NEW YORK STATE ENERGY PLAN

New York State Transmission and Distribution Systems Reliability Study and Report

NEW YORK STATE ENERGY PLANNING BOARD | AUGUST 2012

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Acronym List

Alternating Current (AC)
American Recovery and Reinvestment Act (ARRA)
Area Transmission Review (ATR)
Best Available Retrofit Technology (BART)
Best Technology Available (BTA)
Bulk Electric System (BES)
Bulk Power System (BPS)
Clean-Air Interstate Rule (CAIR)
Clean-Air Transport Rule (CATR)
Combined Heat and Power (CHP)
Comprehensive Reliability Plan (CRP)
Comprehensive System Planning Process (CSPP)
Congestion Assessment and Resource Integration Study (CARIS)
Cross-State Air Pollution Rule (CSAPR)
Customer Average Interruption Duration Index (CAIDI)
Defensive Strategies Working Group (DSWG)
Department of Public Service (DPS)
Eastern Interconnection Planning Collaborative (EIPC)
Eastern Interconnection Reliability Assessment Group (ERAG)
Electric Reliability Organization (ERO)
Electric System Planning Working Group (ESPWG)
Electric Generation Units (EGUs)
Emergency Demand Response Program (EDRP)
Energy Efficiency Portfolio Standard (EEPS)
Energy Policy Act of 2005 (EPAct)
Federal Energy Regulatory Commission (FERC)
Geomagnetic Disturbances (GMD)
Gigawatt Hour (GWh)
High Voltage direct current (HVDC)
Institute of Electrical and Electronics Engineers (IEEE)
Independent Electric System Operator (IESO)
Independent System Operator-New England (ISO-NE)
Indian Point (IP)
Installed Capacity (ICAP)
Installed Reserve Margin (IRM)
Integrated Reliability Index (IRI)
Inter-Area Planning Stakeholder Advisory Committee (IPSAC)
Joint ISO/RTO Planning Committee (JIPC)
Kilovolt (kV)
Local Transmission Plan (LTP)
Local Transmission Planning Process (LTPP)

Long Island Power Authority (LIPA)
Loss-of-Load Expectation (LOLE)
Loss-of-Load Probability (LOLP)
Loss-of-Gas Minimum Oil-Burn Rule (LOGMOB)
Maximum Achievable Control Technology (MACT)
Megawatt (MW)
Megawatt Hour (MWh)
Mercury and Air Toxics Standards (MATS)
Million British Thermal Units per Hour (mmBtu/h)
National Ambient Air-Quality Standards (NAAQS)
National Renewable Energy Laboratories (NREL)
Natural Resources Defense Council (NRDC)
New Brunswick System Operator (NBSO)
New England Power Pool (NEPOOL)
New York City Economic Development Corporation (NYCEDC)
New York Codes Rules and Regulations (NYCRR)
New York Control Area (NYCA)
New York Independent System Operator (NYISO)
New York Power Authority (NYPA)
New York Power Pool (NYPP)
New York State Department of Environmental Conservation (NYSDEC)
New York State Electric and Gas (NYSEG)
New York State Energy Research and Development Authority (NYSERDA)
New York State Reliability Council (NYSRC)
New York State Reliability Council Installed Capacity Subcommittee (ICS)
North American Electric Reliability Council (NERC)
North American Energy Standards Boards (NAESB)
Northeast Coordinated System Plan (NCSP)
Northeast Power Coordinating Council (NPCC)
Nuclear Regulatory Commission (NRC)
Open-Access Transmission Tariff (OATT)
Pennsylvania-New Jersey-Maryland Interconnection (PJM)
Performance-Based Rates (PBRs)
Phasor Measurement Units (PMUs)
Plug-in Electric Vehicles (PEVs)
Public Service Commission (PSC)
Reasonably Available Control Technology (RACT**)**
Regional Greenhouse Gas Initiative (RGGI)
Regional Transmission Operator (RTO)
Reliability Compliance and Assessment Group (RCA)
Reliability Compliance Monitoring Subcommittee (RCMS)
Reliability First Council (RFC)
Reliability Needs Assessment (RNA)

Reliability Performance Mechanisms (RPM)
Renewable Energy Credits (RECs)
Renewable Portfolio Standard (RPS)
Responsible Interface Parties (RIPs)
Rochester Gas & Electric (RG&E)
SERC East-RFC-NPCC (SeRN)
Situational Awareness (SA)
Southeast New York (SENY)
Southeastern Reliability Council (SERC)
Special Case Resource (SCR)
State Pollution Discharge Elimination System (SPDES)
Sulfur Dioxide (SO_2)
Supervisory Control and Data Acquisition (SCADA)
System Average Interruption Frequency Index (SAIFI)
System Impact Study (SIS)
System Reliability Impact Study (SRIS)
System Benefits Charge (SBC)
Targeted Demand Response Program (TDRP)
Transmission Availability Data System (TADS)
Transmission Owner (TO)
Transmission Owner Strategic Transmission and Reliability Study (STARS)
United States Environmental Protection Agency (U.S. EPA)
Upstate New York (UPNY)

A. Introduction

The value to society of safe, reliable electric transmission and distribution systems has evolved over the last 100 years from that of novelty and luxury, then convenience, finally fundamental, absolute economic and life-sustaining necessity. Thus the primary goal of electric system regulators, planners, and operators is to provide safe, reliable service and avoid disruptions.

Recognizing the importance of transmission and distribution systems' reliability, the New York State Legislature, pursuant to Article 6 of the New York State Energy Law (Section 6-108), established and authorized the Energy Planning Board to undertake a study of the overall reliability of the State's electric transmission and distribution systems. At a minimum, the study is to include an assessment of:

> *(A) the current and projected reliability of the electric power system over the term of the planning period, with specific focus on transmission systems and distribution systems within the State. The assessment shall examine: (i) investment in infrastructure, including capital improvements, expansions, and maintenance; and (ii) workforce use.*
>
> *(B) the potential impact of the following on distribution system reliability and on each factor enumerated in paragraph (a) of this subdivision: (i) distributed electric generation, especially generation, using renewable or innovative energy resources; (ii) energy conservation and efficiency; (iii) load control and peak-saving measures; (iv) corporate reorganization of electric utilities; (v) performance ratemaking, multi-year rate agreements, and other departures from traditional regulatory mechanisms; and (vi) large-scale industrial development.*
>
> *(C) the potential impact of the following on transmission system reliability: (i) each factor enumerated in paragraph (b) of this subdivision; (ii) changes in protocols for electricity dispatched through the Bulk System Operator or its successor or successors; (iii) accommodation of proposed new electric generation facilities or repowering or life extension of existing facilities; and (iv) the market-driven nature of decisions to build, size, and locate such facilities.*

Reliability standards for the transmission system differ from those of the distribution system due to the differences in the magnitude and causes of disruptions. Disruptions on the transmission system may have widespread consequences. Since most of eastern North America (including New York State) is comprised of a single synchronous interconnection[1] or "grid," each regional or local system can be adversely affected by the planning and operations of its neighbors. In other words, the reliability of every power system is dependent on the reliability of every other power system on the grid. Disruptions on the distribution system are more localized, but typically these disruptions occur more frequently for a variety of reasons, *e.g.,* downed lines from falling branches, transformer malfunctions, and power pole breakage.

Understanding the general principles of reliability and the characteristics of transmission and distribution systems is essential when assessing reliability. Therefore, an overview of the electric system (transmission, distribution, generation, and load) and reliability follows in this section. Due to the differences between the systems, the reliability of transmission and distribution systems are assessed separately. The transmission system is discussed in Section B and the distribution system in Section C. Section D discusses Investment and Expenditures. Section E discusses Environmental Regulations, which affect both transmission and distribution. Impacts to the transmission and distribution systems from policy directives and future reliability issues also were assessed to provide a more comprehensive view to assist in identifying

[1] Synchronous interconnection is a network of electric transmission lines and generating power units that operate in synchronism as a single system.

recommendations. These potential impacts can be found in Sections F and G. Key findings and recommendations are in Section H.

It should be noted that the statutory requirement, as described above, requires a "snapshot" of the reliability of the transmission and distribution systems at a fixed point in time. Maintaining reliability, however, is a continuous ongoing effort by numerous parties and can be dynamic as system conditions change. Therefore, in the respective transmission and distribution sections, this study also includes an explanation of the process used to develop, implement, and enforce mandatory reliability rules under the current industry structure.

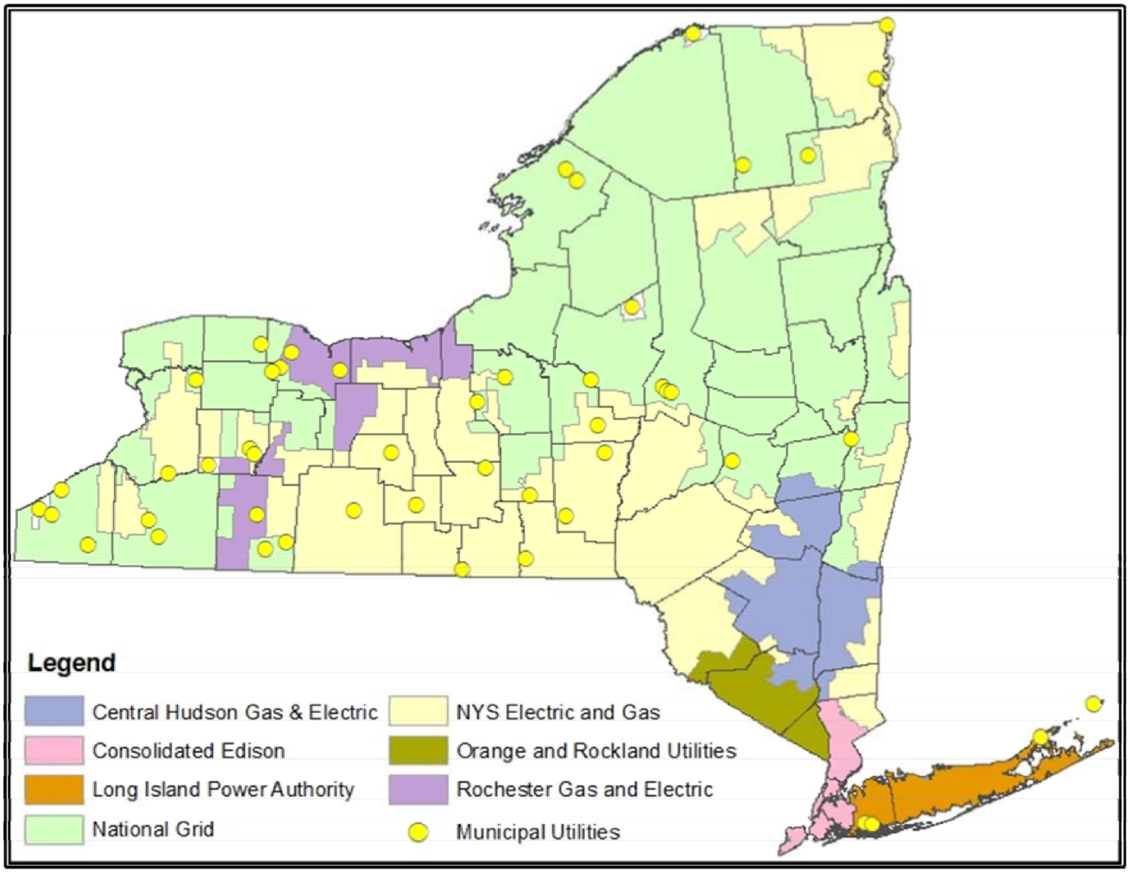
Overview of the Electric System

In broad terms, the electric system is comprised of generation, transmission, distribution, and load. Each of these segments has multiple elements, each with its own operating characteristics and limitations. Reliability standards and rules are developed with an understanding of these elements. This section provides a general description of the major electric-system elements to assist with the understanding of the reliability issues raised later in the document.

Transmission and distribution are owned by respective owners, and who are generally responsible for providing energy to end-use customers. Figure 1 illustrates how New York State electric service territories are delineated. A brief description follows:

- Six investor-owned utilities, regulated by the Public Service Commission (PSC), consisting of Central Hudson Gas & Electric, Inc., Consolidated Edison of New York, Inc., National Grid, Inc. (doing business as Niagara Mohawk Power Company), New York State Electric and Gas Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas & Electric Company
- The Long Island Power Authority (LIPA), which is not regulated by the PSC
- The New York Power Authority (NYPA), which is not regulated by the PSC and not a delineated service “territory”, generates and delivers power to load-serving entities as well as municipal, industrial, and business customers
- Forty-nine municipal utilities, many of which are regulated by the PSC because they do not solely receive power from NYPA
- Four rural electric cooperatives, which receive power from NYPA and are not regulated by the PSC.

Figure 1. New York State Electric Service Territories



Source: DPS, 2012

Transmission System - New York's wholesale electric markets were established coincidentally with the establishment of the New York Independent System Operator (NYISO) on December 1, 1999. At that time, the NYISO assumed responsibility for the operation of New York State's bulk power system in the New York Balancing Authority Area[2] and for the administration of the newly established markets for electric energy, capacity, and related ancillary services. Prior to December 1999, operation of the bulk power system was the responsibility of the New York Power Pool. The NYISO is charged with three overriding responsibilities: 1) maintaining the safe and reliable operation of New York's bulk power system; 2) operating fair, non-discriminatory and effective wholesale electric markets; and 3) planning for the reliability and economic needs of New York State's bulk power system.

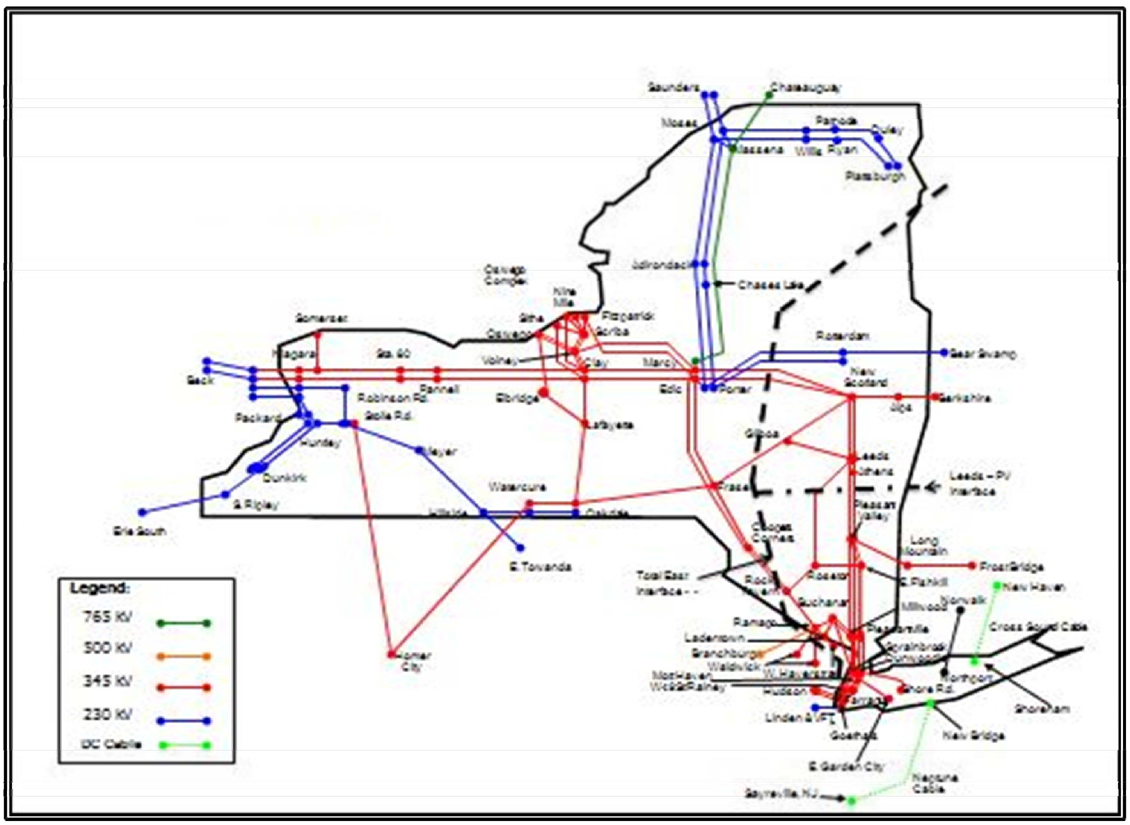
Figure 2 displays the bulk power transmission system[3] for the New York Control Area (NYCA). It shows transmission lines operating at 230 thousand volts (kV) and above. This represents more than 4,000 miles of high voltage transmission lines. If the underlying 138 kV and 115 kV transmission lines are included, the mileage exceeds 11,000 miles.

[2] Balancing Authority Area is a term used by North American Electric Reliability Corporation (NERC) in its Reliability Functional Model and is essentially the same area that New York entities often refer to as the New York Control Area (NYCA). Both terms generally refer to the geographic area under the control of the NYISO.
[3] While historically the focus of the bulk power system has been on the transmission lines, the bulk power system actually includes numerous additional components, such as capacitors, reactors, phase-measuring units, phase-angle regulators, and transformers. As "smart grid" technologies or new methods to use existing technologies are developed, these ancillary components may play a larger role in the bulk power system.

Figure 2 also displays key NYCA transmission interfaces. Transmission interfaces are groupings of transmission lines, where designed capacity limits the amount of power capable of moving from one part of the State to another (*i.e.,* transfer capability)

The "Total East" interface is represented by the dashed line on Figure 2 that spans New York from the North to the South. This interface limits the amount of power moving from the northern and western portions of the State to the eastern and southeastern portions of the State. The upper half of the Total East interface is defined as the Central East interface while the lower half including the labeled black dashed-dotted line is known as the interface between Upstate NY Zones and Southeast NY Zones (UPNY – SENY interface). The dotted part of the line effectively divides the Hudson Valley into a lower and upper part electrically. Below the UPNY – SENY interface the *cable interface* contains all the major underground and/or submarine cables supplying New York City and Long Island. Additionally, Long Island has two high voltage direct current (HVDC) ties, 330 MW to New England and a 660 MW to New Jersey, that are merchant transmission projects.

Figure 2. New York Control Area Transmission 230 kV and Above

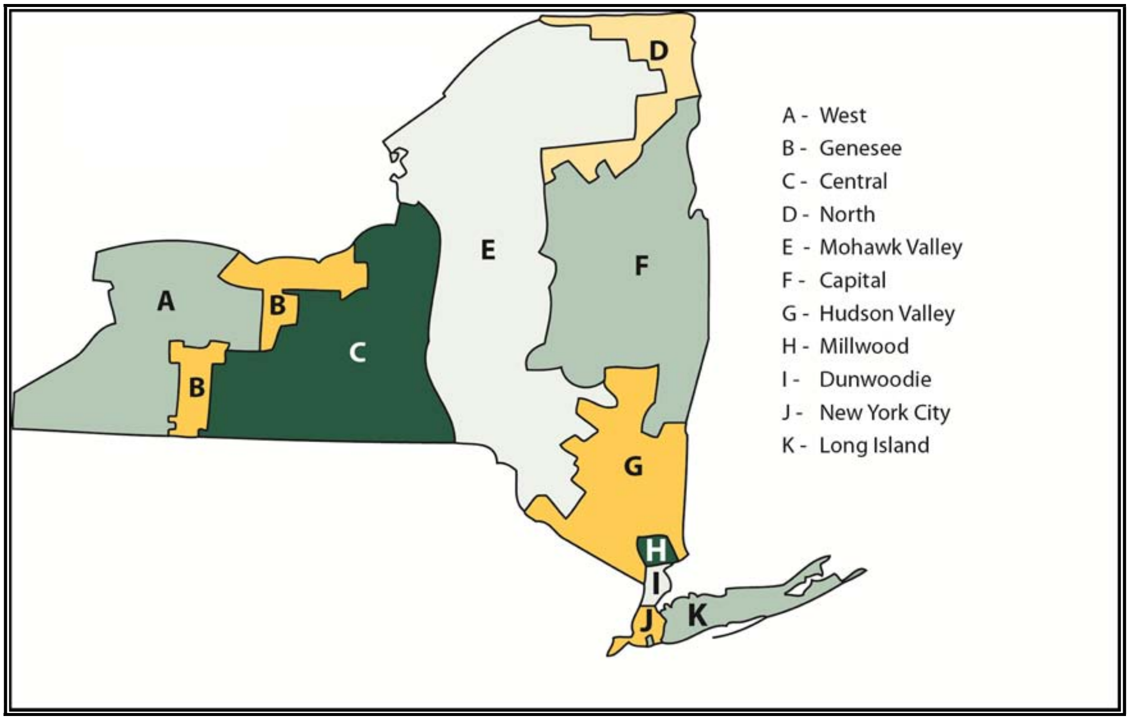


Source: NYISO, 2012

The New York wholesale electricity market is divided into 11 pricing or load zones. Figure 3 presents the geographical boundaries for these pricing zones.

Table 1 presents the nominal or normal transfer capability across the major transmission interfaces defined above that are based on summer peak-load conditions with all lines in service. The transmission facilities that make up the interfaces are the facilities that tie the zones together electrically.

Figure 3. New York Control Area Load Zones



Source: NYISO, 2012

Table 1. Nominal Transfer Capability

Transmission Interface	Transfer Capability (MW)
Total East	5,725
Central East	2,900
UPNY – SENY	5,375
Cable Interface	
New York City	5,350
Long Island	1,950

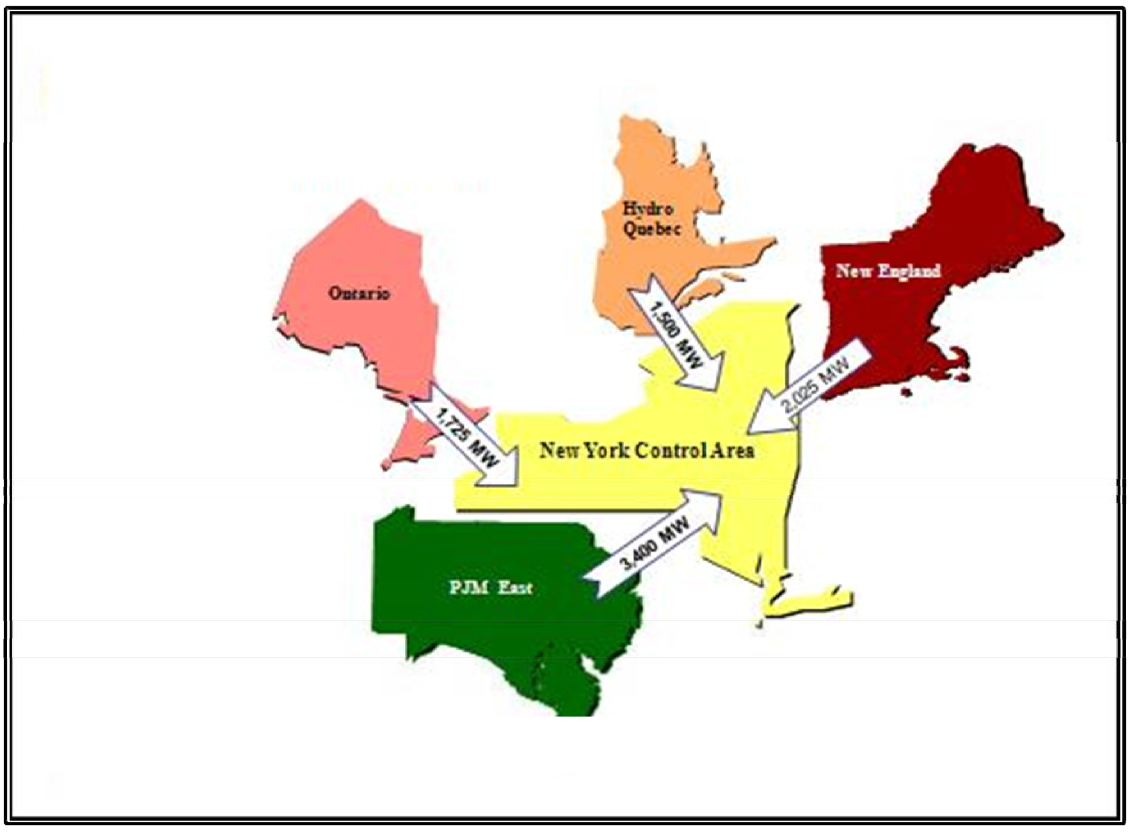
Note: From the New York Independent System Operator's 2010 Comprehensive Annual Transmission Review, which would apply under summer peak-load conditions with all lines available.

As a result of the distribution between load and generating capacity on the NYCA power system and the differences between zonal market prices, power flows are primarily west to east and then southeast or predominantly from the northwest to the southeast into the highly congested zones of New York City and Long Island. Most power flows from the west including the transmission ties to the neighboring control areas of Ontario, Hydro Quebec and Pennsylvania-New Jersey-Maryland must cross the Total East Interface with large portions flowing across the Central East portion of the interface and then across the UPNY – SENY interface to reach the cable interface.

In addition to being highly dependent on the transmission system, the New York City and Long Island zones' electricity generating infrastructure have some of the oldest generating units (generally less efficient, higher operating costs) in the State. Recent plant additions (generally more efficient, lower operating costs) notwithstanding, those zones are still highly dependent on an aging fleet of steam-turbine and combustion-turbine capacity. Additionally, the generation mix in the western and central part of the State has much larger proportions of hydro, nuclear, coal, and now renewable energy sources. This creates the potential for economic power transfers[4] from the Western New York to New York City and Long Island. Much of these power transfers are occurring on transmission that will need to be replaced. Ninety-seven percent of the transmission facilities in service in New York today were built prior to 1990.

In addition to the intrastate interfaces, New York also has interfaces with four neighboring regions illustrated in Figure 4. The interconnections with neighboring regions provide shared resources, which allows these areas to more efficiently meet reliability standards.

Figure 4. Transfer Capability from Neighbors into New York Control Area



Source: NYISO, 2012
Note: Transfer capability from New York to neighbors would be different.

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[4] Economic transfer is the transmission of power from a lower-cost region to a higher-cost region.

Distribution System - New York State's investor-owned utilities distribute electricity to end users and are regulated by the New York State Public Service Commission (PSC). They are responsible for operating and maintaining their respective electric service distribution systems. They respond to customers' requests for service and maintenance, and usually serve as the electric service billing agent. On Long Island, the Long Island Power Authority (LIPA) operates and maintains the electric distribution system through a contract with National Grid that expires in 2013.[5]

Distribution systems are designed as either radial or network systems. Radial distribution systems consist of a number of primary circuits extending radially from a substation connected to the bulk power transmission system. Each circuit serves customers within a particular area. Failure of a circuit normally means a loss of electric service to the customers on that circuit.

A network system is most frequently found in high-load density metropolitan areas. A dense population of customers provides the advantage of economical design and installation of redundant parallel lower voltage feeder cables, network transformers, and protective relays. If a primary circuit or a network transformer fails, protective devices will automatically operate to isolate the failed component. With multiple feeds on a network system, most customers would not be affected by such a failure. Con Edison's extensive underground system in New York City is an example of such a network.

The radial system is principally an overhead system and subject to interruptions caused by tree contact, accidents, and lightning. Network systems are typically underground and are generally unaffected by those causes of interruption, although they can be affected by construction activities.

By their nature, network systems are more reliable than radial systems. In network systems, service interruptions generally occur only when there is a failure within the connection to the customer, or when the substation supplying the network suffers a complete collapse in its ability to serve the load. Otherwise, the network system possesses sufficient robustness in design to withstand most problems that would result in interruptions for radial distribution circuits.

It should be noted however, that service interruptions on the radial system are mitigated by fusing and re-closures that isolate customers downstream from a fault. Customer impact can be further mitigated by isolating the cause of the outage by manually reconfiguring the circuit with field ties. In some instances, utilities install switching equipment that automates the reconfiguration process. Advances in technology are making automation more cost-effective and useful, and will be deployed in the future.

Generation System - The NYISO reports that there are currently more than 700 operational electric generating units in New York State representing approximately 38,902 megawatts of summer capacity. In addition, certain municipal electric utilities and large corporations possess generation resources that further contribute to existing in-state electric generation resources. According to the NYISO's Transmission and Interconnection Study Queue (June, 2012), there were approximately 66 active generating projects at various stages of development in the approval process for interconnection with the State's transmission system. If those projects are ultimately constructed, they would add approximately 9,000 megawatts to the system. Figure 5 presents a breakdown of New York's generating capacity by fuel type. Currently, more than two thirds of the generating fleet operating today was built prior to 1990.

