, and emission allowance prices under various policy and system assumptions. The Infrastructure Issue Brief provides further discussion of many of the issues presented in this Assessment and discusses the need for additional, specific policy actions.

This Assessment emphasizes the importance of the State's '15 by15' energy efficiency goal, which was established by the Public Service Commission (PSC) for its Energy Efficiency Portfolio Standard (EEPS), that was designed to reduce energy use in New York State by 15 percent from what it otherwise would be by 2015.[1] Full and timely implementation of the EEPS will likely delay the need to build new generation and transmission facilities. Further, implementation of the proposed energy efficiency and renewable resource policies is projected over the long term to help moderate increases in the retail price of electricity paid by all ratepayers, while also playing a key role in helping the State to achieve its emission reduction goals.

Replacements and improvements of existing, aging infrastructure are critical for the State in meeting future energy needs. It is essential to guard against failures of the existing transmission system: such failures not only raise safety and reliable service concerns, but also can lead to increased system congestion (with related higher electricity costs) and power plant emission levels. Introduction of "Smart Grid" concepts can facilitate more efficient operation of the system while providing cost savings.

Due to the immense costs and difficulties in siting new transmission facilities, there is a need to identify, evaluate, and implement cost-effective means to optimize use of the State's existing generation, transmission and distribution systems. This could reduce the need for new facilities as well as contribute to lowering costs. Key to this effort is reducing system peak load through implementation of demand response programs and deployment of interval meters, coupled with adoption of time variant rates for large customers. Another promising strategy to increase overall system efficiency is development of utility-scale energy storage facilities, which could also be used to take full advantage of generation from large wind projects.

[1] In his 2009 State of the State address, Governor Paterson announced New York's '45 by 15' clean energy goal, which challenges the State to meet 45 percent of its electricity needs by 2015 through increased energy efficiency and renewable energy. The goal combines the PSC's '15 by 15' EEPS initiative goal with a goal of simultaneously meeting 30 percent of the State's electricity supply needs through renewable resources by 2015. Governor David A. Paterson. *Our Time to Lead: State of the State Address*. 2009. http://www.state.ny.us/governor/keydocs/speech_0107091.html

The competitive electricity market structure in New York is designed to provide transparent price signals for both energy and capacity. Such transparency encourages investors to locate generation, transmission, and demand response resources where they are most needed and it encourages investment in more efficient resources that can compete and bid into the market at lower prices. Since 2000, this market feature has provided incentives to entry of new generation resources totaling more than 7,600 MW, while putting the risk of such investments on investors rather than on ratepayers. Further, the competitive market structure provides for the system to be operated and dispatched in the most efficient manner to minimize total production costs and in the long term to provide electricity to customers at the lowest overall price. While New York's electricity markets and the planning processes to develop them have in large part been successful in achieving their objectives, improvements can be made to benefit both end-use customers and market participants. Continued monitoring and evaluation of the markets by the State is needed to ensure that the expectations of the competitive market structure are met.

The State has a diverse mix of electricity generation sources, including coal, nuclear, hydro, oil, gas, and renewables. Over recent years, in response to improved and more stringent environmental regulations, generators have increased the use of natural gas in place of oil and coal. While this provides environmental benefits, the State also needs to safeguard against becoming overly dependent on any one particular resource for meeting its energy needs, as fuel supply disruptions or other factors could pose reliability risks and/or cause significantly increased price levels and volatility. It is important to continue safe operation of nuclear, coal, natural gas, oil, and hydroelectric generation resources in ways that support the State's energy, environmental and economic objectives. Similarly, there is particular value in the continued availability of dual fuel generation capability, i.e., natural gas/oil, especially in the New York City area for continued ability to shift to oil should there be natural gas delivery problems. The State also needs to pursue the evaluation and development of advanced coal technologies.

Energy efficiency and renewable resources can contribute to meeting climate change and energy security goals, while also providing significant economic benefits. As the State continues to support the expansion of variable generation resources, such as wind turbines, it is important that adequate availability of load-following generation capacity be assured.

With the need to repair or replace aging infrastructure putting renewed upward pressure on New York's relatively high electricity rates (compared with other states), there is a strong need to balance the potential benefits of any new State policies and actions against their aggregate impact on the State and its ratepayers.

2 Overview of New York's Electricity System

2.1 Industry Framework

The electricity industry in New York is primarily comprised of investor-owned utilities; governmental utilities, generation companies, transmission-only companies, and energy service companies (ESCOs). The investor-owned utilities were previously vertically integrated with regard to generation, delivery, and customer service but have since divested the majority of their generation assets and retained primarily only their transmission[2] and distribution (T&D) delivery systems and their customer service functions. The purchasers of those generation assets, known as independent power producers, now serve as the primary generation suppliers in the State. The governmental utilities include the New York Power Authority (NYPA), the Long Island Power Authority (LIPA), municipally-owned electric utilities, and rural electric cooperatives. In general, the generation suppliers engage in wholesale sales, i.e., sales for resale, of energy, ancillary services and capacity through competitive markets administered by the New York Independent System Operator (NYISO). Transmission-only businesses, energy service companies, and both the traditional and governmental utilities, provide a variety of other services to end-users, which are described below.

Wholesale electricity sales and transmission services are regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act,[3] whereas retail sales of energy, i.e., sales to end-use customers, and the accompanying service over local distribution lines (to the extent that they are owned by the investor-owned utilities) are regulated by the PSC under the Public Service Law (PSL). Independent power producers are subject to lightened regulatory requirements by the PSC. Moreover, the PSC has fostered the development of ESCOs that may provide energy to retail end-use customers as an alternative to energy supplied by an investor-owned utility. ESCOs are subject to limited regulation by the PSC, such as compliance with PSL Article 2, also known as the Home Energy Fair Practices Act, and other provisions identified in utility tariffs approved by the PSC.

The municipally-owned utilities, rural electric cooperatives, and public power authorities serve retail customers, and some own generation or T&D facilities. The public power authorities are subject only to limited regulation by the PSC, such as approvals for major transmission facilities. While the public power authorities are generally exempt from FERC jurisdiction, they have voluntarily agreed to participate in the NYISO-administered markets and are thus subject to the terms of the NYISO tariff. Municipally-owned electric utilities that take their entire electric generation supply from NYPA fall outside the PSC's ratemaking jurisdiction, while those utilities that receive supplemental power from sources other than NYPA are regulated by the PSC. The State's four rural electric cooperatives are exempt from PSC jurisdiction by virtue of Section 67 of the New York Rural Electric Cooperative Law. Municipally-

[2] Transmission is defined as an interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electricity systems.

[3] 16 USC §12. *Federal Regulation and Development of Power.*

owned utilities, rural electric cooperatives, and public power authorities typically oversee and take responsibility for their own infrastructure needs.

The NYISO was formed in 1999 as a not-for-profit corporation governed by an independent board of directors consisting of 10 members with varying backgrounds in the power industry, environment, and finance.[4] Unlike neighboring systems, the New York electric system is operated as a single state independent system operator (ISO) organization, and the NYISO operates the State's bulk[5] power system and wholesale markets in accordance with its FERC-approved tariffs. Under the NYISO's shared governance structure, tariff filings made at FERC under Section 205 of the Federal Power Act are subject to approval by the NYISO's Management Committee. The Management Committee is the senior of three standing Committees: the Business Issues Committee, the Operating Committee, and the Management Committee, with the first two being subordinate to the latter one. The Committee voting structure is made up of five sectors: transmission owners, generation owners, other suppliers, end-use consumers, and public power and environmental parties. Actions by the committees require a 58 percent voting approval to pass. The PSC, the New York State Energy Research and Development Authority (NYSERDA) and the Consumer Protection Board (CPB) work with the NYISO and its committees to represent State and consumer interests with regard to all reliability and wholesale market issues.

The PSC and FERC share authority over the reliability of the transmission system. FERC oversees the NYISO's reliability and economic planning processes, but it has limited authority to direct the construction of additional infrastructure. The PSC, however, has authority to order the construction of facilities necessary to serve the public interest.

Jurisdiction over siting of infrastructure facilities is split among the federal, state, and local governments. The siting of electric generation facilities is generally a state and local responsibility, depending on the state and local laws. The siting of electric transmission facilities is also primarily the responsibility of the state governments, except for FERC's back-stop authority under certain circumstances. A more complete description of jurisdiction over the siting of infrastructure is contained in the Siting New Energy Infrastructure Issue Brief.

2.2 Infrastructure[6]

2.2.1 General

New York's physical electricity system is comprised of generation, transmission, and distribution components that provide electricity to end-users. Figure 1 provides a general pictorial description of the electricity system.[7] The generation component consists of numerous interconnected facilities that transform potential energy from basic energy sources, such as wind, coal, oil, natural gas, and nuclear fuel, into electrical energy that ultimately can be consumed by end-users throughout the State and elsewhere. The transmission component delivers electricity from generation stations to facilities

[4] The term "independent" in this Brief means that the members of the Board have no relationship with any market stakeholder.

[5] The major electric transmission and generation system used for wholesale electricity transactions is referred to as the "bulk power system."

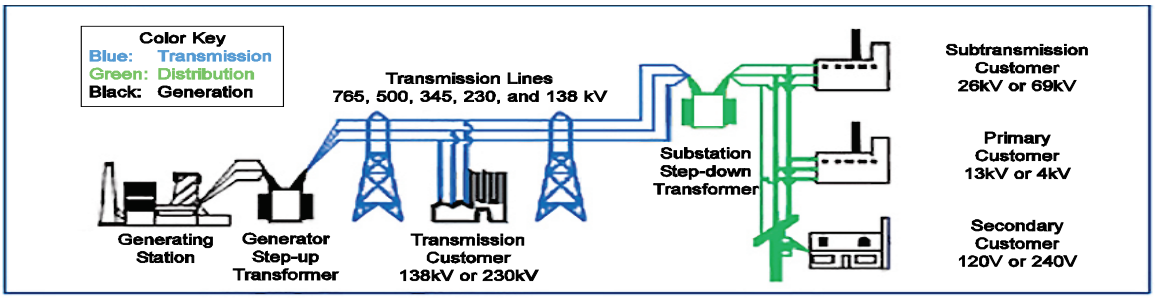
[6] Issues associated with the infrastructure are also addressed in the Energy Infrastructure Issue Brief.

[7] U.S/Canada Power System Outage Task Force. *Final Report on the Implementation of the Task Force Recommendations.* 2006. http://www.ferc.gov/industries/electric/indus-act/blackout/09-06-final-report.pdf

throughout the State that allow the power to be distributed to end-use consumers either through distribution facilities or directly in the case of some large end-use customers. The distribution component of the system is generally used to carry electric power from the transmission component to the locations of end-use consumers.

The movement of power between generators and end-use consumers requires a series of steps that, among other things, are designed to minimize energy losses. First, power is transformed from a relatively low voltage at the generation station to a much higher voltage, which provides greater efficiency during transmission, and then it is stepped back down to a lower voltage at the distribution level. Between the transmission and distribution systems, intermediary components typically exist to transport the electric power between the wholesale electric generation and transmission components, typically referred to as the "bulk power system," to multiple local distribution systems. Substations interconnect the various system components and provide the equipment to transform the voltages between the components, protect the system from electrical failures, and provide switching capabilities for reliable operation of the system.[8]

Figure 1. General Depiction of New York's Electricity System



Source: DOE.

In New York, electricity generally flows east from the Niagara Falls area and then south to New York City and Long Island. This direction of flow results primarily because only about 40 percent of the State's electric generating capacity is located in the New York City and Long Island while the peak demand there was 50 percent of the statewide end-use consumer needs in 2008, and end-use consumer load was about 47 percent of the statewide needs.[9] Additionally, the higher operating cost associated with generating electricity in downstate regions, as compared to the costs of generating upstate, makes it more cost effective to import electric power into the downstate areas much of the time. The location of baseload generating units[10] also contributes to the direction of electricity flow. Of these baseload units, the majority are located in upstate New York areas, thus supporting the west to east to south flow.

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[8] Although this paragraph generally describes a typical electric system, there are also many variations that can and do exist within the State, including those associated with generation resources located directly on the properties of consumers, which may or may not be interconnected with the rest of the State system.

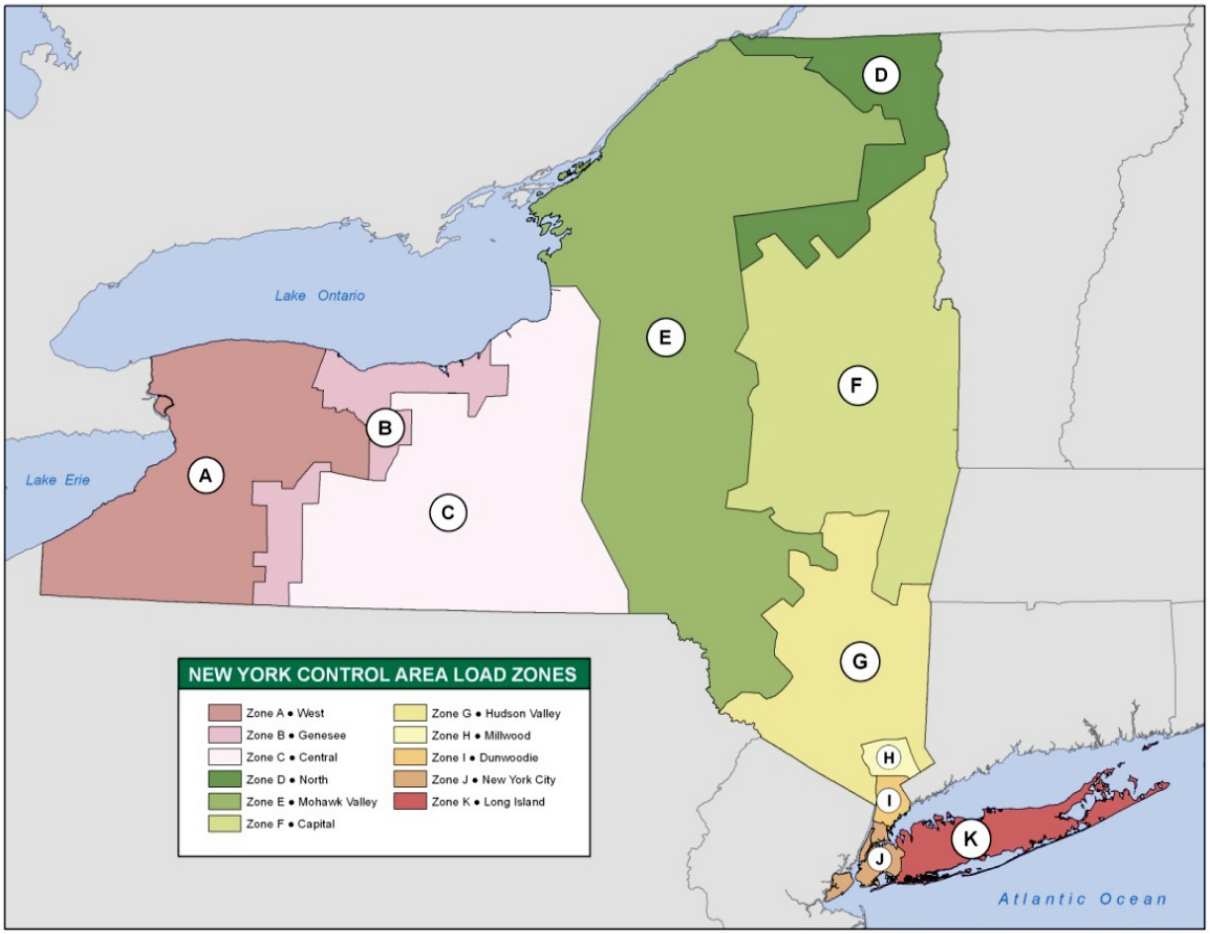
[9] Percentages were calculated based on information presented in the 2009 Load and Capacity Data Report published by the New York Independent Operator. NYISO. *2009 Load and Capacity Data*. 2009. http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC.pdf

[10] Baseload generating units are those units that tend to operate most of the time due to their low fuel and operating costs and other operating characteristics.

2.2.2 System Control

The electricity system in the United States is divided into control areas for the purpose of managing/controlling the operations of the bulk transmission and generation systems.[11] Unlike most other states, New York is a control area by itself for electrical purposes, and the NYISO is the designated operator for bulk power system operations. The New York Control Area (NYCA) is divided into 11 zones, as illustrated in Figure 2 below. The divisions between zones are referred to as interfaces.

Figure 2. New York Control Area Load Zones



Source: NYISO.

[11] Control area is a term used to refer to an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its schedule for interchange of electricity with other control areas and contributing to frequency regulation of any one of the five major electric system networks in North America. Regulation is the continuous balancing of resources with load variations in order to maintain scheduled frequency. Source: North American Energy Standards Board Wholesale Electric Industry Glossary.

Limits to the capability of the system to transfer electricity between the zones are referred to as interface limits.[12] These interface limits constrain the amount of power that can be moved from one zone to another. Similarly, New York is interconnected with neighboring control areas, and there is limited transfer capability to and from each of those control areas: the Hydro Quebec (HQ) control area to the north, the Ontario control area to the west, the Pennsylvania-New Jersey-Maryland (PJM) control area to the south, and the New England control area to the east.

As electricity cannot easily be stored in large quantities today, the production and use of electricity generally takes place in real-time. The NYISO and the individual utilities work together to monitor and control the electric system constantly. The system operators ensure that production of electricity is instantaneously balanced with electric demand and that the system is operated reliably. Reliable operation of the system is guided by established rules that specify voltage, thermal, and other limits within which the system must be maintained. While the goal is to serve load at all times, even under contingency situations, i.e., potential unexpected failure, the operating rules are designed to interrupt load temporarily if necessary to prevent physical damage to the system.

2.2.3 Transmission

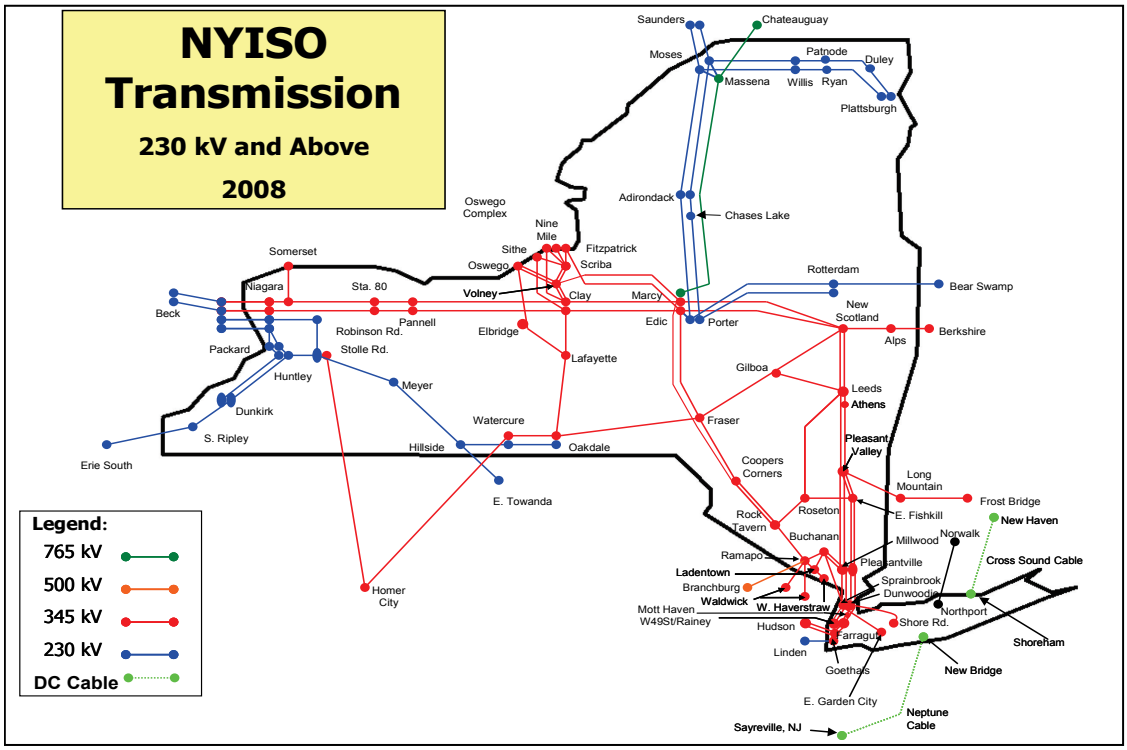
System Overview

Electric power transmission, typically occurs between a central station power plant and a substation where the voltage of the power is reduced, allowing it to be distributed either to a sub-transmission system or directly to a distribution system serving customer loads, neither of which are generally considered part of the bulk power system. Due to the large amount of power involved in transmission, this form of delivery normally takes place at relatively high voltages (115 kV or above) to minimize power losses along the way. Somewhat lower voltages, e.g., 69 kV, are used for sub-transmission, with even lower voltages, e.g., 24 kV and 13 kV, being used for distribution to consumers, with consumers typically taking power at 110V and 220V. Bulk power is typically transmitted over long distances through overhead power lines, although in New York City, underground circuits are used despite their high cost of installation and maintenance.

Figure 3 illustrates the 230 kV and above bulk transmission system in New York under the control of the NYISO. The many transmission facilities in the State lower than 230 kV, i.e., 115 kV and 138 kV, are not shown on Figure 3 due to their large numbers, although most of them are also considered part of the bulk power system.

[12] The limits may be due either to thermal, stability or voltage considerations, or a combination of the three. Thermal limits refer to the maximum amounts of electrical current that transmission lines or electrical facilities can conduct over a specified time period before they sustain permanent damage by overheating or before they violate public safety requirements. Stability is the ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. Voltage limit refers to the voltage on the interconnected system that is acceptable either on a sustained basis or for a time sufficient for system adjustments to be made following a facility outage or system disturbance. Source: North American Energy Standards Board Wholesale Electric Industry Glossary. The System Constraints subsection of this Assessment identifies the major limits now existing in New York that affect planning and operation of the system.

Figure 3. NYISO Transmission



Source: NYISO.

The New York transmission system consists predominantly of alternating current (AC) transmission lines, similar to what exists in most of the United States. Only a small portion of the New York system consists of direct current (DC) facilities. Later sections of this Assessment discuss the aging status of the electricity delivery system in New York and the impact of increasing transmission capability, especially toward New York City.

System Constraints

An interface limit determines the amount of power that can safely flow across zones; the limit is set by the most restrictive value of the thermal, voltage, and stability limits[13] derived from studies conducted by the NYISO.[14] Technically, power can flow in both directions across the interfaces. In fact, however, the normal direction of power flow is from west to east and then south in New York. Table 1 summarizes the interface limits, i.e., the limitation on power flows between zones, and the reasons for the limits, under normal operating conditions.[15]

[13] Thermal, voltage, and stability limits define the maximum acceptable levels of current, voltage, and power flow at or through a point on a facility or system that will allow the facility or system to continue operating appropriately.

[14] An interface between zones consists of multiple lines and components rather than a single point.

[15] The NYISO refers to the west to east to south flow as positive and flow in the opposite direction as negative.

Table 1. Interface Limits

Delineates Zones	Interface Common Name	Summer Thermal Limits (MW)
Zones A/B	Dysinger East	2200 (Thermal)
Zones B/C	West Central	1770 (Voltage)
Zones C/E	Volney East	4270 (Thermal)
Zones D/E	Moses South	2600 (Voltage)
Zones E/F	Central East + Fraser Gilboa	3150 (Thermal)
Zones F/G	Upstate NY/Southeast NY	5150 (Thermal)
Zones G/H	Upstate NY/Con Edison	5000 (Thermal)
Zones H/I	Millwood South	8450 (Voltage)
Zones I/J	Sprainbrook/Dunwoodie South	4000 (Voltage)
Zones J/K	Con Edison/Long Island	486 (Thermal)

Source: NYISO. *2009 Reliability Needs Assessment*.

Similarly, as shown Table 2, transfer capability between New York and neighboring control areas is limited due to transmission constraints. The ability to trade power between control areas and provide support during emergency conditions improves system reliability for all. While imports and exports between neighboring control areas vary by season, market conditions and other factors, New York has over the last several years generally been a net importer from each of its neighboring control areas.

Table 2. Border Transfer Limits

Control Area	New York Import Limit (MW)	New York Export Limit (MW)
HQ	1500	1000
ISONE	1200	1525
PJM	1500	2000
IESO (Ontario)	1450	1550

Source: NYISO. *2009 Reliability Needs Assessment*.

Although the NYISO has a generation scheduling process that is designed to select and dispatch[16] the lowest cost power through the transmission system to meet demand across the State, physical limitations, which are referred to as constraints or congestion,[17] of the transmission system often requires the dispatch of a more expensive source of electricity downstream of the constraint to ensure that the transmission system continues to operate reliably. Congestion on an interface between zones is a primary reason for the NYISO to select a more expensive generator to run. Removal of constraints or congestion typically involves analyses to determine if the cost of the upgrade is acceptable in comparison to the benefits to be achieved. Currently, removal of congestion is not necessary to ensure reliability of the system, and most studies have not shown that the costs of addressing constraints are lower than the economic benefits that would be achieved. Removal of constraints for public policy reasons, however, may be justified in certain circumstances.

To move power through the transmission system, both of its components, real power and reactive power, are required, with the appropriate amount of each.[18] Very often, changes in voltage indicate an imbalance of real and reactive power on the system. When the real and reactive power are out of balance, the voltage either drops or increases unexpectedly, potentially causing serious reliability issues to the entire system. During high load periods, and with the transfer of power over long distances, a shortage of reactive power on the system can cause low voltage reliability problems. Reactive power must then be added. Such a problem occurs frequently for power being delivered to New York City, particularly along the Hudson Valley corridor.

The NYISO tracks the transmission facilities that account for the majority of congestion and presents the results in its annual Reliability Needs Assessment (RNA). The major constraint within the State currently is across the Central-East Interface, which roughly runs between the northwest and southeast portions of the State. In 2008, the Central-East Interface accounted for 46 percent of the total congestion in the State, up from 10 percent in 2003. The next major constraining facility is the Pleasant Valley-Leeds 345 kV line, which runs between the upper and lower Hudson Valley areas, between zones F and G. This facility accounted for 27 percent of the total State congestion in 2008, up from 1 percent in 2003. The next

[16] Dispatch is a term used to describe the control and scheduling of multiple generation sources to meet customer demand and energy requirements.

[17] Congestion is a term used to describe a transmission system operating at or near a security limit or limits, resulting in dispatch of more expensive electricity than those that would be dispatched in an unconstrained system. Security limits are set based upon thermal ratings of system components, e.g., lines and transformers, as well as voltage and stability considerations.

[18] Real power is measured in megawatts (MW), and reactive power is measured in volt ampere reactance (VAR).

significant constraint is the Dunwoodie-Shore Road 345 kV cable that connects the northern Consolidated Edison (Con Edison) system with Long Island, between zones I and K. In 2008, it accounted for seven percent of the statewide congestion, down from 27 percent in 2003. If the first two major constraints (Central-East and Hudson Valley) were eliminated, the major congestion points would move further south, continuing to constrain power flows from upstate New York to New York City and Long Island.

The statewide value of congestion has been calculated by the NYISO since 2003, using a bid-production-cost-savings methodology.[19] The value of the gross congestion has varied from an annual low of about $71.7 million in 2004 to a high of about $243 million in 2008.[20] Note that these dollar amounts are estimated total statewide congestion costs that reflect the money that could be saved if all congestion within the State were eliminated; the cost of relieving the congestion would need to be subtracted from this amount to arrive at net savings. A specific project proposal to resolve congestion would need to be weighed by comparing the annual carrying costs of building and maintaining the facility with the congestion costs that can be saved by reducing the congestion in the area of the new facility. Given the cost of building new transmission and the lack of consistent levels of congestion over a particular path, the historic levels of statewide congestion costs have been considered "economic," i.e., economically acceptable. To address congestion, various approaches need to be considered, such as construction of new transmission facilities, upgrading existing facilities, and/or adding new generation.

2.2.4 Generation

The generation sector in New York today consists of 22,568 MW of independently-owned generation, 2,619 MW of regulated utility-owned generation, 6,635 MW of generation owned by NYPA, 201 MW owned by municipal electric companies, and 6,690 MW of generation owned by National Grid (facilities formerly owned by KeySpan and LIPA). These facilities are located throughout the State. An undetermined amount of customer-owned generation also exists throughout the State to provide for the needs of the facility owners at the sites where they are located. This section describes some of the characteristics of the generation available for use in the wholesale market in New York. The Electricity Assessment: Modeling projects the impacts on generation based on alternative assumptions about load growth in the State.

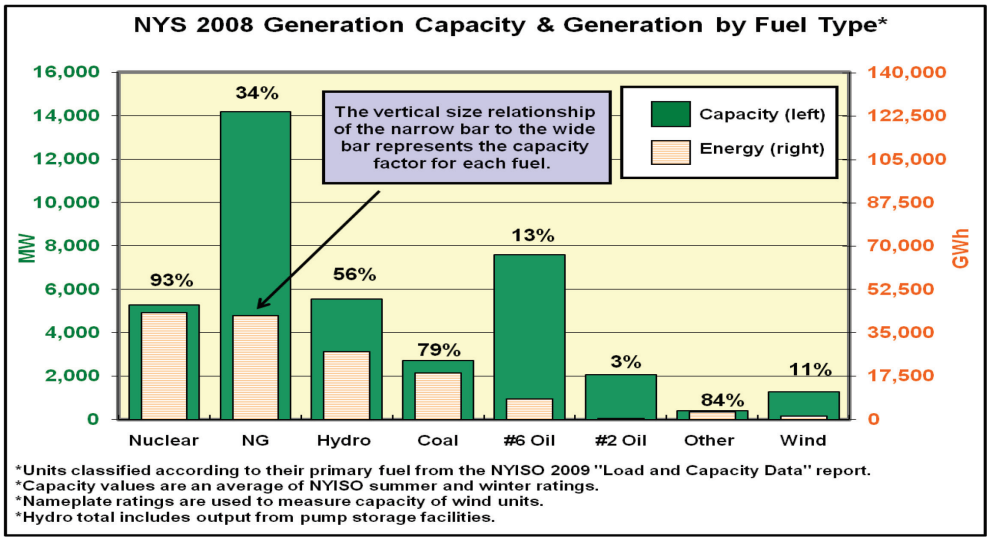
Fuel Mix and Capacity Factor

Figure 4 illustrates New York's 2008 aggregate capacity (MW) and generation (GWh) by fuel type. The aggregate capacity factor (CF), i.e., actual annual generation as a percentage of annual potential generation, for each of the generation fuel types is depicted by comparing the vertical size of the outer bar to the vertical size of the inner bar for that fuel type. The capacity factors are also shown numerically. It is important to note, however, that the information shown for the natural gas and petroleum fuels (No. 6 oil and No. 2 oil) are estimates due to uncertainties associated with dual-fueled units, which are explained below.

[19] This methodology measures the societal resource cost savings gained by operating less expensive generation in place of the more expensive generation located in transmission constrained areas known as load pockets.

[20] NYISO. *2009 Reliability Needs Assessment*. 2009. http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/RNA_2009_Final_1_13_09.pdf

Figure 4. New York State 2008 Generation Capacity and Generation by Fuel Type



Source: NYISO. *2009 Load and Capacity Data Report*.

As shown in Figure 4, residual oil (No. 6 oil) and distillate oil (No. 2 oil) units typically exhibit very different operating patterns. The 2008 No. 6 residual oil aggregate capacity factor was 13 percent compared to three percent for the No. 2 distillate oil units, including kerosene. Most units that burn No. 2 distillate oil are peaking units that were never intended to operate a significant number of hours, as opposed to units that burn No.6 residual oil. Even so, note that capacity factors for both types of oil units have been generally lower in recent years in part due to the disproportionate increase in oil prices as compared to natural gas.

Figure 4 also illustrates that New York's nuclear facilities had the highest aggregate capacity factor (93 percent) of all fuel types in 2008. Coal units and hydro units were second and third respectively, with 79 and 56 percent capacity factors.[21] Unlike natural gas and oil units, operation of these three unit types, often considered to be "baseload" units, are generally less sensitive to wholesale electricity market clearing prices, largely due to the lower fuel costs inherent to these units.[22] The 2008 capacity factors for wood, waste, methane, and wind were 74, 87, 82, and 11 percent, respectively.

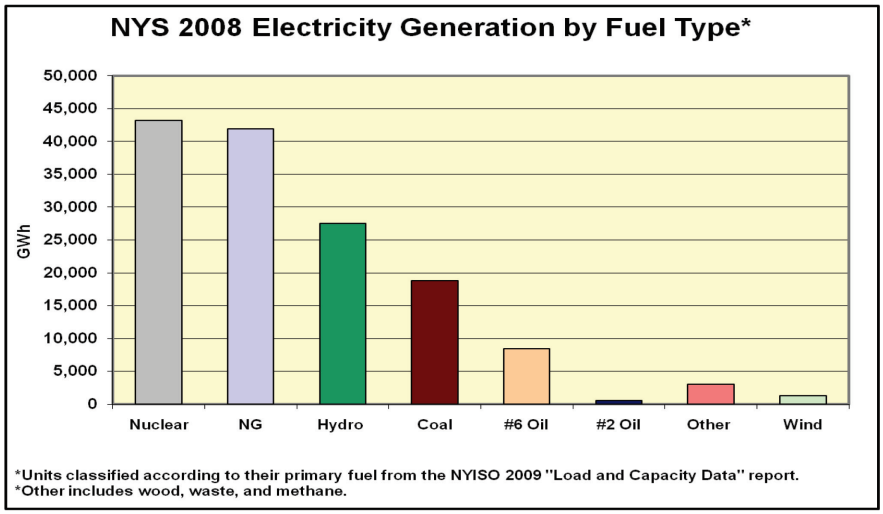
In 2008, 61 percent of New York's existing generation capacity (MW) was fueled by natural gas or oil. Given the low aggregate capacity factors for natural gas and oil units shown in Figure 4, however, these fuels collectively accounted for only 35 percent of total in-State generation (MWh) during 2008. This is because natural gas and oil units have higher operating costs than nuclear, hydro, or coal units, and thus will have fewer accepted generation bids and lower capacity factors than those baseload units.

Figure 5 shows the total 2008 New York generation by fuel type only. As with Figure 4, generation from natural gas and petroleum fuels are estimates, as precise information about which fuel is being used in dual-fuel units at any given time is not available.

[21] Hydro facilities' output is limited by the availability of water.

[22] Baseload refers to generation that generally operates continuously to serve load, whether during peak or off-peak hours.

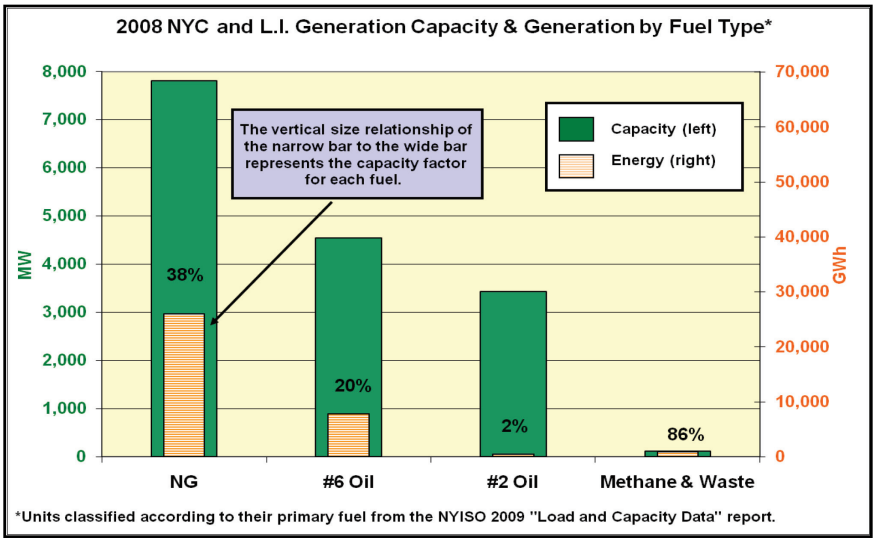
Figure 5. New York State 2008 Electricity Generation by Fuel Type



Source: NYSERDA.

Figure 6 shows the combined New York City and Long Island generation capacity (MW) by fuel type, and also shows each fuel type's aggregate capacity factor as of March 2008. Ninety-nine percent of generation capacity in New York City and Long Island is fueled by natural gas, oil, or both.

Figure 6. 2008 New York City and L.I. Generation Capacity and Generation by Fuel Type



Source: NYSERDA.

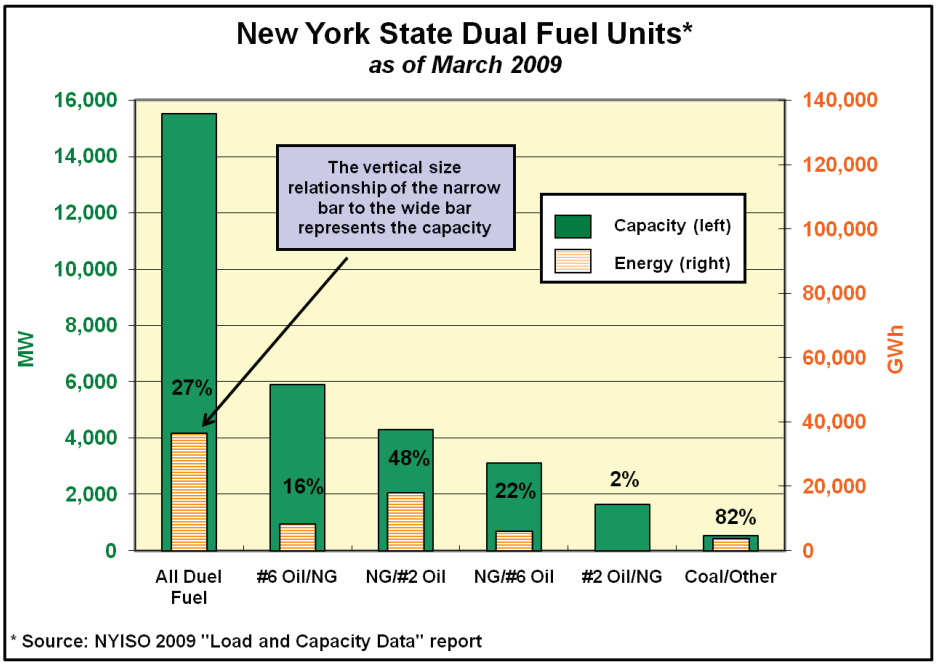
The New York City and Long Island natural gas, residual oil, and distillate oil unit aggregate capacity factors were 38, 20, and 2 percent, respectively, in 2008. The relatively low capacity factors are likely due to the following reasons:

- low load factor, which is the actual annual load as a percentage of total possible annual load, caused in part by high cooling load occurring for only a few hours of the year
- need to comply with locational installed capacity requirements downstate[23]
- high downstate operating costs

The low load factor leads to additional required capacity that is needed for only a few hours a year, providing downward pressure on downstate capacity factors. Additionally, because of downstate transmission constraints, the locational installed capacity requirements mentioned above have been developed to ensure reliability downstate. Despite the locational requirements, however, higher downstate operating costs, such as, fuel costs, property taxes, and labor costs, still lead to the importing of as much lower-cost electricity as possible during the year from external sources, leaving local units idle more often.

Figure 7 depicts total New York dual-fuel capacity (MW) by fuel types as of March 2009. Almost 40 percent of New York generation capacity is capable of burning at least two fuels. In the event that the supply source for one fuel is disrupted, these units can burn an alternate fuel. This diversity provides New York consumers with a valuable electric reliability insurance policy should one fuel supply source be compromised, particularly at a time of high electric system demand.

Figure 7. New York State Dual Fuel Units



[23] A locational installed capacity requirement is a determination made by the NYISO regarding what portion of the statewide installed capacity requirement must be located electrically within a locality in order to ensure that sufficient energy and capacity are available in that locality and that appropriate reliability criteria are met.

Fuel Diversity

As shown above, New York has a diverse fuel mix. This diversity can benefit the State by mitigating the impacts of supply disruptions for any given fuel source and by mitigating price volatility due to fuel price fluctuations. This is not the case, however, in New York City and on Long Island, which rely heavily on gas-fired generation, although some of those units also are able to burn oil.

The State's future fuel diversity is not assured. For example, Entergy's application for a license renewal for Indian Point Units 2 and 3 is under review. Also, increased maintenance costs, loss of thermal efficiency, and more stringent environmental regulations could prompt older coal and oil-fired facilities to close.

Furthermore, the near-term construction of a substantial number of new facilities burning coal or oil appears unlikely at this time. Almost all of the power plants placed in service recently in the northeastern U.S. burn natural gas because they generally have the following advantages over other fossil fuel generators:

- lower heat rates, and thus potentially lower costs
- smaller up-front investments
- lower emissions, including sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2) and particulates
- the ability to be located closer to urban centers
- lower operating costs associated with the relatively low cost of gas to fuel these facilities

However, this increasing reliance on gas-fired plants, while beneficial in some ways, presents several concerns. For instance, the gas delivery infrastructure is generally sized to provide reliable supplies primarily to non-curtailable gas load and the increasing use of natural gas for electricity generation has strained that infrastructure, resulting in occasional curtailments of supply to power plants. Such curtailments are most likely to occur at times when demand for gas for other purposes is greatest, e.g., in extreme winter weather, when demand for electricity may also be high, and potentially lead to a loss of electric supply as well. Extreme winter conditions also coincide with times of difficulty supplying coal to, and obtaining oil deliveries for, older plants.