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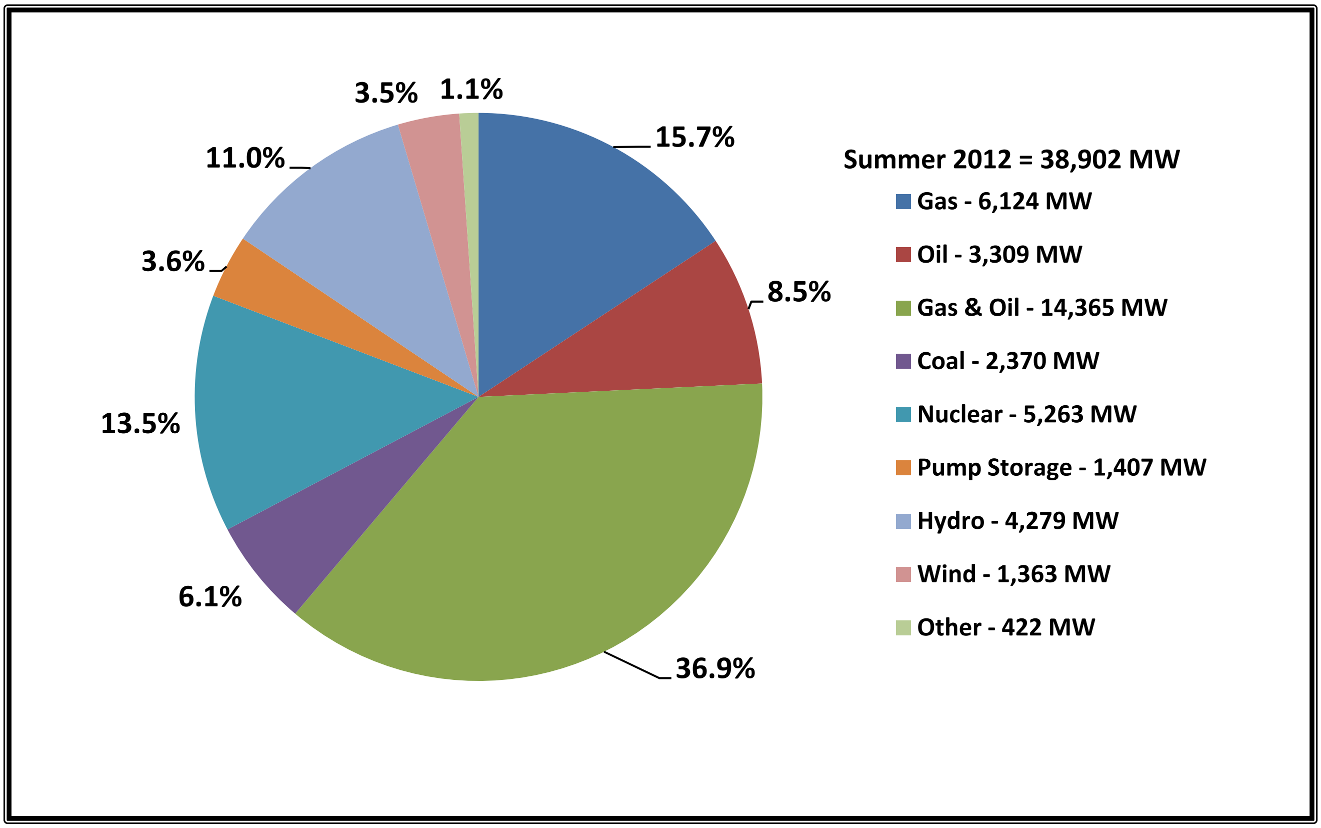
[5] Following termination of the National Grid contract, PSEG , which was competitively selected by LIPA to operate its system, will take over these functions.

Figure 5. New York Control Area Capability by Fuel Type for 2012



Note:

1. All values are based on the NYISO 2012 Load & Capacity Data summer capability of each resource rounded to the nearest whole MW
2. Wind generators are based on nameplate rating
3. Other includes methane, refuse, solar, and wood

Other Suppliers - In addition to these central station generation plants, New York has a large base of installed demand response providers that reduce load when called upon by the NYISO. Demand response providers are classified as mandatory or voluntary load reduction and are compensated accordingly. The Special Case Resource (SCR) program requires the responsible provider to reduce its load when called or be penalized. The providers in the Emergency Demand Response Program (EDRP) can voluntarily reduce load when called. These programs typically are called during system peak conditions, but they can be called by the NYISO at any time in accordance with established protocols. The Special Case Resource and Emergency Demand Response Program programs were called by the NYISO 21 times between 2001 and 2011. The Special Case Resource registration has increased almost four-fold since 2001 and now has approximately 2,000 MW registered in the program while the EDRP has decreased by approximately 100 MW and now has approximately 260 MW. The current amount of registered Special Case Resource capacity is on the same order of magnitude as coal or wind capacity.

Generators and other suppliers receive payments from the capacity market. The amount of capacity required is determined by the Installed Reserve Margin (IRM). The New York State Reliability Council (NYSRC) has established an installed reserve margin requirement of 16.0 percent for the New York State electric system for the capability year May 2012 - April 2013.[6] The reserve margin is the amount of electric generating capacity required in excess of the projected peak customer demand for electricity. The reserve margin is a reliability standard that is designed to ensure that capacity to meet peak load will be present in the event of unexpected higher demand and scheduled or unplanned generation outages. All load-serving utilities and other providers must procure capacity equal to 100 percent of their forecasted peak load plus the reserve margin. Additionally, two areas of the State are required to meet locational generating capacity requirements. The New York City area is required to obtain resources equal to 83 percent of its peak demand from electric generating facilities located within the City for the capability year May 2012 - April 2013. Due to the limited connections to mainland, the Long Island area is required to obtain resources equal to at least 99 percent of its peak demand from electric generating facilities located on Long Island for the same period.

Load - "Load" is defined by the U.S. Energy Information Administration as "the amount of electric power delivered or required at any specific point or points on a system. Load originates at the energy consuming equipment of the consumer." With limited cost-effective energy storage capabilities on the power system, electric energy has to be produced precisely at the time it is needed. Therefore, understanding the nature of load is essential to evaluating the overall reliability of the system.

Growth in load, also known as electrical demand, is the result of countervailing forces. There are positive forces such as economic growth that result in the development of new businesses or construction of new housing units and technological changes that result in new end uses, such as the introduction of air conditioning, computers, and mobile devices. Off-setting these increases are forces that reduce or dampen the growth of electricity such as reduced economic activity and improvement in end-use electrical efficiency. The average annual load growth in New York between 1991-2011 was 0.5 percent. Yet within this period, the annual load experienced a wide range of growth rates of 4.4 percent between 2004-2005 followed by -3.0 percent between 2005-2006 and 3.2 percent between 2006-2007. Figure 6 illustrates historical energy demand for New York State by sector.

As illustrated in Figure 6, the commercial sector has long been the largest segment of the State's overall demand, currently accounting for 54 percent of the demand, followed by residential (35 percent) and industrial (10 percent) demand. Transportation demand has been steady and reflects mass transit demand, not small-scale electric vehicles. This load growth among sectors also affects the reliability of the system. Planning and operating studies rely on historical load shapes (8760 hrs/year) for their analysis. Sector load profiles differ.[7] Consequently, the sector composition of the overall system varies, as does the load profile that introduces uncertainty into system planning and operations.

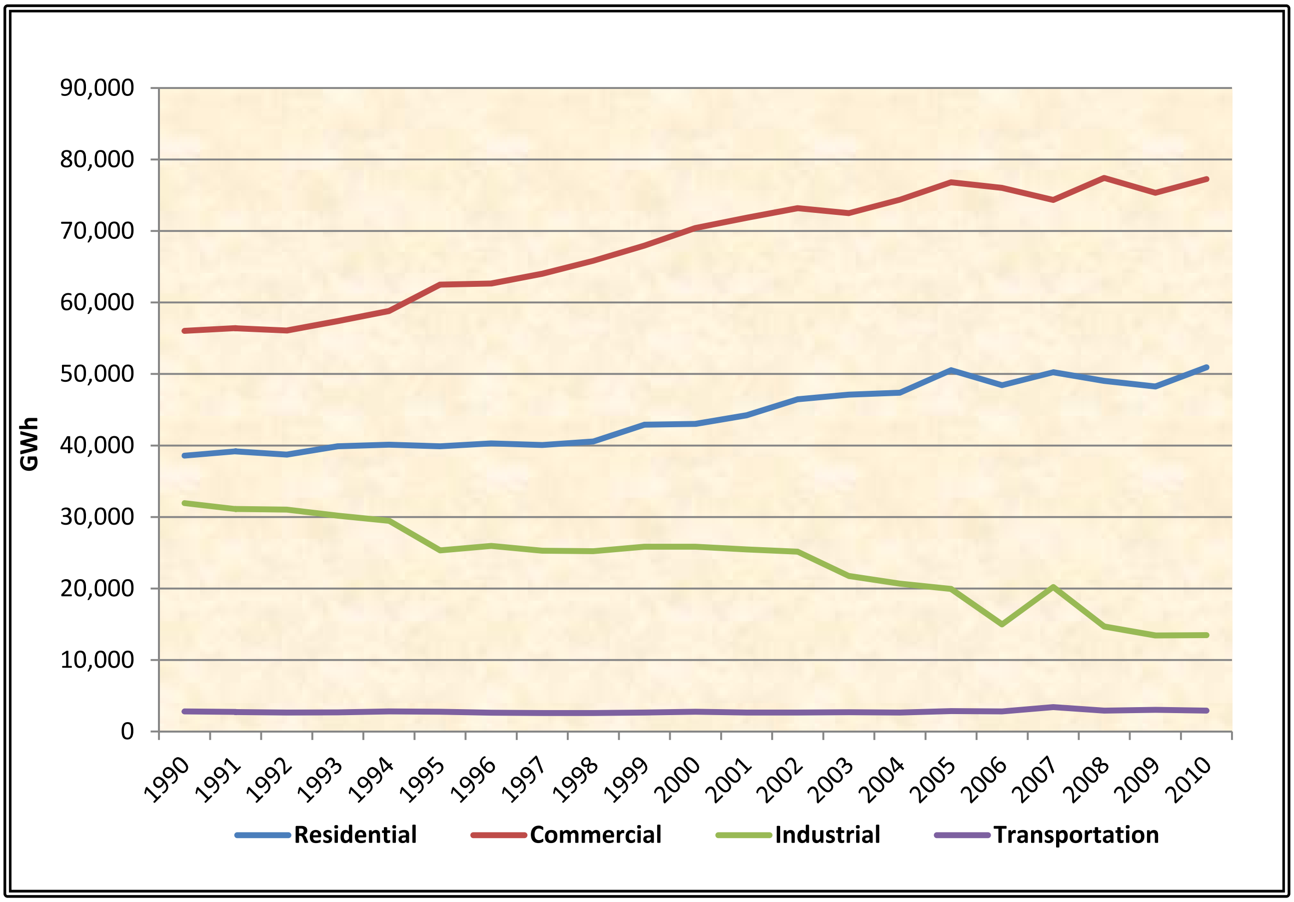
[6] In the past 10 years, the reserve margin has ranged from 15-22 percent. The variation over the years can be attributed to refinement of modeling methodology, changes in generation mix, load levels, and resource availability.

[7] The residential sector load is largely weather dependent, while the commercial sector is weather and business-cycle dependent. The industrial sector is primarily business cycle dependent.

Figure 7, is also important. The areas west of the Eastern interface (Zones A-E) experienced average annual load growth of -0.4 percent between 2000-2010. In the same period, the areas from the Capital Region to lower Hudson Valley (Zones F-I) experienced an average annual load growth of 0.3 percent. New York City and Long Island (Zones J-K) experienced a 1.2 percent annual load growth.

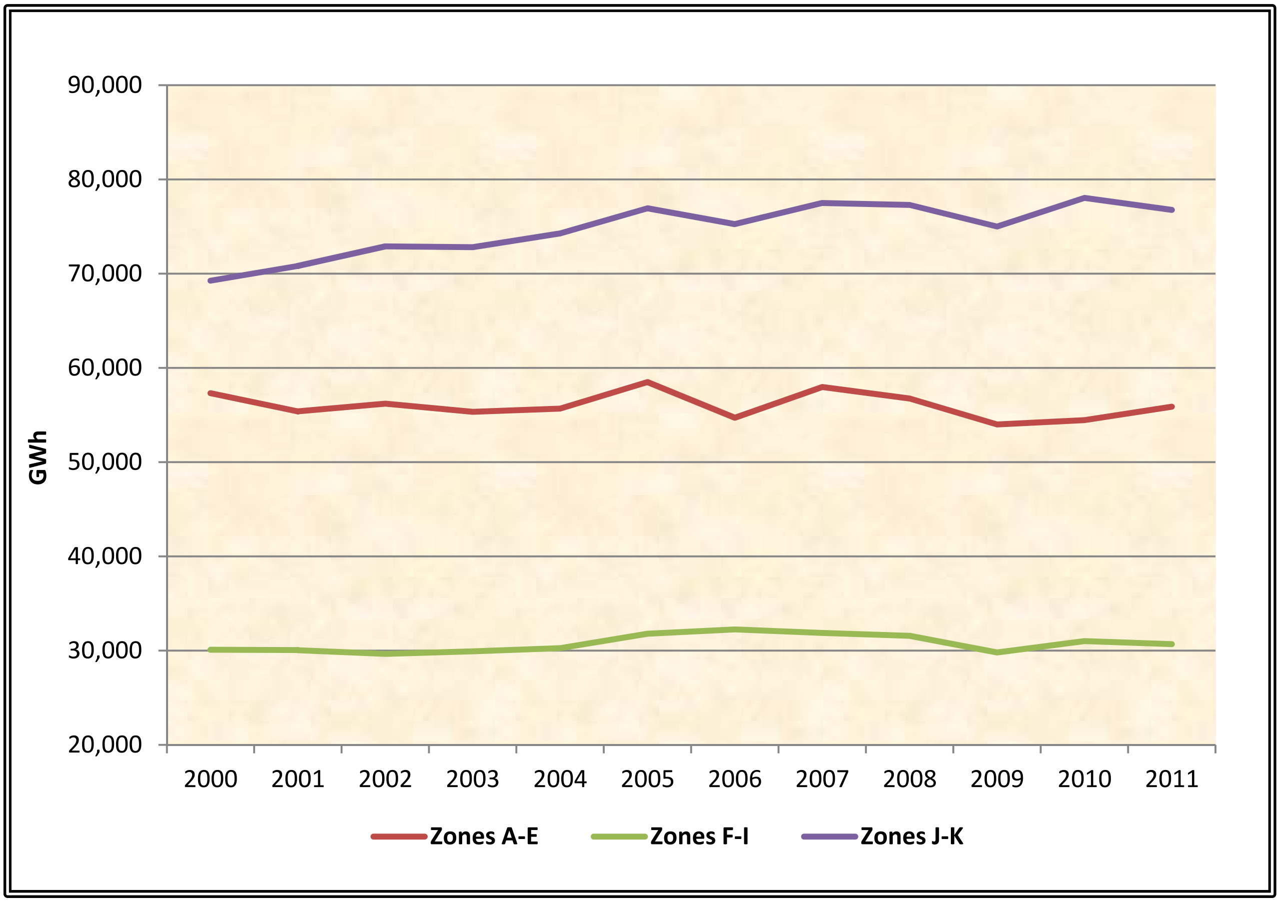
Table 2 presents the 2012 forecasted peak load and summer capacity contained in the zones defined above. This data was derived from the NYISO 2011 "Load & Capacity Data" report.

Figure 6. New York State Historical Electric Demand by Sector



Source: NYSERDA Patterns and Trends, 2012

Figure 7. New York State Historical Electric Demand by Aggregated Zones



Source: NYISO Load & Capacity Data

Table 2. Forecasted 2012 Peak Load and Summer Capacity

Zone	Peak Load (MW)	Summer Capacity (MW)
West (A-E)	9,692	14,750
Hudson Valley (F-I)	6,663	9,072
New York City (J)	11,500	9,466
Long Island (K)	5,440	5,614
Total	33,295	38,902

Note: Values taken from the 2012 NYISO Load & Capacity Data report. Peak load is non-coincident and includes impacts of Statewide Energy Efficiency Programs. Capacity is expected based on information available as of April 15, 2012.

Overview of Resource and Transmission Operating Reliability

Bulk electric system reliability consists of two primary elements:

- Resource Adequacy - are there enough system resources, deliverable when and where needed, to meet demand; and
- Transmission Operating Reliability - is the delivery system adequate to get the power to the demand and can it withstand various contingencies without dire consequences.

Resource adequacy is determined on a probabilistic basis. In the Northeast as in most of North America, the generally applied standard is "one day in ten years." This means that sufficient resources must be available to serve all firm customer demand such that the probability of the involuntary disconnection of firm load is no greater than one occurrence in ten years. Resource adequacy problems, or shortages in generating capacity and other resources, can lead to voltage reductions (brownouts), public appeals, and rotating feeder outages. By their nature, they usually can be anticipated in advance and appropriate preventive actions taken ahead of time.

Transmission operating reliability is assessed on a deterministic basis. Transmission standards or criteria specify a variety of specific potential disturbances or "contingencies" – the bulk electric system must be able to withstand any of these without adverse consequences. Failures of the transmission system can lead to overloads, cascading outages, instability, system separations, and blackouts over widespread areas. They can occur without warning and are rarely anticipated; hence, preventive actions, other than scrupulous adherence to standards and criteria, generally are not possible.

Both resource adequacy and transmission operating reliability are addressed through planning and operating standards and criteria. On a planning basis, resource adequacy is addressed through short-term (one-year) and long-term (five-10 years) probabilistic studies. Probability-based computer models simulate the variations and availability of power grid components to determine generating and other resources required to serve that load, plus a "reserve margin" of additional resources that must be maintained to cover unanticipated shortages in generating capacity. Each year, the NYSRC plans for the following bulk-power system capability year[8] through NYISO reliability planning processes. Locally, the New York State transmission-owning utilities plan for their own systems. On a short-term operating basis (days, hours, minutes), the NYISO addresses resource adequacy and transmission operating reliability through the dispatch of resources to serve actual system loads and meet reliability criteria considering the availability of specific resources in real time.

In conducting a resource planning study, accurate outage information must be collected for all generating units. In today's restructured environment, this is more complicated than in the past, when vertically integrated utilities owned virtually all generation. Nevertheless, generators must report their outage data to the NYISO in accordance with NYISO procedures; updated software and data analysis procedures have been implemented in the last three years. The decision to invest in generation is left to private investors in the first instance, who act in response to price signals from energy and capacity markets. Should sufficient generation resources not be added by private investment, the NYISO has authority to call on responsible transmission owning utilities to proceed with regulated backstop solutions to maintain reliability, which could entail adding transmission, generation, and/or demand response resources. These probabilistic resource studies are complemented by deterministic transmission studies. Mandatory power- system reliability standards and criteria have been developed by the North American Electric Reliability Corporation (NERC) for the United States and Canada, the Northeast Power Coordinating Council (NPCC) for the northeastern United States and Canada, and the NYSRC for New York State. These standards establish the transmission planning and operating requirements to keep the bulk-power system stable and free from overloads, low voltages, cascading outages, system separations, or customer interruptions following a contingency.

[8] Capability Year is defined from May 1st to April 30th of the following year.

Bulk electric system outages due to the failure of transmission or generation equipment exceeding the defined standards are rare, however, when they do occur, their effects can be widespread. Normally the loss of a single facility will not affect customers because the transmission system is designed in accordance with specific standards that effectively provide redundancy. If one transmission or generation facility fails suddenly, power flow is redistributed on the remaining facilities according to the laws of physics (*i.e.,* Kirchhoff's Laws). If a generator trips, its output will almost instantaneously be "picked-up" by all of the other generating facilities on-line throughout the interconnection. This is, however, accompanied by a dip in system frequency. On a slightly longer term basis (*e.g.,* 10 minutes), generators that are not operating at full capacity can be "ramped-up" to replace lost capacity, which will also restore normal 60 Hz frequency. In extreme cases, measures such as calling upon customers to reduce load may be taken. As a final step, load-shedding (disconnecting firm customer load) may be employed to avoid potential cascading or wide area blackouts.

Widespread blackouts typically are instigated by one or more unexpected events on the bulk power system beyond those defined by planning and operating standards and criteria, often involving multiple contingencies. Such extreme events can lead to overloads, cascading outages, instability, system separations, or total blackouts over widespread areas. Blackouts develop in fractions of seconds or seconds, rather than hours or days.

History has shown that stringent, mandatory standards and criteria are particularly important at the planning stage, during operations planning, dispatch and operations, and operator training. Less probable risks can and will occur: actual peak demand will sometimes exceed forecasts; unforeseeable contingencies will arise; human operators will err; sophisticated high-tech and other equipment will fail. The best way to provide the customers with a reliable electric system is to have strong standards and criteria, use sound engineering judgment, follow good utility practice, and plan the system on an integrated rather than a piecemeal basis. Additionally, thorough operator training is essential to ensure appropriate actions are taken when contingencies occur that will minimize widespread impacts. The probability of blackouts and other disruptions is minimized when there are common minimum standards by which all systems abide.

The mechanisms used to measure transmission reliability are traditional load-flow and stability programs. In conducting a transmission planning or reliability study, a variety of generation scenarios typically are chosen for the present or selected future year, and the range of contingencies required by the standards/criteria are simulated for each. Critical contingencies, as defined by the NERC, NPCC, and NYSRC standards, criteria, and rules, are applied to the modeled system for each scenario chosen.

In a planning study, the results of contingency tests will indicate where and to what extent the existing system needs reinforcement. Potential solutions to any violations are chosen and further investigations conducted, until an optimal solution emerges. In a reliability assessment study, the results will be either "pass" or "fail," which normally leads to an investigation to determine what would be required to bring the system into compliance.

Overview of Distribution Reliability

The Public Service Commission (PSC), supported by the Department of Public Service (DPS) staff, is responsible for ensuring that the investor-owned utilities' electric distribution system provides safe and adequate electric service at just and reasonable rates. Through its staff, the PSC also oversees the operations of the distribution systems and monitors these utilities to ensure that they operate in accordance with Commission and statutory requirements. PSC jurisdiction applies to approximately 75 percent of New York State energy sales.

While New Yorkers rarely see blackouts that affect the entire state, they can be affected regionally, and quite severely, by power outages. One has to look no further than Hurricane Irene, Tropical Storm Lee, and the October 2011 snow storm that interrupted electric service to 1.5 million customers in New York State. In large regional events, even transmission facilities are affected.

Mitigating outages in the distribution system has some parallels with the transmission system. Adherence to effective design standards, inspections and maintenance, load studies, adequate capital investment, failure trend analysis with corrective programs, and the application of technology, all play a role.

As a means of monitoring levels of service reliability, the Public Service Commission's Rules and Regulations require utilities delivering electricity in New York State to collect and submit information to the Commission regarding electric service interruptions on a monthly basis.[9] The utilities provide interruption data that enables staff to calculate two primary performance metrics: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration). The information is grouped into 10 categories that delineate the nature of the cause of interruption (cause code). Analysis of the cause code data enables the utilities and DPS Staff to identify areas where increased capital investment or maintenance is needed. As an example, if a circuit were shown to be prone to lightning-caused interruptions, arrestors could be installed on that circuit to try to minimize the effect of future lightning strikes. In general, most of a utility's interruptions are a result of major storms, tree contacts, equipment failures, and accidents.[10] DPS Staff maintains the interruption information in a database that dates back to 1989, which enables it to observe trends.

The Commission also has adopted electric service standards addressing the reliability of electric service. The standards contain minimum acceptable performance levels for both the frequency and duration of service interruptions for each major electric utility's operating divisions. The utilities are required to submit a formal reliability report by March 31 of each year containing detailed assessments of performance, including outage trends in a utility's various geographic regions, reliability improvement projects, and analyses of worst-performing feeders. There are no revenue adjustments for failure to meet a minimum level under the service standards. Utilities are, however, required to include a corrective action plan as part of the annual report. The service standards were last revised in 2004.

In addition, utility performance is compared with a utility's Reliability Performance Mechanisms (RPMs) established as part of the utility's rate orders. RPMs are designed so that companies are subjected to negative revenue adjustments for failing to meet electric reliability targets. While most RPMs typically include targets for frequency and duration, some RPMs have additional measures to address specific concerns within an individual company.

In general terms, performance on the outage frequency measure is based primarily on overall system design, maintenance practices, and weather. Declines in the performance on the outage frequency measure are often due to a lack of timely capital investment and improper maintenance. Decisions made by utilities on capital expenditures and maintenance policies can take several years before being fully reflected in the outage frequency measure. Performance measured by duration of outage is primarily influenced by the availability of workforce, the management of the workforce, and the geographic nature of the service area. Additionally, the complexity of the interruptions and a utility's ability to minimize the number of customers affected when performing repairs affects the overall duration measure.

[9] 16 NYCRR Part 97, "Notification of Interruption of Service" specifies and defines the following 10 cause codes that reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customer equipment, lightning, and unknown. There are seven additional cause codes used exclusively for Con Edison's underground network system.
[10] The accident cause code covers events not entirely within in the utility's control including vehicular accidents, sabotage, and animal contacts. Lightning is reported under a separate cause code.

B. Transmission System Reliability

History

Reliability standards and criteria used for planning and operations have been an integral part of the electric power industry since the first systems were developed in the late 19th century. Standards and criteria were codified and became increasingly important as power systems expanded and merged to form what we now know as synchronous interconnections or "grids."

Early "central station" systems were relatively simple. A major disturbance or "contingency" could, at worst, shut down electric service in a small area; in the case of Thomas Edison's early direct current systems, approximately one square mile. The introduction of high-voltage alternating-current technology permitted the use of long lines at higher voltages. This led to power systems that spanned significantly larger areas. Additionally, shared generation reservation minimized reliability risks from transmission problems allowing interconnections with neighboring systems.

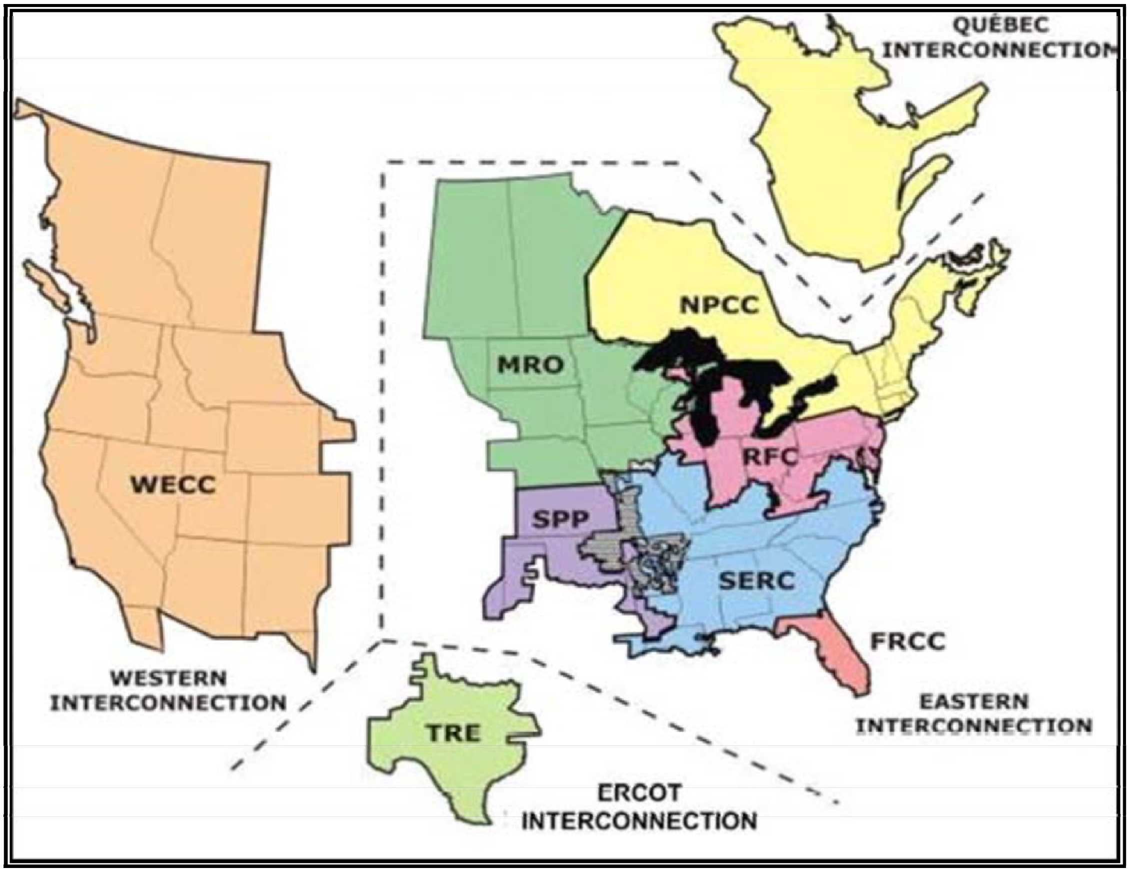
This process took place through most of the 20th century, and eventually power systems in most of the U.S. and Canada consolidated into four large synchronous interconnections, the largest of which, the Eastern Interconnection, stretches from the Eastern Seaboard to the Rockies, and from the Canadian Maritime Provinces to Florida. With systems this large, reliability becomes a major concern, in turn making coordination a critical requirement. Both coordination and reliability require effective and consistent reliability standards.

During the first half of the 20th century, each individual power system had developed and applied its own reliability criteria. With the dramatic growth of synchronous interconnections and the increasing use of the system to transmit power over long distances, the limitations of such an approach were becoming obvious. When the Northeast Blackout of 1965 occurred, it became clear that a more coordinated approach was necessary.

By 1965, the Pennsylvania-New Jersey-Maryland Interconnection (PJM) was already functioning with a uniform set of reliability criteria. The systems involved in the 1965 blackout soon followed suit. Shortly after the blackout, they formed the Northeast Power Coordinating Council (NPCC). The U.S. portion of NPCC formed two new power pools to establish a coordinated generation dispatch among investor-owned utilities within each respective pool. These constituent areas of the NPCC became the New York Power Pool, which evolved into the NYISO, and the New England Power Pool, which eventually became the Independent System Operator-New England (ISO-NE).

Other utilities across North America formed their own regional reliability councils, which eventually encompassed all of the 48 contiguous states and adjacent Canadian provinces. Over time, each regional council established its own reliability criteria and developed procedures for assessing conformance. Individual systems and power pools often maintained their own detailed or more stringent criteria in addition to the regional criteria as a minimum. The regional reliability councils formed the North American Electric Reliability Council (NERC) in 1968 to coordinate activities nationally and develop overall reliability guidelines for their collective systems. Figure 8 illustrates the synchronous interconnections in the lower 48 states, Canada, and the small portion of northern Baja California, Mexico.

Figure 8. NERC Interconnections



Source: NERC, 2012

Over the years, the New York Power Pool developed specific reliability rules and established the installed reserve margin. In 1999, as part of the Federal Energy Regulatory Commission's (FERC) approved restructuring of the wholesale electric industry in New York State, and in recognition of unique characteristics and reliability considerations of the electric grid in New York State, the New York State Reliability Council (NYSRC) was created and separated from the market governance structure to develop, maintain and enforce reliability rules and criteria uniquely required to maintain essential reliability in New York. This delineation from the market was developed to ensure that reliability was not driven by market interests.