As a result, reliance on natural gas for electric generation in New York City and on Long Island during periods of high demand has led to the adoption of a reliability rule to ensure that the loss of a single gas facility does not bring about a loss of electric load within the New York City zone. The rule, for certain system applications, specifies minimum oil burn requirements, i.e., that minimum levels of fuel oil be used, for select generators in New York City and on Long Island to mitigate against the potential loss of electric supply due to generating units tripping off line in the event of a sudden loss of gas supply.[24]

Other concerns regarding reliance on natural gas-fired generation include gas price volatility and the potential future reliance on imported liquefied natural gas (LNG) from unstable international sources. Also, even though natural gas facilities have relatively favorable environmental qualities, gas-fired generation facilities still emit substantial amounts of CO_2.

The capability of gas-fired facilities to burn oil, or some other fuel, in the event of a gas disruption or curtailment was fairly common in the past because the ability to burn the lowest cost fuel at any given

[24] This is referred to as the minimum oil burn rule.

point in time provided an economic as well as a reliability advantage. Many of the older units formerly owned by Con Edison and the former Long Island Lighting Company (LILCO) have that ability.

Dual-fuel capability in newer units has become far less common because such capability requires additional capital investment to construct oil storage facilities and other equipment to be able to burn the second fuel and carry the oil inventory. In addition, environmental permits for newer units tend to be predicated on the use of natural gas to avoid the applicability of specific environmental regulations or to limit the impact applicable regulations may have on the economics of the unit.

These trends, along with other factors such as limitations on the number of hours oil can be burned in dual-fuel units, limit operational flexibility and have a potential impact on fuel diversity and reliability of supply.

2.3 Market Structure and Commodity Pricing

The current competitive generation market in New York began to take shape in August 1994 when the PSC instituted an investigation of the issues related to the emerging competition in the electric industry. As a result, a competitive wholesale electricity market was established and the NYISO was created in 1999.

An integral part of establishing a competitive wholesale electricity market in New York was the separation of the ownership of transmission and distribution assets from the ownership of electric generation assets. This policy was announced in Opinion No. 96-12 of PSC Cases 94-E-0952, et. al.[25] in which the PSC stated that generation should be separated from transmission and distribution to prevent the exercise of vertical market power.[26] In addition to the policy stated in Opinion No. 96-12, the PSC issued a Statement of Policy Regarding Vertical Market Power (VMP)[27] (VMP Policy Statement) that establishes a rebuttable presumption that the ownership of generation by an affiliate of a transmission and distribution company would unacceptably exacerbate the potential for VMP.

The PSC policies adopted in the mid-1990s have resulted in the divestiture of most utility owned generating facilities, the exception generally being some small hydro units and natural gas turbines and units associated with the Con Edison steam system. The divestitures resulted in an upstate generation market with facilities owned by multiple entities, with no significant market power concerns. However, there continue to be market power concerns in New York City. The VMP Policy Statement has since been applied specifically to two recent mergers/acquisitions: National Grid/KeySpan and Energy East/Iberdrola, resulting in the divestiture of generating facilities as a condition of merger. The National Grid/KeySpan merger resulted in the divestiture of the KeySpan Ravenswood generating facilities to TransCanada. The acquisition of Energy East, comprised of New York Electric & Gas Company

[25] PSC. Cases 94-E-0952, et. al. - *In the Matter of Competitive Opportunities Regarding Electric Service - Opinion and Order Regarding Competitive Opportunities for Electric Service*. Issued May 20, 1996. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={076F3B08-917D-47FE-83C0-8B2B32822A67}

[26] Vertical market power (VMP) is the power over a market that a vertically integrated utility can exercise through ownership and/or control of all the different aspects of making, selling, and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system, and distribution lines to provide all aspects of electric service.

[27] PSC. Case 96-E-0900. *Statement of Policy Regarding Vertical Market Power*. Issued July 17, 1998. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={8833CA88-E847-4A0F-89EB-1A2D83C6DC29}

(NYSEG) and Rochester Gas & Electric Company (RG&E), by Iberdrola required the divestiture of all fossil-fueled generation owned by Energy East in New York.

Under the resulting markets, the traditional transmission and distribution owners, such as investor-owned utilities, LIPA, and NYPA, continue to provide delivery service. Numerous owners of generation resources, providers, and aggregators of demand side resources, and a multitude of ESCOs all exist now to provide commodity service to end-use retail customers. Further, market prices have provided incentives since 2000 to entry of new generation resources totaling more than 7,600 MW, although approximately half of those entrants (in the downstate market) have been supported by long-term contracts. The NYISO has instituted planning processes looking 10 years out to ensure that the markets are set to provide resources needed to ensure reliable operation of the system; if the markets fail to do so, there is a backstop process in place to ensure that utilities procure such resources for reliability purposes. The NYISO is also implementing an economic planning process to identify the potential for upgrades that could lower prices. While these market and planning processes have in large part been successful, certain shortcomings will be addressed in the Infrastructure Issue Brief.

Along with the advent of the NYISO came a new system for pricing wholesale electricity, i.e., commodity pricing, known as Locational Based Marginal Pricing (LBMP). A LBMP consists of energy, congestion, and loss components relative to a reference location; it represents the incremental value of an additional unit of energy injected at a particular location.[28] This system of pricing is designed to provide economically efficient price signals throughout the grid, taking all three factors into account.

Using the bids of both suppliers and demand-response resources, the NYISO software economically commits and dispatches resources at the least cost consistent with transmission and other system constraints using a uniform-price auction format. Essentially, this means that the market clearing price paid to all suppliers is based upon the marginal cost of the last unit chosen to serve load.[29] Under this arrangement, suppliers, absent market power, have every incentive to bid into the market their marginal costs of production, because if they bid below it they may run at a loss and if they bid above it they may not be selected for dispatch and will neither run nor be paid. This results in the system being dispatched in the most efficient manner that minimizes total production costs, thus providing power to consumers at the lowest possible price.

Uniform clearing price auctions are often criticized because it seems unreasonable on its face to pay a generator any higher price than that which it bid into the market and was willing to sell for on any given day. It would seem preferable to instead pay them the price that they bid. If such a design were to be instituted and generators did not change their bids, then baseload units, which generally have low marginal running costs and high fixed costs, would only be able to recover from the market the former and not the latter. Such units would not be able to survive for long, and new baseload facilities would not be built. Instead, to recover their full costs and maximize profits, generators would bid at or near what they believe the market clearing price will be. Such an imprecise process will ultimately result in a less efficient dispatch than what would result if actual marginal costs were bid, resulting in higher total production costs and higher costs to consumers. As long as markets are competitive, the uniform clearing price auction will provide the most efficient result. The upstate New York market has consistently been competitive; however, downstate generators are required to bid within strict bounds of their actual marginal costs to mitigate issues related to market power. While generators receive payment based upon

[28] NYISO. *Technical Bulletin 62 – Locational Based Marginal Pricing – Meaning and Myth.* December 2008. http://www.nyiso.com/public/webdocs/documents/tech_bulletins/tb_062.pdf

[29] The marginal cost is the cost to produce the next increment of output. The generating unit that produces that increment is called the marginal unit (or the unit on the margin) at that point in time.

their particular location, prices paid by consumers reflect a weighted average of the LBMPs within a particular area, or zone, of New York. It should also be noted that while some power supply is procured through the NYISO markets, approximately half is secured under individual bilateral contracts, i.e., contracts directly between buyers and sellers.

The NYISO operates both a day-ahead market and a real-time (or balancing) energy market and produces prices for both energy and ancillary services, such as operating reserves[30] and regulation service.[31] Since the NYISO's inception in 1999, the software used to administer the day-ahead and real time markets has continually evolved and improved. State-of-the-art software is used to provide all wholesale electricity products in the most efficient manner possible. By making these improvements, the NYISO market became the first to optimize energy and operating reserves jointly to provide these products in the most efficient manner possible. A discussion of whether sufficient price signals occur to spur investment in generation and demand response resources can be found below and in the Infrastructure Issue Brief.

Although much of New York's electric energy is generated by baseload hydroelectric, coal and nuclear units, natural gas and oil-fired units are usually the units that set the market clearing prices. Because generators typically bid their marginal costs of production, and most of those costs are fuel costs, the price of fuel directly affects the price of electricity. The annual reports of the NYISO's independent market advisor routinely highlight the correlation of electricity and fuel prices. Other significant factors affecting prices are changes in load, which are largely driven by weather, and additions or retirements of large generating units or other changes in system configuration.

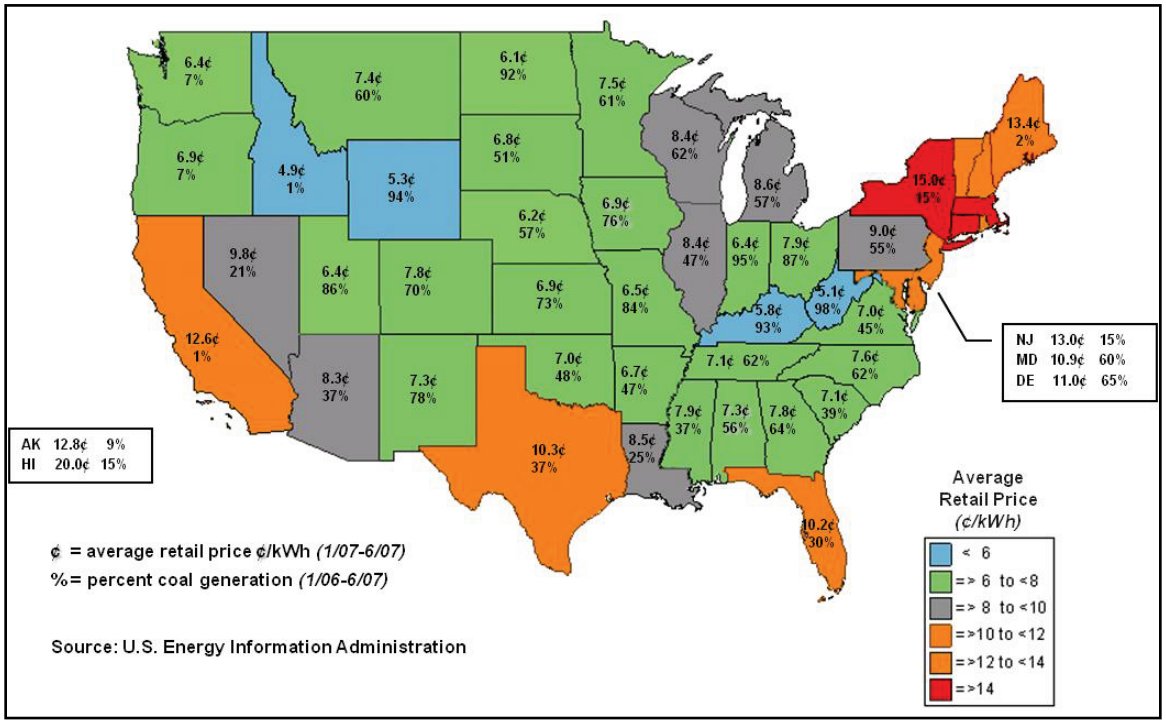
This market and pricing structure has been the subject of much criticism, not only in New York but also in other regions with competitive wholesale markets, and many studies purport to prove or disprove the benefits of such markets. No study, however, can predict with any certainty what prices and other impacts of power generation would have resulted had different policy paths been followed over the past decades. At the outset, it is important to note that electric prices are driven largely by fuel prices, and thus New York prices were high prior to restructuring, and remained high after restructuring although they have recently been falling significantly.

Figure 8 illustrates that average prices across the United States are highly correlated to the percentage of generation fired by coal which, absent the incorporation of emissions costs, is the least expensive fuel available.

[30] Operating reserves refer to capacity that is available to supply energy or reduce demand in the event of contingency conditions, including spinning reserves, 10 minute non-synchronized reserves, and 30 minute reserves.

[31] Regulation service is defined as the capability of a specific generating unit with appropriate telecommunications, control and response ability to increase or decrease its output in response to a control signal every six seconds. This ensures the continuous balancing of resources (generation and interchange) with load variations in order to maintain scheduled interconnection frequency.

Figure 8. Cost Per kWh and Percent of Coal Generation



The markets are designed to provide transparent price signals for both energy and capacity that encourage investors to locate generation, transmission, or demand response where they are most needed for both economics and reliability. The markets are also intended to encourage investment in more efficient resources that can compete and be offered into the market at lower prices and to place the risk of large capital investments on private sector developers rather than captive utility ratepayers. The movement to a competitive market was in fact largely driven by ratepayers being burdened with massive cost overruns for projects, such as Shoreham and Nine Mile Point 2, and excess statutory-rate payments made to qualified facilities pursuant to the Public Utility Regulatory Policy Act (PURPA)[32], which will not recur under the competitive market regime.

Due to the availability of transparent price signals, over 7,600 MW of more efficient and less polluting resources have been added since 2000 with 80 percent of that located below the central-east interface where prices are higher and the resources are most needed. Similarly, over 2,000 MW of demand response resources have also entered the market, much of it in New York City, significantly shaving peak loads when called upon.

Due to competition among suppliers, the average plant availability in New York increased from 87.5 percent between 1992 and 1999 to 94.4 percent between 2000 and 2007; however, plant availability declined somewhat in 2008 due to long scheduled outages. This increase represents the equivalent of adding 2,400 MW in new capacity. When the nuclear units (5,625 MW) are removed from the data, the availability becomes 90 percent between 1992 and 1997 and 93 percent between 2001 and 2007. This means that the nuclear units' availability was worse than the combined generation fleet from 1992 to 1997, given that the availability calculation result was higher without them, and better than the combined generation fleet from 2001 to 2007, given that the availability calculation result was lower without them.

[32] Chapter 46 "Public Utility Regulatory Policies" of Title 16 of the U.S. Code.

Comparing these two periods, the nuclear units went from the fleet's worst performers to the fleet's best performers. These improvements have reduced power plant emissions in all categories and are consistent with what was expected with the restructuring of the generation sector of the electric industry and the competitive wholesale marketplace that developed thereafter.

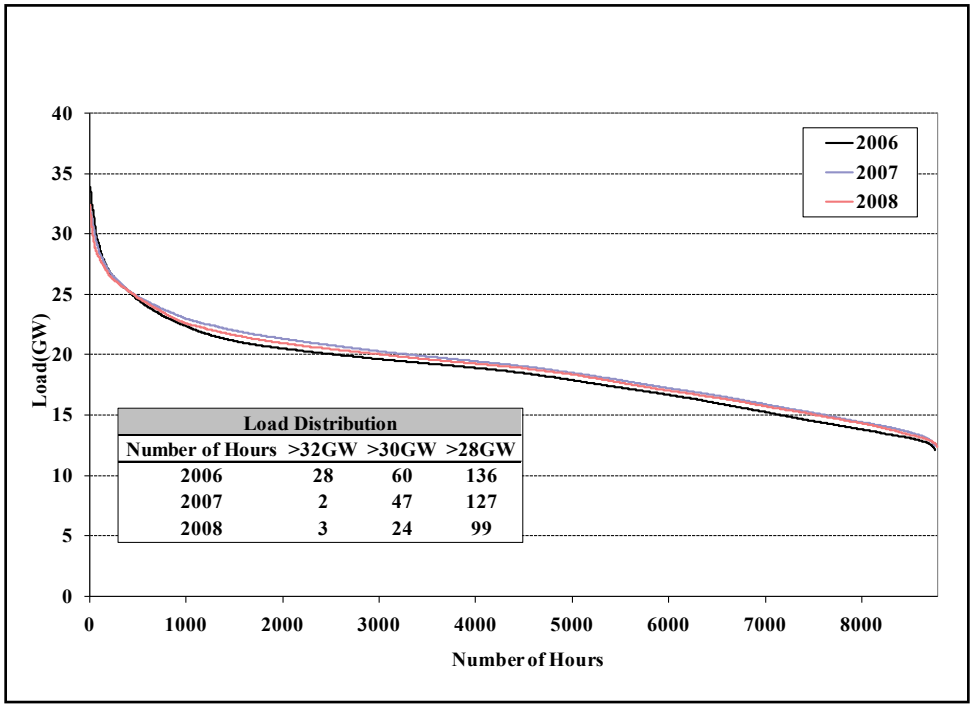
Finally, as well as the NYISO markets function, it should be noted that energy markets (both electricity and others) do not necessarily properly internalize all societal values. As one example, it is likely that electricity prices do not currently reflect the full cost to society of related carbon emissions. The State therefore still has a role to assure that societal goals are addressed in electricity and other energy markets.

2.3.1 Load versus Price

The importance of the above factors is illustrated in the statewide load and price duration curves shown in Figure 9 and Figure 10.[33] These curves show the system load and wholesale energy price based on the number of hours they occur or were exceeded in a year. Figure 9, the statewide load duration curves for 2006 through 2008, shows on the x-axis the number of hours in which the statewide load was greater than or equal to the level shown on the y-axis. The near proximity of these annual curves demonstrates that statewide demand generally changes only modestly from year to year. Much of the small variation can be explained by variations in weather. The price duration curves for the same years, provided in Figure 10, show on the x-axis the number of hours in which the average statewide real-time price was at or above the price shown on the y-axis. The position of these curves relative to each other is largely driven by the year to year change in the price of natural gas. Also, the frequency of high prices since 2005 has been moderated by the addition of new capacity in New York City in 2006 and the addition of the Neptune Line, a new transmission line, to Long Island in 2007. These figures in tandem show how the hours of highest load, which require use of the most expensive resources to meet that load, result in the highest prices. They also show that the need to carry a significant amount of capacity to supply load occurs during only a very few hours of each 8760-hour year.

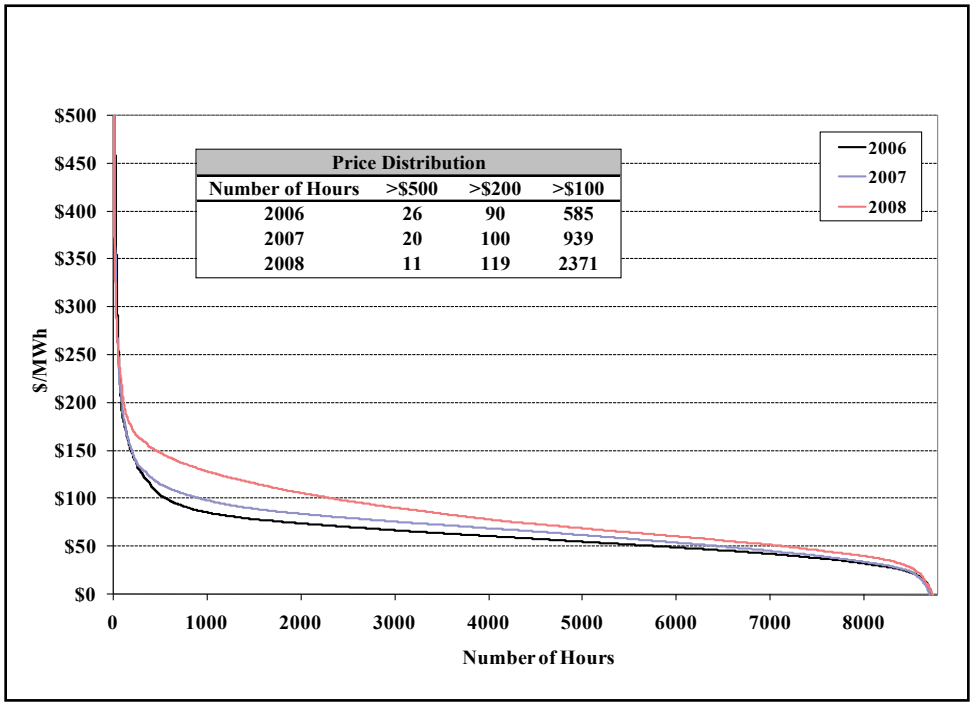
[33] Data for 2009, although not provided, should be similar to the data shown.

Figure 9. Load Duration Curves (2006 to 2008)



Source: NYISO. *Annual State of the Market Report*.

Figure 10. Price Distribution Curves Statewide Average Real-Time Price (2006 to 2008)



Source: NYISO. *Annual State of the Market Report*.

Because the wholesale price of electricity varies from month to month and year to year, largely driven by swings in the price of natural gas, retail prices can be volatile over time. Consequently, the PSC requires that the regulated utilities maintain supply portfolios in order to reduce the volatility of the commodity prices they charge residential, small commercial and industrial customers who elect to take commodity supply from them instead of from alternative providers. Mass market customers generally find beneficial the restraints on electric commodity price volatility that utilities are able to achieve. The major electric utilities hedge their supply portfolios with a combination of fixed and indexed hedges, or contracts, and, where applicable, their own generation. The balance of the supply portfolio is spot market purchases.

The PSC also requires the regulated electric utilities to measure and monitor the price volatility of their supply portfolios and file quarterly reports. Recent reports show that the utilities' portfolio prices were less on average than NYISO market prices, partly due to long-term contracts with nuclear plants and other hedges, and partly due to the availability of less expensive NYPA hydro power.

2.3.2 Installed Capacity Pricing

To ensure resource adequacy, the NYISO administers an installed capacity market. Load serving entities, i.e., transmission and distribution utilities and energy service companies that supply electricity to end-use customers, are required to acquire capacity equal to their forecast peak load plus their share of a required reserve margin established annually to ensure that sufficient resources exist to serve load, and includes locational requirements for New York City and Long Island.[34] The installed capacity markets are still evolving, and the potential for a forward capacity market, which would enable load serving entities to procure capacity several years out, is currently under discussion.

2.4 Reliability and Security[35]

Reliability and security of the electricity system are key concerns. While the cost of infrastructure investment to ensure reliability is high, the cost for allowing reliability levels to slip is even higher. For example, the costs associated with the August 14, 2003 electric system blackout in the United States were estimated to be between $4 and $10 billion.[36] There is, however, a great deal of uncertainty in the accuracy of the various estimates that have been made regarding the cost of power outages, primarily due to data limitations and the need to extrapolate existing subsets of data to a national level. One review of such estimates performed by the Lawrence Berkeley National Laboratory in 2004 produced a base case estimate of the annual cost of power interruptions nationally of $79 billion.[37] Sensitivity analyses performed on the base case resulted in a range of estimates from $22 to $135 billion. These estimates do not include the costs of power quality events, i.e., deviations from ideal power characteristics such as voltage and frequency levels, which could also be substantial. On the other hand, the PSC has tracked the

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[34] Reserve Margin is defined as generating capacity in excess of peak load requirements to be available in case demand is underestimated or normal supplies become unavailable due to repairs, refueling, etc.

[35] The Electricity Assessment: Modeling provides information, based on system modeling, about the reliability of the system going forward under alternative load growth assumptions.

[36] In Canada, the gross domestic product was down 0.7 percent in August, there was a net loss of $18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion in Canadian dollars. U.S/Canada Power System Outage Task Force. *Final Report on the Implementation of the Task Force Recommendations*. 2006. http://www.ferc.gov/industries/electric/indus-act/blackout/09-06-final-report.pdf

[37] Eto, Joseph H., and LaCommare Kristina Hamachi. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.* 2004. http://repositories.cdlib.org/cgi/viewcontent.cgi?article=2531&context=lbnl

actual costs for the nine-day power emergency in the Long Island City electric network in Queens in 2006 at about $103 million, not including the costs that were absorbed by the many businesses, citizens, and community organizations during the event.[38] The costs associated with such failures of the electric system, however, cannot be quantified just in dollars; public health and safety are also at risk.

The New York electricity system, i.e., the NYCA, is directly interconnected with New England, New Jersey, Pennsylvania, Quebec, and Ontario, and by extension to their neighboring systems. Therefore, New York is integrated with the entire "Eastern Interconnection," which encompasses the Mid-West, South, Mid-Atlantic, New England, and Eastern Canada systems. The system is designed such that high-voltage, high capacity lines are used to move power around the State and through neighboring systems. Closer to customer load, lines are operated at lower voltages and carry less electricity. While the higher voltage lines connect large load areas, the lower voltage lines generally consist of a series of small, local grids that are interconnected with the bulk power system. This design tends to keep local problems isolated, so that a low-voltage system problem in one area, e.g., Buffalo, will not affect customer service in another, e.g., Rochester. The overall bulk power system, however, is closely interconnected such that a system response to a disturbance on the bulk power system in Florida, for example, can be seen in the Dakotas.

This characteristic gave rise to the need for reliability standards that establish planning and operating protocols for the bulk power system, with the major goal of preventing local system disturbances cascading into a neighboring system. The driving forces for reliability standards have arisen following major problems. Following the 1965 blackout, New York's utilities formed the New York Power Pool (NYPP) to operate the system and share planning information. Regional entities were then formed as well to share information and draft standards by which the utilities would operate the system and communicate with each other. The Northeast Power Coordinating Council (NPCC) is the regional standards entity for New York, New England, and eastern Canada. Recognizing a need to set overarching policies and protocols for system operation throughout the entire U.S. and Canada, the North American Electric Reliability Council was thereafter formed as an association of all the regional entities in 1968.

Following the major 2003 blackout, the Energy Policy Act of 2005 (EPACT05) transformed the Council's voluntary polices into mandatory standards under the jurisdiction of FERC. The Council remains the main forum for the drafting of bulk power system reliability standards through an industry supported American National Standards Institute process, but FERC must authorize the resulting standards and has the ability to penalize utilities for violations.

The New York Power Pool was transformed into the NYISO in 1999 and its functions were expanded from reliable operation of the bulk power system to operating the wholesale market. Given that market needs often can test the limits of reliability standards, it was decided that an independent reliability entity should be formed. The New York State Reliability Council (NYSRC) was thus established to maintain, institute and monitor the NYISO for implementation of standards, called rules, that are specific to the New York system. Additionally, EPACT05 specifically recognized New York's ability and right to establish and enforce standards that are more stringent than the national standards. The PSC has since adopted the NYSRC and NPCC standards as mandatory and enforceable in the State.

[38] Of this amount, about $65 million was for restoration and about $38 million was for system improvements that would not otherwise have been undertaken at this time. In addition to the $103 million, Con Edison spent another $52 million for planned improvements. The figures given here are as of March 31, 2009 and include projections for expenditure through the remaining portion of 2009.

The reliability of electric supply, known as resource adequacy, and reliability of the transmission system are measured differently.[39] With regard to the former, the risk of a system outage due to the lack of sufficient energy is quantified by a loss of load expectation (LOLE). The PSC has established a rule that no more than one outage in a 10 year period due to lack of sufficient energy is allowable. This rule translates into a loss of load expectation not to exceed 0.10 day per year. The NYSRC determines annually what amount of extra reserve, i.e., the reserve margin, is required to meet the 0.10 day per year LOLE requirement. Currently, the reserve margin requirement is 116.5 percent, i.e., there needs to be generation available equal to at least 116.5 percent of expected statewide peak load to ensure sufficient energy availability.[40]

While resource adequacy is determined based on probability, the reliability of the planning and operations of the transmission system is ensured by deterministic criteria. The scenarios that must be used to plan the system, facility limits, and operating reserve requirements are mandated by North American Electric Reliability Council, NPCC, NYSRC, and PSC standards and rules. System operators must operate the system "24/7" to ensure that the loading on facilities is maintained within prescribed limits. Criteria have been established as to what studies need to be performed and the level to which the system needs to be planned. Planning criteria for non-bulk system facilities are set only as guidelines based on good utility practices that the utilities must follow unless there is a demonstration that the cost to comply is out of line with the cost of the impact if there were a failure.

Until the EPACT05 requirement that reliability and cyber security standards become mandatory nationwide, there was local latitude to interject cost impacts into reliability decisions. While New York has led the nation by being one of the first States with mandatory reliability standards, it had control sufficient to ensure that the utilities and the NYISO accomplished an appropriate level of reliability in a cost effective manner. With the nationalization of standards, however, that control has been diminished. The State, therefore, needs to be prepared to invest in infrastructure to comply with future nationally-driven standards that may or may not consider unique circumstances in New York and thus may or may not be cost-effective. Recent examples of new standards are the expanded vegetation management mandates and cyber security protections that have been decided on a generic basis by the North American Electric Reliability Council and are enforceable by FERC.[41, 42]

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[39] While states maintain jurisdiction over resource adequacy, including authority "to set and enforce compliance with standards for [the] adequacy. . .of electric facilities" (See, 16 U.S.C. § 824o(i)(2)), FERC has taken an active role in matters affecting resource adequacy, namely the restructuring of Installed Capacity markets. This has led to significant disputes regarding the extent of the State's jurisdiction over resource adequacy matters. See Connecticut Dep't of Pub. Util. Control v. FERC, Docket No. 07-1375 et al. http://www.ferc.gov/legal/court-cases/opinions/2009/07-1375-1186743.pdf (D.C. Cir.). Challenging FERC's authority to adopt, in the context of the Installed Capacity market, an Installed Reserve Margin, which is used to quantify the amount of resources needed to ensure adequacy. See also State of New York Pub. Serv. Comm'n v. FERC (D.C. Circuit Docket No. 08-1366, consolidated with Docket Nos. 08-1368, 08-1369, 08-1370, 08-1372). Challenging FERC's authority to prescribe the resources that may be counted toward the State's standards for resource adequacy.

[40] The PSC adopted the current requirement on February 17, 2009. PSC. *Case 07-E-0088: In the Matter of the Adoption of an Installed Reserve Margin for the New York Control Area.* 2009. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={B9C7BFB6-C7E3-4339-B69F-BEADA7D4B59A}

[41] See NERC Standard FAC-003-1 at http://www.nerc.com/files/FAC-003-1.pdf.

[42] See NERC Critical Infrastructure Protection (CIP) Standards at http://www.nerc.com/page.php?cid=2|20.

2.5 Retail Market Structure

2.5.1 Customer Choice

New York's end-use electricity customers may choose to purchase their electric supply from the local electric distribution utility or from an ESCO. The local electric distribution utilities' electric rates, which at one time were stated as single price per unit of use, have since been unbundled into electricity delivery and commodity supply charges to facilitate customer choice and competition among electricity commodity suppliers.[43] According to PSC records, approximately 14 percent of residential customers purchase electricity supply, or the commodity, from ESCOs, as do 24 percent of small commercial customers, and 36 percent of large industrial customers.[44] Some 46 ESCOs are currently serving electricity customers around the State. The remaining customers purchase their electricity supplies directly from their local electricity distribution utilities or others. Customers who purchase their electricity supply from the local electricity distribution utilities may or may not have their commodity price marked-up above the actual wholesale cost to the local distribution utility, depending on the particular utility and the rate structure involved.

Electricity retail competition in New York began in the mid-to-late 1990s. During the initial years of retail competition, the PSC noted inconsistencies in the retail access rules and procedures across the electric and natural gas utilities, and in 1999, the PSC issued *Uniform Business Practices for Retail Competition* to address those inconsistencies.[45] In 2001, the PSC adopted *Uniform Retail Access Billing and Payment Processing Practices* and approved policies and data standards for the implementation of electronic data interchange in New York.[46]

In 2002, the State's Home Energy Fair Practices Act was modified to apply to ESCOs as well as the traditional delivery utilities. Under the modified statute, residential customers purchasing their energy commodity from ESCOs were provided the same essential consumer protections as customers who buy their commodity supply from the utilities.[47] Important safeguards, such as deferred payment agreements, low income customer protections, cold weather rules, medical emergency provisions, and deposit regulations were now applicable to customers of all commodity suppliers. These protections provided a level playing field among load-serving entities, both utilities and ESCOs, so that consumers comparing services could do so with the knowledge that core consumer protections apply to all providers.

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[43] Unbundled or unbundling is the separation of utility cost of service into its component parts, e.g., for an electric utility into commodity and delivery charges.

[44] This translates into about 39 percent of the statewide consumer load and 16 percent of the statewide customer accounts. The load and customer account migration percentages for the regulated utilities alone are somewhat higher at about 47 percent and 18 percent, respectively.

[45] PSC. Case 98-M-1343. *In the Matter of Retail Access Business Rules – Order adopting Uniform Business Practices and Requiring Tariff Amendments.* January 22, 1999. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={73A71A99-5A36-48E9-A645-FD9152DF292F}

[46] PSC. Case 99-M-0631. *In the Matter of Customer Billing Arrangements*. Case 98-M-1743. *In the Matter of Retail Access Business Practices – Order Establishing Uniform retail Access Billing and Payment Processing Practices.* May, 18, 2001. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={BAF2691D-2A61-4CC4-AC06-1423F91A9562}

[47] The Home Energy Fair Practices Act relates to both electricity and natural gas.

The PSC's 2004 *Statement of Policy on Further Steps Toward Competition in Retail Energy Markets*[48] identified important steps to accelerate development of competition in New York's energy markets.[49] In that document, the PSC directed the largest distribution utilities in the State to develop individual implementation plans for the continued development of retail energy markets. The PSC also ordered the development of statewide initiatives based on a number of identified "best practices" for fostering the availability of competitive choices to consumers. These best practices included: ESCO referral programs, utility purchase of ESCO receivables; release of utility account numbers to ESCOs with customer authorization; alignment of financial incentives for utility shareholders with the success of retail access; and the use of hourly pricing for commodity for the largest industrial and commercial customers.

In an *Order Determining the Future of Retail Access Programs,*[50] the PSC directed utilities to continue the programs and structures that ensure markets will continue to evolve, such as electronic data interchange and purchase of receivables, but determined that ratepayers should no longer incur incremental costs related to promotional programs unless a particular program directly benefits ratepayers. The PSC also determined that utilities should continue to provide information on competitive markets to their customers through utility outreach and education programs.[51]

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[48] PSC. Case 00-M-0504. *Proceeding on Motion of the Commission Regarding Provider of Last Resort Responsibilities, the Role of Utilities in Competitive Energy Markets and Fostering Development of Retail Competitive Opportunities – Statement of Policy on Further Steps toward Competition in Retail Energy Markets*. August 25, 2004. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={2D3CEE54-2436-4B88-980E-D3112DDF2F29}

[49] The policy statement relates to both electricity and natural gas.

[50] PSC. Case 07-M-0458. *Proceeding on Motion of the Commission to Review Policies and Practices Intended to Foster the Development of Competitive Retail Energy Markets – Order Determining Future of Retail Access Programs.* October 27, 2008. http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={5EEE2C8C-CA7C-4B8B-B58C-4F3399FE5E77}

[51] These provisions relate to both electricity and natural gas.

3 Meeting Electricity Needs[52]

Additional electricity needs can be met by building new central power plants, upgrading existing plants, adding smaller distributed resources throughout the system (including equipment that is installed "behind" customers' meters), or by importing electricity from surrounding states or countries. Other important opportunities to meet electricity needs include adding transmission capability to enable existing generation to reach loads and increasing the efficiency of electricity use at the customer level.

3.1 Electric Energy Requirements[53]

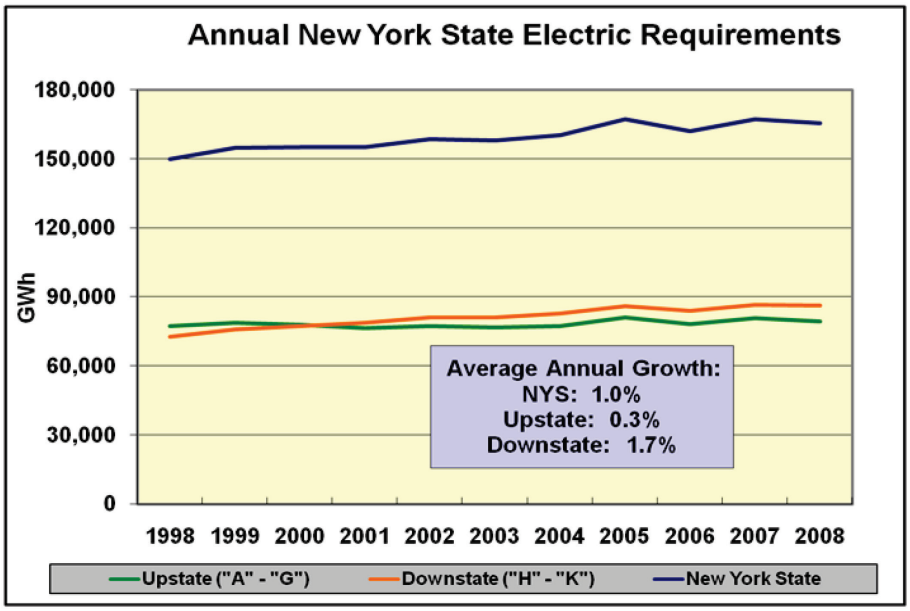
As shown in Figure 11, New York electric energy requirements grew by an average of one percent annually from 1998 through 2008. Downstate electric energy requirements, i.e., in NYCA load zones H through K (Millwood through Long Island) grew at an average annual rate of 1.7 percent, while upstate, which includes NYCA load zones A through G (Western New York through the Hudson Valley), collective growth averaged 0.3 percent annually. In 2008, zones J and K (New York City and Long Island) accounted for 47 percent of statewide electric energy requirements. For comparison purposes, in 1998, New York City and Long Island accounted for 43 percent of the total statewide electric energy requirements, indicating an increased need for additional energy resources in the downstate areas.

Figure 12 shows the NYISO zonal electric energy requirements during 2008 and the 10-year historic average annual growth rate of electric energy requirements for each zone. For example, zone H (Millwood) consumed about 2,700 GWh of energy and experienced a 4.1 percent average annual growth in consumption over the ten year period. Positive average annual growth is evident in all zones except A (Western New York), E (Mohawk Valley), and F (Capital Region), with growth rates ranging from -1.9 percent to -0.2 percent. Zone K (Long Island) and zone J (New York City) requirements both grew by an average of 1.8 percent annually over the last 10 years. Three zones set a new record for requirements in 2008: zone D (North), zone H (Millwood), and zone J (New York City).

[52] Modeling has been performed for this Plan to consider cases with and without an aggressive energy efficiency policy, e.g., the State's '15 by 15' program, to constrain and reduce load and thus reduce the need for additional infrastructure.

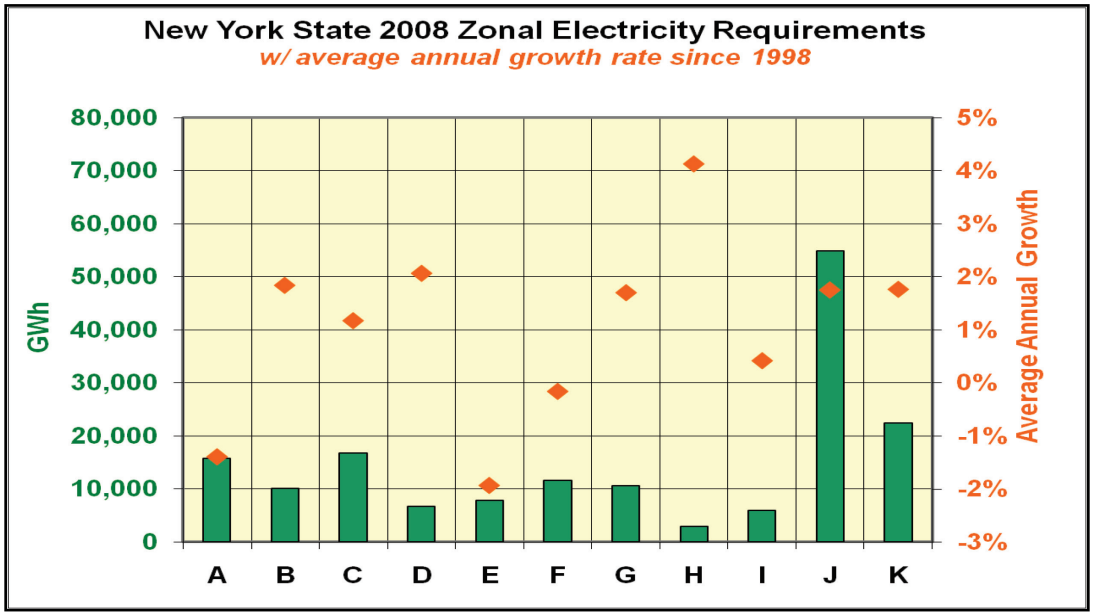
[53] "Electric energy requirements" refers to the amount of electric energy that must be produced to supply end-use customers plus allow for the energy losses that occur during delivery and necessary uses at the generator required to produce the electric energy.

Figure 11. Annual New York State Electric Requirements



Source: NYISO. *2009 Load and Capacity Data Report*.