On August 14, 2003, the blackout of the Midwest and Northeast United States and Ontario, Canada resulted in major industry changes codified in the Energy Policy Act of 2005 (EPAct). Section 215 of EPAct expanded FERC's authority to include oversight of mandatory reliability rules administered through an Electric Reliability Organization (ERO) designated by FERC. Section 215 expanded FERC's authority to include penalty authority of up to a million dollars per day for failures to comply with standards and rules promulgated pursuant to Section 215. NERC was ultimately designated by FERC as the ERO to be responsible for the development and compliance of mandatory reliability standards.

Regulatory / Oversight Framework

The following is a brief summary of the roles of the major entities involved in the regulation and oversight of transmission and the development of transmission reliability rules. A brief discussion of standards and criteria is provided as background and to facilitate a better understanding of the mechanisms that may be needed to mitigate potential impacts to reliability identified in various studies described later in this section.

FERC - The Federal Energy Regulatory Commission (FERC; formerly the Federal Power Commission) is the independent federal agency that regulates sales for resale of hydroelectric power, electric, gas, and oil in interstate commerce including the transmission of electricity and the maintenance and enhancement of the reliability of the bulk power system. Among other electric energy-related responsibilities, the EPAct gave FERC additional responsibilities in the areas of interstate electric transmission siting and planning. Specific FERC responsibilities include:

- Regulation of the transmission and wholesale sales of electricity in interstate commerce
- Protection of the reliability of the high-voltage interstate transmission system through mandatory reliability standards and enforcement of regulatory requirements through imposition of civil penalties and other means
- Review of certain mergers and acquisitions and corporate transactions by electricity companies
- Review of the siting application for electric transmission projects under limited circumstances
- Monitoring and investigation of energy markets
- FERC does **not**: deal with local distribution facilities, regulate retail electricity and natural gas sales to consumers, have the authority to order or approve the physical construction of electric generation facilities other than hydroelectric facilities, or regulate the activities of the municipal power systems, federal power marketing agencies or most rural electric cooperatives

NERC – The North American Electric Reliability Council (NERC) is an international, independent not-for-profit corporation with the responsibility to ensure the reliability of the North American bulk power system through the establishment and enforcement of reliability standards.[11] NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States, Canada, and a portion of Baja California in Mexico. Within the U.S. boundary, NERC serves as the FERC designated ERO. ERO activities in Canada related to the reliability of the bulk-power system are recognized and overseen by the appropriate governmental authorities in that country.

NERC responsibilities include:

- Working with stakeholders and regional reliability councils to develop and enforce standards
- Assessing resource adequacy annually with a 10-year forecast, as well as summer and winter forecasts
- Educating, training, and certifying industry personnel
- Investigating and analyzing the causes of significant power system disturbances

Originally reporting to a board composed mostly of regional reliability council executives, during electric industry restructuring, NERC evolved to governance by an independent board. NERC also changed its policies of regional councils proposing new standards to the assumption of FERC directives to adopt new standards.

NERC standards apply to the entire country, from areas that are vertically integrated with little interaction with neighboring control areas to other areas that have separated generation from transmission with a single grid operator overseeing the markets and dispatch. In all instances, the power system must be operated in a secure and reliable manner. As a result of this hybrid structure, NERC developed categories to specify tasks required to maintain reliability rather than a generic title, as was the case prior to deregulation. These categories, or functional entities, are defined in the NERC Functional Model document and serve as the basis for assigning roles and responsibilities. All organizations involved in ensuring reliability must register with NERC as one or more of the functional entities. In some instances, compliance with NERC rules is reported

[11] NERC is governed by a 12-member Board of Trustees consisting of 11 independent directors plus the CEO. The independent directors are appointed by the sector based Member Representative Committee. NERC is funded by the Federal Governments of the U.S., Canada, and Mexico. Its 2013 budget is $54.3 million.

through other parties, such as the NYISO reporting that a transmission owner (TO) or generator has met certain standards. In other cases, the TO or generator is responsible to report compliance directly to NERC. This distinction will become important when compliance is discussed later in this section.

NPCC – Northeast Power Coordinating Council, Inc. (NPCC)[12] encompasses a geographic region that includes the State of New York and the six New England states as well as the Canadian provinces of Ontario, Québec, New Brunswick, and Nova Scotia. NPCC's responsibilities include:

- Development of regional reliability standards and regional-specific criteria, compliance assessment, monitoring, and enforcement
- Administration and enforcement of continent-wide and regional standards in coordination with NERC
- Coordination of system planning, design, operations, and reliability assessment among member planning areas, transmission owners, and others

As a regional entity, NPCC operates under a delegation agreement with the NERC. This agreement recognizes that NPCC qualifies for delegation by NERC of certain roles, responsibilities, and authorities as defined by Section 215 of the Federal Power Act and Canadian provincial regulatory agreements. As with other regional reliability councils, the NPCC effectively functions both as the agent and administrative arm of NERC at the regional level, including:

- Administration of compliance processes
- Lead role in all compliance audits and compliance functions
- Administration processes of NERC with respect to notices of alleged violations and proposed penalties or sanctions; and
- Conducting investigations, hearings, and negotiations for potential and alleged violations of reliability standards.

NPCC also establishes its own regional reliability criteria that are more specific or more stringent than NERC reliability standards.

Today, the NPCC remains the regional reliability organization for New York State and, pursuant to EPAct, national reliability standards developed by the ERO (NERC) do not pre-empt actions by regional or state reliability entities to ensure safety, adequacy, or reliability, *provided* that they are consistent with NERC standards. Thus regional, state, or local reliability organizations may have their own more stringent reliability criteria, provided they are consistent with NERC standards at a minimum. Current NPCC criteria are somewhat more stringent than the national standards promulgated by NERC and endorsed by FERC.

NYSRC – Pursuant to Section 215 of the Federal Power Act, the State of New York may promulgate and enforce reliability standards that are more specific or more stringent than NERC standards or NPCC criteria as long as those standards do not degrade reliability outside of New York. The New York State Reliability Council's (NYSRC's) Rules set forth requirements that are more stringent or specific than either NERC standards or NPCC criteria and are adopted by the PSC.[13] Formation of the NYSRC was approved by the FERC as part of the comprehensive restructuring of the bulk power system and wholesale electricity market in New York State in 1999 to help maintain and enhance the reliability of the bulk electric grid in the State. The NYSRC is governed by a 13-member executive committee comprised of weighted representation by

[12] NPCC Board of Directors consists of 15 members; two representatives from each of the seven voting sectors and one independent representative. The sectors appoint their representatives while the Board selects the independent member. The estimated 2013 budget is approximately $15 million.
[13] For example, NPCC/NYSRC n-1-1 standard that prepares the system to withstand sequential outages is more stringent than NERC. Also, NERC does not have a federal resource adequacy standard, whereas NPCC/NERC apply a loss of load expectation of one in 10 years.

transmission owners, wholesale generators, large consumers, municipal power agencies, and unaffiliated individuals.[14]

Working in close conjunction with the NYISO, the NYSRC's responsibilities include:

- Development of bulk power system and local reliability rules that are more stringent or specific than NPCC and NERC standards and criteria, and that are necessary to meet the special physical, geographic, and demographic system requirements of New York's bulk electric grid
- Assessment of NYISO and New York market participant compliance with those reliability rules through independent compliance reviews

NYSRC imposes on the NYISO the responsibility to meet all applicable NYSRC rules by developing tariffs, procedures, and manuals to effectuate these rules. The NYSRC monitoring activities are performed by the Reliability Compliance Monitoring Subcommittee (RCMS). This specific data required from the NYISO are reviewed and considered by the RCMS. These data serve as evidence of compliance with NYSRC rules. The NYSRC also is responsible for the establishment of the annual statewide installed capacity requirement (*i.e.,* Installed Reserved Margin) for the New York Power System. The IRM represents the amount of generation capacity that must be in place to ensure an acceptable level of reliability.

NYISO - The New York Independent System Operator (NYISO) was formed as part of the restructuring of the wholesale electric markets in New York State. It was approved by FERC and commenced operation in 1999. The NYISO is an independent, not-for-profit entity, the responsibilities of which include:

- Operation and management of the State's bulk electric grid to maintain and enhance regional reliability
- Administration of open and fair wholesale electric markets
- Planning for the future of the bulk electric system
- Serving as an authoritative source of information for policy makers, stakeholders, and investors and
- Developing and implementing technology improvements on the bulk power system, including smart grid projects

In the New York Control Area, the NYISO is currently registered with NERC in the following functional capacities: Balancing Authority; Interchange Authority; Planning Authority; Reliability Coordinator; Resource Planner; Transmission Operator; Transmission Planner; and Transmission Service Provider. As such the NYISO has primary responsibility for overall bulk electric system planning and operations, as well as administration of the markets for capacity, energy, and ancillary services.

Transmission Owners (TOs) – TOs are the public utilities, authorities, or merchant transmission providers that own transmission, distribution facilities, or both and provide transmission services under FERC approved tariffs and state regulatory oversight. Transmission owners are responsible for the assessment and planning of transmission and distribution reliability on their own systems and for meeting the requirements of all Control Area, regional and national reliability standards and criteria.

New York State Public Service Commission (PSC) - The PSC regulates the State's electric, gas, steam, telecommunications, and water utilities, and is charged by law with responsibility for setting rates and ensuring the provision of safe and adequate service by the utilities it regulates. While the EPAct provided FERC the authority to establish a process for developing and approving national reliability standards for the bulk electric system, it also granted New York State the authority to establish rules that result in greater reliability within New York State, provided that such actions do not result in reduced reliability outside the State than that provided by the FERC-approved standards. To clearly establish New York State's oversight role, the PSC, by order dated February 9, 2006, adopted in their entirety the reliability rules established by the NYSRC, and periodically adopts updates to those rules. Additionally, unlike FERC, the PSC has the

[14] Each TO and sector appoints their representative and unaffiliated members are appointed by the Board. The NYSRC is funded by the transmission owners and the proposed budget for 2013 is $753,000.

authority to direct a TO to develop a plan to mitigate any deficiency that could include construction of additional generating facilities and infrastructure necessary to serve the public interest.

State Energy Planning Board (SEPB) - Every four years, the New York SEPB develops a State Energy Plan that includes broad policy recommendations to guide the State in reliability meeting its future energy needs. The State Energy Plan assesses current and future status of various energy systems (*i.e.,* electric, natural gas, petroleum, coal), energy costs, and public health and environmental impacts. This Transmission and Reliability Study is a supplemental report to the State Energy Plan to help inform the SEPB of the current and future status of electric reliability.

Reliability Standards and Criteria

Defined - The terms "standards" and "criteria" as used in the context of electric reliability are often confused. Current electric industry use generally refers to "standards" as the mandatory requirements developed and enforced by NERC (with FERC approval), and "criteria" as the requirements independently maintained and enforced by the regional reliability councils and distinct from the NERC standards.

The term "guidelines" is also occasionally used. NERC's original planning criteria were general in nature; guidelines as to what topics the regional councils should address in their own criteria. Today, guidelines are published to provide guidance in applying reliability practices. Guidelines serve to provide information on those approaches to planning and implementing effective reliability programs based on experience, lessons learned, and state-of-the-art techniques. The approaches and procedures are based on the concepts documented in the standards.

Developed - National reliability standards are drafted through a NERC process that includes industry participation from the proposal through the approval stage.[15] All proposed standards must be approved by a super-majority of registered entities throughout the industry, including each of the various industry sectors. The next step is review and approval by the NERC Board. The final step is review and approval by FERC. Technically, FERC is not authorized to impose new standards or modifications to existing standards on its own: however given its review and approval powers, FERC is given considerable deference in this area.

NPCC rules are developed through a similar procedure. Any person or entity materially affected by an existing criteria or with the need for new or revised criteria may initiate the process. After drafting and posting for comment, a final version must be approved by the NPCC Reliability Coordinating Committee and a weighted super-majority vote of the NPCC membership.

At the State level, a modification or new reliability rule can be initiated by the NYSRC or any other party. All requests for a new or modified rule are reviewed by the NYSRC Reliability Rules Subcommittee. The subcommittee reviews, assesses, and, if determined to be appropriate, seeks Executive Committee approval to develop a draft rule. All draft rules are posted for comments, which are taken under consideration by the Reliability Rules Subcommittee; however, the Executive Committee has the authority to approve the final rule.

The NYSRC also is an active participant in the NERC and NPCC Reliability Standards Development Process. The Reliability Rules Subcommittee reviews and comments on all new or revised NERC and NPCC Standards. It also drafts revisions of the NYSRC reliability rules as necessary to comply with NERC and NPCC standards.

Applied - Even before enactment of the EPAct, compliance with the regional council reliability criteria was mandatory for NPCC membership. While NPCC did not endorse or assign monetary penalties, NPCC criteria were given great weight with a compliance program that included the equivalent of peer review and reporting of violations to the NPCC Reliability Coordinating Committee.

[15] These are international standards, since Canadian systems are involved, but this discussion focuses on the United States

Today, the NYISO, TOs, and generating companies are subject to the reliability standards established by NERC. The NERC Reliability Standards are available from the NERC web site (http://www.nerc.com). Additionally, the NYISO, TOs, and generating companies also are subject to the NPCC Criteria and the NYSRC Reliability Rules. TOs each have supplemental transmission planning reliability criteria as well. NYISO and the TOs also adhere to various documents (procedures, guidelines, etc.) that define or strongly relate to practices for assessment of the transmission system for planning purposes. All planning criteria, documents, procedures, and guidelines pertaining to the design of the New York Transmission System are filed annually with FERC as part the NYISO Annual Transmission Planning and Evaluation Report filed as FERC Form 715.

Bulk Electric System (BES) Definition – NERC standards are applicable to the "Bulk Electric System" (BES). The appropriate definition of the BES has been a matter of considerable controversy during the past several years. FERC has argued for applicability of NERC standards to all transmission facilities 100 kV and higher, unless facilities are granted exemptions. Some of the regions, notably NPCC and the Western Electric Coordinating Council, have argued that a "one size fits all" approach will not improve reliability. The existing BES definition generally applies to facilities rated at 200 kV or higher, but could include some lower voltage facilities that may impact the overall system. In Orders 743 and 743-A, FERC allowed for exceptions from the 100 kV definition. At the time of this writing, the extent of the BES definition continues to evolve as FERC finalizes its precedent. The criteria for an exemption from the BES is currently being resolved though the standards process. The NERC drafting team submitted the proposed 100 kV BES definition, as well as a set of protocols for requesting exceptions, to FERC on January 25, 2012. On June 21, 2012 FERC issued a notice of proposed rulemaking soliciting comments on the NERC'S proposal. Once FERC approves the filing, participants will have from 18 to 24 months to be in compliance or obtain an exception, depending on the language of the Order. The NYISO, even prior to the NERC BES filing, has been working with the New York TOs on the necessary Transmission Operator and Transmission Planning registrations, as part of the NERC Functional Model definition previously described, and implementation plans that are expected to be required by the NERC BES definition, if it is approved by FERC.

To date, the terms "bulk electric system" and "bulk power system" have been used interchangeably, but now that the NERC has adopted a bright line definition these two terms have distinct meaning. By the NERC definition, the BES constitutes all facilities 100 kV and above that do not receive exemptions. By the NPCC definition, the BPS constitutes facilities that, if lost, could have significant adverse effects outside the local area where the disturbance occurs. There will be fewer BPS facilities than BES facilities.

Compliance and Enforcement

FERC, NERC, NPCC, NYSRC, and NYPSC – At the highest level, FERC plays a significant role in maintaining and enhancing the reliability of the bulk power system through enforcement of compliance with applicable standards and criteria. FERC oversees NERC (the ERO) and the eight Regional Entities, including the NPCC. NYISO is charged with day-to-day reliability responsibilities, with oversight by NYSRC, NPCC, and NERC. All three conduct audits and investigations relating to reliability programs and potential violations; FERC processes Notices of Penalty to the registered entity assessed by NERC or the Regional Entities for violations of electric reliability standards.

FERC can investigate alleged violations of reliability standards independently or in coordination with NERC, or review conduct that is the subject of a Notice of Penalty filed with the FERC. FERC investigations primarily focus on violations resulting in actual harm, either through the loss of load or through some other means, as well as cases involving repeat violations of reliability standards or a violation of a standard that carries a substantial actual risk to the system. Reliability investigations may result in detailed compliance plans, reliability enhancements, and significant civil penalties being imposed of up to one million dollars per day per violation.

FERC conducts reliability observation, independence, and standards audits on a proactive basis to ensure:

- Regional Entities are conducting their own robust audits

- Regional Entities are properly carrying out their responsibilities in an independent manner, and
- Regional Entities comply with the Reliability Standards. In some cases FERC performs these audits in conjunction with NERC.

Under FERC approved procedures, NERC files Notices of Penalty, which detail findings and resolution of violations or alleged violations by NERC or the Regional Entities. A Notice of Penalty may result in a settlement agreement and also describes mitigation efforts and factors considered by NERC or the Regional Entity in determining the appropriate remedy. FERC's enforcement program attempts to work in coordination with other FERC efforts on reliability, such as the review and approval of new Reliability Standards, educating the regulated community about FERC's reliability efforts, and promoting excellence in electric utility operational practices designed to enhance reliability.

In New York State, while NERC performs overall reviews, primarily through periodic on-site audits, the NPCC monitors compliance from a regional perspective through its task force structure. The NYSRC also conducts independent compliance reviews through its Reliability Compliance Monitoring Subcommittee, ultimately reporting to the NYSRC Executive Committee. As noted earlier, the PSC has adopted the NYSRC requirements as its own, enforcing compliance with those requirements when necessary.

Control Area / NYISO – As the NERC registered entity for a number of functions within the New York Control Area, primary responsibility for overall bulk electric system planning and operations rests with the NYISO, based on NERC's current definition of the BES at the time of publication.

The NYISO's program for maintaining compliance with electric power industry reliability and business standards is administered by its internal Reliability Compliance and Assessment Group (RCA). The RCA monitors mandatory and enforceable reliability standards, coordinates the NYISO's compliance reporting, and oversees the NYISO's adherence to the requirements and rules promulgated by NERC, NPCC, NYSRC, and the North American Energy Standards Board (NAESB)[16].

Each year the NERC, NPCC, and NYSRC identify a set of standards, criteria, and rules that will be monitored in a given calendar year.

The NYISO provides certifications of compliance with NYSRC Reliability Rules to that organization's Reliability Compliance Monitoring Subcommittee every year. In addition, NERC and NPCC conduct periodic on-site audits and off-site spot audits.

Transmission Owners - As owners of the transmission facilities in the State of New York, the TOs are responsible for compliance with applicable NERC standards and associated requirements. Since NERC standards became mandatory, NERC can and has conducted audits to monitor and ensure compliance. In functional areas of bulk system operations where the NYISO is registered with NERC, it must rely on the New York Transmission Owners to execute certain tasks.

The New York Transmission Owners also are responsible for compliance with applicable requirements and criteria of the NPCC and the NYSRC.

Generators - The New York State Generators are required to register with the NERC as Generator Owners and, as applicable, Generator Operators and are responsible to meet and comply with the applicable NERC standards and associated requirements. Since NERC standards became mandatory in 2007, NERC can and has scheduled audits of the New York Generator Owners. With respect to generator compliance with the NYSRC Reliability Rules, the NYISO develops rules and procedures, typically through its manuals, procedures,

[16] NAESB serves as an industry forum for the development and promotion of business standards that provide an efficient marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities.

and tariffs approved by FERC, that require the New York Generators to comply with applicable NYSRC Reliability Rules.

Impact of Restructuring - Industry developments have somewhat complicated the process of monitoring and ensuring transmission reliability. Restructuring effectively separated ownership of generating resources from transmission in New York. In much of the country, electric power resources are now provided through wholesale competitive markets rather than through vertically integrated utility monopolies. The parts of the country where single-system planning and operating power pools already existed, including the New York Power Pool, the New England Power Pool, and Pennsylvania-Jersey-Maryland, adjusted more readily than other parts of the country. These organizations were able to transition to Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) with little change in reliability protocols. Further, EPAct established new procedures for drafting reliability standards and measuring compliance in restructured markets. Responsibility for planning and operating the bulk system reliably now rests primarily with the Transmission Planners for the Control Areas, but all Market Participants are required to comply with applicable reliability standards and criteria.

Through its predecessor the New York Power Pool, the NYISO and NPCC each has a long history of developing reliability criteria and monitoring compliance, adapted fairly easily to the new mandatory enforceable reliability standard environment. Moreover, because of their control-area-wide operational and planning responsibilities and independence from any financial interest in generation or transmission facilities, as well as increased efforts at interregional coordination reduction of "seams" and enhancements in technology, the system reliability and planning efforts in these regions exceeds what was possible in the past.

Transmission System Planning

Adequate transmission system planning is essential to anticipate reliability issues and develop mitigation or protocols to counter potential needs in the system. Transmission planning occurs over short (one-year), medium (five-year), and long-term (10-year) periods. The following section summarizes the general concepts of transmission planning. A detailed explanation of the Comprehensive System Planning Process follows. Finally, key reliability studies are described. Findings from these studies are used to assess reliability and identify possible reliability impacts from policy decisions that are presented later in the report.

Protocols, Processes, Methodologies

The NYISO is the Planning Coordinator and one of two Transmission Planners (the second is National Grid) for the New York Control Area that operates within the footprint of the NPCC. The NERC Transmission Planning (TPL) group of Reliability Standards consists of six Reliability Standards that are applicable to the functional entities called Transmission Planners, Planning Coordinators, and Regional Reliability Organizations.

The NERC Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. Transmission planning is a process that involves a number of stages including:

- Developing a model of the Bulk Power System
- Using this model to assess the performance of the system for a range of operating conditions and contingencies
- Determining those operating conditions and contingencies that have an undesirable reliability impact; and
- Developing and evaluating a range of solutions and selecting the preferred solution, taking into account the time needed to place the solution in service

The proposed Transmission Planning Reliability Standards address:

- The types of simulations and assessments that must be performed to ensure that reliable systems are developed to meet present and future system needs and
- The information required to assess regional compliance with planning criteria and for self-assessment of regional reliability

Transmission System Standards for Normal and Emergency Conditions are the key part of the Transmission Planning Reliability Standards. They establish the system performance requirements for a range of contingencies grouped according to the number of elements forced out of service as a result of the contingency. Category A requirements apply to the normal system with no contingencies. Category B requirements apply to contingencies resulting in the loss of a single element, defined as a generator, transmission circuit, transformer, or single DC pole with or without a fault. Category C requirements apply to a contingency resulting in loss of two or more elements, such as any two circuits on a multiple circuit tower line or both poles of a bi-polar DC line. Finally, Category D requirements apply to extreme contingencies resulting in loss of multiple elements, such as a substation or all lines on a right-of-way. The system performance expectations for Category C contingencies are lower than those for Category B contingencies, in that they allow unspecified amounts of planned or controlled loss of load.

The NYISO addresses the requirements of the Transmission Planning Standards in conjunction with any more stringent or more specific requirements specified by NPCC and the NYSRC through three main assessments produced by the System and Resource Planning Department:

- The Area Transmission Review (ATR)
- The Reliability Needs Assessment (RNA); and
- The Comprehensive Reliability Plan (CRP)

The RNA and the CRP are major components of the NYISO's overall Comprehensive System Planning Process, and are discussed in that context below.

Area Transmission Review (ATR) - The Area Transmission Review is an NPCC required annual reliability assessment of the planned bulk power transmission system conducted by the NYISO. The purpose of these assessments and subsequent reports is to demonstrate that the New York Control Area planned bulk power transmission system is in conformance with the NERC Transmission Planning Standards and NPCC Design and Operation of the Bulk Power System. For each annual review, the study year is four to six years from the reporting date to allow for minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond six years to address identified marginal conditions that may have longer lead-time solutions. A Comprehensive ATR is required at least once every five years with Intermediate or Interim Reviews conducted in the years between Comprehensive Reviews to address changes in the system. The most recent ATR is one of the assessments used to develop base case assumptions for studies listed in this report, including those that are part of the NYISO Comprehensive System Planning Process.

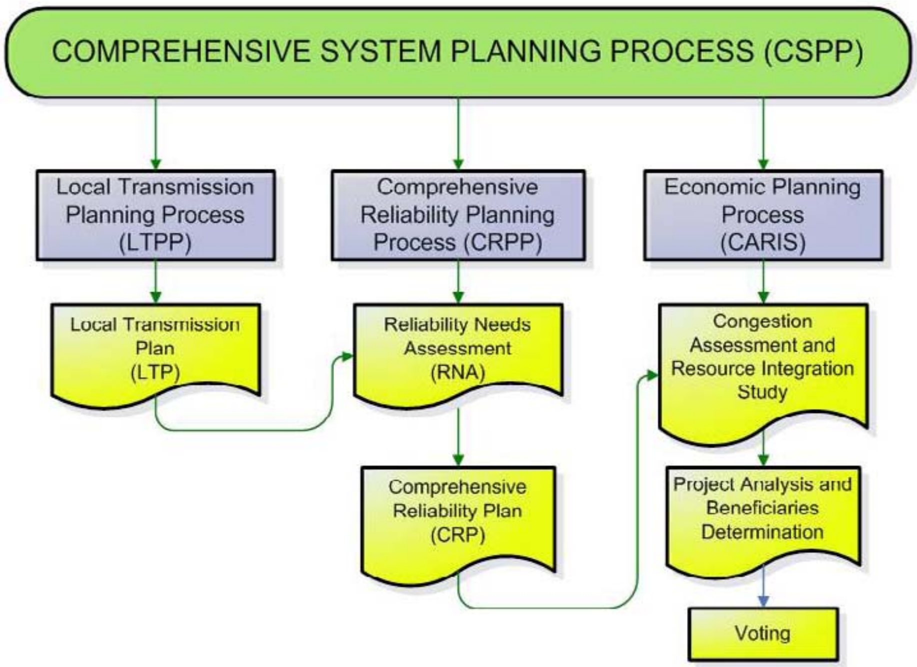
NYISO Comprehensive System Planning Process (CSPP) - Planning for the bulk electric system in a restructured environment, in which resources are acquired through wholesale competitive markets, is in some aspects very different and more complex than under a vertically integrated "command-and-control" paradigm. Today, the traditional planning aspects of grid operations are inextricably linked to the workings of the competitive markets. Thus the NYISO, as a federally registered Control Area Operator responsible to FERC for overall bulk system operations and planning in the New York Control Area, developed the Comprehensive System Planning Process (CSPP).

As required by FERC, NYISO conducts the CSPP as a transparent, ongoing process. The primary objectives of the CSPP are:

- To ensure that upgrades or other actions necessary to meet long-term reliability needs or potential reliability needs are identified in a timely manner, and
- To comply with all mandatory national, regional, and state reliability standards and criteria

The CSPP integrates the traditional elements of transmission owners' local (service area) transmission planning, statewide resource adequacy planning, and transmission system security with the economic planning required to account for and accommodate the workings of the competitive markets. Figure 9 illustrates the components and their interaction in the CSPP.

Figure 9. Comprehensive System Planning Process Components



Source: NYISO, 2012

Transmission Owner's Local Transmission Planning Process (LTPP). Each TO in New York State is required to engage in a LTPP, which results in a Local Transmission Plan (LTP) with a 10-year horizon, based on the TO's assessment of its system's reliability needs. The LTP is reviewed annually and formally updated and presented to market participants biannually. The TOs are responsible for administering their own LTPP, including providing adequate time for stakeholder input, as well as adhering to a number of specified procedures for disseminating information relative to the LTP, hearing and comment opportunities, and a dispute resolution process.

Each LTP is required to include identification of:

- The planning horizon
- Data, models, and assumptions used
- Needs and issues addressed
- Potential solutions under consideration, and
- A description of the transmission facilities covered by the plan

Any planning criteria or assumptions by the TOs are required to meet or exceed any applicable NERC, NPCC, or NYSRC criteria. The LTPPs are substantially integrated into the NYISO processes by tariff and serve as major input and basis for the RNA.

The Transmission Owner Strategic Transmission and Reliability Study (STARS) covers the long-term planning horizon from years 10 – 20 and is described in more detail later in this Section. Project plans and recommendations from STARS may be evaluated in the LTP as potential solutions.

Reliability Needs Assessment (RNA). The RNA is developed by the NYISO in conjunction with market participants and all interested parties. The RNA is performed to assess electric system reliability over the next 10-year period, consistent with NERC standards and NPCC criteria. The system characteristics from the ATR and LTPP as well as other assumptions such as load forecast, new/retired generation, and fuel forecast, serve as the basis for the reliability analysis. A base case and multiple sensitivities are evaluated using the resource adequacy criteria and transmission operating reliability/security criteria to understand the impact to reliability under varying conditions. After approval of the RNA, if a reliability need is identified in the base case with either a resource adequacy violation or transmission operating reliability/security violation, the NYISO will request market-based solutions from all interested parties and, simultaneously, a regulated reliability backstop solution from the designated responsible transmission owners to address the identified reliability needs. Developers also can propose alternative regulated solutions to serve as a backstop if market-based solutions do not materialize according to the schedule required to meet the reliability need. No action is taken if a violation of the reliability criteria is identified in only the sensitivities.

Comprehensive Reliability Plan (CRP). The CRP is the next major step in the CSPP. If a reliability need is identified in the RNA, the NYISO evaluates all proposed solutions to determine whether they will meet the identified reliability needs over the 10-year study period. From this evaluation, the CRP is developed, setting forth the plans and schedules that are expected to be implemented meet those needs.

The approved NYISO ATR and CRP demonstrate that all applicable NERC Reliability Standards and NPCC Criteria can be maintained, and identify any system reinforcements and additions necessary to maintain the required level of reliability. Area Transmission Reviews are submitted to and approved by NPCC annually and reviewed by the NYSRC. The ATR is available on the NYISO website. Reliability Needs Assessments and Comprehensive Reliability Plans are reviewed and approved by NYISO stakeholders and are posted on the NYISO public website as well.

Congestion Assessment and Resource Integration Study (CARIS) / Economic Planning. Building on the CRP, NYISO next undertakes the CARIS. Directed and developed pursuant to FERC Order 890. CARIS is designed to:

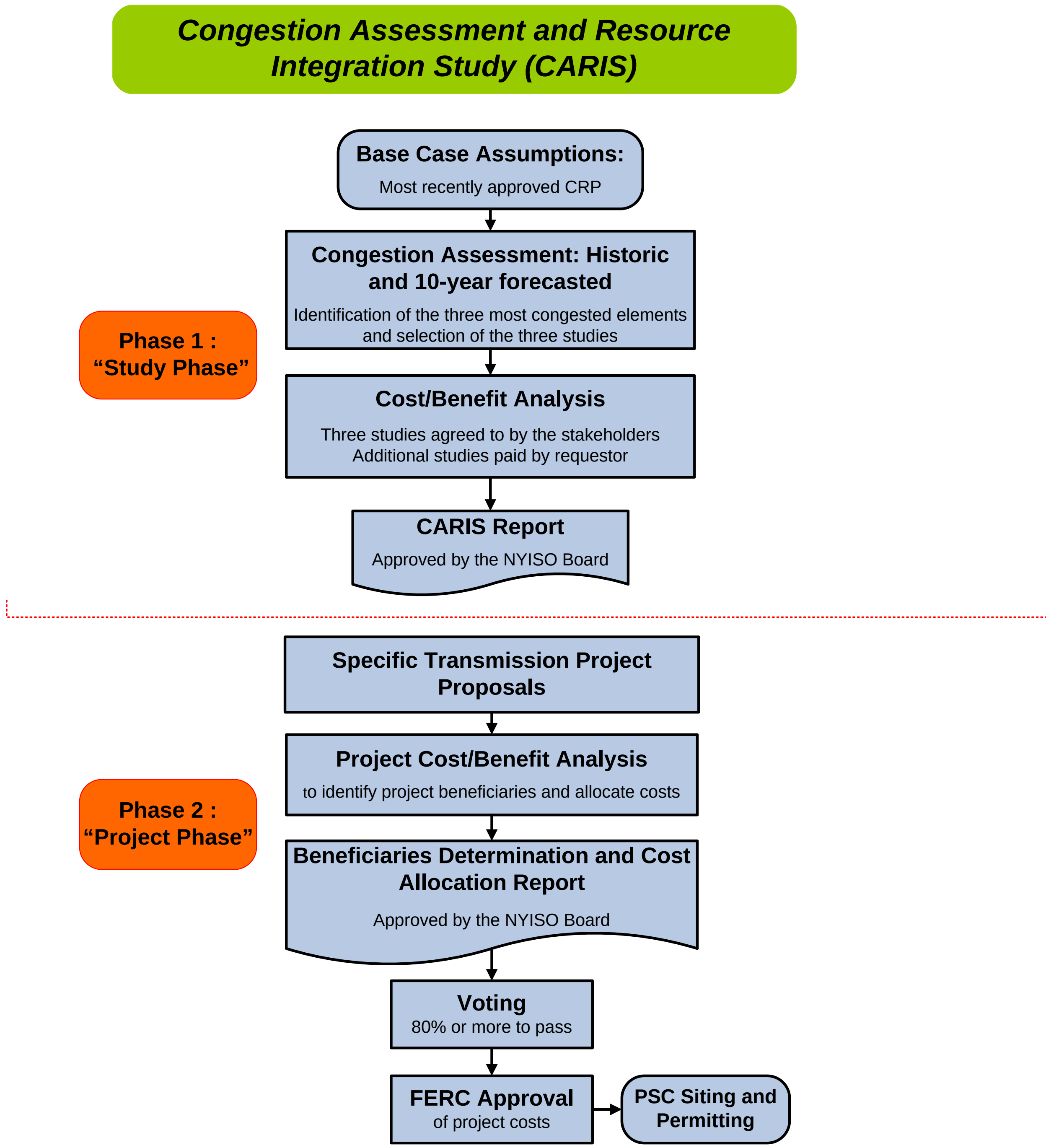
- Assess both historic and projected congestion on the New York bulk power system and
- To estimate the potential economic benefits of relieving that congestion by studying the effect of integrating potential transmission, generation and demand response resources, thereby providing information to stakeholders and facilitating the development of solutions to the identified congestion

The objectives of the CARIS economic planning process are to:

- Provide estimates of future congestion on the New York State bulk power transmission facilities over the 10 year CSPP planning horizon
- Through the development of appropriate scenarios, identify factors that might mitigate or increase congestion
- Provide information to market participants, stakeholders, and other interested parties on generic solutions to reduce congestion
- Provide an opportunity for developers to propose solutions that may reduce the congestion
- Provide a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff

The CARIS builds on and aligns with the CRP and assumes a baseline reliable system identified in the CRP for the 10-year study period. The CARIS process depicted in Figure 10 is described in detail in the following section. With the LTPP and the CRP, the CARIS completes the overall CSPP.

Figure 10. Congestions Assessment and Resource Integration Study Process



Source: NYISO, 2012

CARIS Phase 1 - Study Phase. In Phase 1 of the CARIS process, the NYISO, in collaboration with market participants and other interested parties, develops a 10-year projection of congestion, identifies and ranks the three most congested elements in the New York bulk power system, determines the three CARIS studies, applies the generic solutions to the congestion identified, and conducts the benefit/cost analysis of the applied generic solutions. In addition, the NYISO also performs scenario analyses, with scenarios including but not limited to load forecast uncertainty, fuel forecast uncertainty, new resources, retirements, emissions changes, environmental proposals, and energy efficiency programs.

For each of these three studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types, generation, transmission, and demand response are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, demand response, and generation resources placed individually in key locations on the system to measure their effects on relieving each of the three most congested elements.

Upon completion of the Phase 1 analysis, the results are presented to stakeholders for review through the NYISO governance process. Thereafter, the draft CARIS is forwarded to the NYISO board for review and action and also is provided to the Independent Market Advisor for review and consideration. The Board may approve the CARIS report as submitted or propose modifications on its own motion for further consideration. Upon approval by the Board, the NYISO issues the CARIS report and posts it on its website.

In addition to the three CARIS studies, stakeholders also may request additional studies of system congestion at their own expense. Requests may be made at any time, and studies will be conducted to the extent the NYISO's resources allow.

CARIS Phase 2 – Project Phase. Phase 2 of the CARIS is conducted after the approval of the Phase 1 report by the NYISO board. In Phase 2, the developers of potential transmission projects that have an estimated capital cost in excess of $25 million to alleviate congestion may seek regulated cost recovery through the NYISO Tariff. Such developers must submit their projects to the NYISO for analysis of benefits and costs (benefit/cost analysis) at any time prior to the input phase (Phase 1) of the next CARIS cycle, in accordance with the cost allocation principles and methodologies contained in the Tariff. Projects are eligible for regulated cost recovery if they would produce net savings based upon a comparison of the NYCA wide production cost savings with the annual total revenue requirements for the project, both computed over the first 10 years following the projected in-service date of the facility. The costs for the benefit/cost analysis will be supplied by the developer of the project using a reasonable amortization period. Specific project cost for the benefit/cost analysis will then be expressed as the net present value of the first ten years of the annual total revenue requirement for the project, starting from the proposed commercial operation date of the project. A CARIS Phase 2 study could cover up to 20 years.

"Beneficiaries" will be load serving entities in load zones determined to benefit economically from the project. Cost allocation among load zones will be based relative to economic benefit. The beneficiary determination for cost allocation purposes will be based on each load serving entity's use and zonal net locational based marginal pricing load savings.

As appropriate the NYISO also will analyze and present additional information by conducting scenario analyses appropriate, regarding future uncertainties, such as possible changes in load forecasts, fuel prices, and environmental regulations, as well as other qualitative impacts, such as improved system operations, other environmental impacts, and integration of renewable or other resources. Although this data may assist and influence how benefiting uses vote on a project, this data will not be used for purposes of cost allocation.

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to stakeholder working groups and committees pursuant to its governance process for comment and, if approved, will forward to the NYISO board of directors for its review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board and posted on the NYISO's website, the identified beneficiary LSEs then vote on whether the project is approved for cost allocation. For a project to be approved for regulated cost recovery, the Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process does not relieve the developer of the responsibility to file with FERC for approval of the project costs and with the appropriate state authorities to obtain siting approval for the project. To date, no project has gone through this voting process.

Other Key Studies

This section highlights other key New York and regional studies that are conducted to ensure reliability. Table 3 follows with a more comprehensive list of studies that summarizes the purpose, frequency, and other relevant information from the studies and illustrates the ongoing commitment of various stakeholders to maintain reliability.

NYISO Transmission Expansion and Interconnection Studies – The NYISO Tariff includes processes for parties to pursue construction of new transmission facilities or interconnection of new generation to the New York State Transmission System. Transmission facilities studied under the NYISO Tariff include transmission expansion and merchant transmission. Transmission expansion relates to the addition to, or modification of transmission facilities for the purpose of creating incremental transfer capability or to address reliability or other operational concerns. The transmission expansion process applies to upgrades or additions of facilities owned by TOs.

Interconnection facilities studied under the NYISO Tariff include proposed interconnections of large generating and merchant transmission facilities, as well as small generators and load. A "large" facility can be a large generating facility (generating capacity of more than 20 MW) or a merchant transmission facility (*e.g.,* an HVDC line). "Small" generating facilities (smaller than 20 MW) are subject to different and less complex studies. All of these transmission expansion and interconnection facilities are subject to studies coordinated or performed by the NYISO with considerable input from the TOs.

Preliminary Reliability Studies. The Feasibility Study, System Impact Study (SIS) and System Reliability Impact Study (SRIS) are all preliminary evaluations of the system impact and cost of interconnecting a facility to the New York State Transmission System. The studies look at the impact of the proposed facility on the reliability of the electric system and the potential for adverse system impacts. Among the primary objectives of these preliminary studies are:

- To confirm whether a proposed new or modified facilities associated with the project comply with applicable reliability standards
- To assess the impact of the proposed project on the reliability of the pre-existing power system
- To assess the impact of the proposed project on transmission transfer limits, considering thermal, voltage and stability limitations, and estimate the increase or decrease in the transfer capability of affected transmission interfaces
- To identify and evaluate alternatives to eliminate adverse reliability impacts, if any, resulting from a proposed facility

These preliminary reliability studies identify the specific interconnection facilities or equipment that would be required to interconnect a proposed facility to the transmission system in a reliable manner, taking into account the requirements and guidelines of NERC, NPCC, NYSRC, the applicable TO, as well as NYISO's own transmission planning guidelines and practices. These studies also provide a preliminary non-binding good faith estimate of cost responsibility and estimated time to construct the facilities or equipment needed to reliably interconnect a proposed facility.

Facilities Studies. The facilities studies are the final and most comprehensive interconnection studies. An Interconnection Facilities Study (Class Year Study) is performed concurrently for an entire group of developers in a combined study. The purpose of the Class Year Study is to identify and determine the cost allocation of the facilities or equipment required to reliably interconnect a project to the New York State Transmission System. Developers use the results of the Class Year Study to decide whether or not to accept their allocated system upgrade costs and move forward to an Interconnection Agreement. The Class Year Study is performed for all large and some small interconnection facilities. Those small generating facilities that are not subject to the Class Year Study need only to complete an individual Facilities Study that specifies and estimates the cost of the equipment, engineering, procurement, and construction work needed to implement the conclusions of the SIS. Similarly, the Facilities Study for a transmission expansion project (performed by the affected TO) provides a good faith estimate of the cost and time to construct the new facilities identified in the SIS and, if applicable, may provide a nonbinding estimate of the feasible TCCs that may result from the construction of the new facilities.

Installed Capacity Requirement - The Installed Reserve Margin (IRM) represents the amount of generating capacity that must be in place to maintain resource adequacy. It is measured by the amount of generation and other capacity resources above 100 percent of forecasted peak load that must be available to serve all customers without interruption. The NYSRC Installed Capacity Subcommittee (ICS) conducts an annual reliability study that consists of a base case and multiple sensitivities. The NYSRC reviews and approves the IRM study and uses the study to establish the annual statewide IRM for the New York power system. Both FERC and PSC approve the IRM.

These studies use probabilistic computer modeling techniques to calculate the probability of involuntarily losing electric load in the event of insufficient capacity.[17] Extensive work goes into developing, reviewing, and approving voluminous input data. Through its stakeholder process, the ICS reviews and approves the data, while the NYISO processes the data in the model. Consistent with the NYSRC IRM, the NYISO establishes the amount of installed capacity New York LSEs must purchase. Using the IRM, the NYISO also establishes the amount of generating capacity that must be located within certain transmission-constrained regions such as New York City and Long Island.

The IRM has fluctuated based on the results of the IRM study process. In 2011, the NYSRC study determined an IRM increase for the 2012-2013 Capability Year from 15.5 percent to 16.0 percent based on an updated load forecast, changes in plant availability, and other factors. It should be recognized that variations of required IRM levels from year to year such as these do not increase or decrease New York electric system reliability. The amount of IRM required for a given year is designed to meet the resource adequacy criteria that at any given time, the probability of an involuntary disconnection of firm load should not exceed one occurrence in 10 years.

Defensive Strategies Working Group - Following the August 2003 Blackout, the NYSRC formed the Defensive Strategies Working Group (DSWG) to explore mechanisms to protect the NYCA during major system disturbances. Since then, the DSWG has considered various technologies, and concluded that additional phasor measurements could provide the protection needed during a major system disturbance. The working group is comprised of representatives of the NYCA transmission owners, NYISO, DPS Staff, NPCC, and members of the NYSRC Executive Committee.

The DSWG has closely monitored various studies conducted by NPCC and the NYISO, while conducting its own investigations of “coherent generation groups” and other means by which intentional separation from the Eastern Interconnection and/or within the NYCA bulk power system might protect major portions of the New York system from internal or external disturbances. As part of this effort, the DSWG has planned and hosted several technology presentations by equipment and software vendors to study, review, and evaluate applications of system protection devices and phasor measurement units and to evaluate the potential applicability of these technologies. The DSWG also invited input from systems analysis experts (including Brookhaven National Laboratories, Pacific Northwest National Laboratories, and Electric Power Research

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[17] For many years, the New York power industry has pioneered the application of probability methods for capacity planning, including the development of computer models, reliability evaluation techniques and methods, and resource adequacy criteria. Studies for establishing statewide capacity requirements using probabilistic techniques were implemented during the late 1960s by the New York Power Pool.

Institute) on developing concepts for controlling the separation of the power system during major disturbances. The DSWG concluded that the application of additional phasor measurement technology could permit direct monitoring of the behavior of coherent generation groups and detect imminent system instability, and thereby might be used to implement the controlled separation concept.

The DSWG worked with the NYISO to develop a feasibility study for the application of phasor measurement technology with U.S. Department of Energy Smart Grid funding. Its objective is to develop and assess the feasibility of a protection system that would address where, how, and when to separate the system when an external or internal disturbance makes separation inevitable.

The study began the first quarter of 2011 and continued into 2012. It will include careful simulation of a variety of system events, originating both outside and within to the NYCA, to demonstrate security as well as dependability. It will be closely coordinated with a related NPCC study, referred to as Task 5 of the 2003 Blackout follow-up effort. While the New York study is focused on the interests of the NYCA and probes the security issue in detail, the NPCC Task 5 study is focused on initial feasibility findings related to the entire NPCC region. Should feasibility be demonstrated, the DSWG will work with the NYISO in pursuit of detailed design and implementation studies. These will include the areas related to communications infrastructure, hardware/firmware/software deployment, interfaces with the NYISO control center, and cyber security issues.

Any application of phasor measurement or other new technologies to protect the NYCA from external or internal disturbances like those in August 2003 should be viewed as a long-term undertaking.

New York Transmission Owner State Transmission Assessment and Reliability Study (STARS) Initiative - The New York State Transmission Assessment and Reliability Study (*i.e.,* the STARS initiative) has been a major long-term (20-year outlook) review of the transmission system in New York by the Transmission TOs. Proactively initiated by the New York TOs, in early 2009, the goal of the study was to optimize the reliability of the New York transmission system and explore opportunities to expand transmission system capability in the context of replacing aging infrastructure. It was not the result of regulatory requirements. The Study examined the long-term reliability and economic upgrade alternatives, including smart grid applications and delivery of renewable power, consider different capacity and transmission expansion and retirement plans. A major focus of the review was to analyze the age of the existing transmission facilities and assess their expected useful life. The Study has proposed various strategies for upgrading, refurbishing and/or building new transmission in New York to replace aging infrastructure, support the integration of renewables, and improve the economic efficiency of the New York power grid.

The scope of work for STARS was reviewed and supported by the NYISO, the DPS, and NYSDEC. Moreover, the study responds to recent FERC policy advocating rebuilding existing and constructing new transmission facilities to maintain a secure, reliable bulk power system, to lower congestion costs, and to support renewables resource integration.

STARS looked beyond replacement in-kind to identify and analyze opportunities to overlay the basic rebuild options with enhancements designed to integrate renewable resources cost effectively, particularly upstate wind and possibly Canadian hydroelectric power resources, into the grid. The assessment also identified opportunities for economic transmission upgrades to relieve congestion.

STARS is being conducted in three phases. Phase I completed in January 2010, identified potential additional transfer capability needs to meet Loss of load Expectation (LOLE) for various generation expansion scenarios. Phase II, completed in April 2012, identified the most suitable and cost effective transmission alternatives to replace aging infrastructure and achieve the necessary transfer capability. Phase III will include additional sensitivity analyses and assessments identified throughout Phases I and II. The NYISO is supporting this effort by providing databases and conducting the economic analysis.

These results provide key inputs into both the NYISO's comprehensive system planning process, as well as the New York State Energy Plan. The study process has been completely open and transparent with regular stakeholder meetings through the NYISO's Transmission Planning Advisory Subcommittee and consistent with FERC Order 890.

Finally, the results of the STARS assessment have been provided to an even broader interregional transmission planning assessment known as the Eastern Interconnection Planning Collaborative (EIPC). EIPC is conducting reliability and economic planning analysis of the electric systems throughout the Eastern Interconnection of the United States and Canada east of the Rocky Mountains. Transmission planning authorities are working together closely to analyze grid reliability and security, while facilitating grid modernization to allow wholesale markets to work more efficiently and accommodate renewables.

Regional and Interregional Planning - On February 16, 2007, the FERC issued Order No. 890, which reformed the FERC's *pro forma* open access transmission tariff to provide for an open, transparent, and coordinated planning process at both a regional and a local level. FERC stated that "each of the Commission-approved RTOs in the Northeast, Midwest, Southwest, as well as California, provides for a coordinated and regional planning process with stakeholder input from every industry segment" and that it "fully supports these existing efforts…." FERC further recognized that in regions where significant processes were already in existence, such processes may not need to be drastically changed to comply with Order No. 890. FERC acknowledged that RTOs and ISOs had transmission planning processes in their tariffs. The NYISO developed a process that incorporated the planning principles that each transmission provider had to address in its planning process (*i.e.,* coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects).

Most significantly, to comply with the Order No. 890 transmission planning principles, the NYISO created the Comprehensive System Planning Process. The CSPP was built on the core processes of the CRP modified to: expand the existing economic planning process, add a local transmission planning component, and introduce cost allocation and recovery for regulated reliability projects. Ultimately, the Commission accepted all of the NYISO's planning processes.

FERC Order No. 1000. In July 2011, FERC issued Order No. 1000, a major ruling on transmission planning and cost allocation. FERC has reaffirmed the Order on rehearing; however, aspects of the Order may be litigated. It likely will have major impacts on transmission system planning on a regional and interregional basis, cost allocation for new transmission projects, and consideration of state and federal public policies in the transmission planning processes. The Commission stated that Order No. 1000 is intended to build on Order No. 890's planning requirements. Order No. 1000 is aimed at achieving two "primary objectives." Specifically, to:

> (1) [e]nsure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who receive benefits from them.

Order No. 1000 requires participation by public utility transmission providers in regional transmission planning processes. These regional processes must "evaluate transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utilities in their local transmission planning processes," including the consideration of needs driven by Public Policy Requirements. FERC also directs the improvement of coordination across regional planning processes and the establishment of cost allocation methods for facilities identified through regional transmission plans. Additionally, Order No. 1000 mandates that cost allocation for new transmission facilities be based on the "beneficiaries pay" principle and directs that costs "not be involuntarily allocated to entities that do not receive benefits." Regional and inter-regional transmission plans must consider transmission facilities proposed by all entities. Order No. 1000 also requires that “generation, demand resources, and transmission be treated comparably in the regional transmission planning process.”

Order No. 1000 acknowledges that some regions already have such processes in place and the directed reforms “are not intended to undermine progress being made in those regions.” Consequently, Order No. 1000 provides that “to the extent existing transmission planning processes satisfy the requirements of this Final Rule, public utility transmission providers need not revise their open access transmission tariffs and, instead, should describe in their compliance filing how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission.”

In general terms, Order 1000:

- Applies to “new transmission facilities” which are those subject to evaluation or reevaluation within local or regional transmission planning processes after the effective date of the compliance filings. [It is generally believed that the planning processes of existing RTOs/ISOs, including the NYISO, will qualify as regional transmission planning processes for the purpose of the Order with limited modification.]
- Requires transmission planning at the regional level to consider and evaluate possible transmission alternatives and produce a regional transmission plan
- Requires the cost of transmission solutions chosen to meet regional transmission to be allocated fairly to beneficiaries

Compliance filings on most requirements under the Order are due in October 2012, except for filings with respect to inter-regional issues, which are due in April 2013.

Eastern Interconnection Planning Collaborative. A group of electric system Planning Authorities has formed the EIPC to pioneer a grass-roots effort to perform interconnection-wide transmission analysis. Currently, EIPC is engaged in an interconnection transmission study effort funded by the U.S. Department of Energy scheduled to conclude at the end of 2012. The Project represents a first-of-its-kind effort to involve Planning Authorities in the Eastern Interconnection to model the impact on the transmission grid of various policy options determined to be of interest by state, provincial, and federal policy makers and other stakeholders. The basic approach for the Project builds existing models of the bulk power system and refines them as necessary to support interregional analysis of the combined regional plans for the entire Eastern Interconnection. This approach will ensure that the existing regional plans have fully taken into consideration both opportunities and impacts from grid enhancements in regions throughout the interconnection. Furthermore, the Project builds upon, rather than substitutes for, the current local and regional transmission planning processes developed by the Planning Authorities and associated regional stakeholder groups within the entire Eastern Interconnection. Those processes, and the resulting transmission expansion plans, are developed in accordance with the requirements of federal, state, and provincial jurisdictions and meet NERC Reliability Criteria. Although some coordination has long existed in the Eastern Interconnection, the potential integration of large amounts of renewable resources offers greater opportunities and significant challenges.

The Project uses an open and transparent multi-constituency stakeholder process representing the entire Eastern Interconnection. This diverse stakeholder body has identified eight specific resource futures that are being studied from an economic standpoint. This coordinated interregional approach to interconnection-wide transmission analyses will enable evaluation of a wide range of renewable resource options, some of which are found in remote areas not currently accessed by robust, high voltage transmission infrastructure. Further, the resource expansion scenarios will consider development for 20 years into the future, well beyond the existing regional planning horizons.

Phase I was completed in November 2011 with stakeholder selection of three scenarios for detailed analysis in the following year. EIPC provided an interim Phase I report to the DOE in December 2011. In Phase II, EIPC will perform reliability and production cost analyses of alternative transmission options to support the expansion scenarios selected during Phase I. High-level cost estimates also will be developed for both the generation and transmission expansion facilities for each scenario. These efforts will result in a final Phase II report in Q4, 2012.

Northeast Coordinated System Plan. ISO-NE, the NYISO, and the PJM each produce its own regional plan covering the needs of the region that each ISO/RTO serves. In addition, these ISOs/RTOs work jointly under a formal protocol studying numerous issues related to interregional electric system problems, developments, and performance. Hydro-Québec TransÉnergie, the Independent Electric System Operator (IESO) of Ontario, and the New Brunswick System Operator (NBSO) participate on a limited basis to share data and information. The intent of this collaboration under the joint planning protocol is to plan on a wider interregional basis in a proactive and well coordinated manner.

The current protocol establishes procedures that accomplish the following tasks and will be revised to accommodate the FERC Order No. 1000 requirements:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts, and
- Develop the Northeast Coordinated System Plan (NCSP) on a periodic basis, typically every two years

To implement the protocol, the Joint ISO/RTO Planning Committee (JIPC) was formed that includes representation of all the ISOs and RTOs, and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) was created to discuss work conducted by the JIPC.

Eastern Interconnection Reliability Assessment Group. The purpose of the Eastern Interconnection Reliability Assessment Group (ERAG) is to further augment the reliability of the bulk power system in the Eastern Interconnection through periodic studies of seasonal and longer-term forecasted transmission system conditions.

As part of the joint ERAG agreement signed by the six reliability regions in the Eastern Interconnection, the SERC East-RFC-NPCC (SeRN) Steering Committee, under the direction of the ERAG Management Committee, conducts appraisals of the SeRN interregional system performance. On a regular basis, the SERC East-RFC Working Group and the RFC-NPCC Working Group, under the guidance of the SeRN Steering Committee, performs the interregional transfer capability studies. The studies, which are used as a means to measure system strength and evaluate system performance, are completed semi-annually with anticipated operating conditions of the near-term summer and winter peak load conditions. Long-term studies are periodically performed.

NPCC Overall Transmission Assessment. In accordance with the NPCC Reliability Assessment Program, the Task Force on System Studies is mandated to review the need for an Overall Transmission Assessment. The overall study builds upon and supplements the Transmission Reviews conducted annually by each of the NPCC Areas by examining the system from a broader regional and inter-regional perspective. The last Overall Transmission Assessment was conducted in 2009 by the SS-37 Working Group under the direction of the Task Force on System Studies. The Overall Transmission Assessment is typically performed every three years. The objectives of the 2009 assessment were to:

- Assess the dynamic and steady-state performance of the NPCC system in a future year for various design, extreme, and beyond criteria contingencies
- Evaluate the impact of proposed large future system developments in the adjacent RFC region and simulate the effect of extreme contingencies originating in the RFC region
- Determine if the dynamic performance of the system exhibits trends that could adversely impact reliability under significantly increased penetrations of variable generation such as wind powered generation

Table 3. List of Reliability Studies

Name	Responsible Entity	Purpose	Frequency	Planning Horizon	Required by
Area Transmission Review	NYISO	To demonstrate the system is in compliance with NERC standards	Comprehensive: Once/five years Interim/Intermediate: Annually to address system changes	Five years	In compliance with NPCC/NERC requirements
Reliability Needs Assessment	NYISO	Long-range reliability assessment of both resource adequacy and transmission security	Every other year (Even years)	10 years	FERC-approved NYISO Tariff
Congestion Assessment and Resource Integration Study	NYISO	Assesses historic and future congestion and provides cost/benefit to relieve congestions (not a reliability study)	Every other year (Odd years)	10 years	FERC-approved NYISO Tariff
Locational Minimum Installed Capacity Requirements Study	NYISO	To determine local ICAP requirements for applicable NYCA zones such as NYC and Long Island	Annually	Next capability year May-April	Performed by NYISO in compliance with NYSRC Rules A-R2 and A-M2
Seasonal Operating Studies	NYISO	To determine if the system can operate reliably for the upcoming season and to evaluate inter- and intra-area interface transfer capability	Every six months	May-October November-April	NPCC/NYSRC
Interconnection Studies (Small and Large)	NYISO	Assess potential reliability impacts from a new project and to identify remedial options	As needed	Project in-service date	NYISO Tariff

Name	Responsible Entity	Purpose	Frequency	Planning Horizon	Required by
Wind Study	NYISO	To study the impacts of wind generators on system operations, planning, and energy production	Two special studies conducted	10 years	Market Participants
Annual Fault Current Assessment	NYISO	To assess fault current levels, identify critical substations with potential overdutied circuit breakers, and recommend remedial actions	Annually	Current year	NPCC
Reliability Assessments (seasonal)	NPCC	Determine the reliability and adequacy of NPCC for the season	Every six months	Upcoming season	NPCC
Review of Interconnection Assistance Reliability Benefits	NPCC	Estimate amount of emergency assistance each Balancing Authority could obtain from its neighbor	Annually	Current year and fifth year	NPCC
Installed Reserve Margin	NYSRC/ NYISO	Provides parameters for establishing the installed reserve margin	Annually	Next capability year May-April	NYSRC
State Transmission and Reliability Study	Transmission Owners	Evaluate need to build, upgrade, refurbish or retire transmission facilities	Special study conducted	20 years	Not Applicable
Losses Proceeding/NYISO System Efficiency Study	DPS/NYISO	To assess the benefits of reducing electric system losses	Special study conducted	2006	PSC

Transmission System Operations

The operation of the New York State Power System is coordinated by the NYISO Control Center in conjunction with each TO's Control Center, and requires instantaneous exchange of scheduling information. The operating policy of NYISO and operational role of the TOs are described in the NYISO Transmission and Dispatching Operation Manual. Under the terms of the NYISO Agreement, the NYISO/Transmission Owner Agreement, and the NYSRC Agreement, the NYISO has the authority to direct the operation of the New York State Power System to maintain system reliability in accordance with good utility practice and applicable Reliability Rules. NYISO is responsible for the coordination of the operation of those facilities under its Operational Control with the responsible TOs. The TOs are responsible for physically maintaining and operating facilities under direction and control of the NYISO to assure secure operation of the NYISO Secured Transmission System in the New York Control Area. The TOs are also responsible for operating Local Area Transmission System Facilities (*i.e.,* the distribution system), provided it does not compromise the reliable and secure operation of the NYS Transmission System.

Transmission System Operations addresses three general timeframes:

- Operations planning, which looks ahead over the next six-month electric system capability period
- Day-ahead of actual system operations; and
- Real-time operations. Each timeframe is focused on maintaining system reliability and security. Compliance with all reliability rules is monitored to maintain system conditions for voltage, frequency, stability, and thermal limits within acceptable levels

Transmission System Operators are obligated to follow three sets of reliability requirements. The first are the Standards implemented by NERC, which apply to all of North America. Second are criteria of NPCC, which apply to the northeastern United States and Canada. Third, operators must follow rules developed and implemented by NYSRC, which are New York specific rules that are more specific or more stringent than the NERC Standards and NPCC Criteria. These standards include requirements to perform operations planning studies, develop day-ahead plans, continuously monitor real-time operations, and have qualified and properly trained system operators monitoring and operating the system on a 24-hour schedule.