Figure 12. New York State 2008 Zonal Electricity Requirements

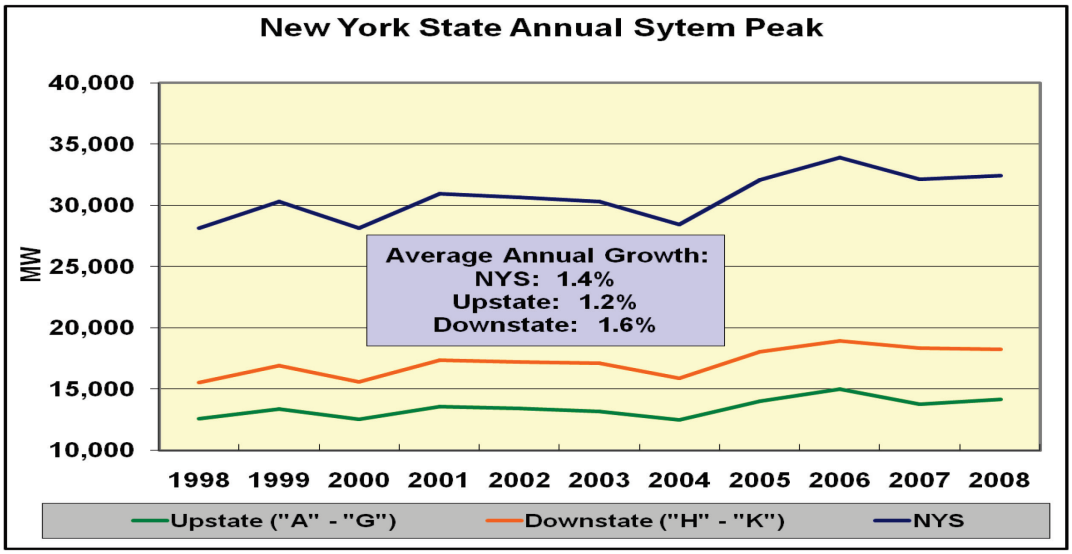


Source: NYISO. *2009 Load and Capacity Data Report*.

3.2 Electric Peak Demands[54]

As previously noted, reducing system peak demand is important for improving system efficiency, reducing wholesale electricity prices, and delaying the need for additional infrastructure. Figure 13 illustrates the statewide, upstate, and downstate annual instantaneous peak demands from 1998 through 2008. The 2006 peak demand of 33,939 MW set an all-time record for New York. While statewide electric energy requirements grew by an average of one percent annually from 1998 to 2008, as shown in Figure 121, the statewide electric peak demand grew by an average of 1.4 percent per year, as shown in Figure 13. Upstate regions had their peak demands grow faster than their energy requirements over the 10-year period, but downstate regions saw their energy requirements grow slightly faster than their peak demands.

Figure 13. New York State Annual System Peak

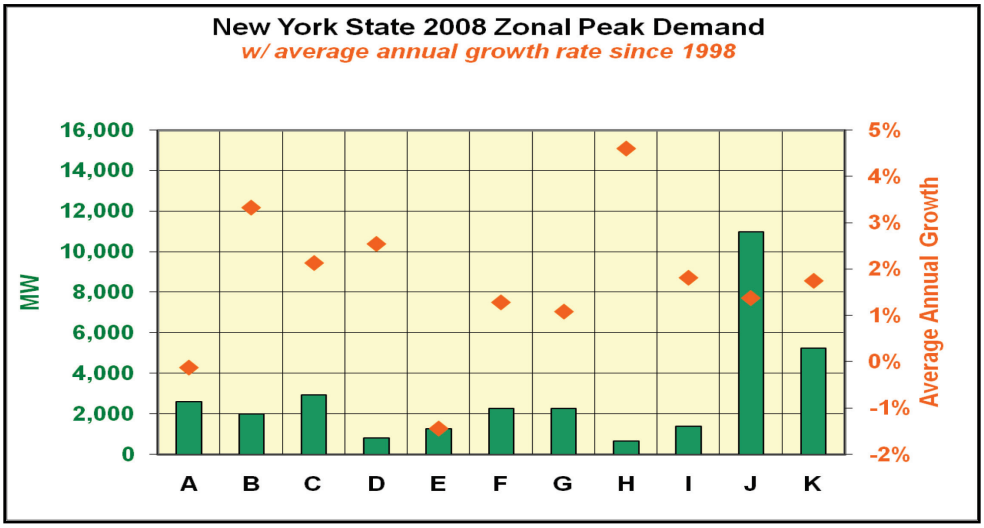


Source: NYISO. *2009 Load and Capacity Data Report*.

Figure 14 shows the 2008 peak demands for each of the NYCA load zones and the average annual 10-year growth rate of peak demand for each zone. Similar to the change in electric energy requirements, negative peak demand growth occurred in zones A (Western New York) and E (Mohawk Valley). While zone F (Capital Region) also had a negative energy requirements growth, peak demand in the zone was slightly positive. Downstate, although their energy requirements were essentially the same, zone K's (Long Island) peak demand grew at a faster rate than zone J's (New York City) peak demand over the last 10 years.

[54] The data represent actual points in time and are not adjusted for weather conditions.

Figure 14. New York State 2008 Zonal Peak Demand



Source: NYISO. *2009 Load and Capacity Data Report*.

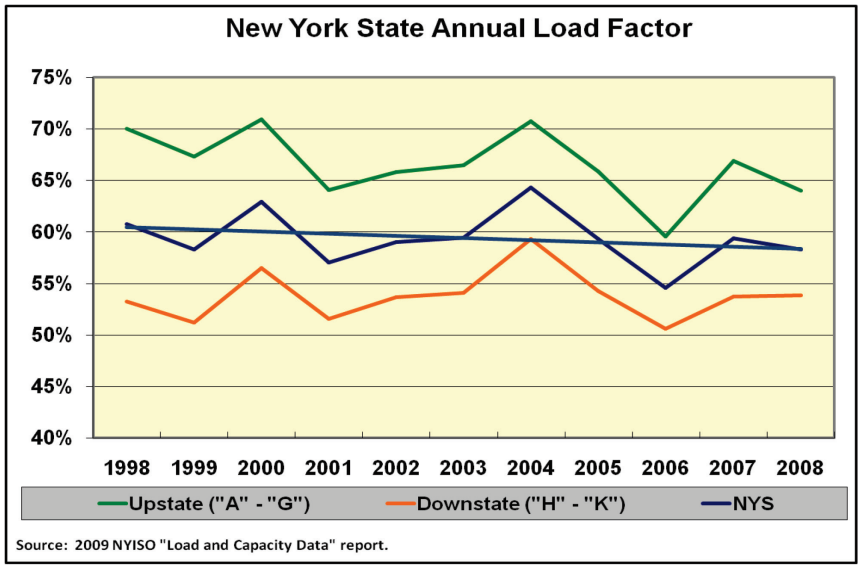
3.3 Load Factor

Load factor is a measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.[55] A high load factor indicates high utilization of a system's equipment and is a measure of efficiency. Using a year as the designated period, the load factor is calculated by dividing the electricity requirements during the year by the peak load for the year times the total number or hours during the year. Using this measure, the trend in New York has been toward a less efficiently used system. Approaches, such as expanding programs for mandatory hourly pricing, demand response, and advanced metering, are being pursued to address this trend.

Figure 15 shows the trends in upstate New York (zones A through G) and downstate New York (zones H through K) load factors from 1997 to 2008. While drawing conclusions for any one year can be misleading (e.g., the load factor percentage in any given year will be significantly affected by the magnitude of the instantaneous system peak), Figure 15 shows a trend of statewide load factor decline since 1998. Figure 15 also shows strikingly lower load factors in downstate New York zones as compared with the upstate zones, although the overall trend for the downstate load factors was essentially stable relative to a declining trend upstate. Although not depicted directly by the figure, lower load factors are generally seen in zones south of zone F (Capital). However, from 1998 to 2008, the individual load factors in zones J (New York City) and K (Long Island) increased or showed improvement.

[55] North American Energy Standards Board Wholesale Electric Industry Glossary.

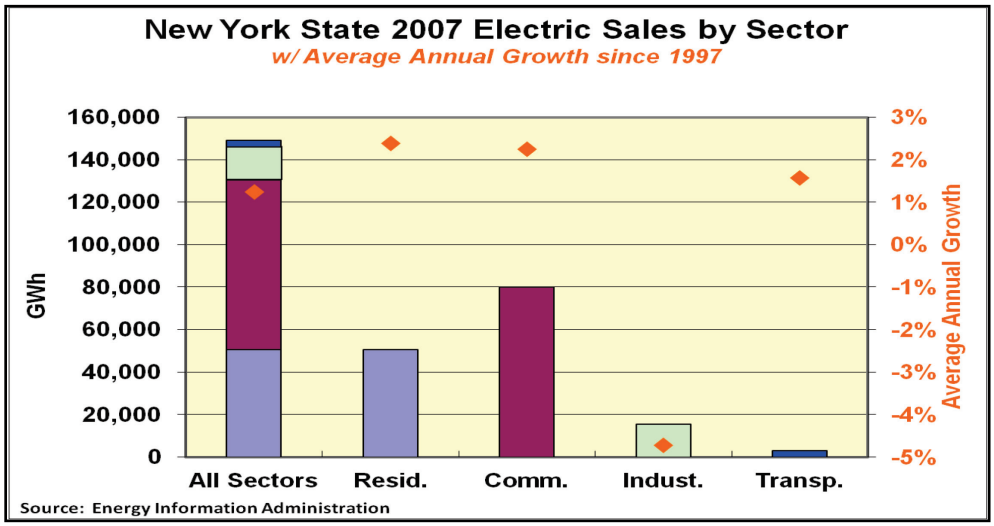
Figure 15. New York State Annual Load Factor



3.4 Electricity Sales

Figure 16 depicts 2007 New York electricity sales by sector, with the 10-year average annual growth for each sector also shown.[56] Sales in the commercial sector made up about 54 percent of total sales in 2007, compared to about 49 percent in 1997. Sales growth in all sectors averaged 1.2 percent over the 10 years. Average annual growth in the residential, commercial, and transportation sectors was 2.4, 2.2, and 1.6 percent, respectively. While the industrial sector averaged a 4.7 percent annual decline in sales, part of this decline is due to a re-classification of customers by certain utilities.

Figure 16. New York State 2007 Electric Sales by Sector



[56] 2008 data will not be available from the EIA until January 2010.

4 Aging Transmission and Distribution Infrastructure

Maintenance of safe and reliable service at a just and reasonable cost, including guarding against the failure of existing transmission, is a primary objective for the State. Transmission outages increase costs due to congestion and likely increase emission levels due to the need to redispatch the system. This objective is particularly challenging, given the vintages of some of the State's transmission and distribution infrastructure.

4.1 Overview

While age is not the sole determinant as to when facilities should be replaced, the electric grid is composed of mechanical components that reach a point where maintenance costs exceed replacement costs. As such, the average age of facilities is an indicator of when large expenditures are likely to occur to replace infrastructure. Although the PSC has always provided funding through electric rates for maintenance and replacement of infrastructure facilities, it initiated a focused effort in 2007 to understand better the condition of transmission and distribution facilities across the State and to work with the regulated utilities to ensure that their infrastructure facilities can provide reliable service at the least cost to ratepayers.

4.2 Utility Specific Transmission & Distribution (T&D)

The PSC is at different stages of assessing utility program development to address aging infrastructure programs. As a result, directly comparable utility-to-utility evaluations are not yet available regarding the condition of facilities across the State. With that said, below is representative general information by utility about the approximate age and condition of electric system facilities.[57]

The average age of Con Edison's underground and overhead cables is 42 and 37 years, respectively. Transmission stations (345 kV, 138 kV, and 69 kV) average 46 years of age, whereas area stations (33 kV, 27 kV, and 13 kV) average 35 years. Distribution cable systems range in average age from 25 years for underground primary to 48 years for overhead secondary cables. Con Edison assesses the condition of its individual T&D assets at least once every five years, with some elements targeted for inspection more often, and it has developed programs by system component type to replace or upgrade facilities based on performance and condition. Con Edison plans a substantial increase in capital expenditures to ensure that reliability does not deteriorate.

[57] Based on information provided by each utility to the PSC.

The majority of Central Hudson's electric system was constructed before the mid-1970s, with some towers, poles and conductors dating back to 1915. Central Hudson assesses the condition of its individual T&D assets at least once every five years, with some elements targeted for inspection more often.

The majority of National Grid's electric system was constructed before the mid-1970s, with a major portion of its steel towers dating back to the 1920s and 1930s. About nine percent of the steel towers have been rated by the Company to be in its lowest rating category. National Grid also reports that about half of its circuit breakers and one third of its transmission-level transformers need to be replaced or refurbished within the next 10 years. In contrast, National Grid reports that only five percent of distribution-level transformers need to be addressed. National Grid says that it will need to replace the following assets within the next 15 years: 173 transformers, 385 circuit breakers, 8,100 steel towers, 3,400 wood poles and 5,000 miles of conductors. National Grid says that it assesses the condition of individual T&D assets once every five to 20 years, with some elements targeted for inspections more often.

In NYSEG's system, the average age of transmission poles and towers is 43 years, and the average age of distribution poles is 37 years. T&D transformers average 44 and 42 years, respectively. Transmission conductor ages range from 34 to 47 years. For distribution cable, the average age is 40 years for overhead circuits and 21 years for underground. NYSEG has a defined set of procedures that calls for inspections from once every other week (230 kV substations, general inspection) to once every eight years (instrument transformers), depending on equipment category. NYSEG, as part of Energy East, has a Transmission and Distribution Infrastructure Replacement Program that is used to evaluate and replace equipment based on various criteria, including age, condition, operational issues, equipment obsolescence and maintainability and outage history or performance.

Orange and Rockland reports that the average age of its transmission lines are: 35 years for 345 kV overhead lines; 50 years for 138 kV overhead; 22 years for 138 kV underground; 50 years for 69 kV overhead; 36 years for 69 kV underground; and 70 years for 35 kV overhead. Transformer average ages are between 21 and 31 years. Orange and Rockland identifies that underground cables will be the most significant asset that will need replacing in the near future.

For RG&E's system, the average age of transmission poles and towers is 29 years, and the average age of distribution poles is 37 years. Transmission transformers average 26 years of age, and distribution transformers average 42 years. The average ages of transmission conductors range from 37 to 48 years; for distribution cables, the average age is 34 years for overhead circuits and 25 years for underground. RG&E's T&D Maintenance Program Specifications call for inspections from once every other week (230 kV substations, general inspection) to once every 10 years (instrument/power transformers), depending on equipment category. RG&E, similar to NYSEG as part of Energy East, also has a Transmission and Distribution Infrastructure Replacement Program.

The average age of LIPA's transmission system is over 35 years for poles and towers and 34 years for 69 kV and 138 kV transformers. The average age of distribution transformers is also 34 years. In 2001, LIPA performed a comprehensive inspection of its steel towers; it has addressed high priority deficiencies, and lower priority deficiencies are included in ongoing remediation programs. New transmission structures are being designed for 130 mile per hour winds, a more stringent criterion than that required by the National Electric Safety Code (NESC).

NYPA's transmission system ranges in age from 17 to 66 years. NYPA's two Moses to Adirondack 230 kV lines are the oldest in its system and are being evaluated for possible replacement or upgrade in the context of the increasing transmission constraints occurring in the North Country.

4.3 Cost of Upgrades, Rate Impacts and Consequences

Because New York's electric infrastructure is old, significant capital investments will need to be made in the utilities' electric T&D systems to meet future electric demand and allow them to continue to provide reliable service. Building new facilities to relieve congestion makes sense only if the existing facilities continue to work reliably.

It is likely that a higher than historic level of electric infrastructure investments will be needed for some time and will put upward pressure on rates. The PSC may be required to decide whether it is more effective and efficient for the utilities to repair and maintain aging infrastructure or to invest more heavily in new technologies, such as photovoltaics and greater customer-driven resources.

In the recent National Grid-KeySpan merger proceeding, concerns were raised about the age of National Grid's facilities and whether they will be able to ensure reliability in the future.[58] The PSC's August 22, 2007 Order in the proceeding required National Grid to report on the condition of all the physical elements of its Niagara Mohawk system and prepare a plan and schedule identifying needed remedial actions, monitoring programs, and repairs. National Grid also committed to invest at least $1.47 billion in its upstate facilities over the period 2007 through 2011. National Grid's most recent updated five-year capital spending plan, however, proposes spending about $3.5 billion for the five-year period, 2009 through 2013, beyond the expenditures it already made in 2007 and 2008 under its prior plan. In comparison, National Grid's T&D capital expenditures for the five-year period 2004 through 2008 were about $1.3 billion.

Similarly, Con Edison's February 27, 2008 compliance filing with the PSC[59], containing a five-year forecast of capital expenditures, shows Con Edison's intention to spend more than $7 billion over five years (2008 through 2013) on infrastructure upgrades - a level about three times higher than expenditures in the previous decade. However, its capital expenditures for the latter half of the prior 10 years (2004 through 2008), which increased steadily to result in a total of about $6 billion, reflected a significant increase over the previous five years (1998 through 2003). Aging infrastructure was presented as a major driver of the increased investment.

In the PSC's September 9, 2008 Order in the Iberdrola-Energy East merger case,[60] NYSEG and RG&E were ordered to each file with the PSC a report that includes: an assessment of the physical conditions of all elements of its electric system; and repair plans, remedial actions, and monitoring programs for correcting problems with facilities found deficient. NYSEG proposes to spend about $720 million on capital investments over the period 2009 through 2013, about twice what it spent for the 2004 to 2008

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[58] PSC. Case 06-M-0878. *Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and other Regulatory Authorizations. – Order Authorizing Acquisition Subject to Conditions and Making Some Revenue Requirement Determinations for KeySpan Energy delivery New York and DeySpan Energy Delivery Long Island.* Issued September 17, 2007.

[59] PSC. Case 06-E-0894. *Proceeding on Motion of the Commission to Investigate Electric Power Outages in Con Edison's Long Island City Network.* Issued February 27, 2008. Compliance filing for Staff recommendation No. 80 of "Department of Public Service Staff Report on its Investigation of the July 2006 Equipment Failures and Power Outages in Con Edison's Long Island City Network in Queens County, New York", entitled "Consolidated Edison Company of New York, Inc. Electric Capital Projected Expenditures 2008 – 2012".

[60] PSC. Case 07-M-0906. *Joint Petition of Iberdrola, S.A., Energy East Corporation, RGS Energy Group, Inc., Green Acquisition Capital, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation for Approval of the Acquisition of Energy East Corporation by Iberdrola, S.A. – Abbreviated Order Authorizing Acquisition subject to Conditions* Issued September 9, 2008.

period, and RG&E proposes to spend about $580 million over the same period, having spent about $406 million for the 2004 through 2008 period.

Orange and Rockland proposes to spend over $412 million through 2013, and Central Hudson proposes to spend over $317 million, both significantly more than what they spent between 2004 and 2008. In total, the utilities project that infrastructure investment for the entire State could be over $13 billion for the next five years (2009 through 2013) as compared with about $8.5 billion over the prior five years (2004 through 2008).

It should be noted that while the utilities are projecting significant increases in T&D expenditures, the PSC reviews proposed projects on an ongoing basis to ensure that projects are reasonable and necessary, taking into consideration customer rate impacts.

4.4 Resource Constraints

The power industry, in general, is experiencing shortages of technical expertise, construction equipment, and escalating costs of materials. There are personnel shortages in all technical categories, including engineers, contractors, and line workers.[61] Construction equipment, which traditionally is rented based on the needs of a particular project, has long reservation lead times. World prices for copper and steel, which are used in conductors, towers and transformers, have escalated significantly over the past few years, driving up facility replacement costs. Concerns also exist because the major manufacturers of some of the electric system components are now located overseas. Overall, New York's system replacement needs are competing with the needs of other world economies, especially the growing third world economies, thus affecting both cost and lead times needed to order cable and transformers.

The utilities also have cited the need for streamlined regulatory processes related to permitting and siting and for assurances of cost recovery in a timely manner. Other obstacles cited include the difficulty in acquiring and perfecting rights-of-way, high use of the existing system that limits the removal of facilities from service during construction, and community opposition to construction.

[61] To address this growing problem, National Grid has recently instituted a contracting model for its transmission work that involves a shared services agreement with a contracting group, which National Grid calls a "Regional Delivery Venture" group, made up of a consortium of competent contractors. National Grid will measure, track, and document the result of using this model and will compare the ongoing results with its traditional approaches, which will also continue to be used.

5 Opportunities and Issues

Identified below are several additional key emerging and evolving matters that are having, or will have, significant impacts on the future of the electricity industry in the State. Issues related to the siting of generation and transmission facilities in New York are addressed in the Siting New Energy Infrastructure Issue Brief.

5.1 Smart Grid

Smart Grid encompasses use of advanced/enhanced technology and two-way communications to improve the operations and the efficiency, and thus the load factor, of the entire electric grid from generation to end-use consumption. Such an approach, theoretically, would:

- enable active participation of consumers
- enable the grid to accommodate all generation and storage options
- enable new products, services, and markets
- provide improved power quality for the digital economy
- optimize asset utilization and operational efficiency
- anticipate and respond to system disturbances

Currently, the electric grid in New York, as well as most other large power systems in the world, uses up-to-date, modern, and extensive technology and approaches to control electricity flow and operations. Increased use of the Smart Grid concept in New York could result in significant improvements. It could:

- enhance operator decision-making to avoid events similar to the 2003 Northeast Blackout and 2006 Long Island City Outages
- reduce power system losses
- provide customers with greater demand response options and results
- mitigate fault duty issues, thereby enhancing distributed generation
- vastly improve outage management systems
- improve Con Edison's secondary network monitoring, which is very limited and does not allow operators to have a good understanding of loadings on secondary cables or how many customers are out-of-service
- automate operation of the distribution system[62]
- modernize older utility systems
- increase dynamic reactive compensation and power flow control in key parts of the system to maintain proper voltages and increase power flow transfers or at least reduce power transfer

[62] Distribution automation involves the remote monitoring, coordination, and operation of various distribution equipment, e.g., automatic sectionalizing switches.

degradations due to system demands and conditions, and also reduce effects of system disturbances[63]

Several initiatives to expand the use of advanced technology and implement Smart Grid elements are underway in New York. In addition, the State is pursuing Smart Grid through an integrated approach and strategy through its work with utilities and on various task forces and consortiums.

5.1.1 Increased Use of Advanced Technology

New York's T&D system already has significant technical capability. The bulk power system is the most advanced because of its critical nature and the fact that it has fewer elements than the other system components. In general, Smart Grid monitoring and communication equipment is employed for transmission systems above 115 kV. Distribution facilities, however, are typically less sophisticated than transmission systems, particularly in remote areas of the State. Recent enhancements include Con Edison's 14 kV autoloop system, which is more resilient and sophisticated than most radial circuits, as well as its Dynamic Feeder Rating program for 345 kV feeders, which provides real-time information regarding thermal conditions of feeders to network operators, allowing for greater power transfers and operational flexibility. Con Edison is currently installing similar functionality on select 138 kV feeders.

The PSC has also approved several projects in rate proceedings that could fall under the Smart Grid umbrella, including developing dynamic feeder ratings for transmission lines, replacing outdated circuit breakers, bifurcating network primary feeder cables, and installing enhanced distribution automation.

5.1.2 Current Research and Development (R&D) and Pilots

Utilities in New York are currently undertaking several Smart Grid R&D activities. Orange and Rockland has a Smart Grid pilot project that will test increased monitoring and communication on two distribution circuits. Con Edison plans to use the Long Island City network as its primary location for hosting pilot projects, and it will host a superconductor pilot project funded by the U.S. Department of Energy (DOE). Both Orange and Rockland and Con Edison are also participating in the Electric Power Research Institute (EPRI) Green Circuit program, which is a R&D effort aimed at reducing distribution line losses. In addition, NYSERDA has also issued several notices to support R&D projects for Smart Grid technologies. Finally, the PSC has instituted a proceeding to identify measures that should be taken to reduce electric system losses and optimize system operations.[64] Utilities have submitted proposals for how they would make such reductions, including the use of Smart Grid elements.

The Advanced Energy Center at Stony Brook University is coordinating efforts to assist the various business sectors of the Smart Grid community with R&D needs as well as providing a center for validation and verification of product functions and capabilities. It is working with universities from around the State to provide a comprehensive array of services. In addition, the Northeast States' Regional Greenhouse Gas Initiative (RGGI) may also serve as a funding mechanism for Smart Grid activities.

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[63] These systems are generally referred to as Flexible AC Transmission Systems (FACTS), which covers a number of system-types that can control voltage and transmission capacity, e.g., Static VAR Compensator (SVC), Static Synchronous Compensator (STATCOM) and those that can control flows, e.g., Unified Power Flow Controller (UFPC), Interline Power Flow Controller (IPFC), and Variable Frequency Transformer (VFT).

[64] PSC. Case 08-E-0751. *Proceeding on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them*.

5.1.3 Integrated Strategy for Smart Grid Implementation

The State is pursuing a comprehensive, integrated strategy to enable Smart Grid technology. The Department of Public Service (DPS) has several efforts underway to oversee the regulated utilities' activities with regard to Smart Grid, including interacting with utilities in rate cases and through regular quarterly meetings. A key objective is to ensure that prior to making infrastructure investment decisions, utilities have appropriately considered investment in a qualified Smart Grid system, consistent with the 2007 Energy Independence and Security Act (EISA). That legislation also created a Smart Grid Advisory Board, of which National Grid is a member, as well as a Smart Grid Task Force. The bill further allocated funds to support the advancement of Smart Grid research. The Task Force has been working with the industry and interested stakeholders to improve the focus on Smart Grid developments.

The American Recovery and Reinvestment Act (ARRA), signed into law on February 17, 2009, creates a significant new opportunity to expand the Smart Grid in New York, through national funding of an Electric Delivery and Energy Reliability Program totaling $4.5 billion. Federal funding is available for up to 50 percent of a project's cost; applicants must secure funding for the remaining portion of the project. On April 17, 2009, DOE issued a draft Notice of Intent (NOI) for $3.375 billion in Smart Grid Investment matching grants and a draft Funding Opportunity Announcement (FOA) for $615 million in Smart Grid Demonstrations/R&D, which include regional demonstrations, synchrophasors, and energy storage.[65] Final FOAs were issued by DOE on June 25, 2009, establishing initial filing dates of August 6 and August 26, 2009, respectively, for the investment grant program and demonstration program.[66]

On April 17, 2009, the regulated utilities filed project proposals with DPS to commence the process for securing matching funds, where necessary.[67] DPS, the transmission system owners, NYSERDA, the NYISO, and the New York State Foundation for Science, Technology, and Innovation (NYSTAR) have worked together to develop suitable project lists for Smart Grid grants. On July 2, 2009, the utilities submitted to DPS updated filings based on the final FOAs. Some of the proposed projects, such as phasor measurement unit deployment and capacitor bank installation, provide statewide benefits to the bulk power system and will be coordinated by the NYISO.

On July 24, 2009, the PSC approved approximately $825 million for projects of which ratepayers would fund a portion thereof. The PSC's objectives are to ensure that utility infrastructure investment decisions will not create barriers to future Smart Grid developments and that the regulated utilities employ advanced technology where possible. The PSC is supportive of utility Smart Grid learning projects, while trying to maintain a balance between the need for such projects and utility rates. As efforts are underway to address the aging condition of the utilities' infrastructures, incorporation of Smart Grid concepts, as appropriate, makes sense. Smart Grid projects, such as those that provide real-time energy usage and price information to customers and/or automated load control, may result in reduced energy usage or peak demand which would, in turn, reduce or delay the need for additional infrastructure investment.

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[65] Smart Grid grants fall under EISA section 1306 and Smart Grid Demonstrations/R&D under section 1304. The demonstration/R&D funds will group potential projects into three distinct categories: 1) Regional Demonstrations – these projects would include distribution automation, advanced metering, home area networks, etc.; 2) Synchrophasors (phasor measurement units) - predominantly targeted towards the transmission grid; and 3) Energy storage.

[66] DOE is reviewing the proposals. As of the end of October 2009, it had so far selected for 50 percent grant awards over $348 million in projects for New York State.

[67] The PSC held a technical conference on June 11, 2009 with interested parties to explore issues associated with the development and deployment of Smart Grid technologies in New York, including use of federal funding.

The State will also benefit from national efforts to develop Smart Grid standards. A critical component of the Smart Grid landscape is the communication framework, or the ability of various systems and equipment used for communications between the grid and its customers, to "talk" to each other. The National Institute of Standards (NIST) is developing standard-based protocols for Smart Grid.

The State's efforts to develop a holistic strategy and approach to Smart Grid is complemented by the work of the New York Smart Grid Consortium, comprised of representatives from the power generation, transmission, and distribution sectors, including utilities, transmission companies and independent providers, technology companies, State governmental entities, energy and grid technology researchers from universities, and the Brookhaven National Laboratory. The Consortium has developed a work plan and vision statement to guide the phased development of the Smart Grid. The agreement on a common vision among Consortium members allows all stakeholders to understand their roles, responsibilities, and opportunities in a roadmap toward the New York Smart Grid. Further, it allows them to make investments that they know will be relevant.

5.2 Energy Storage[68]

Electricity markets are unique among major commodity markets in that they generally require instantaneous matching of supply and demand. Other energy commodities, such as natural gas and oil, can be effectively stored in large quantities providing a buffer between supply and demand. Without an effective means of storage, the electric grid has traditionally maintained excess capacity in generation and transmission. Although it is difficult to store electricity directly, electric energy can be stored in other forms, such as chemical and mechanical energy, and efficiently converted back to electricity as needed. Both bulk electricity storage, capable of providing hundreds of megawatts of power for several hours, and distributed energy storage, capable of injecting/absorbing up to several megawatts for seconds or minutes, can provide economic benefits and improve the stability and reliability of the grid.

Bulk electricity storage includes pumped hydro, compressed air energy storage (CAES), batteries, and flywheels. Pumped hydro systems store energy by operating a turbine in reverse to act as a pump when low-cost electric energy is available to pump water uphill to an elevated reservoir. Water is discharged through the turbine when energy is needed for grid support, or for arbitrage. NYPA operates the 1,000 MW Blenheim-Gilboa and the 240 MW Lewiston Reservoir pumped storage plants. The availability of suitable sites for additional conventional pumped hydro storage plants in New York is limited, and it is highly unlikely that new facilities will be permitted and constructed in the future. There is a new twist to the technology that is under investigation whereby the upper reservoir is replaced by a below-ground storage cavern. Existing bodies of water such as rivers and lakes would serve as the upper reservoir. Several sites are being evaluated in the State.

In a CAES plant, air is compressed when electric energy costs are low and the compressed air is stored in an underground reservoir. When needed for grid support, or for arbitrage, the stored compressed air is

[68] In his State of the State address, Governor David A. Paterson announced the creation the New York Battery and Energy Storage Technology Consortium, known as NY BEST, to help position New York as the global leader in energy storage technology. The research and development initiative is one of the first of its kind in the nation and is a critical component in advancing the plug-in hybrid electric vehicle (PHEV) industry in New York. Under the guidance of NYSERDA, NY BEST will capitalize on the State's existing technical and industrial capabilities and help bring together scientists, engineers and entrepreneurs to advance New York's clean energy and storage technology industries. The State will invest more than $25 million to finance the Consortium, using funding from New York's participation in the federal Clean Air Interstate Rule. A portion of that funding will also go toward the development of a battery-testing laboratory to be located in New York. Additional information on the consortium is available at http://www.nyserda.org/cair/nybest/

heated and expanded through a turbine. There are two commercially operating plants worldwide: the 290 MW Huntdorf plant in Germany which is designed for an eight-hour charge and two-hour daily generation cycle, and the McIntosh plant in Alabama which can generate 110 MW for 26 hours; a 35 MW CAES plant in Japan, and a 100 MW CAES plant in Israel are under construction, and the Iowa Stored Energy Project and the Norton CAES plant are in the evaluation and design phase domestically. There are currently no CAES facilities operating in New York, but siting and design studies are in progress for a facility that could be as large as 350 MW.

Modern battery energy storage and power conditioning equipment have performance characteristics and capacities that are becoming competitive for grid applications. These applications can include grid voltage support, regulation service, spinning reserve, power quality, load shifting, substation upgrade deferral, and renewable energy capacity firming. Battery systems have the ability to meet multi-function requirements. Grid connected demonstrations of large nickel-cadmium (Ni-Cd), lithium-ion, sodium-sulfur (NaS), and lead-acid battery systems are underway. Golden Valley Electric Authority in Fairbanks, Alaska installed a 27 MW Ni-Cd battery, expandable to 40 MW, to provide voltage stability and standby power on the intertie between Anchorage and Fairbanks. The battery reduced the need for customer load shedding when power instabilities and outages occurred on the intertie about 30 times per year. AES demonstrated a 2 MW lithium-ion battery for frequency regulation service at an Indianapolis Power & Light substation. American Electric Power installed a 1 MW NaS battery at a substation near Charleston, West Virginia for peak load shifting, which allowed substation upgrade deferral. NYSERDA is co-funding the demonstration of a 1 MW NaS battery in Garden City, Long Island for summer peak load shifting on a LIPA feeder. In Japan, numerous NaS batteries are in service for load shifting. Most recently, Japan Wind Development installed a 34 MW NaS battery system to firm the output from a 51 MW wind farm.

Flywheel energy storage technology focuses on the grid regulation service market. Unlike fossil-fuel generating sources, flywheels can rapidly inject/absorb electric energy to and from the grid, without emitting combustion products. These are high power, low energy devices that can swing from full charge to full discharge in about four seconds according to Beacon Power Corporation of Tyngsboro, Massachusetts, a leader in flywheel applications for grid regulation.[69] Analytical studies have shown that this rapid response characteristic may reduce the required power capacity for regulation service by half. NYSERDA will be co-funding a 20 MW flywheel energy storage plant connected for regulation service to a transmission line in Stephentown, New York. The plant will operate in response to a NYISO regulation signal and compete in the ancillary markets developed for non-generation sources.

In addition to electric energy price arbitrage, bulk electricity storage can meet peak demand and reduce the need for new generation capacity, can provide spinning reserve and voltage support, and can provide black-start capability. It can reduce transmission congestion and associated line losses. Bulk storage provides capacity firming and time shifting of energy from renewable generation resources, will enhance the value of renewable generation and reduce the impact of intermittent generation on the grid.

Distributed energy storage technologies include electrochemical batteries, super or ultra-capacitors, flywheels, above-ground mini-CAES, and supermagnetic energy storage. These technologies are focused on the end user. Aggregated and coordinated control and dispatch of these storage technologies, however, can benefit the grid. Distributed storage can inject reactive power where needed for voltage support. Customers with time-of-use energy pricing and/or demand charges are able to reduce costs for electricity with storage systems. Electric power quality, which is increasingly important in the modern electronic world, as well as reliability are improved for customers with installed storage systems.

[69] Beacon Power Corporation. *About Flywheel Energy Storage*. http://www.beaconpower.com/products/about-flywheels.asp

5.3 Nuclear Licensing and Relicensing

Nuclear generation in New York represents approximately 5,264 MW of electric capacity or 14 percent of the State's installed generation capacity. In 2008, the six nuclear generators produced 43,203 GWh, or 30 percent, of the electric generation in the State.[70] Ownership of nuclear generation, the location, rated capacity, and licensed life are shown on Table 3 below.

Table 3. Nuclear Generation Facilities in New York

	Owner	Location/ County	Summer Capability (MW)	License Expiration
Ginna	R.E. Ginna Nuclear Power Plant, LLC	Wayne	580	9/18/29
FitzPatrick	Entergy	Oswego	854	10/17/34
Indian Point Unit 2*	Entergy	Westchester	1025	9/28/13
Indian Point Unit 3*	Entergy	Westchester	1040	12/12/15
Nine Mile 1	Nine Mile Point Nuclear Station, LLC	Oswego	621	8/22/29
Nine Mile 2**	Nine Mile Point Nuclear Station, LLC	Oswego	1143	10/31/46

*Applied for 20-year license extensions. **LIPA owns 18 percent.

Sources: NYISO. *2009 Load and Capacity Data Report*; NRC. *2007-2008 Information Digest*.

The Indian Point reactor sites have applied for 20-year license extensions.[71] The State is opposing the license renewals of Indian Point Units 2 and 3 due to significant safety and environmental impacts associated with their operation. Various topics, such as the integrity of containment structures, embrittlement of the reactor pressure vessels and associated internals, metal fatigue on key reactor components, and environmental impacts of radionuclide leaks from spent fuel pool leaks, are being reviewed by the U.S. Nuclear Regulatory Commission (NRC). A decision by NRC is not expected until

[70] NYISO. 2009 Load and Capacity Data Report. 2009. http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2009_LoadCapacityData_PUBLIC.pdf

[71] Modeling has been undertaken for this Plan to evaluate impacts of ceasing operation of the Indian Point facility. That modeling indicates that air emissions and wholesale costs would increase. The NYISO's 2009 Reliability Needs Assessment (RNA) also models a scenario that postulates closure of the plant. It projects the impacts from retirement of the Indian Point 2 and 3 units in 2010. The result is an immediate seven-fold violation of resource adequacy criteria, or 7.4 days of outages expected in a 10-year period. This rises to 41 days of outages expected in a 10-year period by the end of the planning horizon.

2010. The Ginna, FitzPatrick, and Nine Mile 1 and 2 plants have all already had their licenses renewed for an additional 20 years.[72]

Nuclear power faces a number of challenges, particularly waste disposal. The Nuclear Waste Policy Act of 1982 gave DOE the responsibility to construct and operate a geologic repository for high-level waste. DOE filed an application on June 3, 2008 with NRC seeking authorization to construct a geologic repository at Yucca Mountain in Nye County, Nevada. NRC formally docketed DOE's license application on September 9, 2008. NRC's Atomic Safety and Licensing Board Panel (ASLB) will conduct an adjudicatory hearing. ASLB expects to appoint multiple boards of three judges to hear a variety of legal and technical contentions regarding the application. NRC will issue a construction authorization only if DOE can demonstrate that it can safely construct and operate the repository in compliance with established regulations.

Until the federal repository is operational, reactor sites will hold spent nuclear fuel in either the wet spent fuel pools on site, or if the sites run out of wet storage space, fuel will be stored in dry casks outside, but within the sites' secured areas. Currently, in New York, the James A. FitzPatrick and Indian Point sites have separate independent spent fuel storage installations for dry cask storage, while the R.E. Ginna site is undergoing construction for a storage site to use in the near future and plans are underway for dry cask storage for the Nine Mile No. 1 and No. 2 units.

NRC has streamlined the review and approval process for licensing of new reactors. Developers can request a combined operating license (COL). By issuing a COL, NRC authorizes the licensee to construct and, with specified conditions, operate a nuclear power plant at a specific site, in accordance with established laws and regulations.

In New York, UniStar Nuclear, a joint venture of Constellation Energy and EDF Development, proposed constructing a new 1,600 MW nuclear station to be located on Constellation property at the Nine Mile Point reactor site. UniStar filed an application with NRC on September 30, 2008, which was accepted for docketing by NRC in December 2008. The safety and environmental reviews will take place over the next three years. In parallel, NRC will review the application.[73] The schedule for completion of the final safety review has not been released, but should occur around October 2013. If approved, construction would not begin until after the October 2013 safety review and the reactor would not be in service until, at the earliest, late 2018. The modeling for this Plan provides information about the emissions and wholesale electricity price impacts associated with the addition of this unit or one similar to it in the Oswego area.

Power uprates of existing reactors have also occurred or are planned. Constellation is proposing to increase the capacity of its Nine Mile Point Unit 2 to 1,400 MW gross, an increase of 20 percent over the original licensed operating capacity; there was a previous 4.3 percent rating increase in 1995. The increase is proposed to occur in 2012.

Nuclear generation in the U.S. produces 70 percent of all low carbon electricity. Although nuclear power plants do not emit greenhouse gases when generating electricity, certain processes used to build and fuel

[72] Associated with the relicensing processes, the Department of Environmental Conservation (DEC) also undertakes a review of water quality issues and, if appropriate, issues a Water Quality Certification under section 401 of the Federal Clean Water Act. It also undertakes a review to determine if a State Pollution Discharge Elimination System (SPDES) permit can be issued for discharges into waterways.

[73] An Evolutionary Power Reactor (EPR) is proposed to be used. The EPR enhances existing pressurized reactor water technology and incorporates design features to meet or exceed security and safety requirements. Some improvement examples are: double containment with ventilation and filtration; four redundant safety systems; and a core melt catcher and spreading area.

the plants do, as is true for all energy facilities. However, even when greenhouse gas emissions are analyzed for the entire life-cycle of a nuclear power plant (from uranium mining to electricity production to used fuel management) nuclear energy has a low carbon footprint that is comparable to geothermal, hydropower and wind energy.[74]

The cost to build new nuclear facilities is very high, and obtaining financing for such projects hinges largely on whether or not the project secures a loan guarantee from the federal government. While the economics of nuclear will be greatly improved if the federal government imposes a price on carbon emissions, financing and federal support remain as issues to be addressed for nuclear facilities. Accurately projecting construction costs for multi-billion dollar projects is a challenge, and recent nuclear construction projects around the world have experienced cost overruns.[75] In New York's restructured electricity market, if a new nuclear facility were proposed as a merchant plant, such risks would be borne by the project investors, not the ratepayers of the State.

5.4 Generation versus Transmission into Southeast New York

The need for additional and upgraded generation and transmission infrastructure can be weighed against three sets of criteria: reliability, economics, and public policy. Reliability refers to the ability to operate the electric system within limits and without interruption of service to consumers. Economics refers to removal of constraints (or congestion) on the system that limits the ability to transfer relatively cheaper power from one location to another. An electric system can be operated reliably with congestion, i.e., times when the physical limits of certain elements of the transmission system are reached, although this may result in a more expensive and/or more polluting dispatch of generation. On the NYCA system, it is likely that a different configuration of generation and transmission could provide economic benefits by reducing congestion, which may lower the cost of energy, although this configuration might not be needed for the purpose of meeting reliability criteria and may not be worth the cost. Reducing environmental pollution, addressing global warming concerns, and promoting energy independence are examples of public policy considerations that may, via an increase in renewables and/or access to them, also drive the development of transmission for reasons other than reliability and economics.