Operations Planning - Operations Planning evaluates the next operating season and performs reliability assessments in preparation for the next operating season capability period. These studies are commonly referred to as the Operating Studies and focus on determining and monitoring transfer limits on key interfaces to better understand anticipated conditions for the next capability period. The results are presented to NYISO System Operations and System Operators in preparation for the next capability period. These studies are coordinated with the New York TOs, other NYISO stakeholders, and neighboring electric systems.

Day-Ahead Operating Plan - The NYISO uses a Security Constrained Unit Commitment[18] in the Day-Ahead Analysis that provides a least cost economic commitment of generation that is a secure Day-Ahead Operating Plan. This study performs a security constrained economic dispatch observing reliability rules, including local reliability rules established by the NYSRC. For the Day-Ahead Analysis, this assessment produces a day-ahead operating plan that is provided to the system operators and TOs in New York in preparation for the next day operations.

Real-Time Operations - NYISO System Operations evaluates system conditions and secures the system in real time by performing real-time assessments with a Real-Time Commitment / Dispatch. A series of assessments are performed while monitoring system conditions as they change through the day, including unplanned events, and observing reliability rules and maintaining system reliability at all times.

[18] Terms that are capitalized are defined in the NYISO's tariffs, which are posted at the NYISO website at http://www.nyiso.com/public/markets_operations/services/customer_support/glossary/index.jsp.

The system operators monitor system conditions such as thermal, voltage, and stability limits, in addition to system frequency, and "area control error", which represents the amount of actual net interchange at any given moment in variation from scheduled interchange power flows. As system conditions change, conditions may deviate from the normal states due to unplanned events. Operators issue corrective actions to be implemented that are scaled to how far the system has deviated from normal state and the urgency of the situation. These corrective actions are assigned to different Operating States.

System Operating States - The NYISO operates to five different Operating States: Normal, Warning, Alert, Major Emergency and Restoration. The objective of the NYISO is to operate the New York State Power System within the Normal State. System Operators are alerted when the system enters into each of these states, which allows the Operator to take a predefined set of actions to return the system to normal. These actions include re-dispatching, returning equipment to service, adjusting reactive devices, adjusting phase-angle regulator taps, activating Emergency Demand Response Programs (EDRPs) and/or Special Case Resources, (SCRs) purchasing emergency power, and others, up to and including load shedding when in a Major Emergency State.

The System Operating States provide a means for operators to communicate the status of the system while having available an escalating set of actions to address non-normal system conditions to return the system to normal state.

In cooperation with the NYISO, the NYSRC is currently addressing the reliability rules, testing requirements, and compliance monitoring procedures for the NYISO's System Restoration Plan and TOs' restoration plans for re-energizing the New York State bulk power system following a system-wide blackout. One element critical to the success of this plan is to maintain adequate "black start" generating capacity throughout the system, but especially in the New York City area. By definition, black start generators have the capability, following a major or total system blackout, to independently start-up and energize a portion of the system without an outside electric supply. Failure to provide sufficient black start resources to restore the electric system promptly could have significant adverse consequences, particularly in New York City.

Operations Communications - Communication protocols have been developed between the NYISO, each of the New York TOs, and with neighboring power systems. These protocols include communications during normal and emergency operations to coordinate actions to take in anticipation of and during system emergencies.

The NYISO works closely with the TOs in day-to-day operations with well established processes and procedures. The NYISO also works closely with the neighboring power systems to respond to requests or provide assistance to maintain or return the system back to normal conditions.

The NYISO has redundant voice communication paths to the TOs and Neighboring Control Areas. Those paths consist of direct hardwire phone circuits, dial up phones, hot line phone, satellite phones, and cell phones. The normal path of voice communication from the NYISO to the generators is through the appropriate TOs. This provides the TOs with operational awareness of the request by the NYISO or generators within their footprints to support local reliability requirements.

The NYISO does not have direct physical control over each component of the transmission system. Instead, the system operators receive telemeter information on system conditions and provide direction to the TOs and generators regarding actions needed to operate the system. For example, following an indication that a generator has tripped off line, the NYISO will confirm information received through the NYISO telemetered data with the TO in whose service territory the generator interconnects, and the TO will confirm the generator trip.

Operator Training - NERC recognizes the NYISO as a continuing education provider. The NYISO Grid Operations Training Group develops, implements, and administers specialized training for NYISO and TO Operations staff based on all NERC, NPCC, NYSRC, and NYISO requirements.

Under NERC oversight, the NYISO System Operator Training Program is structured to assure reliable interconnected system operation by experienced and highly qualified personnel at all times, including through the initial and ongoing training of system operators.

The standard NYISO Operator shift schedule protocol has a training week built into the schedule every six weeks. During the training week, Certified Operators participate in classroom lectures, training exercises, simulation sessions and seminar programs with local, regional, and national organizations.

The NYISO Training Simulator environment, used in initial and ongoing operator training, includes the same EMS model and displays used on the operating floor. The market information system is integrated into the simulator to allow the operators the full use of tools and indications they would have available during normal operation. Challenging and realistic scenarios are presented to the operations crew during these simulator sessions to prepare them for real time normal and emergency operations.

During spring training, NYISO Operators train with the New York TOs using a simulator environment to restore the NYISO Bulk Power System Backbone following a blackout condition. These sessions are designed to be realistic and have proven effective in communications, coordination, and system response during system restoration.

Assessing Transmission Reliability

As indicated in the previous section, electric system reliability generally encompasses two concepts: 1) transmission operational reliability/security – the ability of the electric system to withstand disturbances such as electric short circuits or unanticipated loss of system elements; and 2)resource adequacy - the ability of the system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonable expected unscheduled outages of system elements.

As reflected by the various metric processes described in this section, resource adequacy is determined on a probabilistic basis. Significant resource adequacy problems, (i.e. shortages in generating capacity or other resources) can lead to a broad range of service disruptions. By their nature, these issues generally can be monitored and anticipated, and appropriate preventive actions can be taken in advance. Conversely, transmission operating reliability/security is assessed on a deterministic basis. A variety of disturbances or "contingencies" may occur to transmission system facilities that can lead to service disruptions. Disturbances such as storms, equipment failure, or other emergencies often occur with little or no warning and can rarely be anticipated; hence, preventive action, other than scrupulous adherence to standards and criteria, are generally not possible.

The means and metrics for assessing the reliability of the bulk transmission system, which conveys power across and between large control-areas for wholesale delivery, are necessarily different from those applicable to the distribution system in which LSE (*e.g.,* local utilities) distribute power to individual retail customers. The distribution system can readily quantify reliability in terms of frequency, duration, and percentages of individual customer outages through metrics such as SAIFI and CAIDI (discussed under Distribution).

The most visible measure of power system reliability, and arguably most meaningful to electric customers and public officials, is whether the system operator has had to curtail service or provide load relief measures to maintain stable system operation. Other than the events of 9/11/01 and the 2003 Northeast blackout, caused by a sudden severe power surge originating outside the New York Control Area, the NYCA has not had to provide load relief measures at the bulk power system level for reliability purposes since 1996.

The NYISO engaged The Analysis Group to examine the first 10 years of the NYISO's operation. The Analysis Group concluded that the bulk electric system in New York State had operated both "reliably and efficiently," during that period. Those conclusions were based on metrics, which showed that there had been "fewer reserve activations than were needed under the NYPP, better transmission outage scheduling co-optimized system management and improved, and more centralized load and wind generation forecasting."

While there are a number of established, detailed, ongoing processes by which the reliability of transmission systems is measured, NERC, in a July 2011 report, Risk Assessment of Reliability Performance stated that "(C)urrently, there are no measures, datasets, or reports that explicitly and completely state the historical performance of the (bulk electric) system".

As independent regional grid operators and market administrators, ISO/RTOs serve more than 60 percent of the electric load and roughly 70 percent of the generators in the United States. One of the benefits of this restructuring has been greatly increased transparency in the operation and performance of the bulk system, with far more data routinely being made available, examined, and acted upon by regulators and market participants.

At the same time, these fundamental changes in the structure of the industry, along with technological advances and other factors, have contributed to the need for new and evolved means of measuring and quantifying the reliability of the bulk electric system. Restructuring has resulted in the ongoing evolution of long-standing processes for measuring reliability and the development of more sophisticated reliability metrics required for increasingly regionalized 21st century grids and markets.

Loss of Load Expectation (LOLE) - Historically, LOLE is one of the most widely used metrics for measuring power system resource adequacy. New York was the pioneer in the development of this probabilistic technique. It currently is applied in New York as well as other control areas in the United States and is the standard used in the reliability rules of the NPCC and NYSRC. A probabilistic measure of the ability of the system's resources to meet its load, the NERC defines LOLE as:

> "The expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of daily peak demand exceeding available capacity for each day and adding these probabilities for all the days of the year."

This widely accepted standard has been further defined by the NYSRC as the probability of the need to disconnect any firm load due to resource deficiencies, on average not more than once in 10 years[19] or , no more than 0.1 day per year.

A wide range of inputs goes into the complex computer modeling used to arrive at LOLE forecasts of the amount of installed capacity required to meet the 1-in-10 criterion, including: load forecast uncertainty due to factors such as weather and economic conditions; variables of generating resource availability, such as retirements, forced outages, maintenance, and seasonal de-ratings; and the status and emergency capability of transmission connections to other systems.

In conducting resource adequacy planning, accurate outage information must be collected for all generating units and other sources. In today's restructured environment, this is considerably more complex than in the past, when vertically integrated utilities owned virtually all generation. The option of adding generation to maintain a desired LOLE is now the responsibility of the marketplace, pursuant to NYISO administration and procedures, supported by simultaneous "regulated backstop solutions" if the marketplace does not respond.

LOLE has a number of applications, the primary being its use to calculate the amount of installed capacity required to maintain the resource adequacy criteria. In that regard, it plays a significant role in establishing capacity prices. It can be applied to the economic assessment of proposed transmission versus new generation resources or to calculate the reliability benefits of transmission connections to neighboring systems.

[19] Also referred to as "one day in 10 years" or "1-in-10".

The LOLE analysis incorporates NYS Transmission System emergency transfer capability between zones rather than a detailed assessment like the transmission system security analysis described below. While not a detailed representation of the transmission system, it does provide insights on the adequacy of the transmission system to deliver capacity to the load, on whether sufficient capacity exist in the localities to meet the criterion, or the benefits of interconnections with neighboring systems.

System Security Analysis or Transmission Operating Reliability – As characterized by NERC, bulk electric system "(s)ecurity is a planning and operating deterministic concept. This means that possible events are identified as having significant adverse reliability consequences, and the system is planned and operated so that the it can continue to serve load even if these events occur. Security requirements are sometimes referred to as N-1,N-1-1 or N-2. "N" is the number of system components; an N-1 requirement means that the system can withstand single disturbance events (*e.g.,* one component outage) without violating thermal, voltage, and stability limits or before affecting service to consumers."

Generally, mechanisms used to evaluate transmission operating reliability/security include load flow and stability analyses and programs. In conducting a transmission planning or reliability study, a variety of generation scenarios are typically chosen for the present or selected future year, and the range of contingencies required by the standards/criteria are simulated for each. Critical contingencies, as defined by the NERC, NPCC, and NYSRC standards, criteria and rules, are applied to the modeled system for each scenario chosen. In a planning study, the results of these contingency tests will indicate where and to what extent the existing system needs reinforcement. Potential solutions to any violations are chosen and further investigations conducted until an optimal solution emerges.

This standard approach to system security analysis is used widely throughout the industry, including in applicable NYISO processes.

Data Used to Assess Reliability

Transmission Availability Data System (TADS). Consistent with NERCs obligations under Section 215 of the Federal Power Act, on October 23, 2007, the NERC Board of Trustees approved the collection of the Transmission Availability Data System (TADS) data beginning in calendar year 2008. TADS collects transmission outage data in a common format for:

- AC circuits ≥ 200 kV (overhead and underground)
- Transformers with ≥ 200 kV low-side
- AC/DC back-to-back converters with ≥ 200 kV AC on both sides
- DC circuits with ≥ ±200 kV DC voltage

The TADS effort began in 2006 with the formation of the TADS Task Force under the NERC Planning Committee. This task force designed TADS and the associated processes for collecting TADS data. On June 30, 2009, the task force issued its first reports for data collected in 2008. NERC uses the information to develop transmission metrics that analyze outage frequency, duration, causes, and many other factors related to transmission outages. NERC also issues an annual public report showing aggregate metrics for each NERC region. Each transmission owner reporting TADS data will be provided a confidential copy of the same metrics for its facilities.

While TADS is not intended to provide deterministic performance measures, it is used to quantify certain performance aspects. In addition to collecting simple transmission equipment availability, TADS collects detailed information about individual outage events that, when analyzed at the regional and NERC level, provides data that may be used to improve reliability. Specific equipment outages are linked to disturbance reports filed with NERC, enabling better association of transmission outages with load and generation outages. Additionally, outages by one TO are now being tracked to outages of other TOs so that any relationship between multiple outages can be established.

FERC ISO/RTO Metrics Reports. In 2008, based on recommendations of the U.S. Senate Committee on Homeland Security and the Government Accountability Office, FERC undertook an effort to standardize and update measures to track the performance of ISO/RTO operations and markets and to report the performance results to Congress and the public.

The performance metrics developed through that process now form the basis for an annual ISO/RTO Metrics Report, filed with FERC for the first time in 2010. The reports establish and examine metrics with respect to three broad areas: Reliability, Markets, and Organizational Effectiveness. With respect specifically to Reliability, the metrics established by FERC require information to be provided on:

- Compliance with and violations of national and regional reliability standards
- Dispatch behavior
- Load forecast accuracy
- Long-term generation and transmission planning
- Planned outage coordination

Based on the information provided by the 2010 and 2011 Reports from all of the ISO/RTOs under FERC jurisdiction, the Reports conclude, among other things, that the "Balancing Authority areas operated by ISO/RTOs function reliably.

The NYISO submitted data for the 2010 and 2011 Metrics Reports pursuant to its NERC-registered functional roles as: the New York Control Area Authority, Balancing Authority, Interchange Authority, Planning Authority, Reliability Coordinator; Resource Planner, Transmission Operator, Transmission Planner, and Transmission Service Provider. Based on FERC-specified metrics, key findings of NYISO's portion of the Reports included:

- No audit-identified or self-reported violations of NERC or NPCC operating reserve standards
- NYISO had not used load-relief measures in the NYCA due to any standards violation
- Dispatch Operations met or exceeded Compliance Performance Standards (CPS-1 and CPS-2)
- NYISO is moving to reduce Transmission Load Relief curtailments through Broader Regional Market initiatives to reduce "unscheduled flows" including better coordination of the flows around Lake Erie and to remove barriers to more efficient regional trading
- Load Forecast Accuracy has been at a consistently high level and increased, with a commensurate decrease in Mean Absolute Percentage Error (a standard load forecasting metric), over the 2006-10 period
- Wind forecasting accuracy has been enhanced with a state-of-the-art forecasting system enabling New York to have the first grid operator to dispatch wind power fully balancing reliability requirements with economic dispatch
- In 2009-10 (the only years for which data are available) Planned Outage Coordination metrics showed advanced notification of at least one month prior to outage commencement for 91 percent of transmission outages, and that less than one percent of planned outages were cancelled
- In transmission planning, New York uses a market-based approach, involving TO's Local Transmission Plans, NYISO's Comprehensive System Planning Process, and the CARIS economic planning process, in which all types of resources are eligible to meet a reliability need. This process is significantly different from those of other regions, and several of the reporting metrics used by other RTOs do not have comparable applicability; however, NYISO does point to significant private and public investment in generation and transmission since 2000, most of it in the downstate region where demand and the need for such investment has been greatest.

These metrics, as the reliability focused elements of a more comprehensive set of metrics assessing the performance of ISO/RTOs generally, also may have certain qualitative limitations in that they tend to be outcome or results-based metrics that do not generally measure the specific state of the transmission infrastructure or quantify its physical performance. Nor do these metrics directly require input or data from the TOs as to the state of those assets.

NYISO Monthly Operations Performance Metrics Report. Each month the NYISO also submits a report on a range of reliability and market performance metrics to the NYSRC and the NYCA market participants and posts it on its website. In terms of reliability performance, the standard metrics reported currently include:

- Alert State Declarations
- Major Emergency State Declarations
- Interconnection Reliability Operating Limit Exceedance Times
- Balancing Area Control Performance
- Reserve Activations
- Disturbance Recovery Times
- Load Forecasting Performance
- Wind Forecasting Performance
- Lake Erie Circulation and ISO Schedules.

NERC 2011 Long-Term Reliability Assessment. With its designation by FERC and Canadian authorities as the ERO for North America, pursuant to Commission regulation, NERC files annual Long-Term Reliability Assessments with FERC. While these Assessments are based on data and self-assessment summaries provided by the eight regional reliability organizations (based on established criteria and metrics), the key findings, summaries, and recommended actions represent NERC's independent judgment. Thus the underlying metrics supporting the Assessment are standard metrics and criteria currently used in the industry.

As presently structured, on both a continental and regional basis the Assessment examines:

- Resource Adequacy
- Peak-Demand Projections
- Long-Term Forecast Uncertainty
- Demand-Side Management
- Generation, Transmission, and Operational Issues
- Standing and Emerging Reliability Issues, including:
  - Risk Assessment, Ranking, and Evolution
  - Environmental Regulations Impacts
  - Integration of Variable Generation from Planning and Operations Perspectives
  - Critical Infrastructure Protection
  - System Modeling Improvement and Coordination
  - Increased Natural Gas Generation

In the November 2011 Long-Term Reliability Assessment, with respect to the New York Control Area, NERC stated that:

- In terms of Operational issues: "There are no existing or potential systemic outages that could potentially impact reliability during the 2011-21 timeframe within the NYCA."
- In terms of Transmission issues: "The interface into southeast New York and New York City could become significantly limiting and impact reliability if there are unanticipated delays in new projects, unexpected retirements, or unanticipated load growth…. If a significant reliability issue manifests itself during the next CSPP cycle, the NYISO will address the issue in the next Reliability Needs Assessment."
- With respect to emerging and standing reliability issues: "(T)he immediate outlook for New York's electric system is positive. As a result of developments that have contributed to a more reliable system over the past decade, as well as planned additions in the near future, the adequacy of power resources is not an imminent concern. Nevertheless, the sustained adequacy of resources may be challenged by several factors." Specifically, NERC citied:

- Impacts from federal and state environmental regulations that may affect the existing generation fleet; in this regard NERC stated "… attention (also) must be paid to the cumulative impact of impending federal and state environmental regulations on the continued operation of various existing power plants. The proposed regulations are estimated to impact more than half the installed generating capacity in the State. Considerable lead time is required for power infrastructure project execution, given the time frames needed to finance, permit, and construct major energy projects. The planning horizons of policy makers and regulators should encompass the time required for the electric industry to address new laws and changes in regulatory requirements."
- The aging infrastructure; specifically NERC stated "(T)he expected adequacy of New York's power resources over the next decade does not diminish the need to address aging generation and transmission infrastructure. As of the close of 2010, 60 percent of New York State's power plant capacity and 85 percent of the high-voltage transmission facilities, went into service before 1980."

NERC 2011 Risk Assessment of Reliability Performance Report. In an effort to further refine and evolve bulk power system reliability metrics, in 2007 NERC established the Reliability Metrics Working Group. The group's initial efforts on a metric development process and the establishment of approved system metrics lead to a 2010 report on Integrated Bulk Power System Risk-Assessment Concepts.

Building on that work, in July 2011 NERC issued the 2011 Risk Assessment of Reliability Performance (2011 Risk Assessment), which it characterized as "a foundational report, with the goal to provide a view of risks to reliability based on historic performance. The object is to integrate many ongoing efforts … providing technical analysis and feedback on risk attributes and reliability trends…".

The 2011 Risk Assessment embraced the recommendation of the 2010 Concepts report for development of a single Integrated Reliability Index (IRI) comprised of existing metrics from three broad indices: events driven, condition driven, and standards/statute driven. At the same time it recognized that many of the standards and measures to be used in these processes are still developing. NERC's stated goal is to have the IRI offer a unified analysis and serve as the basis for an annual "State of Reliability" report "that will provide an industry reference for historical bulk power system reliability, analytical insights with a view to action, and will enable the discovery and prioritization of specific, actionable risk-control steps."

NERC indicated that "(t)his is an evolution that will take time" and the reports issued in 2011 will begin the "transition from a metric performance assessment to a 'State of Reliability' report…" The first assessment of reliability using the three component indices of an IRI is expected in 2012.

Reliability Issues Identified in Planning Studies

For planning purposes, the electric transmission industry historically has focused on load forecasts and new resources needed to meet the load growth. The NYISO's 2010 Comprehensive Reliability Plan (CRP) also recognized that increasingly, factors other than load growth can significantly contribute to reliability concerns and the need for timely planning to maintain reliability. These factors, in turn, necessitate that industry and regulatory agencies continue to work together on system planning and the impacts of related governmental actions to maintain the reliability of the bulk power system.

Issues Identified in CRP. The 2010 NYISO CRP, and the RNA on which it was based, considered the uncertainties associated with aging infrastructure, the possibility of the Indian Point Units 2 and 3 operating licenses not being renewed, and the numerous significant environmental regulatory initiatives that could cause the retirement of critical system resources.

The 2010 RNA report identified a number of uncertainties beyond the base case assumptions that could adversely affect the reliability of the system over the planning horizon. As stated, actions to mitigate reliability issues are taken only if the base-case finds reliability violation. No action is taken if reliability violation is identified in only the sensitivity. These scenarios include:

- The potential for higher than expected load growth that results from higher than expected economic growth or less than expected energy efficiency achievements or a combination of both;
- A determination by the Atomic Safety Licensing Board not to renew the licenses of Indian Point Units 2 and 3, which expire in 2013 and 2015, respectively. The 2010 RNA scenario analysis shows that resource adequacy criteria would not be met under these circumstances. The NYISO found that, without Indian Point, there would not be sufficient resources from 2016 through 2020 to meet reliability requirements, and there would be an increased likelihood that customer load interruptions would be necessary to avoid wide-scale blackouts in Southeast New York. These vulnerabilities could be mitigated with replacement generating capacity and/or additional transmission.
- New environmental regulatory programs designed to improve air quality and address the impact of power plants' cooling water systems on aquatic life also were assessed for the potential impacts on reliability. These regulatory initiatives, which are being promulgated by both state and federal environmental regulatory agencies, cumulatively will require considerable investment by the owners of New York's existing thermal power plants to comply with these new regulatory requirements if promulgated as currently proposed. The programs assessed were the following:
    - NO_x RACT – Reasonably Available Control Technology
    - BART – Best Available Retrofit Technology
    - MACT – Maximum Achievable Control Technology
    - BTA – Best Technology Available
- The NYISO determined that as much as 23,957 MW in the existing fleet, or 64 percent of existing NYCA capacity, will have some level of compliance requirements related to the new regulations as detailed in the 2010 RNA and further discussed in the 2010 CRP. The first three environmental programs listed above are designed to reduce power plant air emissions while the last addresses power plant cooling water. The NYISO analysis revealed that many facilities would be subject to a number of these regulations. In some instances, the size of the investment to meet the BTA regulations on cooling water intake structures and cooling systems could have significant impacts on power plants that rely on surface waters for cooling. The magnitude of the combined investments required to comply with the four initiatives could lead to unplanned plant retirements for which the NYISO's reliability planning processes must further account.

The NYISO has recently issued the draft 2012 RNA, but the report will not be finalized prior to this publication. It should be noted, however, the base case identifies potential reliability issues beginning as soon as 2013 that will be addressed through the NYISO procedures described above.

Issues Identified in STARS. As previously discussed, beyond the NYISO planning processes the STARS, led by the New York TOs, with participation of the NYISO, is evaluating the condition of New York's transmission system infrastructure and identifying potential economically beneficial transmission projects that would reliably support New York State's energy needs over the next 20 years. STARS has identified major issues associated with replacing or upgrading New York's aging transmission infrastructure, with a significant portion of New York's high-voltage transmission lines having been built several decades ago. STARS provided estimated investment costs and quantified benefits for certain parts of the bulk power transmission system to be upgraded using the existing right-of-ways. The study is being performed in three phases:

Phase I (2009-2010) - The condition of aging transmission infrastructure in New York State was assessed. This phase identified the need for additional cross-state transfer capability to meet resource adequacy requirements under various generation expansion scenarios. The condition assessment has found needs within the next 20 years to refurbish or replace many circuits 230 kV and above, specifically across Moses South, Central East, and UPNY-SENY. This phase was completed in January2010.

Phase II (2010-2011) - STARS has created a *Replacement-in-Kind Plan* reflecting replacements of aging infrastructure and minimal low-cost upgrades that would be necessary to maintain the reliability of the system over the next 20 years. An initial *Base Transmission Plan* was then developed taking into account economic benefits and the delivery of upstate wind to downstate. Additionally, numerous variations of the Base Transmission Plan were assessed. The Base Transmission Plan and its variations all met resource adequacy criteria.

Phase III (2012-2013) - The impact of the final *Base Transmission Plan* will be evaluated for various sensitivities and scenarios such as generation retirements and environmental regulations.

Through STARS, New York TOs are developing plans to upgrade, modernize, and expand the power grid to optimize its use and thus enhance a key asset underlying our transition to a more efficient, more secure, and more independent energy future consistent with energy marketplace and public policy demands. This philosophy was embodied within the broad-based policies set forth within the State's 2009 Energy Plan.

Aging Infrastructure. Though generally well maintained by utility owners, the transmission infrastructure is aging. As discussed the typical transmission line in New York State is 40+ years old. Within the next 10 years, it is estimated that more than 2300 miles of New York transmission 115 kV and higher will reach the age threshold of 70 years (wood pole lines) or 90 years (steel pole lines) and may be at higher risk for replacement. Between the years 2020 and 2030 an additional 1,200 miles of New York transmission will reach these age thresholds, and an additional 1,100 miles of New York transmission in the State will reach these thresholds between the years 2030 to 2040.

The last significant upstate transmission expansion occurred in 1987, with the completion of the Marcy-South line. Routine maintenance requirements are increasing, along with attendant costs and greater likelihood of downtime. Equipment failures are increasing as well, resulting in costly repairs and outages. For these reasons, the New York TOs continue to actively invest in transmission infrastructure to maintain a strong, secure, reliable system to meet growing energy needs, while achieving the State's and the nation's energy policy initiatives. Transmission investment also will benefit customers by dampening price volatility, reducing environmental impacts, and, through the integration of new technologies, will reduce losses, improve system performance, and increase throughput.

New York State's investor-owned utilities play a major role in rebuilding the transmission infrastructure. Transmission owners own and maintain the assets, including the rights-of-way, and possess the skills and expertise to rebuild and replace these assets on a prioritized basis. Maximizing the use of existing infrastructure and rights-of-way would provide the most efficient use of capital while minimizing environmental impact.

In summary, electric system planning is an ongoing process of evaluating, monitoring, and updating base-case assumptions as conditions warrant. Through the various planning and operating studies and other processes, New York is well positioned to monitor and respond to changing conditions. However, added uncertainties, such as load, retirements, and the performance of new technologies, will require additional vigilance and deliberation on the part of policy makers, regulators, the owners and operators of infrastructure, and all market participants and stakeholders.

Energy Highway. The recently developed Energy Highway Initiative recognizes the transmission challenges and the need for upgrading generating plants. The Energy Highway Initiative will evaluate a broad range of projects that proposed to achieve the following goals:

- Reduce transmission constraints to and within the downstate region and expand its diversity of supply
- Assure long-term reliability
- Encourage utility-scale renewable generation development
- Increase power generation efficiency

A task force has been formed and is evaluating projects submitted as part of a request for information process. The task force will issue an Energy Highway Action Plan include recommendations to meet the initiative's objectives. The Action Plan should be available fall 2012.

C. Distribution System Reliability

Key distribution reliability targets are defined by two general categories: frequency and duration of customer outages. Frequency is influenced by factors such as system design, capital investment, maintenance, and weather. Duration is affected by workforce levels, management of workforce, and geography. Investor-owned utilities have been required to report interruption statistics to the DPS for decades. DPS has been keeping electronic records of these statistics since 1989. The reporting requirements for utilities are set forth in 16 NYCRR (New York Code of Rules and Regulations), Chapter 2, Part 97. LIPA also maintains interruption data consistent with these rules.

Utilities are required to prepare annual reports analyzing their reliability performance for each of their operating areas. The PSC establishes performance targets for individual operating areas. Although failure to meet operating area targets does not result in a revenue adjustment. The PSC prefers to reward and/or penalize performance through performance-based rates rather than operating areas and this topic is discussed in more detail in Section F. The utility would be required to present a corrective action plan as part of its annual report.

The reliability of New York's distribution systems is measured by sustained interruptions (longer than five minutes) as defined by the following indices:

CAIDI - Customer Average-Interruption Duration Index. The CAIDI measures the average time that an affected customer is out of electric service. It represents the number of customer hours divided by the number of customers affected.

SAIFI - System Average-Interruption Frequency Index. The SAIFI measures the average number of interruptions experienced by customers served by a utility. It represents the number of customers affected divided by the number of customers served at the end of the previous year.

For both of these indices, a mechanism based on an individual utility's performance was developed to ensure a high level of reliability. These standards are part of reliability performance mechanisms (RPMs) that the PSC has incorporated into investor-owned utilities' rate plans. If a utility does not meet the standards, it is subject to negative revenue adjustments.

The PSC also establishes "minimum" and "objective" performance levels for both the CAIDI and SAIFI. A utility exceeding the minimum performance level is expected to take steps to reduce the number and duration of the interruptions to bring the CAIDI and SAIFI indices below the threshold. The objective performance level represents the target that the PSC has determined for the utilities. Utilities can have varying minimum and objective performance targets depending on the nature and configuration of their service territory. For example, in urban service areas with concentrated load and distances between feeders or substations are close, there may be cost-effective methods to reduce outage frequency and duration. In rural and areas with low density, and longer distances between substations, there may not be an alternate connection to provide back-up service following an outage to minimize the extent and time needed to respond.

Additional metrics are used when analyzing distribution reliability. 16 NYCRR, Chapter 2, Part 97, has specific interruption definitions, data requirements, record retention, and filing requirements for information that must be contained in monthly reports to the PSC. The section breaks out the types of interruptions into 17 separate classifications based on the type of interruptions, including: major storm, tree contacts, apparatus errors, events on services, and for incidents outside of the utility's control.

Annual Reliability Report

Investor-owned electric utilities also are required by the PSC for annual reliability reports by March 31st of each year.

The reports include sections on:

- Overall Assessment of reliability performance
- Projects/Investments to enhance distribution reliability
- Projects/Investments made in response to PSC-required safety inspection program
- Division/Operating Area Performance, *e.g.*, SAIFI/CAIDI analyses by cause codes for annual and five-year duration, performance adherence to the SAIFI/CAIDI targets, and follow-up on corrective actions from the previous year
- Reliability Programs including:
    - Power Quality
    - Circuit Performance (Network)

DPS staff uses these reports to help in meet its statutory obligation that utilities provide safe and adequate service and to guide its oversight of investor-owned utility infrastructure investment.

Electric Utility Emergency Plans

Public Service Law, Sec. 66; 16 NYCRR 105 requires each electric power corporation in New York to file with the PSC an emergency plan describing how a utility would restore electric power following a power outage caused by a major storm or similar widespread outages. 16 NYCRR Chapter 2, Part 105 requires investor-owned electric utilities to have formal emergency plans. These reports are reviewed annually by DPS staff for conformance to the rules and to evaluate any enhancements made as a result of any emergency restoration in the preceding year. The rules require the following minimum components of an emergency plan:

- An annual storm drill (or equivalent)
- Validation of personnel contacts
- Emergency criteria definitions for varying severities
- Training for workers performing out-of-title duties during restoration
- Updated contact list for all utility personnel, mutual aid and contractors, life support and special needs, human services agencies, media outlets, motels and restaurants, local government officials including emergency and police, medical facilities, and vendors
- Emergency anticipation
- Service restoration procedures, including damage assessment, crew use, and coordination with state and local government
- Organization chart and descriptions of personnel responsibilities
- Customer contacts, addressing large call volumes, special needs and life support customers, and dry ice distribution
- Outside aid, describing criteria and procedures for obtaining extra-company assistance
- Support services, including logistics required to feed and house a large temporary work force, as well as supplying the material and required fuel
- Performance assessment reports following any emergency restoration period of more than three days. Reports are due 60 days after completion of restoration.

The following sections further detail the typical components of an emergency (or restoration) plan, as well as a program to storm-harden the system to limit damage during a major storm events. There can be other programs that are designed to accomplish similar types of improvements as a single “ideal” plan or strategy is not appropriate for every locality. Plans may vary significantly with regard to geographic location, population make-up and dispersal, form of government, intergovernmental relationships among localities, as well as the degree of local concern and support for the concept. Furthermore, since storms come in all degrees of severity, restoration activities would vary accordingly. In the case of LIPA, for example, there are three condition levels listed below, with each level progressing in severity and the response required.

- Normal Operations: This also would include minor storms and daily outages
- Major Storm events: Major damage but limited in scope
- System Disasters: Hurricanes, ice storms

Restoration Plan

In general, a restoration plan is broken into several areas of responsibility. Those areas could consist of operations, communications, and media information, as briefly discussed.

An operations group within the plan would be responsible for restoring electric service during emergencies. This includes mobilization and direction of an emergency restoration organization that surveys damage and makes repairs to transmission and distribution systems. External utility crews and contractor crews also can be used depending, on the extent of damage and in consideration of agreements with other utilities such as the Edison Electric Institute Mutual Assistance Agreements, to augment the affected area's repair forces. The operations group is expected to maintain contact with the PSC during emergencies.

A communications group would be responsible for taking customer calls and communicating with special customers, municipal agencies, and government officials through customer call centers, local offices, and local emergency command centers. Communications would be coordinated through a coordination center.

A third group would be the interface with the general media as well as company employees working on the restoration. Regular communications, including news briefings and releases, would be conducted by this group to keep all parties informed. Special meetings between field and office workers and the media would be coordinated by this group.

The first priority in any restoration effort is to make conditions safe. After that, priority is given to restoring the most customers the quickest, such as the substation, then the feeder (*e.g.,* lock outs), then the three-phase main, followed in progression to single customers, with priority consideration given to customers such as hospitals and other critical facilities. In general, following a major storm, the first few days often see restoration of major groups of customers as locked-out circuits and three-phase mains are restored. As larger jobs are completed, localized damage to single and small groups of customers would be addressed.

After customers are restored, it is often necessary to resurvey the system for damage that may not have been identified or occurred after the initial review. This survey can identify outstanding repairs *e.g.*, final repairs to temporary fixes, and non-critical conditions.

Storm Hardening

Severe storms pose a high risk to electric-power systems with distribution at the highest risk due to miles of wire and proximity to trees. Some expect severe storm frequency to increase due to climate change. [20] Recognizing these conditions, utilities generally have adopted a proactive policy to address the threat of severe storms, including long-term programs anticipated to improve the capability of the electric system to withstand severe storm impacts. This shortens the time required to restore service to customers when outages occur due to less severe storms. A policy incorporates three main goals:

- Improve the ability to withstand severe storms without damage (durability)
- Improve the ability to continue service despite some system damage (resilience)
- Reduce the time necessary for recovery when service is disrupted (restoration)

[20] *Responding to Climate Change*, Columbia University, City of New York University, Cornell University, 2011.

Durability efforts may include reconfiguration or reconstruction of substations to avoid damage from flooding and wind, improved transmission line design and construction to withstand high winds, and improved distribution design and construction to withstand high winds. Resiliency efforts may include leveraging distribution-automation systems to manage the scope of outages and employing distributed generation and micro-grids. Restoration efforts may include proactively de-energizing circuits, implementation of outage management system, improvement of voice and data communication channels, implementation of a resource control system, implementation of an electronic damage-inventory system, improvement of damage-assessment processes, improvement of the restoration management system, improvement of restoration logistics processes, development of human resources support to ensure employee commitment to the restoration effort, and ensuring effective contractor response.

Reliability Improvements

Utilities can and do implement programs to maintain and improve the reliability of distribution feeders. These programs also speed restoration of service after an outage. This section describes several types of programs that might be used. Each utility would have its own programs to address issues specific to its region and issues that are causing problems.

Circuit Improvement Programs - When customer complaints or analysis of interruptions causes on distribution feeders falls below average reliability levels, those affected feeders circuits can be selected for improvement. This involves a detailed field inspection of the entire circuit to identify corrective actions and all substandard conditions that are likely to be causing the interruptions. The field survey enables development of customized improvements that may not have been apparent from an office analysis of interruption data. In addition to identifying substandard conditions, other reliability improvement programs such as tree trimming, installation of lightning arrestors, and replacement of armless insulators, hot-line clamps, and automatic-style wire splices are applied to the affected circuits as appropriate to enhance reliability. The reliability performance of circuits targeted under these programs experience a significant improvement compared to untargeted circuits.

Manual and Automatic Sectionalizing Programs - Sectionalizing distribution feeders allows an electric utility to more easily isolate faults on its feeders and thus speed restoration of customers. These devices can be field operated, *e.g.*, fuses on taps, load-break disconnects, and switches, as well as automatic or centrally controlled devices such as automatic circuit reclosers and automatic sectionalizing units.

An Automatic Sectionalizing Unit (ASU) Program involves the installation of supervisory controlled auto-sectionalizing switches at or near the mid-point and end-point (tie-point) of distribution circuits that provide automatic sectionalizing of downstream faults and operator-controlled switching to sectionalize and restore portions of faulted circuits. This process limits the number of customers interrupted when a main-line fault occurs. On select circuits with above average numbers of connected customers, additional ASUs are installed in series, breaking up large load centers into smaller components. This protocol results in an increase in overall circuit reliability due to a smaller number of customers experiencing a sustained interruption during a mainline fault, and increased flexibility in operating the electric distribution system.

Aged and Poor Condition Cable Replacement Programs - Based on aged and poor performance of distribution equipment, *i.e.,* failures of same or similar equipment, proactive replacement programs of equipment prior to failure can be implemented. One such program is a cable replacement program to replace existing three-phase underground main-line exit cables and main-line underground dips. Locations would be prioritized for replacement based on their field condition and historical risk factor, such as recent failure history. Programs such as this can use failure data to determine which underground cables have higher historical risk factors and are thus eligible for testing. Exit cables with no known failures can be proactively tested as to their field condition. Considering the potentially large quantity of aging exit-cables and the fact that an exit-cable failure typically interrupts an entire circuit, exit cables can be a high priority. Cable test results can be analyzed in conjunction with historical data to better manage cable assets, which will reduce outages while improving the program cost effectiveness.

Power Quality Issues on the Distribution System

In addition to outages, power quality has become more important to electric customers and a major concern for electric utilities. Among the issues that affect power quality are harmonics and flicker. Power quality typically is associated with electric power that drives an electric load and with the extent to which this load functions as desirable under the supplied voltage. Therefore, power quality is primarily of concern in distribution systems where most loads are connected. Similar issues and concepts can be extended to the transmission grid. Typically, the quality of electric power is described as parameters associated with:

- Variations in voltage magnitude (voltage sags and swells)
- Variations in the voltage frequency (under or over)
- Transient voltages and currents (under or over)
- Harmonic content in the sinusoidal waveforms

Continuity of service at the transmission level is of lesser concern than that at the distribution level primarily because of the topology of the bulk power system as opposed to the radial nature of the distribution system. Network topology provides alternate power-flow paths and multiple contingencies are required to result in severe extended power interruptions at the transmission level. Generating unit synchronization and wide-area power oscillations are of more importance to the bulk power system, as such conditions can lead to blackouts or brownouts of large parts of the system with long waiting times for service restorations.

Voltage magnitude variations are important, as they can affect operation of voltage-sensitive loads such as industrial induction motors and high-tech electronic loads. A voltage swell or sag is an event where the root mean square voltage goes above or below the nominal voltage by more than 10 percent for a duration of a few milliseconds to one minute. Undervoltages (or overvoltages) occur when the root mean square voltage drops below 90 percent (or rises above 110 percent) of the nominal voltage for more than one minute. Abrupt, brief overvoltages are usually referred to as spikes, impulses, or surges and generally are caused by large inductive loads being turned on or off. Or, more severely in the transmission network, by lightning. Lightning is an issue that affects the quality of power at the transmission level both by creating voltage surges on the system and by affecting reliability due to transmission line outages.

Frequency variations and large frequency excursions from nominal are caused by severe system events, such as loss of generating units or load interruptions. Continuous load variations also cause small frequency deviations. System frequency is controlled primarily by generating units. In particular, there are three levels of control: the first level is the inertia of the generator rotors, the generating unit governor systems that comprise the primary frequency control, the secondary frequency control is achieved via an automatic generation control system as part of the NYISO ancillary services market. With the replacement of large conventional generating units with small power-electronic-controlled sources or converter-controlled renewable resources, a reduction in total system inertia may be observed in the future. This might lead to increased values of the area control error and some issues with respect to frequency control. In general, the intermittent nature and the reduced controllability of renewable energy resources (or other distributed generation) is a factor that must be accounted for to maintain future power quality.

System imbalance also is an issue that could appear in transmission systems. In general, the transmission system is assumed to operate under balanced conditions among all three phases. Contrary to distribution feeders that can be heavily unbalanced, transmission lines are considered almost perfectly balanced, as the imbalances are smoothed at the transmission level. However, there are cases where loading imbalances of more than a few percent are observed among the three phases. Voltage imbalances are considerably less, on the order of less than one percent.

Harmonics on the power system are defined as the sinusoidal voltage and currents at frequencies that are integer multiples of the fundamental frequency. The most common harmonic index, which relates to the voltage waveform, is the Total Harmonic Distortion, defined as the root mean square of the harmonics expressed as a percentage of the fundamental component. Harmonics are injected into power systems by large power-electronic transmission equipment (*e.g.,* FACTS, high-voltage direct current [HVDC], etc.), certain large industrial loads, and by the aggregate injection of the pervasive penetration of distorting consumer loads such as home entertainment, electronically ballasted lighting, variable-speed high-voltage alternating-current equipment, etc. Utility measurements indicate that there can be a substantial level of background harmonic distortion throughout the electric system, most notable, the fifth harmonic. Utilities typically use Institute of Electrical and Electronics Engineers (IEEE) standard 519 which establishes IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems as a guideline for establishing its criteria. Utilities can require the total voltage distortion at any point of interconnection for devices on the transmission system be less than one percent for any individual harmonic and less than three percent for the root sum-square total of all harmonics orders two to 50. Keeping harmonics lower at the transmission system, where they are more easily controlled and would potentially be a larger contributor, helps minimize harmonics to the customer. That said, devices contributing to harmonics that are connected to lower voltages also should be investigated to determine if corrective actions are required. Some customer equipment, such as large variable frequency drive motor, may be damaged by harmonics.

The term Power Quality has recently achieved a high level of visibility with the emergence of the digital economy. Today, there is widespread use of digitally controlled devices in all areas of New York's customer equipment. Many of these new devices are highly sensitive and may not operate properly in the event of voltage variations or disruptions such as voltage spikes, sags, or dips.

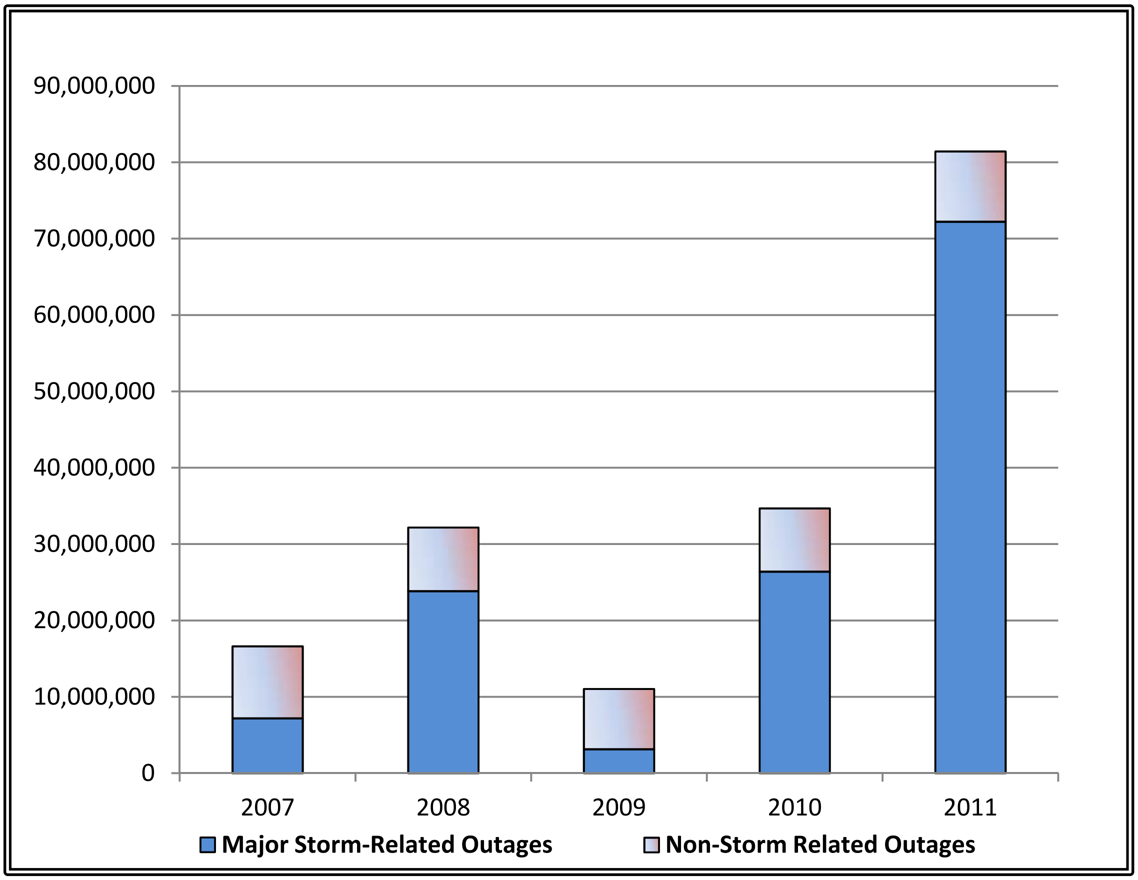
Service voltage levels are provided within a steady-state tolerance range per American National Standards Institute, ANSI C84.1. This specification requires that voltage be provided within +/- five percent of the nominal voltage level. Voltage dips or spikes and brief service interruptions of varying duration and severity occur due to operating conditions on the electric system. These irregularities do not cause malfunction of lighting or motor loads but may affect computers and other equipment.

Assessing Distribution Reliability

As a means of measuring the performance of investor-owned utilities, DPS staff compiles detailed monthly reliability performance, primarily CAIDI and SAIFI data, into an annual report. The 2011 Interruption Report contains detailed interruption data for each utility and statewide statistics for the past five years. Individual company discussions identify issues or actions within each company that influenced performance levels for 2011 and indicate company-specific trends, where applicable.

Figure 11 illustrates customer-hour interruptions over the past five years. Customer-hours of interruptions are used to calculate CAIDI and are measured by the number of customers without service multiplied by the hours those customers are without service. A short duration but widespread outage in a populated area such as downstate could significantly increase the annual customer-hour of interruptions. Likewise, a long duration over a small area could also increase the customer-hours interruptions. In 2011, total customer-hour interruptions were the highest during the past five years driven largely by storm events. In fact, customer-hours of interruptions from storms were the highest during the past 20 years because there were two major storm events during the same year, Hurricane Irene and an early snowstorm. As illustrated in the figure, storms are one of the largest factors for customer-hours of interruptions, accounting for more than 70 percent during the past five years.

Figure 11. Number of Customer-Hour Interruptions



Source: DPS

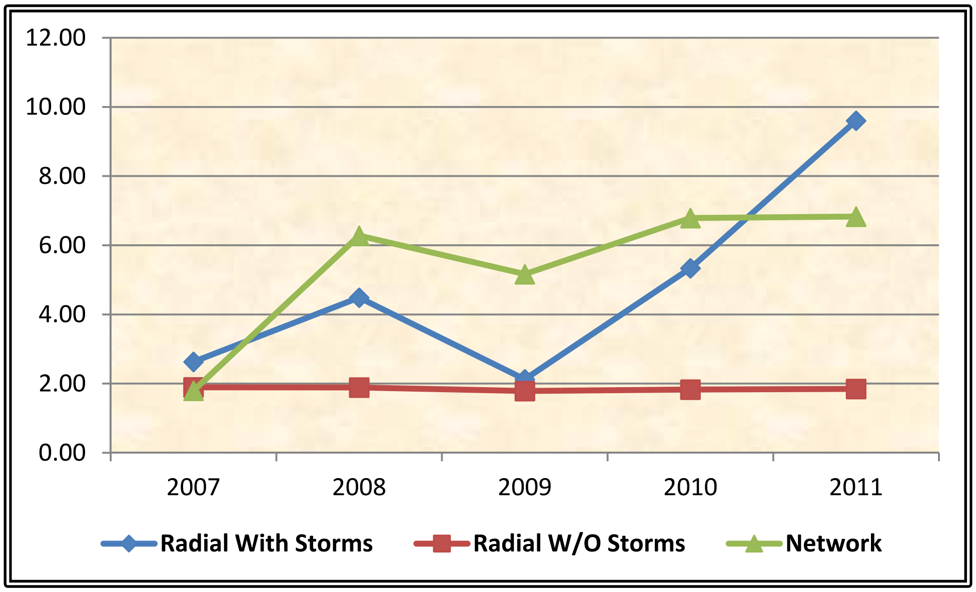
Figures 12 and 13 illustrate the statewide duration of interruption (CAIDI) and interruption frequency (SAIFI) between 2007-2011. Comparing the two indices that non-storm related outages occur more frequently, however, it is the storm outages that increase the duration of interruptions.[21]

Excluding major storms, the statewide interruption frequency for 2011 has been nearly identical for the past three years and better than the five-year average. Central Hudson Gas & Electric Corporation (Central Hudson), Niagara Mohawk Power Corporation d/b/a National Grid's (National Grid), and Orange Rockland Utilities (O&R) non-storm performance improved when compared with 2010. The remaining electric companies' 2011 performances were not as good as 2010 levels, although they still performed satisfactorily and met the criteria in the performance mechanisms to which they were subject.

Utilities served approximately 7.8 million customers[22] in 2011, of which 68 percent were on radial systems and 32 percent on network systems. Con Edison service territory accounted for 42 percent of the statewide customers. Due to concentrated population, Con Edison is the only utility that has a substantial network system, which accounts for 73 percent of its 3.3 million customers. Typically a network system results in much lower SAIFI values.

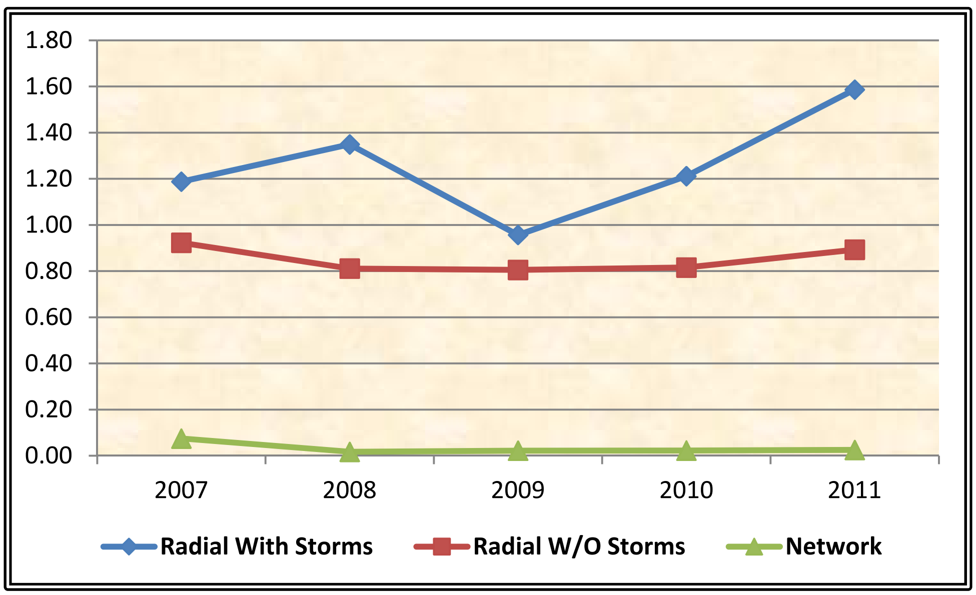
[21] CAIDI network service does not include a major storm category.
[22] A customer is defined by the point of interconnection with the utility or an electric meter.

Figure 12. New York State CAIDI for Radial and Network



Source: PSC 2011 Annual Reliability Report

Figure 13. New York State SAIFI for Radial and Network



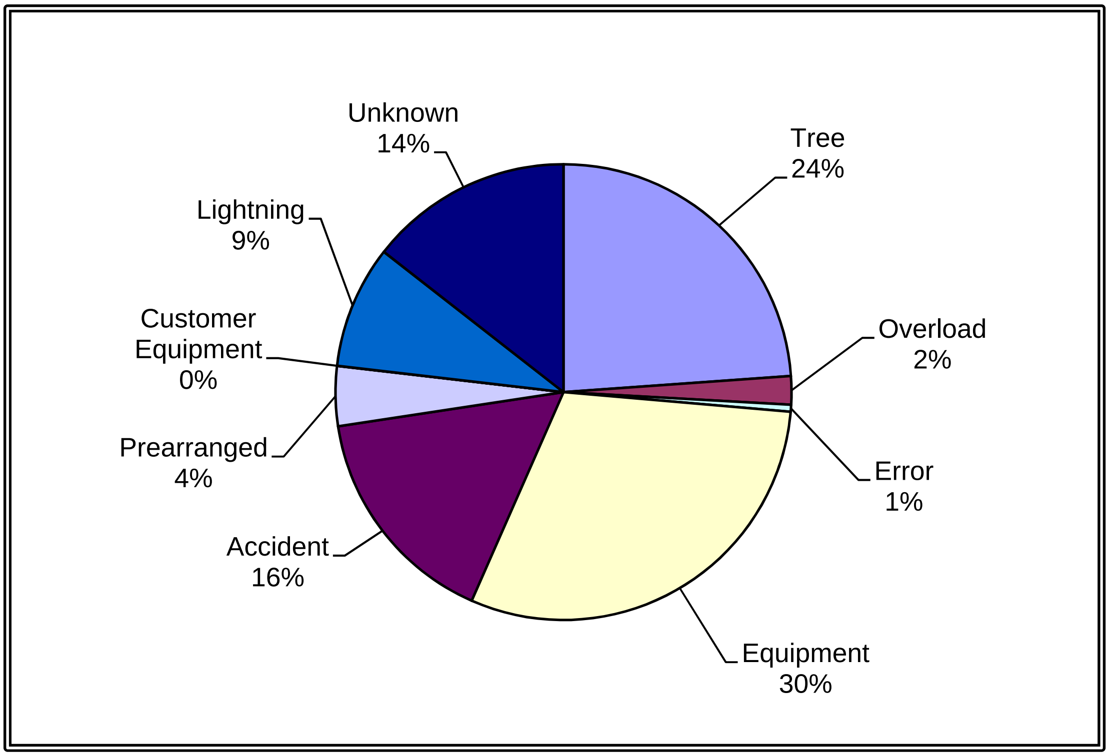
Source: PSC 2011 Annual Reliability Report

Utilities and DPS staff use cause code data to identify areas where maintenance or increase in capital investment is necessary to improve reliability. Overall, electric reliability performance across the State has been steady. There are, however, individual concerns that are being addressed through various staff efforts. Quarterly meetings on reliability with utilities are proving valuable and rate proceedings address different aspects of service reliability.

When not including major storms, the sources of interruptions for radial distribution (not including the Con Edison network) were dominated by tree, equipment, accident, and unknown sources as illustrated in Figure

14. Annually trees and equipment interruptions are the top two causes of non-storm interruptions. They differ in proportion from company to company depending on their individual characteristics such as the number of trees adjacent to lines within the service territory. Accidents not only include vehicular accidents, but also outages caused by animal contact. Utilities address the major problem areas with line clearance (tree trimming) programs, programs to replace problematic equipment, and animal guards around susceptible electric equipment.

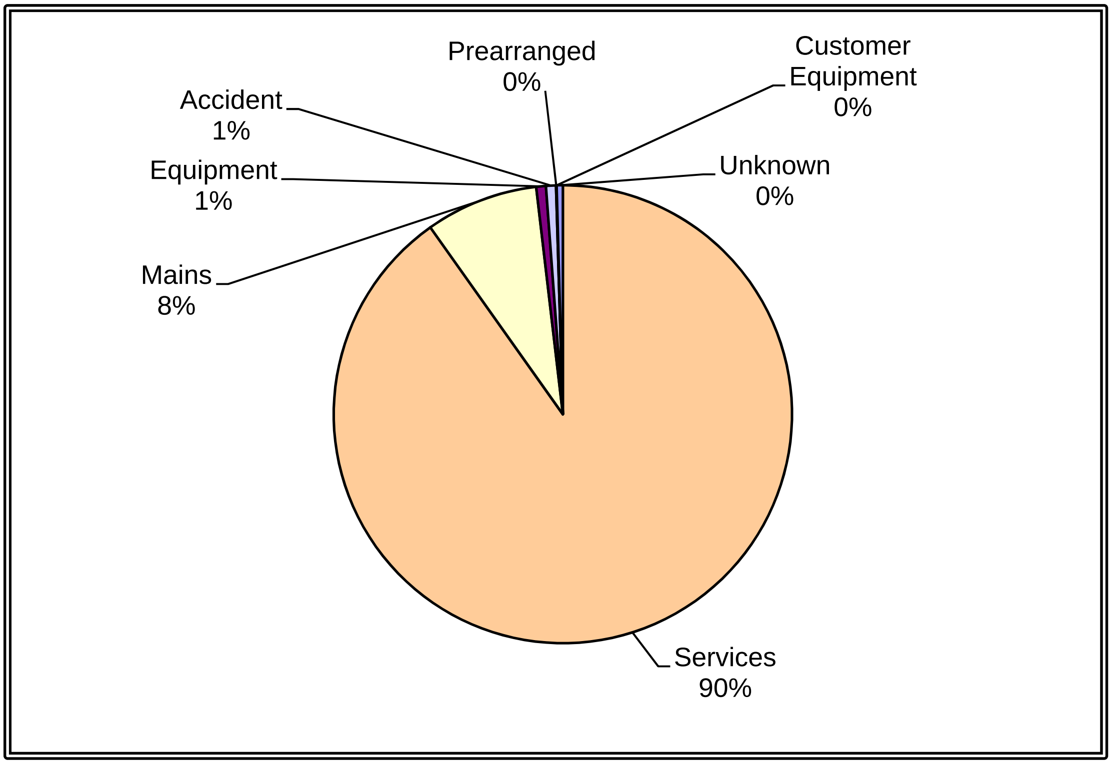
Figure 14. Radial Interruptions - 2011



Source: DPS

For network (Con Edison) interruptions, a different set of cause codes are used, with individual services (*i.e.,* the line that connects an individual customer to Con Edison's network) historically dominating outage causes. To minimize the frequency of customer outages, Con Edison's networks are designed with redundant supply paths. Individual service lines to customer premises, however, lack any supplemental supply. Given these design criteria and underground settings, the majority of interruptions are associated with the service portion of the network system, as shown in Figure 15. Failures on parts of the network grid itself are the second highest cause for interruptions. As an example of corrective action, Con Edison plans to modify and expand its troubleshooting staff use to minimize interruption duration (CAIDI).