Current analysis by the NYISO indicates that there are no statewide reliability needs on the bulk electric system that require new or modified generation or transmission, beyond that already being developed, to be undertaken over the next ten years. However, due to uneven growth rates throughout the State and aging facilities, there are likely local reliability concerns that will need to be addressed through new construction, upgrades or load reduction.

Currently, the bulk transmission system in New York can move about 3,050 MW of power from the western and northern portions of the State into the Hudson Valley and about 5,150 MW from the lower Hudson Valley into New York City and Long Island. To ensure reliability, given the concentrated load in New York City and Long Island, New York City needs to maintain generation resources within the City equal to at least 80 percent of its peak load and Long Island needs to maintain generation resources equal to at least 97.5 percent of its peak load. Increased transmission into either of these areas could reduce the locational requirements. These requirements are established each year by the NYISO.

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[74] Nuclear Energy Institute. *Environment: Emissions Prevented*. http://www.nei.org/resourcesandstats/nuclear_statistics/environmentemissionsprevented

[75] *In Finland Nuclear Renaissance Runs Into Trouble.* The New York Times. May 28, 2009.

There is insufficient transmission, however, to move all the available, relatively inexpensive energy from upstate, Ontario, Quebec and New England at all times to the major load centers in New York. Even so, some level of congestion is economic and need not be resolved; i.e. when the cost of system upgrades exceeds the benefits of the lower energy price. However, there is an increasing focus on economic planning to examine these constraints. Information concerning some of the impacts and effects associated with expanding transmission between Quebec and New York City has been developed through modeling for this Plan.

The NYISO's 2009 RNA base cases indicate that retirement of the Poletti generation unit downstate in 2010 does not result in any statewide reliability violations. New York City's local capacity-to-load ratio, however, was estimated to be 80.2 percent in 2010 falling to 75.7 percent by 2018, while the current locational reserve requirement for this area is 80 percent. As locational reserve requirement analysis is performed on a yearly basis and not projected into the future, and will change as the transmission system is modified, it is not known at this time whether 75.7 percent will be sufficient in 2018.

The New York City Economic Development Corporation (NYC EDC) commissioned a Master Transmission Plan for New York City to secure a reliable supply of power for the City.[76] The goals of the plan were to:

- decrease the cost of electric service to New York City ratepayers and reduce the costs of electricity production statewide;
- improve the reliability of bulk power supply to New York City;
- reduce New York City's electricity carbon footprint; and
- ensure a fair, competitive market for electricity generation and transmission in the City.

The study identified and evaluated the costs and benefits of various proposed and conceptual generation and transmission options that have the potential to meet New York City's energy needs. Overall, the projects evaluated did not show significant net benefits either by production cost or consumer benefit standards. The analysis found that new capacity will be required in New York City in 2019 to meet reliability requirements, and that a gas turbine combined-cycle generating unit would be the economically optimal solution to meet the need. In addition, in-city generation would serve other public policy objectives such as providing economic development benefits, such as construction jobs and tax revenues, and reducing emissions, particularly if combined with repowering of an older higher emitting generator. The addition of transmission facilities upstate, e.g., from Leeds to Pleasant Valley, would provide consumer benefits in New York City, but would potentially raise prices upstate. Other in-city options, which include a controllable cable between New Jersey and New York City and offshore wind generation, also showed projected New York City consumer benefits and additional analysis will be conducted. A key finding of the study was that the fact that there is not an immediate reliability need for additional capacity, decision makers have adequate time to decide which projects to move forward with. The study recommended, however, that New York City seek ways to encourage clean, efficient in-city generation, pursue policies that reduce energy consumption, and pursue joint planning studies within New York and with neighboring regions.

[76] New York City Economic Development Corporation. *Master Electric Transmission Plan for New York City*. 2009. http://www.nycedc.com/NewsPublications/Studies/MasterElectricTransmissionPlanforNYC/Documents/MasterElectricTransmissionPlanforNYC.pdf

5.5 Renewable Generation

As discussed in the Renewable Energy Assessment, renewable generation is increasing in New York, primarily as a result of the State's Renewable Portfolio Standard (RPS). Although the relatively trouble-free introduction of wind power into the grid has demonstrated the maturation of the technology, the introduction to the NYISO markets has required facilitation through relief at most times from the obligation to follow a set schedule of output. As a result, there is an increased need for other resources to follow load; the cost to do so has so far been socialized in the existing market system, and the environmental costs are not clearly apparent. It may be timely to consider mechanisms by which wind power could continue to maximize its production while minimizing the increased costs. Energy storage is one possible approach. A wind power resource might also contract with another resource close by within the region to provide a combined output that follows a dispatch signal.

As additional wind facilities and other renewable generators are added upstate, concerns are also arising about the adequacy of the transmission facilities needed to allow such generation to be transferred to other areas, particularly to downstate areas. Studies have been commissioned to assess the infrastructure needs to address this public policy concern. The Electricity Assessment: Modeling describes the impact of changing the State's renewable policy goal from 25 percent by 2013 to 30 percent by 2015.

5.6 Advanced Coal Technologies

Coal-fired generators provided about 13 percent of the electricity used in New York in 2008. Carbon dioxide (CO_2) and other emissions from such facilities, however, provide significant challenges for their continued use and for additional use of coal as a fuel in the future. With that said, advanced technologies for abatement of carbon and other emissions are being considered. Technologies, such as advanced pulverized coal combustion and advanced fluidized bed combustion, can increase coal plant efficiency, which in turn can reduce emissions of CO_2 below what it otherwise would be. Co-firing biomass, which is generally considered a carbon-neutral fuel, with coal is another method to reduce CO_2 emissions; such emissions can be reduced by about eight percent through use of 10 percent biomass by heat input. A third method, with the potential to reduce carbon emissions by 90 percent or more, is called carbon capture and sequestration (CCS); the method uses pre-combustion,[77] post-combustion,[78] and oxy-combustion techniques[79] to remove for storage the CO_2 gas. Once captured, CO_2 is dried and compressed and then transported via pipeline to be used in enhanced oil, gas, or coal bed methane recovery, or stored in geological formations. The main challenges associated with efficiency improvements involve advanced super-alloy material development and cost. The major technical challenges associated with biomass co-firing include fuel procurement, handling and storage, potential increases in corrosion, decreases in overall efficiency, ash disposition, pollutant emissions, and overall economics. The major challenges

[77] Pre-combustion capture is only possible for an Integrated Coal Gasification Combined Cycle (IGCC) power plant where coal is gasified to create a synthesis gas (syngas). CO_2 emissions can be prevented in an IGCC plant by transferring almost all carbon compounds in the syngas to CO_2 through a water gas shift reaction and then removing the CO_2 before it is diluted in the combustion stage.

[78] Post-combustion carbon capture processes treat flue gas at the tail-end, immediately before it is exhausted from the plant. At this point, the flue gas is at or close to atmospheric pressure, warm, saturated with water vapor, and has a CO_2 content of about 12 percent.

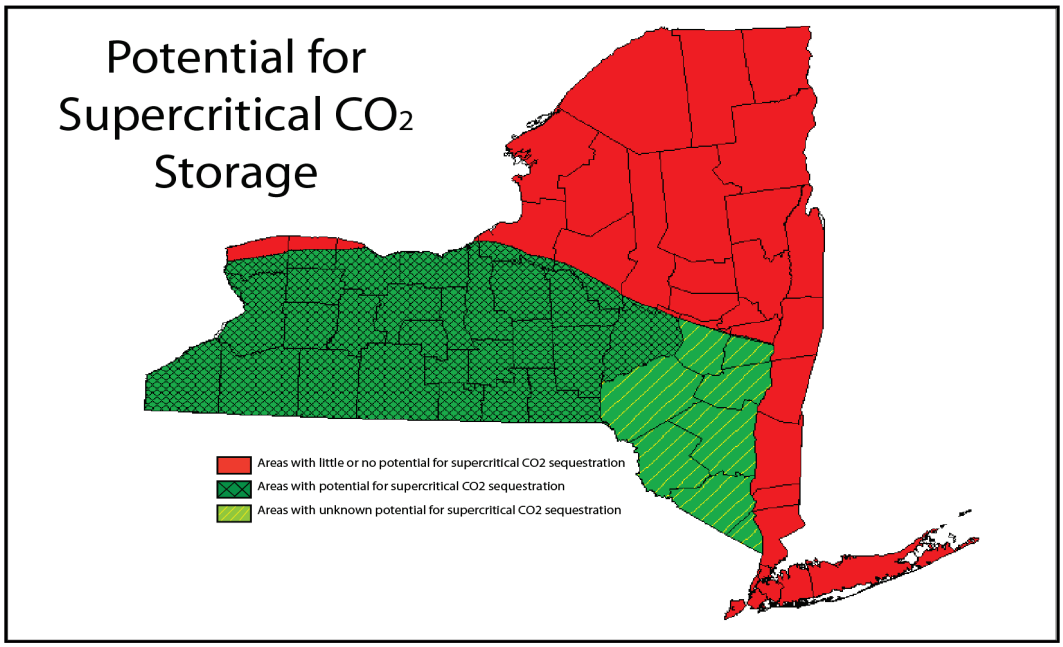
[79] Oxy-coal combustion is an emerging technology that concentrates CO_2 in the flue gas to allow for better post-combustion capture. It involves the combustion of pulverized coal in a mixture of pure oxygen and recirculated flue gas, which reduces the net volume of flue gas and substantially increases the concentration of CO_2 in the flue gases – as compared to the combustion of pulverized coal in air.

associated with carbon capture and sequestration technologies are efficiency and cost. Additional research and development is needed to address these challenges.

After an intensive 18-month development effort, plans to construct a 680 MW advanced coal power plant at the Huntley Station in Tonawanda was shelved due to the economic challenges and risks of the project. However, in June 2008, Governor Paterson announced regulatory and financial support for a new advanced clean coal demonstration plant for Jamestown. As contemplated currently, the project will use a Circulating Fluidized Bed (CFB) boiler with 50 MW gross and 30 MW net capacity, and employ the oxy-coal combustion technology to achieve greater than 90 percent CO_2 capture. The captured CO_2 will be stored near the site in brine-saturated sandstone formations.

Figure 17, based on a preliminary assessment of New York geologic formations conducted by NYSERDA, shows that western New York appears well-suited for CO_2 storage. The exact locations and techniques for sequestration will need to be developed if the Jamestown, or another, project goes forward.

Figure 17. Potential for Supercritical CO_2 Storage



Source: NYSERDA.

5.7 Municipal Solid Waste (MSW)

The State's solid waste management policy established in Environmental Conservation Law (ECL) 27-0106, also known as the hierarchy, was established in the interest of public health, safety, and welfare in order to conserve energy and natural resources. As specified in ECL 27-0106(2), technical and economic feasibility are to be considered in the implementation of this policy. The following are the solid waste management priorities in the State hierarchy:

- first, to reduce the amount of solid waste generated;

- second, to reuse material for the purpose it was originally intended or to recycle material that cannot be reused;
- third, to recover, in an environmentally acceptable manner, energy from solid waste that cannot be economically and technically reused or recycled; and
- fourth, to dispose of solid waste that is not being reused, recycled or from which energy is not being recovered, by land burial or other methods approved by the DEC.

5.7.1 Municipal Waste Combustion and Landfill Gas-to-Energy

Where technically, environmentally, and economically achievable, municipal waste combustor facilities are the preferred alternative to landfills for the management of solid waste that still requires disposal after waste reduction, reuse, and separation of recyclable materials. Modern municipal waste combustors produce energy through the combustion of municipal solid waste in specially designed furnaces equipped with pollution control equipment. In addition to providing a municipal solid waste disposal option, combustors produce both electricity (approximately 650 kWh per ton of solid waste combusted) and steam as off-takes. Both ferrous and nonferrous metals can be recovered from the ash residue.

Many municipalities, companies, universities, and research institutions are working to develop the next generation of municipal waste conversion technologies as an alternative to conventional mass burn combustion. These technologies use advanced thermal, biological, or chemical processes to convert the organic portion of the waste stream into a syngas that can be used to produce electricity, synthetic fuels, and/or chemical products.

Although landfilling of solid waste is the option given the lowest priority in the State solid waste management policy, landfilling in- or out-of-state currently accounts for the bulk of our solid waste disposal. Nevertheless, some energy recovery can still be achieved from this solid waste management activity. Landfill gas is generated by the natural degradation of organic waste by anaerobic micro-organisms. It contains about 50 percent methane (CH_4), the primary component of natural gas, about 50 percent CO_2, and a small amount of non-methane organic compounds. Landfill gas-to-energy projects control the migration of explosive gases, reduce methane emissions, and can produce electricity or low Btu pipeline quality gas.

DEC is currently developing a new Solid Waste Management Plan that will take stock of the State's solid waste management strategies, evaluate priorities, and articulate a vision for maximizing material and energy recovery and minimizing waste. The Solid Waste Management Plan will address the broader environmental implications of solid waste management alternatives, including global climate change, and it will include an analysis of the environmental and economic benefits of its recommendations to maximize material and energy recovery and reduce waste. More information may be found in the Environmental Impact Issue Brief.

5.8 Environmental Requirements

New environmental requirements that could be enacted during the planning horizon include those associated with: the federal climate change and carbon policy program, which may include a "cap and trade" program; federal or State rules on continued or future use of once-through cooling systems; a regional NO_x control trading program to replace the clean air interstate rule (CAIR); and a more specific NO_x reduction program driven by ozone problems and targeted at plants in southeastern New York.

Coal and oil-fired units will be especially vulnerable to cost increases as a result of environmental requirements associated with obtaining CO_2 and NO_x allowances. Such units depend on net revenues from energy sales for a considerable portion of their operating income. The combination of increased production costs due to the requirements to obtain emission allowances and decreased opportunities for energy sales will create economic challenges that may lead to retirement of some of these units, thus shrinking the pool of units available to follow load. This could have particularly adverse consequences where the penetration of wind resources, which increase the need for load-following units due to the variability of their output, is increasing.

In southeastern New York, there are a number of units known as High Electric Demand Day (HEDD) units. HEDD units typically operate on days of peak demand when ozone and $PM_{2.5}$[80] air quality are at unhealthy levels. These are units that generally have low capacity factors and many are quick start gas turbines; others are steam units that provide spinning reserve. They are generally the highest polluting and least efficient units in the system. In addition to the potential cost for CO_2 and NO_x allowances, these units have been targeted by the Ozone Transport Commission HEDD program to achieve NO_x emission reductions that could lead to their retirement, thus further limiting the pool of units available for load following and regulation. DEC has been considering a rule to reduce NO_x emissions on HEDD units. While the NYISO did not perform a HEDD rule scenario analysis for its 2009 Assessment, it did perform such an analysis for its 2008 Assessment.[81] Because the base case load levels used for forecast peak conditions in the two assessments were within 300 MW of each other, the 2008 HEDD analysis is reasonably informative for 2009. The 2008 HEDD scenario analysis found that implementation of the HEDD limits being considered by DEC at that time would result in an unreliable system. DEC is now proposing to address HEDD units as part of a broader effort to revise Reasonably Achievable Control Technology (RACT) standards.

If generation units are retired for environmental reasons, reliability issues could arise in some situations. In its 2009 RNA, the NYISO considered the possibility of generation retirements by performing a Zones-at-Risk analysis. It removed generation in blocks of 250 MW in selected Zones until the results violated reliability criteria. The results indicate if, for any reason, 750 MW of capacity were removed from the lower Hudson Valley or between 500 and 750 MW of capacity were removed from the New York City area, reliability criteria would be violated by 2018. Table 4 shows the results for study year 2018.

[80] $PM_{2.5}$ refers to particulate matter with a diameter of 2.5 micrometers or less.

[81] NYISO. *2008 Comprehensive Reliability Plan*. 2008. http://www.nyiso.com/public/webdocs/newsroom/press_releases/2008/2008_Comprensive_Reliability_Plan_Final_Report_07152008.pdf .

NYISO. *2008 Reliability Needs Assessment: p. I-23 to I-25*. 2007. http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2008_RNA__Supporting_FINAL_REPORT_12_12.pdf

Table 4. Loss of Load Expectations (LOLE) Resulting from Capacity Decreases

Loss of Load Expectations (LOLE) Resulting from Capacity Decreases		
Zone	Capacity Decrease	Resulting LOLE
B	500 MW	0.13
G	750 MW	0.20
H	750 MW	0.10
J	500 MW	0.08
J	750 MW	0.15

Source: NYISO. *2009 Reliability Needs Assessment*.

The NYISO's 2009 Assessment also modeled the retirement of 1,248 MW of coal-fired generation. The results indicate that there would be a need for bulk power system reliability reinforcements by 2017 for the State to be able to meet peak load requirements.

5.9 Demand Response[82]

Demand response takes advantage of customer load that can respond to short-term, also referred to as "day-ahead" or "real time" price signals, during peak load periods. Such reductions, which are often referred to as "peak shaving," improve the peak system load factor and system efficiency. Reducing peak load, in turn, reduces the need to build additional generation and transmission facilities. Customer response can take the form of reducing consumption of electricity or use of on-site generation, both of which reduce the use of supply from the grid.

There are numerous initiatives, including energy efficiency initiatives described in the Energy Efficiency Assessment, underway in New York that can reduce the need for additional generation, transmission, and distribution capacity and also improve the efficiency of the system. These activities are focused on reducing the total amount of electricity used, but also on decreasing the demand for electricity, especially during times of peak usage. The load and price duration curves previously shown on page 21 in Figure 9 and Figure 10 for New York, and in Figure 18 and Figure 19 for New York City, illustrate the substantial reduction in price volatility and the need for peaking capacity achievable by reducing load during a relatively few hours of the year.[83]

Figure 9 shows that the electrical load in the State has followed a fairly consistent pattern during the 8,760 hours of each of the past few years, requiring between 12 and 35 GW of capacity during the year. The shapes of the curves show that the capacity need drops off over time, with the greatest amount of

[82] There are two major categories for demand response resources: 1) those that eliminate load entirely; and 2) those that remove the load from the grid system and supply it instead from on-site generation.

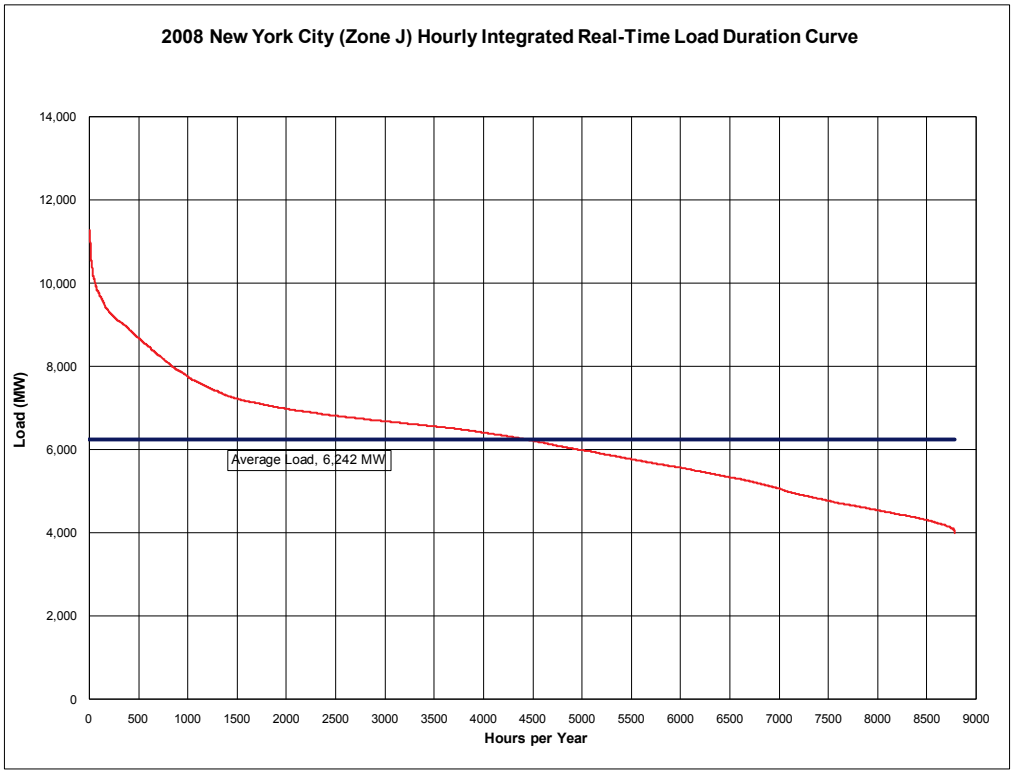
[83] Figures 9, 10, 18, and 19 were all developed from data in the Independent Market Monitor's *2007 State of the Market Report* posted on the NYISO's website. NYISO. *2007 State of the Market Report*. 2008. http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2007_SOM_Final.pdf

capacity needed for a relatively short portion of the year. Thus, appropriate demand response efforts employed during those short portions of the year will reduce the amount of generation capacity needed to supply load and make the system more efficient. Employment of new technologies, such as energy storage, may also help make the system more efficient, especially during peak load periods. DOE, NYSERDA, the NY BEST Consortium and others are pursuing research and development of such technologies.[84]

Similarly, Figure 10 shows the relationship of the wholesale price of electricity versus the amount of time such prices exist during the year. The curves there indicate that the price of electricity is relatively high for only a few hours of the year compared to the prices during most of the year. In particular, the price is relatively stable for all but approximately 500 hours of the year. Consequently, a reduction in demand, or use of stored energy, during those peak hours can be projected to reduce the cost significantly.