Figure 15. Network (Con Edison) Interruptions - 2011



Source: DPS

D. Investment and Expenditures Issues

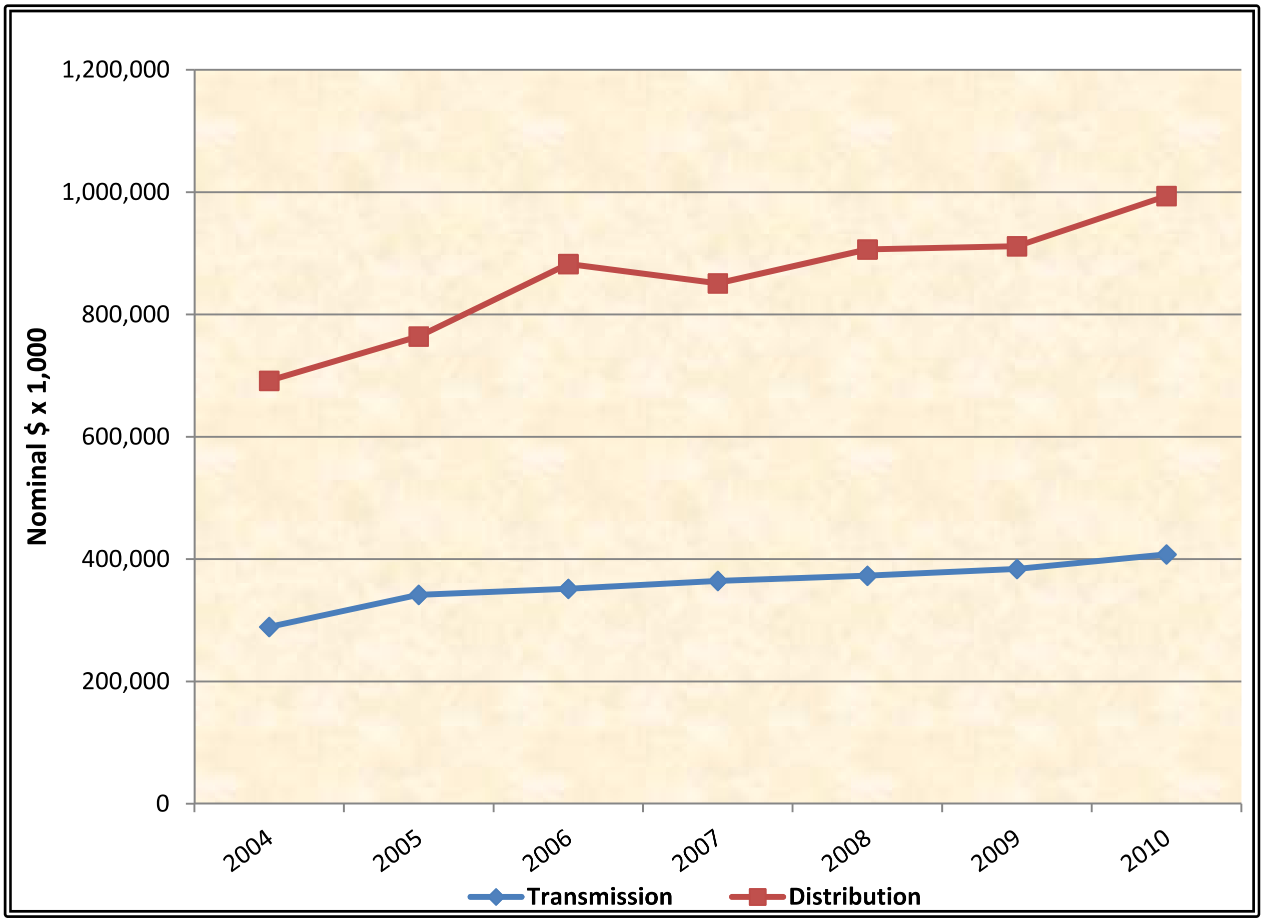
Not surprisingly, utility spending can have an effect on reliability. For capital expenses, delaying projects that replace old equipment, maintain or improve reliability, or fix specific problems can have varying effects on reliability. Saving operations and maintenance expenses, for example, by reducing the mile of lines cleared of trees or the number of line mechanics also will have an effect on electric reliability.

The tendency of both types of spending reductions is to have long-term rather than short-term effects. It might take years for the effects to be seen in reliability statistics, but it also will be years before the deficiencies are recovered. A lack of crews to respond to interruptions will be seen sooner in the duration metric (CAIDI).

While detailed examinations of utility spending occur during a rate case, the typical three-year rate agreement warrants additional attention during the "out" years. A concern for utility spending on reliability is the reason that the DPS staff has put the capital and operations and maintenance expenses reporting requirements, detailed earlier, into the utilities' annual reliability report. In addition, quarterly meetings help with information gathering between rate cases.

Financial data for New York State TOs filed with FERC and the PSC were reviewed. The data included operating expenditures for the transmission and distribution systems from 2004 to 2010 and actual and planned capital expenditures for transmission and distribution systems from 2004 to 2015. As shown in Figure 16, transmission operating and maintenance expenditures have trended higher in recent years. The increase in O&M expenses is in part associated with work related to the increase in capital expenditures discussed later and enhanced inspection protocols for the investor-owned utilities.

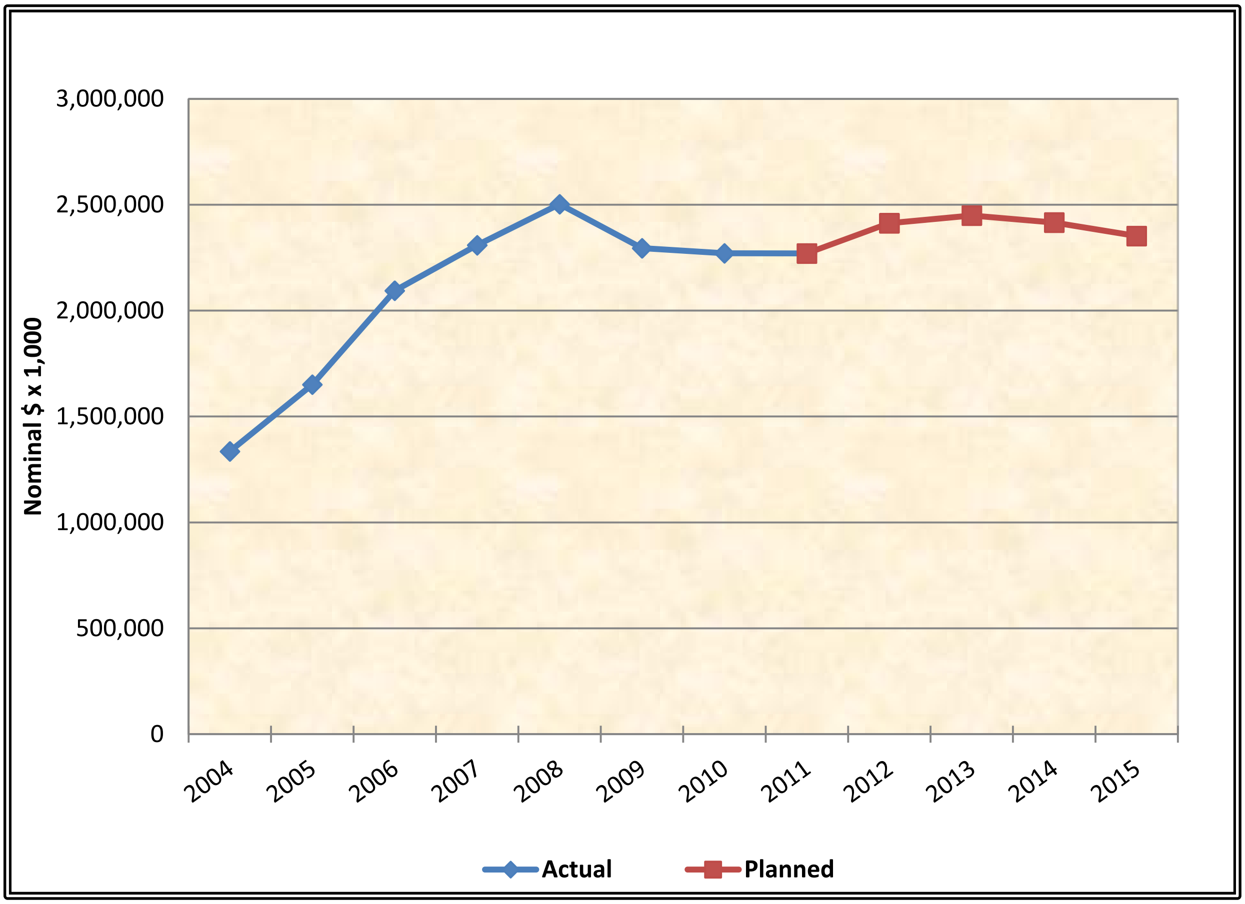
Figure 16. Electric Operations and Maintenance Expenses



Source: DPS

Figure 17 includes all the major utilities in New York, shows total actual electrical capital expenditures from 2004 through 2010 and total planned capital expenditures from 2011 through 2015. Capital expenditures increased significantly from 2004-2008, reflecting the need to add or upgrade facilities as they reached their capacity limits. For example, Con Edison built a number of new substations for the first time in years. Capital expenditures also increased because of much higher commodity costs, caused at least in part by higher global demand. Both copper and aluminum prices, which are a significant portion of the costs in cable and transformers, increased substantially during the mid-2000 time period. Commodity prices in general declined slightly during the recession. A downturn in capital expenditures starting in 2009, influenced by economic conditions, is predicted to be succeeded by modest, if any, growth in the next five years.

Figure 17. New York State Utility Electric Capital Expenditures



Source: DPS

Reliability and Cost Considerations

Costs to comply with transmission and distribution reliability rules or criteria are reflected in utility rates. There are generally incremental costs associated with compliance. Costs may include additional capital investments, changes to operations, and incremental operation and maintenance expenses. In addition to utility costs, ratepayers also may be affected by reliability compliance costs related to generators or non-utility transmission owners, which may be reflected in market prices of electricity and, ultimately, electricity commodity costs.

Transmission - Historically, the cost of complying with reliability criteria was not considered to be necessary. Rather, bulk power system reliability was considered a base line. Few if any opposed this concept, because there was a common interest in the strict observance of minimum planning and operating standards.

When new standards or changes to existing standards are proposed, it is becoming increasingly common for the sponsoring entity to perform an analysis of the cost of compliance. For example, NPCC and NERC recently have begun to consider both the benefits and costs to implement reliability standards. This process is at the early stages of development and the current proposed process is more qualitative than quantitative, although it may evolve into a more quantitative approach.

While the concept that reliability considerations must outweigh cost is unlikely to change, determination of the cost of compliance probably will become a requisite parallel effort when proposals for new standards are considered.

Distribution - The balancing of reliability and costs is an ongoing challenge for electric distribution systems. For example, Con Edison's network system (network systems also exist to a limited extent in some of the major upstate cities[23]), is inherently much more reliable in terms of interruption frequency. While theoretically possible, it would, however, be cost prohibitive to put such a network in place throughout the State. Similar although less extreme comparisons could be made between more densely populated areas and the more rural areas of the State. Another challenge is the call for widespread undergrounding of existing overhead facilities in the aftermath of a major storm(s). Again, however, the cost to do so would be extremely high. A study performed after three major storms affected Con Edison in 2006 estimated the cost to underground all of Con Edison's overhead facilities and other associated utility facilities (*e.g.,* telephone) at $45 billion dollars. The estimated cost to underground all of LIPA's overhead facilities including transmission, distribution, and service drops is approximately $39 billion (2012) dollars. These estimates do not include the cost to modify customer equipment to underground connections.

In determining "safe and adequate service" at "just and reasonable rates," the PSC tries to maintain a balance between what is acceptable reliability versus what is an acceptable rate impact to utility customers. The reliability performance mechanisms and electric service standards mentioned elsewhere in this report are intended to help ensure that appropriate reliability in maintained. Many studies have shown that reliability is one of the more important concerns of utility customers, but that cost is the most important concern. One of the challenges being faced is modernizing the distribution infrastructure (or, conversely, not letting it deteriorate) and embracing new technology, while simultaneously controlling costs so that they are not unreasonable. One means of doing so is using enhanced technology to improve efficiencies, thus offsetting increases in other areas such as those due to increased commodity costs.

[23] For example, networks also exist in Albany, Troy, Syracuse, and Buffalo. These networks serve a portion of the downtown business district in each of these cities and are relatively small in size.

E. Environmental Regulations

Siting Law

Article X of the New York State Public Service Law was reestablished and revised through the Power NY Act of 2011 which took effect on August 4, 2011. The new Article X law is permanent and applies to the siting of new generation plants and certain upgrades to existing plants. The capacity threshold for a project to be subject to Article X is 25 MW (the previous threshold was 80 MW). A wider range of generation projects, including combustion sources, wind, solar, and other renewable projects are now subject to the Article X siting process. Environmental Justice analyses must be conducted under the new law (see capsule for Part 487 in Appendix A). In addition, CO_2 standards have been established for new fossil-fuel-fired generators (see capsule for Part 251 in Appendix A). Part 251 and Part 487 were adopted in July 2012. The State must approve or disapprove applications within 12 months of the date an application is determined to comply with Section 164 Public Service Law or within six months for modified or repowered facilities meeting certain criteria including, but not limited to, net emissions reductions.

Environmental Regulations

Electric generating units (EGUs) are subject to environmental regulations addressing air emissions, water discharges, and solid and hazardous waste management. Regulations impacting this sector have been adopted by the NYSDEC and the United States Environmental Protection Agency (U.S. EPA). Lists of regulations affecting this sector are presented in Table 4 (NYSDEC) and Table 5 (U.S. EPA). Capsule summaries of these regulations are presented in Appendix A.

The NYISO evaluated the impacts of the following regulations on the reliability of the grid in the NYCA in the 2010 Reliability Needs Assessment:

- NYSDEC's NO_x RACT Rule (Subpart 227-2)
- NYSDEC's Best Available Retrofit Technology (BART) Rule (Part 249)
- Utility MACT Rule (40 CFR 63, Subpart UUUUU)
- NYSDEC's Best Technology Available (BTA) Policy

NYSDEC's NO_x RACT Rule - Subpart 227-2, Reasonably Available Control Technology (RACT) for Major Facilities of Oxides of Nitrogen (NO_x), also referred to as the NO_x RACT Rule, is a component of the NYSDEC's strategy to bring the State into compliance with the National Ambient Air Quality Standard for ground-level ozone. In 2009, the NYSDEC was considering tightening standards for NO_x emissions from large coal- and oil-fired boilers such as those used at electricity generating stations. General Electric was retained by the NYISO in 2009 to conduct a study of the control technologies and costs to comply with the NO_x emission standards under consideration by the NYSDEC. General Electric concluded that the lower emission standards would not result in negative operation margins and recommended that the revised standards not take effect until July 1, 2014. The NYSDEC incorporated General Electric's recommendation into Subpart 227-2. It is not expected that a significant quantity of capacity will retire solely due to the provisions of Subpart 227-2.[24]

NYSDEC's Best Available Retrofit Technology (BART) Rule - The purposes of the Best Available Retrofit Technology (BART – Part 249) Rule are to reduce regional haze and improve visibility in Federal Class I Areas (*e.g.,* national parks). Fossil fuel-fired steam electricity generating units with heat inputs greater than 250,000 mmBtu/h and a potential to emit more than 250 tons per year of NO_x, SO_2 or PM_{10} are potentially subject to Part 249. The units specifically affected by Part 249 are those that commenced operation or

[24] "2010 Reliability Needs Assessment," New York Independent System Operator, September 2010. Page 45.

underwent reconstruction between August 7, 1962 and August 7, 1977. EGUs subject to Part 249 may not have to install any additional controls beyond what is required to comply with Part 227-2. It is not expected that a significant quantity of capacity will retire solely due to the provisions of Part 249.

Utility MACT Rule - The U.S. EPA released a proposed rule on May 3, 2011 to establish Maximum Achievable Control Technology (MACT) emission rate standards for hazardous air pollutants from coal- and oil-fired steam generators with a nameplate capacity greater than 25 MW. A final rule, which is essentially the same as the proposed rule, was signed by the U.S. EPA Administrator on December 16, 2011 and is known as the Mercury and Air Toxics Standards (MATS). It is estimated that the MACT rule (40 CFR 63, Subpart UUUUU) will affect 32 units that represent 10,844 MW of capacity in New York. The majority of the New York coal fleet has installed emission control equipment that will put compliance within reach. Certain coal-fired units, however, may need to fuel switch or undertake extensive emission control retrofits. The impact of the rule to heavy oil-fired units in New York is not expected to be significant. The sources will need to monitor fuel moisture or conduct periodic stack testing or both to comply with the rule. Facilities will have three years to comply with the rule (February 16, 2015). Under the Clean Air Act, NYSDEC can grant an additional year for technology installation.

NYSDEC's Best Technology Available (BTA) Policy - The purpose of the NYSDEC's Best Technology Available (BTA) Policy is to minimize the adverse environmental impacts caused by industrial facilities with cooling water intake structures in connection with point source thermal discharges. Water withdrawals from surface water bodies through cooling water intake structures cause injury and mortality to fish and shellfish through impingement at the intake and entrainment through the cooling system. The policy applies to all existing and proposed industrial facilities designed to withdraw at least 20 million gallons of water per day from the waters of New York State, where at least 25 percent is used for contact or non-contact cooling, and that are subject to the requirements of Section 704.5 of 6 NYCRR Part 704 and Section 316(b) of the federal Clean Water Act. The policy is flexible, since it allows for equivalent performance goals that could be met in lieu of the preferred cooling water intake structure technology. The NYSDEC finalized the BTA Policy on July 10, 2011. In the 2010 RNA, the NYISO estimated that 4,410 MW to 7,736 MW of capacity in the NYCA could face significant capital expenditures to meet the requirements of the BTA Policy.[25]

New and Future Regulatory Initiatives

There are several additional regulations that are coming into effect or may be finalized in the next two years that may pose potential reliability concerns in NYCA. The three most significant rules and the potential corresponding effects are discussed below.

Cross State Air Pollution Rule (CSAPR) - This rule was to establish NO_x and SO_2 emissions budgets for fossil fuel-fired electricity generating units with nameplate ratings greater than 25 MW in 27 states (including New York) in the central and eastern portions of the United States. In New York, CSAPR would have affected 167 units representing 23,275 MW of capacity. The emission budgets for New York in the July 6, 2011 version of the rule were below the historical annual emission totals for the electricity generating sector. Several modeling deficiencies were identified in the work done by the U.S. EPA. The NYSDEC and NYISO provided technical support information to U.S. EPA for its use to propose the technical correction to the CSAPR rule (released on October 7, 2011) that provides additional emission allowances for NY generators. U.S. EPA has estimated New York's annual allowance costs for 2012 at $65 million. This rule was stayed by the United States Court of Appeals for the District of Columbia Circuit on December 30, 2011 and vacated and remanded to the U.S. EPA on August 21, 2012. The Clean Air Interstate Rule (CAIR), another emission allowance rule, remains in effect. In New York, CAIR is administered through Parts 243, 244 and 245 (see capsules in Appendix A) and applies to fossil fuel-fired generators with nameplate capacities equal to or greater than 25 MW.

[25] Ibid, page 47.

Cooling Water Intake Structures - Federal rules are similar to the NYSDEC's BTA Policy except that the applicability ranges are different. A proposed rule was released on March 28, 2011, and a final rule is expected in June 2013. If the final rule is not substantially different than the proposed rule, then the BTA Policy will likely be the governing requirement that New York facilities must meet.

Coal-Combustion Residuals - The U.S. EPA proposed two options for regulating coal-combustion residuals on June 21, 2010. Coal-combustion residuals include bottom ash and fly ash. These materials currently are not considered solid wastes by the NYSDEC under Subpart 360-1.15 ("Beneficial Use") if they are used as specified in paragraphs 360-1.15(b)(14-16) (*e.g.,* manufacture of roofing shingles, concrete products, etc). This beneficial use may be eliminated if the U.S. EPA decides to regulate coal combustion residuals as hazardous waste (special waste). It is not clear when or if U.S. EPA plans to release a final rule for coal-combustion residuals.

CO_2 Emissions Allowance Programs - A regional carbon-dioxide emissions trading program (Regional Greenhouse Gas Initiative or RGGI) took effect on January 1, 2009. Ten states, including New York, were part of RGGI at that time. In New York, a CO_2 allowance program was adopted through 6 NYCRR Part 242.

The NYISO evaluated the potential impacts of the RGGI CO_2 allowance program as part of the 2009 Reliability Needs Assessment and the 2009 Comprehensive Reliability Plan. It was concluded that the RGGI program would not have adverse impacts on reliability in the short term, based on the fuel forecast and environmental program costs at that time of the analysis. Nevertheless, if the availability of allowances decreases to the point where carbon prices reach levels of $35 - $50 per ton, high carbon emitting coal-fired capacity would be financially strained. Additionally, as the spread between coal and natural gas decreased, owners of coal-fired plants would have to consider the continued viability of their plants.

At this point, there is no national CO_2 allowance program. It is too early to estimate the impact of such a program on the reliability of the electric grid in New York.

Table 4. – New York State DEC Regulations and Policies

Subject	Regulation	DG	Central Station Power Plants						
			Coal	Oil	Gas	MSW	Wood	LFG	Nuclear
Air – General									
Permitting Requirements	Part 201	x	x	x	x	x	x	x	
Air Quality Regulations (Emission Standards)									
Incinerators	Subpart 219-2					x			
Distributed Generation	Part 222	x							
Sulfur Content in Fuel	Subpart 225-1	x	x	x					
Particulate Matter	Subpart 227-1	x	x	x			x		
NO_x RACT	Subpart 227-2	x	x	x	x		x	x	
New Source Review	Part 231	x	x	x	x	x	x	x	
Mercury Reduction – Coal-fired EGUs	Part 246		x						
Regional Haze (BART)	Part 249		x	x					
CO_2 Standards	Part 251		x	x	x				
Air Emissions Allowance Programs									
CO_2 Trading Program	Part 242		x	x					
CAIR – Ozone Season NO_x	Part 243		x						

Subject	Regulation	DG	Central Station Power Plants						
			Coal	Oil	Gas	MSW	Wood	LFG	Nuclear
CAIR – Annual NO_x	Part 244		x						
CAIR – SO_2	Part 245		x						
Fuel Storage and Waste Management Regulations									
Solid Waste Management	Part 360		x	x		x			
Hazardous Waste Management	Parts 370-374		x			x			
Petroleum Bulk Storage	Parts 612-614	x		x					
Cooling Water Intake and Water Discharge Regulations									
SPDES Permits	Part 750		x	x					x
Cooling Water Intake Structures	BTA Policy		x	x					x
Environmental Justice									
Environmental Justice (Article X only)	Part 487		x	x	x	x	x	x	x

Source: DEC

Key

BART – Best Available Retrofit Technology
CAIR – Clean Air Interstate Rule
DG – distributed generation
EGUs – electric generating units

BTA – Best Technology Available
LFG – landfill gas
MSW – municipal solid waste
RACT – Reasonably Available Control Technology

Table 5. U.S. EPA Regulations

	Regulation	DG	Central Station Power Plants						
			Coal	Oil	Gas	MSW	Wood	LFG	Nuclear
New Source Performance Standards – (40 CFR 60)									
Spark Ignition Engines	Subpart IIII	x		x					
Diesel Engines	Subpart JJJJ	x			x			x	
Turbines	Subpart KKKK	x		x	x				
National Emission Standards for Hazardous Air Pollutants – Air (40 CFR 63)									
Engines	Subpart ZZZZ	x		x	x				
Coal- and Oil-fired EGUs	Subpart UUUUU		x	x					
Cross-State Air Pollution Rule (40 CFR)									
EGUs (>25 MW)	Parts 51, 52 et. al.		x	x	x				
Cooling Water Intake and Water Discharge Regulations (40 CFR)									
Cooling Water Intake Structures	Parts 122 & 125		x	x					x
Effluent Limits	Part 423		x	x					x
Coal Combustion Residuals (40 CFR)									
Coal Combustion Residuals	Parts 257 & 261		x						

Source: DEC

F. Transmission and Distribution Reliability Impacts from Policy

Numerous public policy initiatives have resulted in changes to the electric system. Legislative regulatory and administrative activities, initiatives, programs, mandates, and other changes, particularly sudden unexpected changes affecting any component of the electric system *(i.e.,* load, generation, or transmission) can have significant impacts on the system. This section highlights the recent policy initiatives and presents how the electric system has accommodated these changes through system planning and operation.

Load

As discussed in Section A, load forecast plays a critical role in system reliability. Load forecast uncertainty is a major factor in determining the appropriate installed reserve margin. Actual load almost always differs from the load forecast, however, a robust forecast generally predicts the actual load within the bandwidth of accepted tolerance. Power system planners consider this bandwidth when designing systems.

If the load characteristics change slowly over time, forecasters can build these effects into their forecasts, as long as they have data that can quantify the sources of the changes. If the load characteristics change rapidly beyond those reflected in the bandwidth of tolerance then, the system could be vulnerable.

Energy Efficiency - Well structured energy efficiency programs provide a cost-effective reduction in energy consumed and reduce the need for infrastructure upgrades. Recognizing the benefits of energy efficiency, in June 2008 the PSC issued an Order establishing an Energy Efficiency Portfolio Standard (EEPS) with the goal to reduce forecasted electric load by 15 percent (26,885 GWH) by 2015 (15 x 15); and authorized funding through 2011. With such an aggressive goal in a relative short period of time, the PSC directed all investor-owned utilities and NYSERDA to implement new efficiency programs, augmented by LIPA, NYPA, and NYSERDA's current activity. Targeted savings among these program administrators account for 68 percent of the overall goal, while the remaining portion is from expected improvements in building codes and appliance efficiency standards. In October 2011, the PSC authorized funding and issued revised goals through 2015 for NYSERDA and the state's investor-owned utilities.

While energy-efficiency programs provide a similar resource to conventional generation in terms of satisfying system-demand requirements, there is greater uncertainty associated with the energy savings of energy efficiency programs that is compounded in longer term load projections. If the achieved energy savings are lower than the policy goals or lower than projections, then reliability is potentially at risk because the forecast would be too low. If, for example, the actual energy efficiency savings were 10 percent less than the 15 x 15 goals, this would be equivalent to adding approximately 2,690 GWh or 1.6 percent to the 2015 forecasted load.[26] Assuming that energy efficiency has the same load factor as the overall load, such a 10 percent deviation from the goal would equate to an increase of approximately 580 MW in peak demand.

Consequently, for planning purposes, the load forecaster is guided by program goals and past performance but does not follow the goals explicitly. Energy-efficiency programs with clear, targeted customers have a higher degree of confidence of obtaining specified goals than programs with more ambiguous customers such as market transformation. Additionally, it is difficult to delineate potential overlap between market transformation savings and building codes and standards savings, and it's difficult to explicitly quantify either. Two important reliability studies described in Section B, the Reliability Needs Assessment (RNA) and

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[26] The 1.6 percent savings is based on the 2009 NYISO "Load and Capacity Data" 2015 energy forecast with conservation impacts. (2,690 GWh/168,690 GWh= 0.0159)

the Installed Reserve Margin (IRM) study, depend on accurate load forecasts. In a long-term forecast such as the 10-year RNA, energy efficiency goals are more uncertain than in the near-term, year-ahead forecast used for the IRM, where the energy efficiency goals are more certain.

To capture these uncertainties, load forecasts used in reliability studies are developed jointly by the NYISO and major state utilities and power authorities. For the IRM Study, NYPA, LIPA and the state's major investor-owned utilities (IOUs) provide year-ahead forecasts to the NYISO. These forecasts include planned impacts of energy efficiency for each utility or agency based on program administrators' projections. The NYISO evaluates the utility forecasts in terms of expected levels of economic growth and energy efficiency impacts for the coming year.

A 10-year forecast is required for the RNA. The NYISO combines forecasts provided by LIPA and Con Edison with its own forecasts for all other areas of the State. A two-stage process is used. In the first stage, energy and peak demand forecasts are based on econometric projections prepared by NYISO, LIPA, and Con Edison. In the second stage, the NYISO and the two utilities deduct from the econometric forecasts their projections of the energy savings impacts of efficiency programs, building codes, and appliance efficiency standards. The energy-efficiency program impacts are based on goals and budgets provided by the PSC, NYPA, and LIPA. The energy-efficiency forecasts account for uncertainty in expected savings due to potential shortfalls in expected spending levels and future impacts, based on recent history of program administrators' actual spending and achievement levels. The forecast used for the RNA is discussed and reviewed with the NYISO's Electric System Planning Working Group, which includes market participants, consumer advocates, NYSERDA, and DPS Staff.

Large Load Growth - Unforeseen large-load growth also creates uncertainty in system planning. When public policy actively promotes specific or targeted economic development projects, the resulting concentrated growth, most likely from a large-scale industrial development, can have an impact on the distribution system. It should be noted, however, that the industrial sector accounts for only approximately 10 percent of New York State's demand. Industrial sector demand has declined 47 percent since 2001, while commercial sector demand increased by 24 percent.

On the distribution system, such impacts could require significant new investments to the system, such as upgrading the capacity of individual circuit conductors, replacing transformers that would become overloaded, or installing new distribution substations. TOs reach out to businesses at a local level to anticipate regional load growth; large new business loads usually work directly with the TO to ensure they meet utility connection requirements. Generally, these projects do not affect the bulk power system as abruptly. Rather, the effects of these increased loads are generally anticipated and captured in the planning studies.

Other Load Variation Mechanisms - In addition to energy efficiency and load growth, conservation and load shifting are other mechanisms that affect load. Load shifting generally occurs when consumption from periods of high demand (high costs) shifts to periods of low demand (low costs). Such mechanisms are largely driven by economics. Times of high energy prices can result in sudden changes to load from conservation. If loads respond consistently to price, then the load response can be reflected in the forecast. If load response is inconsistent, then capturing these variables in the forecast becomes difficult. Therefore, an inconsistent response creates uncertainty in the forecast that can impact reliability.

Load Control and Peak Shaving

NYISO Demand Response Programs. The NYISO has two demand response programs that provide load control and peak shaving to support reliability of the bulk-power grid by providing incentives for retail loads (i.e. electricity consumers, either individual, aggregated, or LSEs such as utilities) to participate in the wholesale market. The first is the Special Case Resource (SCR) program, which is part of the Installed Capacity (ICAP) market, and the second is the EDRP. In addition, the NYISO administers the Targeted Demand Response Program for the TO for Zone J. SCR and EDRP resources are deployed for forecast or actual operating reserve shortages or other emergency reliability needs. Demand response resources may enroll as EDRP or ICAP/SCR, but cannot participate in both programs.