Figure 18 and Figure 19 provide similar information for the New York City load areas during 2008. As with the statewide load and price curves of Figure 9 and Figure 10, capacity needs and hourly price for New York City are typically high for only a relatively short period of the year. Consequently, demand response efforts during those short periods would be beneficial for customers.

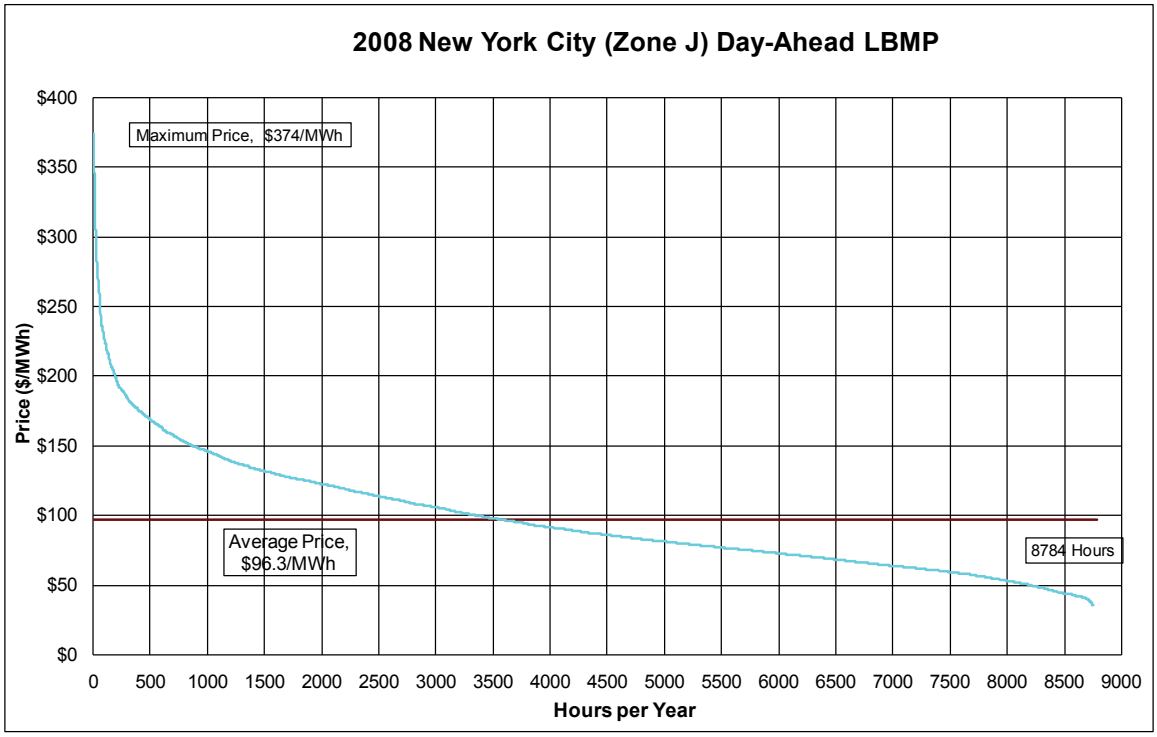
Figure 18. 2008 New York City Hourly (Zone J) Integrated Real-Time Load Duration Curve



Source: NYISO.

[84] As previously noted, the NY BEST initiative will capitalize on the State's existing technical and industrial capabilities and help bring together scientists, engineers and entrepreneurs to advance New York's clean energy and storage technology industries.

Figure 19. New York City (Zone J) Day-Ahead LBMP



Source: NYISO.

5.9.1 NYISO Demand Response Programs

The NYISO is primarily responsible for enabling most of the statewide demand response programs currently in place. Its programs grew fairly rapidly during their initial years, but participation has flattened out recently as most of the low cost and high payback measures, using current market prices, appear to have been deployed. For customers to respond effectively to the NYISO's short-term price signals, they must have advanced technology meters, such as interval meters, that can record the customer loads at least hourly. Advanced meters permit the NYISO and the local utilities to charge hourly day-ahead or even real-time prices to those customers having such meters. Customers with advanced meters can take advantage of short-term price signals by shifting their loads to off-peak periods or curtailing their loads during price spikes, thereby reducing their average rates. The NYISO developed operating procedures and computer software to permit individual demand-response resources to provide high-valued ancillary services, such as operating reserves and regulation, to reduce the NYISO's reliance on expensive and often relatively dirty sources, such as quick-start generators. A similar program for aggregated resources is currently under development.

As noted above, the load management programs administered by the NYISO provide opportunities for electric customers to get paid for curtailing electric load during electric grid high-demand periods. Three of these programs are designed to improve system reliability, while another is focused on giving wholesale customers the opportunity to submit economic load reduction bids. The programs are open to all types of customers, and each program has different performance requirements and incentives. Customers can sign up for these programs through their load serving entity or through an independent curtailment services company.

The NYISO's Installed Capacity Special Case Resource (ICAP/SCR) program is focused on improving system reliability and involves paying electricity customers to provide load reduction capability for a specified contract period. Program participants receive payments for an agreement to curtail usage during times when the electric grid could be jeopardized. Based upon system condition forecasts, participants are obligated to curtail their resources when called on to do so with two or more hours notice, provided they were notified the day ahead. Participants curtail the subscribed amount of capacity either through the use of on-site generation and/or by reducing electricity consumption.[85] Performance is mandatory, and any under-performance could result in a penalty.

The NYISO's Emergency Demand Response Program (EDRP) provides resources an opportunity to earn the greater of $500/MWh or the prevailing LBMP for electricity curtailments when the NYISO calls on them.[86] There are no consequences for enrolled participants that fail to curtail. Participants can register for EDRP or ICAP/SCR, but they cannot use the same resources for both programs.

Since the summer of 2001, the NYISO has activated these two reliability programs a total of 17 times: four times each in 2001 and 2002; twice in 2003 (during the August blackout restoration), once in 2005 and six times in 2006 (primarily in zone J during a network outage in the Con Edison service territory).[87] Six of these events were called statewide; the remaining events were called in the eastern and southeastern zones (zones F-K) in various combinations. In 2007, the NYISO activated EDRP and ICAP/SCR resources under the zone J Targeted Demand Response Program (TDRP), described below, on only two occasions. Highlights of these programs include the following:

- more than 2,700 large commercial and industrial customers have participated
- approximately $24 million in incentives were paid to EDRP/SCR program participants
- peak load was reduced by as much as 900 MW during reserve shortages
- these programs have been very important in helping New York City meet its reserve requirements, especially in 2001
- programs accelerated the recovery process after the August 2003 blackout

The enrollment levels for SCR/EDRP programs, as of May 2009, are shown in Table 5 and Table 6 below.[88]

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[85] On-site generators use a variety of fuels. Those that have high emissions are of concern.

[86] These resources are called upon when reserve shortages are anticipated and when prices are typically high. In contrast, the 2008 average Day-Ahead price was $100/MWh in eastern New York and $67/MWh in western New York.

NYISO. *2008 State of the Markets Report*. 2009.
http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/NYISO_2008_SOM_Final_9-2-09.pdf

[87] No activations occurred in 2007, 2008, or 2009.
http://www.nyiso.com/public/webdocs/products/demand_response/general_info/Historical_EDRP_SCR_performance.pdf

[88] As determined from the NYISO's June 1, 2009 filing with FERC.

Table 5. Special Case Resources (SCR) May 2009

Location	# of Customers	Load Reduction (MW)	On-Site Generation (MW)	Total MW
Upstate	1079	1489.6	70.4	1560
New York City	1701	368.7	128.8	497.5
Long Island	613	137.8	45.2	183
SCR Total	**3393**	**1996.1**	**244.4**	**2240.5**

Source: NYISO.

Table 6. Emergency Demand Response Program (EDRP) May 2009

Location	# of Customers	Load Reduction (MW)	On-Site Generation (MW)	Total MW
Upstate	209	69.3	88.8	158.1
New York City	136	90.5	25.5	116
Long Island	32	53.6	1.8	55.4
EDRP Total	**377**	**213.4**	**116.1**	**329.5**

Source: NYISO.

The NYISO introduced a TDRP in July 2007. TDRP is a newer reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a transmission owner, in targeted subzones. The targeted program is only available in zone J (New York City) in nine subzones designated by Con Edison. Prior to the program, the NYISO was required to call all resources within a zone when the above-listed EDRP and SCR programs were activated.

Finally, the NYISO's Day Ahead Demand Response Program (DADRP) is an economic program that offers electricity customers a chance to bid load reduction capability in New York's wholesale electricity market. To participate, customers bid their load reduction capability, on a day-ahead basis, into the wholesale electricity market, where these load reduction bids compete with generators' offers to meet the State's electricity demands. The enrollment levels for the program as of May 2009 are shown in Table 7 below.

Table 7. Enrollment Levels for the Day-ahead Demand Reduction Program (DADRP) May 2009

Location	# of Customers	Load Reduction (MW)	Dist. Gen. (MW)	Total MW
Upstate	18	309.8	0	309.8
New York City	2	6.6	0	6.6
Long Island	30	15	0	15
DADRP Total	**50**	**331.4**	**0**	**331.4**

Source: NYISO.

It should also be noted that the NYISO is now allowing Demand Response resources to participate in the ancillary services markets. No customers are currently participating in this program, but several have filed applications and are in various stages of installing the necessary communication devices and instantaneous meters that are required to operate in this market. The testing of the first customers is expected by the end of 2009.

5.9.2 Con Edison Demand Response Programs

While all of the utilities have the right to sign customers to participate in the NYISO programs, only Con Edison has its own separate programs. It administers two demand response programs: Distribution Load Relief Program (DLRP) and Direct Load Control Program (DLCP).

DLRP is a tariff program, funded by Rider University of Con Edison's tariff, which provides compensation for load reduction during load relief periods designated by Con Edison for its system reliability. Third-party aggregators are allowed to aggregate customers to participate, and both curtailable load and distributed generation are allowed to participate in this program. The program has a two-tiered reservation payment, with higher payments being paid to participants in higher priority electrical distribution networks designated by Con Edison. The program operates during a summer capability period from May through October. Approximately 248 MW of generation and load participated in the program in 2009; 202 MW from aggregators (on a mandatory basis) and 46 MW from individual customers (on a voluntary basis).

DLCP is a thermostat-controlled program operated by Con Edison through a telecommunications device. It focuses on central air conditioners. Customers are awarded an upfront incentive to sign up to participate on a voluntary basis. No further payments are made under this program to customers. A customer can override the thermostat with no penalty. During program year 2007, there was potential reduction for about 34 MW of combined residential (23 MW) and business customer (11 MW) participation that could be controlled. Con Edison received PSC approval to continue and expand the program through December 2010.

A May 15, 2008 report[89] prepared for, and released by, Con Edison assessed opportunities for short-term

[89] Summit Blue Consulting, LLC. *Con Edison Callable Load Study*. 2008. http://www.summitblue.com/attachments/0000/0488/r6_-_Con_Edison_Callable_Load_Study.pdf

reduction in system demand, typically four hours or less in duration, that can be provided by individual customers, or aggregated groups of customers, through curtailment of their electricity consumption or deployment of emergency generation on request in New York City and Westchester County, referred to as callable load opportunities. The study was intended to achieve two primary objectives: 1) assess the potential, in megawatts, for peak load reductions that can be called by Con Edison; and 2) present program concepts that provide pathways to achieve this potential cost effectively. The study estimated that the additional achievable callable load potential that can be available in 2017 is 815 MW; this potential is above that currently provided by the NYISO and the two existing utility programs. To achieve the potential, the study identified a series of steps and programs Con Edison could pursue in both the short and long terms.

5.9.3 Mandatory Hourly Pricing

Enhancing the information provided to electricity consumers in advance of or at the time of use facilitates informed decision-making and helps reduce customer energy bills. Providing electricity pricing information to consumers at the time consumption decisions are being made, and charging consumers accordingly, enhances economic efficiency and can also help reduce system peaks.

The PSC has taken action in this regard, including requiring that the State's largest commercial and industrial customers, generally those with electricity demand exceeding 500 kW, have interval meters to encourage control of daily electric load and discourage use at peak hours. In contrast, the vast majority of residential and small commercial electricity customers are informed of the applicable price of electricity only upon receipt of a monthly bill, up to 30 days after the fact. Moreover, that unit price represents an average throughout the billing period and does not reflect the consumer's pattern of energy use throughout the month. These small customers also generally receive very little information about their consumption behavior and how changes in usage patterns can reduce their energy bills. Finally, these customers do not know when the electricity system is peaking and is using the most expensive units to meet that load. Mandatory time varying rates for residential customers are at this time prohibited by law. Giving the PSC authority to require that electricity be priced on a time of use basis for all customers, upon a finding that it is in the public interest to do so, could similarly improve system efficiency and allow customers to better manage their energy costs. This is discussed further in the Energy Efficiency Assessment.

5.9.4 Demand Response Proceeding

Under the auspices of the PSC's EEPS proceeding, a working group was convened to consider whether additional demand response measures and utility incentives could be developed to encourage customers to further shift usage and reduce output from certain peaking units and thus improve system efficiency. Informed by the efforts of the working group, the PSC instituted a new demand response proceeding on February 17, 2009 and removed demand response program considerations from the purview of the EEPS proceeding.

The new proceeding (PSC Case 09-E-0115) will initially focus on demand response efforts in the NYISO zone J (New York City), which is served by Con Edison. Zone J experienced the greatest rate of peak load growth and thus relies on numerous peaking units. Consequently, it has the highest wholesale energy and capacity costs. Con Edison was directed to file a report that assesses the potential cost effectiveness of demand response initiatives and a proposed demand response goal for summer 2015 as well as goals for the intervening years. Con Edison was also directed to identify cost effective programs that could be targeted to reduce system peak, network peaks, and operation of generating units in environmental justice areas.

Con Edison made a filing on June 1, 2009 that proposed four demand resource programs. After a series of collaboratives and the filing of Comments, the PSC approved four modified programs for Con Edison's New York City service territory that are specifically aimed at peak load reduction, using a pre-determined trigger for activation for all its programs based on a forecast of day-ahead loads. As a point of reference, New York City's peak demands are in the range of 11,500 to 12,000 MW. The programs are as follows:

- Commercial System Relief Program (CSRP), the most significant of the programs, will provide separate capacity and energy payments to participants that can reduce their demand by a minimum of 50 kW individually, or 100 kW through aggregation, with a minimum of 24 hours notice before an expected high demand day (a day ahead forecasted load level that is at least 92.5 percent of the forecasted summer system peak).

- Residential Smart Appliance Program (RSAP) will provide payments to customers that allow utility control of the customers' curtailable electric appliances, with customer override capability.

- Critical Peak Rebate Program (CRPP) will provide rebates to customers that curtail load by at least 1 kW during peak periods.

- Network Relief Program (NRP) will target specific networks that are in need of system relief or infrastructure upgrades.

The PSC is currently awaiting the filing of a tariff from Con Edison to implement the programs. It is anticipated that the four demand response programs described above should be operating and available for the months of June, July, August, and September 2010.

5.9.5 Challenges

As previously noted, the amount of capacity registered in the NYISO demand response programs grew fairly rapidly from their inception in 2001 up until about 2006, but it has grown at a much slower rate since that time. This is because most of the low cost and high payback measures that allow customers to become more flexible in their energy use have been deployed. As the demand response market has matured, it has taken more effort to find additional load curtailment strategies that meet the payback expectations of end-use customers. In particular, lower market prices outside of New York City and Long Island make pursuing the programs less attractive to end-users because the investment in demand response technologies will have longer and less attractive payback periods. Also, facilitators (Curtailment Service Providers and Responsible Interface Parties) have often cited revenue uncertainty, e.g., variable ICAP prices, as a barrier to expanding demand response in New York. With specific regard to the NYISO's DADRP, in addition to developing load reduction strategies, participants must also develop effective bidding strategies, and not everyone is willing to develop such expertise.

While the majority of the SCR and EDRP needs are met with load reduction, most of which is believed to be through conservation measures, a significant share of the load management from these programs is met with on-site generation. On-site generation is often accomplished with diesel generators that have limited environmental controls. One significant challenge for these resources is a proposed DEC rule for distributed generators. The proposed environmental regulations may make distributed generators in the NYISO's programs subject to more stringent emissions requirements: DEC draft 6NYCRR Part 222 Distributed Generation Rule would impose more restrictive emission limits for NO_x, particulate matter, carbon monoxide, and non-methane hydrocarbons (NMHC) for various types of distributed generators. It may also result in limiting the absolute quantity of distributed generators that may participate in the NYISO reliability-based demand response programs. Consequently, the draft proposed rule has had

multiple revisions based on comments made by parties during public forums. It is thus unclear at this time whether or to what extent such regulations will have an effect on demand-response resources.

In the demand response proceeding, both DEC and the environmental justice (EJ) communities filed comments regarding the use of distributed generation in EJ areas that already had peaking units. In consideration of these comments, the PSC's Order prohibited the use of distributed generation in any of the four Con Edison proposed demand response programs, in areas where peaking units already exist. Furthermore, distributed generation is to be limited or capped at 20 percent of the total demand response participating in the remaining areas of Con Edison's service territory that do not have peaking units, as well as limiting distributed generation to year 2000 vintage or newer. Because Con Edison's programs will not become operational until 2010, it is difficult at this time to assess the extent to which the above described restrictions will have on participation in the four programs.

5.10 Distributed Generation/Combined Heat and Power (DG/CHP)[90]

In recent years, New York has led a growing number of efforts to support the expansion of DG/CHP resources. The CHP Working Group of the Governor's Renewable Energy Task Force has led policy efforts to lower barriers to further DG/CHP development.[91]

The PSC and DPS have led initiatives to develop standardized interconnection requirements (SIR) for distributed generation and electric service standby rates. New York's SIRs have been a model for other states and have been revised several times. Recent revisions have improved and expedited processing and review of small installations 25 kW and less. With respect to standby rates, the PSC recently extended for six years the exemption from standby rates for certain distributed generator facilities that meet certain eligibility requirements.

New York's utilities have worked to help implement DG/CHP projects by putting in place the required standardized interconnection procedures and standby tariffs for DG/CHP projects in their service territories. In New York City, where DG/CHP projects are an important resource to delay or defer expensive utility infrastructure investments, Con Edison has worked diligently with DPS, NYSERDA and the DG/CHP community to facilitate projects. For example, Con Edison has a dedicated full-time DG/CHP Ombudsman to help in DG/CHP siting and interconnection issues. Also, the City's PlaNYC includes a recommendation that building codes be modified to require any new residential or commercial development over 300,000 square feet to conduct a feasibility study of District Energy systems, including combined heat and power systems. While the code has not been formally changed, the City is encouraging all large developments now on the drawing boards to conduct such an analysis before proceeding further.

NYSERDA manages New York's successful DG/CHP demonstration program. This program has two primary objectives: to deliver significant load reduction and energy savings through the installation of

[90] DG is defined as power production resources that generally do not use the State's electrical grid for delivery to consumers. Typically, such generation is located on the consumers' site behind their meters and any interconnections with the State grid. CHP, also known as "cogeneration", is defined here as self-production of electricity on-site, i.e., a DG facility, but which also provides beneficial recovery of the heat byproduct from the generator for other uses at or near the generator site. Although DG units have historically been associated with peak-shaving, their use in association with CHP allows them to go beyond that single purpose use in many cases.

[91] Includes representatives of NYSERDA, DPS, New York City and the general DG/CHP community, including developers, building owners and economic and industrial development agencies.

clean and efficient CHP equipment and to gather marketplace intelligence for education of policymakers, customers, project developers, and equipment vendors, in order to lower barriers and spur improvements in technology. The program emphasizes both the thermal and electric components of successful CHP installations by showcasing emerging (fuel cells and microturbines) and conventional (reciprocating engines and gas turbines) distributed generation technologies coupled with thermal systems such as absorption chillers and domestic hot water systems. The program selects applications through a competitive solicitation process. Since 2001, NYSERDA has committed over $80 million to 108 CHP demonstration projects with a projected installed peak load reduction of 211 MW and a total cost of $412.5 million. As of November 2009, 57 projects are operational with an installed capacity of 34 MW.