SCRs are end-use loads capable of being interrupted when called upon, and distributed generators that are invisible to the NYISO's Market Information System. They enroll in the ICAP market through Responsible Interface Parties (RIPs). To participate in the ICAP market, resources must be rated at 100 kW or higher, which can be achieved by aggregating SCRs, as long as they are in the same zone. RIPs are responsible for all forms of communication to and from the NYISO, including enrollment, offering into auctions, certification, notification of events, and dispatch of SCRs. They also are responsible for determining the amount of load reduction provided by the SCRs, submitting load-reduction data to the NYISO, and distributing program payments from the NYISO to the SCRs. SCRs participate in ICAP auctions in the same manner as other ICAP suppliers. The amount of capacity an SCR is qualified to sell in the ICAP auction is based on the SCR's pledged load reduction and its performance factor. The performance factor reflects the historical performance of the SCR, which is determined from actual performance data. Once during each Capability Period[27], SCRs are required to perform a test of their pledged reduction. Each SCR's performance factor is based on the load reduction achieved during tests as well as any events during the capability period.

When possible, RIPs are given at least 24 hours advance notice that SCRs may be required the following day and a second notice two hours in advance of an event. The EDRP program allows participants to be paid for reducing their energy consumption upon notice from the NYISO that an operating reserves deficiency or other emergency exists.

In response to a request for assistance from the TO for Zone J, the NYISO can activate the TDRP in one or more of eight sub load pockets within Load Zone J. Notifications will be made through the NYISO's demand response notification system; events will clearly be identified as TDRP advisories or activations. Participation in the TDRP is voluntary.

For the summers of 2001 through 2011, the NYISO activated the EDRP and SCR programs a total of 21 times: four times each in 2001 and 2002; twice in 2003 (during the August blackout restoration), once in 2005, six times in 2006, twice in 2010, and twice in 2011. No activations of EDRP or SCR occurred in 2007, 2008, or 2009. Seven of these demand response events have been called statewide; the remaining events were called in the eastern and southeastern zones (NYISO Zones F-K) in various combinations. The NYISO activated EDRP and ICAP/SCR resources under the TDRP in zone J, described below, on two occasions in 2007 and twice in 2010.

Highlights of the reliability demand response programs include the following:

- During the summer of 2011, more than 5,800 retail loads were enrolled
- Approximately $29 million in energy payment incentives have been paid to EDRP/SCR program participants between 2001 and 2011
- The NYISO's reliability demand response programs accelerated the recovery process after the August 2003 blackout
- Peak load was reduced by as much as 1,400 MW during demand response events in the summer of 2011 and 1,000 MW during the NYISO's all-time peak in August 2006

SCRs are currently the fastest growing segment of the NYCA resource capacity mix, having increased from approximately a 1,000 MW in 2005 to almost 2,000 MW of capacity in five years, and provide capacity contribution roughly equivalent to that of coal or wind, as providers migrate from the NYISO's EDRP program to the more remunerative SCR program. Consistent with the growth in these programs, New York resource adequacy calculations have begun to exhibit significant reliance on these resources. Nevertheless, it remains untested to what extent the system will be able to rely upon a high level of SCR response in the face of repeated calls during peak hours that most impact reliability. The NYSRC and NYISO conducted a technical

[27] Summer capability period is from May 1st to October 31st and winter capability period is from November 1st to April 30th.

performance evaluation of SCRs to assess past performance, to ensure accurate representation of these resources in the Installed Reserve Margin Study, and to better understand any reliability implications. The joint NYISO/NYSRC evaluation concluded that three performance discount factors should be applied to the SCR capacity to reflect measurement errors, performance, and fatigue *(i.e.,* persistence). The fatigue factor was selected based on qualitative judgment due to virtually no empirical data available on which to estimate the degradation of performance after frequent activations over a short period of time.

LIPA Peak-Load Reduction Program. The LIPAEdge program is a demand response program designed for residential and small commercial applications on Long Island. The program is available to any customer with central air conditioning in either its home or office. The program uses programmable thermostats as an interface between the customer's central air-conditioning condensing unit and LIPA software. LIPA provides the thermostat at no cost to the customer. The thermostat is connected to a communication board, which is usually located at the air handler in the customer's home. The communication board is "connected" to the LIPA system via a wireless two-way paging network (similar to the technology used in old beepers). When the customer enters the program, they are agreeing to terms allowing LIPA to control their central air-conditioning systems up to seven times between the months of June and September. This unique control devise results in lowering customer bills, but it also enables the customer to contribute in protecting Long Island's precious resource. During the summer months when the load is high, LIPA has the ability to curtail approximately 50 MW of load. When the program is activated, LIPA cycles the customers compressors on and off for 30 minute intervals over the course of four hours. To sign up for the program, customers fill out an online application at www.lipaedge.com; LIPA then schedules a site visit. A load-modifier benefit would reduce the ICAP need for the following year if the program is activated coincident with the peak. Historically, LIPA has activated every thermostat (~33,000) during these events but LIPA has the ability to activate them individually or in high-load pockets, by circuit, etc. LIPA activated the program in both 2009 and 2010, but not 2011.

Con Edison Demand Response Programs. Con Edison is the only investor-owned utility with its own demand response programs. It administers three demand response programs: Distribution Load Relief Program (DLRP), Direct Load Control Programs (DLCP), and Commercial System Relief Program (SCRP). The DLRP provides compensation for load reduction during distribution system load-relief periods designated by Con Edison for its system reliability. Both curtailable load and distributed generation are allowed, and 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 DLCP is a thermostat-controlled program operated by Con Edison through a telecommunications device, focusing on central air conditions. Customers are awarded an upfront incentive to sign up to participate on a voluntary basis and can override the thermostat with no penalty. The SCRP is a mandatory load-reduction program that provides reservation payments monthly and energy payments for load reductions made by the customer during event hours. This program is activated by Con Edison during Con Edison's summer-peak days or system-critical situations.

NYPA Peak Load Reduction. NYPA has a demand response program, the Peak Load Management program, offered during the summer, which calls upon enrolled facilities to reduce their demand during times of peak load or system emergency. The peak load is assessed using NYPA's day-ahead and in-day forecast. This program lowers capacity costs to the customer and enhances system reliability. NYPA's flagship peak reduction program had 66 facilities (29.6 MW) enrolled in New York City. The contract with these facilities allows for up to 15 events per summer. In the summer of 2010 and 2011, there were four and six events, respectively.

New York State Agency Peak-Load Reduction. The New York State DPS program for peak-load reduction was implemented in 2003 for the six largest NYS Agency energy consumers. Over the years, the program was expanded to include all state agencies, their affiliated entities, and the County Emergency Management Offices. The DPS program is implemented when the NYISO activates SCR and or EDRP, when the National Weather Service issues a Heat Alert, when local electric system conditions warrant activation, and for prolonged Ozone Advisory periods. In conjunction with NYSDEC, DPS would recommend when it might be appropriate to implement reductions based on prolonged ozone periods. DPS estimates the load reduction to be approximately 60 MW when the program is implemented by all State agencies.

Generation

Renewable Portfolio Standard - The New York State Renewable Portfolio Standard (RPS), established by the PSC in 2004, sought to enlarge the proportion of renewable electricity used by retail customers. In December 2009, the PSC expanded the RPS goal to increase the proportion of renewable electricity consumed by New Yorkers from 25 percent to 30 percent by 2015. The new 30 percent goal equates to a target of 10.4 million MWh of renewable electricity by 2015.

The Renewable Energy Assessment of the 2009 New York State Energy Plan reports, "New York produced 28,067 gigawatt hours (GWh) from renewable resources in 2007, representing 16.8 percent of the State's total electricity generation. Of that, conventional hydropower provided 90.0 percent of the State's renewable electricity, followed by biomass (5.6 percent), wind (3.1 percent) and biogas (1.3 percent)." In 2011, NY produced 33,251 GWh from renewables which represented 24 percent of the State's total electricity generation. Of the renewable energy, conventional hydro power provided 83 percent, wind provided 8.4 percent, and the balance (8.5 percent) provided by bio-mass, bio-gas, and solar. Increasing production from renewables results in decreased emissions by displacing fossil-fuel generation and enhancing New York's fuel diversity.

In New York State, the RPS program is funded through a surcharge on customer bills from investor-owned utilities. The New York State Energy Research and Development Authority (NYSERDA) conducts annual auctions for the purchase of Renewable Energy Credits (RECs), which are proposed to be produced from new qualified renewable-generation facilities. The amount of new renewable resources to be procured translates to roughly 10.4 million MWh by 2015. To date, NYSERDA's six solicitations have procured approximately 47 percent of this target. A seventh solicitation concluded in 2011. The projects awarded contracts under the seventh solicitation are expected to be in-service by December 2012.

The intermittent nature of the output from renewable resources such as wind and solar generation presents operating and system security challenges that need to be addressed. To evaluate the challenges posed by a highly variable or intermittent resource such as wind and solar, the NYISO has conducted two studies. Since wind projects totaling approximately 8,000 MW have proposed to interconnect to the New York power system, the studies have focused on wind generation.

In 2004, the NYISO conducted its first wind study which concluded that up to 3,500 MW of wind could be integrated without any adverse reliability impacts. This analysis was conducted in response to New York State adopting an RPS whereby 25 percent of electrical energy would be supplied by renewables by 2013. Since that initial study, New York State has increased its RPS to 30 percent by 2015. The NYISO interconnection queue significantly exceeds the 3,500 MW identified in the 2004 study as having no adverse reliability impacts. Installed nameplate wind now totals 1,363 MW as of January 2012. As a result, the NYISO updated its 2004 findings by studying the integration of installed wind plants with nameplate ratings that ranged between a total of 3,500 MW and 8,000 MW for multiple years in the future.

The study was completed in October 2010, and found that wind generation could supply reliable clean energy at a low cost of production to the New York power grid. This energy results in significant savings in overall marginal system production costs, reductions in greenhouse gases such as CO_2, other emissions such as NO_x and SO_2, and an overall reduction in wholesale electricity prices. Wind plants require a significant up front capital investment, and because of their variable nature and the uncertainty of their output, provide a greater challenge to power-system operations than conventional power plants. The study determined that the NYISO's updated systems and procedures, which include placing wind resources on security-constrained economic dispatch and daily forecasting wind output with AWS Truepower, will allow for the integration of up to 8,000 MW of installed wind plants without any adverse reliability impacts.

The fluctuating nature and the uncertainty associated with predicting wind plant output levels manifests itself as an increase in overall system variability as measured by the net load (load minus wind). In response to these increased operational challenges, the NYISO has implemented changes to its operating practices. It is the first ISO to incorporate variable generation resources into security constrained economic dispatch and to implement a centralized forecasting process for wind resources. The study concluded that at higher levels of installed wind generation, the system will experience higher magnitude ramping events and will require additional regulation resources to respond to increased variability during the five-minute dispatch cycle. The analysis determined that the average regulation requirement will need to increase by approximately nine percent for every 1,000 MW increase in wind generation between the 4,250 MW and 8,000 MW installed base.

Accordingly, sufficient resources must be maintained to support the reliability of the power system when wind output declines. The study determined that 8,000 MW of wind would reduce the need for conventional or dispatchable fossil-fired generation on the order of 1,600 to 2,000 MW, or an amount equivalent to 20-25 percent of the installed nameplate wind. This is the result of the much lower overall availability of wind-produced energy when compared to conventional generation. This means that fossil generation equivalent to 75-80 percent of the nameplate-installed wind must be available for those times when the wind isn't blowing or the wind plant output is at low levels. Non-wind generation is needed to respond to the higher magnitude ramps that will result because of the variable nature of wind. As wind resources are added to the resource mix, their lower availability could result in an increase in the installed reserve margin. It is important to note that such an increase in the installed reserve margin would not necessarily drive an increase in the ICAP requirements assigned to LSEs. Increasing wind also could drive a decline in spot market prices in certain NYISO Zones where such resources are located. As of the publication of this study, the full spectrum of power system and market impacts from these changing conditions has not been analyzed.

Although the focus of these studies was wind generation, in general, similar findings would apply to other variable or intermittent resources, such as solar.

Distributed Generation - Distributed generation (DG) involves the use of small-scale technologies to produce electricity at the end-user level for the sole use of an individual residential, commercial, or industrial customer. Distributed generation technologies often consist of modular (and sometimes renewable-energy) generators, and offer a number of potential benefits. The advantages of this approach are to allow these customers to reduce their demand and/or consumption and, in some cases (through net-metering or sell-back arrangements), to provide excess capacity to the utility grid. Reduction in load and demand can provide benefits for the distribution system, reducing stress on local distribution feeders and associated equipment, resulting in increased life cycles and deferral or elimination of costly system upgrades. DG does not contribute to an overall improvement in system reliability in the event of a grid outage, as utilities require that these systems be disconnected when service is interrupted. When used in the proper scheme, however, they can allow individual customers to serve a portion of their load in the event of an outage.

<u>Net Metering</u> **–** Renewable DG technologies currently installed in New York State include solar, wind, farm waste, and hydroelectric power. Many of these installations have been commissioned to take advantage of current net metering statutes, which mandate the purchase of excess capacity by the local utility. The vast majority of these systems are small in scale, generally less than 10 kW. Recent expansions of these net metering statutes to 2 MW for many technologies, the addition of remote net metering, and the inclusion of combined heat and power (CHP) and fuel-cell projects should result in further implementation of these technologies.

<u>Traditional Generation Technologies</u> - These installations use traditional rotational generation sources and include CHP as well as induction and synchronous generation. CHP systems have the advantage of using waste heat from the generation process for building heat or hot water, increasing the efficiency of the system and providing a shorter economic payback of the costs. Induction generators are often used in wind turbines and some hydro installations due to their ability to generate power at varying rotor speeds. Induction generators are generally smaller in scale than synchronous generators, which have the advantage of providing self-excitation and can be used in the absence of the utility grid.

The Table 6 lists the combined capacity of all DG projects that have been processed under the New York State Standardized Interconnection Requirements to date, which has a size limit of 2 MW.

Table 6. Distributed Generation Capacity in New York

Technology	Total (kW)
Wind	1,142
Photovoltaic	31,817
Microturbine	4,775
Farm Waste	3,131
Fuel Cell	1,952
Combined Heat and Power	2,556
Hydro Turbine	143
Hybrid	45
Fossil Fuel	21,914
Total	***67,475***

Source: DPS, 2012

CHP Technologies - CHP systems recently installed in New York State range in size, with the following being typical:

- 50 – 150 kW is applicable for nursing homes with 100 – 300 beds
- 100 – 300 kW is applicable to apartment buildings with 300 – 500 dwelling units
- 400 kW is applicable to a 70,000 square-foot supermarket
- 800 – 2,500 kW is applicable to commercial office buildings ranging from 30 – 40 stories and providing 0.5 – 1.5 million square feet of occupied space
- 7,500 kW is applicable to a large hospital with 2,400 beds
- 30,000 kW is applicable to a large college campus serving 20,000 students

Although CHP systems of a size approximately 1 kW are available on the market and would be suitable for a single-family residence and are becoming popular in Europe and Asia, a negligible amount of market penetration has occurred to date in New York State. CHP systems typically are fueled by natural gas, although some are fueled by anaerobic digester gas, landfill methane gas, or wood biomass. Recovered heat typically is used to supplement domestic hot water, comfort heating of occupied spaces, industrial process heating, and to activate absorption chillers that are used for comfort cooling of occupied spaces or industrial process chilling. Recovered heat is frequently used for multiple purposes and configured either for multiple purposes concurrently throughout the year, or configured for a single purpose that differs according to the season.

NYSERDA's CHP Market Potential Study for New York State[28] indicates a technical potential for approximately 8,500 MW of new CHP statewide spread across roughly 26,000 sites, the full breadth of potential CHP host sites based on their presumed load profile, not a "likely adoption" scenario. This estimate does not include residential-scale CHP for single-family residence or small commercial facility. Approximately 40 percent of the statewide technical potential both in terms of number of sites and MW capacity is located in the Con Edison territory.

Transmission and Distribution

Bulk Electric System - As described in Section B, the Bulk Electric System (BES) definition may be expanded through application of a FERC Order to include all facilities 100 kV and above. Pursuant to that

[28] Combined Heat and Power Market Potential for New York State; Energy Nexus Group - Onsite Enery Corporation, 2002.

order, the NERC has proposed a final bright-line definition of BESs of 100 kV and above; however, facilities may be included if they are below 100 kV or exempted if they are above 100 kV based on criteria subject to FERC accepting their proposal. Consequently, the NPCC will continue to apply its own criteria and performance-based methodology for those facilities that are part of the BPS. FERC determined that the affected entities may recover prudent costs they incurred to comply with the 100 kV BES definition in electric rates. Currently, of the several hundred transmission substations considered part of the BES, only 63 are defined as part of the NPCC bulk power system. Therefore, numerous substations will require assessment to determine what upgrades, if any, are needed. Based on the assertions of affected utilities that are party to these discussions, NPCC has indicated that the cost of compliance could run into the hundreds of millions of dollars in NPCC, although these assertions have not been thoroughly analyzed or documented. The number of substations that will be included in the new definition and the associated cost to comply is uncertain at this time.

As described in Section B, the NPCC as a NERC Regional Entity uses a functional definition to identify who is required to comply with a respective rule. Currently, the NYISO is registered as the sole Balancing Authority, Reliability Coordinator, and Planning Coordinator for New York State, which is not expected to change. The NYISO also is registered as a TO for certain identified higher voltage facilities over which the New York TOs have granted the NYISO authority. The NYISO has also registered as a Transmission Planner for certain facilities listed in relevant agreements. At this time, the NPCC has not determined what entities should register as TO and Transmission Planner for electric system facilities that are 100 kV and above where the NYISO is not registered for those functions. While this area remains in flux, continued collaboration among the NYISO and transmission owners will be an important aspect of determining the appropriate compliance regime.

Regulatory

Corporate Reorganization of Electric Utilities - Restructuring of the electric industry in New York State significantly altered the means by which system planning and resource acquisition is conducted to maintain reliability.

Prior to restructuring, each utility conducted coordinated and integrated resource planning, within its region, encompassing the production or procurement of power through to its delivery to their own end use customers. To eliminate concerns with respect to the potential exercise of vertical market power by utilities that owned both generation resources and the transmission and distribution assets to deliver that power to end-use customers, the NYPSC required that the utilities under its jurisdiction file plans to divest of nearly all their generating assets. The privilege of serving end use customers was opened to competition from independent energy service companies, and the NYISO was created to take operational control of the New York State's bulk-transmission system and administer competitive wholesale power markets.

In a competitive environment, transparent and location-based power prices should provide the impetus for merchant developers to site and build new generation resources in areas where they are most needed. Demand side resources have similarly been developed in regions of New York State where they are most needed. To ensure that the reliability of the electric system is maintained, the NYISO has developed statewide planning processes, and participates in regional and interregional coordination studies as cited in Table 3. These supplement the local transmission and distribution planning studies that are undertaken by individual utilities. All of these processes ensure that, when and where necessary, competitive resources can be supplemented by regulated resources, so that system reliability can be assured.

In recent years, corporate reorganization has occurred through the merger and consolidation of various companies in the energy industry. New York's investor-owned utilities have experienced mergers and consolidations, including Con Edison's acquisition of Orange and Rockland Utilities, the purchase of Niagara Mohawk by National Grid of Great Britain, the purchase of New York State Electric & Gas Corp and Rochester Gas & Electric by Iberdrola of Spain, and the proposed acquisition of Central Hudson Gas & Electric Company by Fortistar, Inc., a Canadian company. These consolidations, which as a basis of PSC's approval, can provide certain efficiencies and lower costs to consumers, can sometimes result in internal competition for investment funds, potentially directing limited financial resources away from needed investment in transmission and distribution assets.

Because the PSC continues to regulate transmission and distribution companies, it will continue to ensure that these companies provide adequate resources to achieve performance and reliability standards. While PSC orders have provided for lightened regulation of generators under Article 4 of the Public Service Law, they explicitly provide that generators remain subject to Public Service Law jurisdiction with respect to matters such as safety, reliability, and system improvement. Therefore, generators must, for example, provide notice prior to retiring units, and obtain the PSC's consent prior to abandoning black start service. The corporate reorganization of electric utilities is not expected to significantly affect the reliability of the electric system due to the continued application of regulatory oversight by the PSC and FERC, NYISO compliance requirements, and mandatory reliability standards that remain in effect.

Performance Rate Making, Multi-Year Rate Agreements, and Other Departures from Traditional Regulatory Mechanisms - Public utility regulatory bodies, such as the PSC, have traditionally sought to establish rates as low as possible, yet sufficient to provide for safe and adequate service to customers while balancing the needs of utility shareholders to earn a fair rate of return on their investment. Generation services are now largely deregulated, and open access to transmission services allows participation by firms exempt from most traditional ratemaking regulations, while transmission and distribution service and reliability remains fully regulated.

The introduction of competition in the electric industry has enabled generating companies to compete in delivering services to customers. Such competition has led to the construction of additional generation facilities or transmission system upgrades that reduce congestion on the transmission system, resulting in improved reliability.

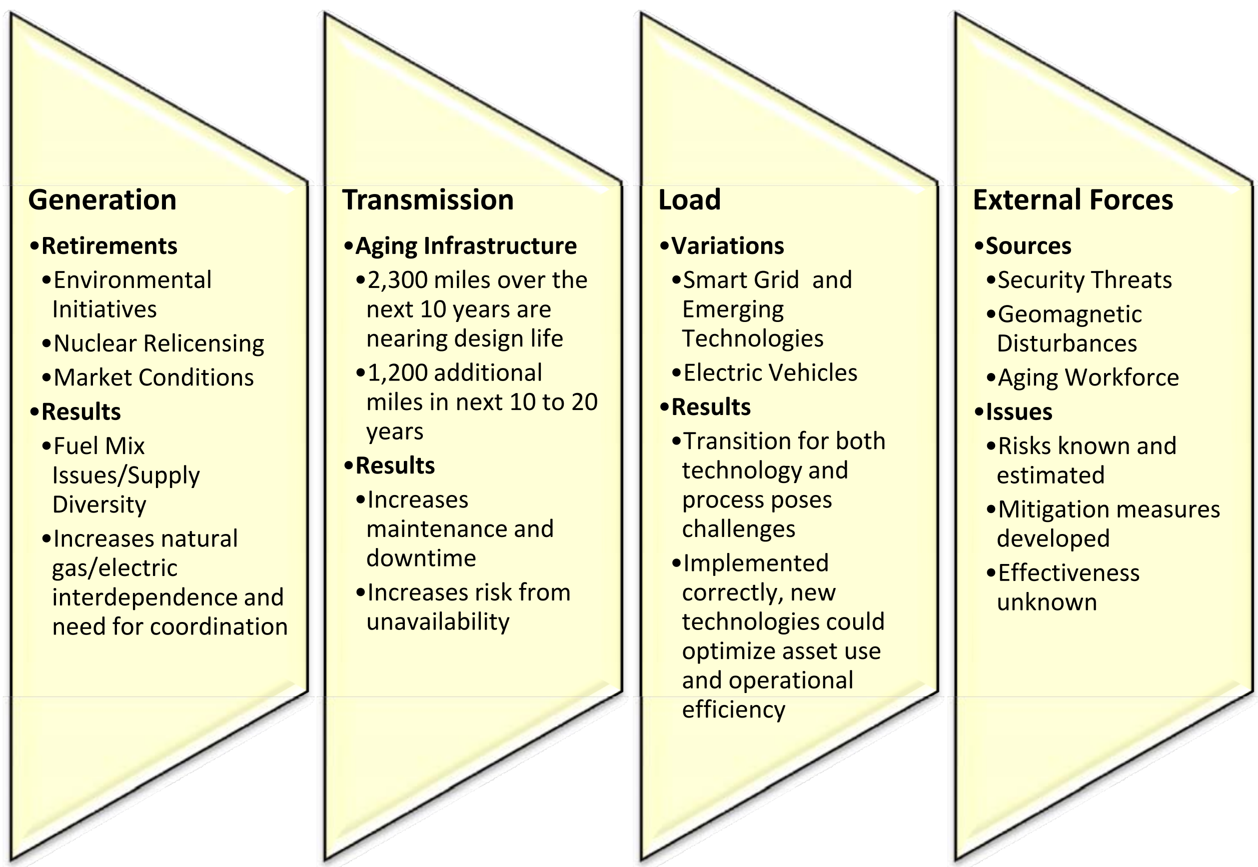
Distribution companies continue to own the wires and circuits/ties to most customers, and provide the bulk of metering and billing services. A "cost-of-service" regulatory approach is used to fairly compensate utilities for operation, maintenance, and capital costs.

Performance-based rates (PBRs) have been used by the PSC as a preferred regulatory process for fully regulated utilities. PBRs allow the regulator to reward superior service providers and/or penalize inferior service providers. PBRs typically are used as incentive for distribution companies to meet minimum reliability standards (*e.g.,* SAIFI, CAIDI). PBRs are also used by the PSC on a case -by -case basis to address areas that are not meeting expectations. Currently, the PSC can impose financial penalties for below standard performance. PBRs tied to such indices can have a positive impact on system reliability.

G. Future Transmission and Distribution Reliability Issues

Complex transmission and distribution planning and operating practices are based on the fundamental reliability principal of maintaining balance between load and generation; yet numerous future events could jeopardize this balance. Anticipated generation retirements resulting from environmental initiatives, nuclear relicensing uncertainty, and market conditions have the potential to create reliability impacts from a resource adequacy and operational reliability perspective. Changes in New York State's generation fleet result in a greater reliance on natural gas for which system delivery capability may create a vulnerability on the electric system. Aging transmission systems require increased maintenance and downtime, which increases risks when lines are unavailable. On the load side, new technologies provide an opportunity to create a new electric system that uses its assets better and improves operational efficiency. The process of incorporating these new technologies, however, can create risks that must be acknowledged and addressed while simultaneously promoting innovation. External forces probably are the most difficult to address. The likelihood of certain risks are known or can be estimated, in response to which mitigation measures are developed. But the full effectiveness of these measures cannot be fully understood unless there is an actual event. Figure 18 summarizes the possible imbalance causes and results; this section provides the details.

Figure 18. Possible Future Reliability Issues



Generation Retirements

The New York Power System's resource base today is in a surplus position. While this surplus is supported, in part, by reduced load growth and new plant additions, there exist key uncertainties on the horizon, including pending and potential power plant retirements. Notwithstanding that certain facilities that were expected to retire have continued to operate and that new plants and transmission options have been added to the system, statewide plant retirements have exceeded the amount that was included in the NYISO's 2010 RNA by 700 MW. Further, market conditions could result in the retirement of generating units that may cause local transmission problems that would have to be resolved by individual TOs.

The 2010 RNA highlighted the potential for a significant increase in plant retirements as a key uncertainty. The RNA identified two primary drivers for a potential increase in plant retirements. These are new environmental regulatory programs and the uncertainty as to whether the licenses for Indian Point (IP) Units 2 and 3 will be renewed when they expire in 2013 and 2015, respectively; their retirement was studied as a scenario in the 2010 RNA, and continues to be analyzed.

Nuclear Power - The Nuclear Regulatory Commission (NRC) is responsible for approving initial federal operating licenses, subsequent license modifications, and license renewals for nuclear power plants. States retain the authority over other permitting processes such as land use, coastal-zone management, effluent discharges, water quality certificates, and other regulatory issues. IP has two operating nuclear power reactors in the lower Hudson Valley (Unit 2 and Unit 3 have net electrical capacities of 1,078 MW and 1,083 MW, respectively), and is seeking relicensing of the initial licenses, which expire in 2013 and 2015, respectively. The NRC's Atomic Safety Licensing Board is conducting a series of hearings and administrative proceedings on the license renewal applications. The State of New York has petitioned the NRC in opposition to relicensing.[29] If the NRC proceedings extend beyond the expiration of the federal operating licenses *(i.e.,* 2013 and 2015), the plants may seek approval from NRC to continue to operate under federal licenses during the pendency of those hearings, and any related appeals.

Reliability issues associated with a potential shutdown of IP Units 2 and 3 have been part of a broader public discussion of the facility, both in the media and through commissioned consultant studies if the units were not relicensed and both closed at the end of 2015.[30] While there is significant uncertainty about when IP Units 2 and 3 would cease operations, the NYISO has analyzed the possible impacts if the units were not relicensed. In a 2010 RNA sensitivity analysis, the NYISO showed that there would be a deficiency in 2016. Similarly, for the purposes of a Draft 2012 RNA sensitivity, assuming that both units would close at the end of 2015, the NYISO determined that, absent adequate replacement resources in place prior to such closure, there would be a deficiency of approximately 1,000 MW by the summer of 2016, and that this deficiency would increase over time.[31] However, there are mechanisms in place that would adequately replace any deficiency related to the closure of the IP units. New York has robust planning and regulatory processes that would automatically implement either market-based options or regulatory backstop solutions in the event a deficiency is identified.

In addition, there are a variety of generation and transmission projects that are in different stages of development that could provide adequate replacement power. For example, since the 2010 RNA, the Hudson Transmission Project, currently under construction, will provide at least 320 megawatts of supply to New York City by mid- 2013. There are also a number of projects in the NYISO queue, including generation projects proposed in Southeast New York that may come into service by 2015, adding up to 2,000 MW, as well as several proposed transmission projects that could bring up to 3,000 MW of additional capability into

[29] The State's admitted contentions concern, among other things, the degradation of reactor vessels, steam generators and other components, and other safety upgrades.
[30] "Indian Point Retirement Report" prepared by Charles River Associates (CRA) for the New York City Economic Development Corporation (NYCEDC); "Indian Point Energy Center Nuclear Plant Retirement Analysis; Replacement Options, Reliability Issues and Economic Effects" prepared by Synapse Energy Economics Report for Natural Resources Defense Council (NRDC) and Riverkeeper.
[31] NYISO, "2012 Reliability Needs Assessment" Draft Report, January 13, 2012.

Southeastern New York by 2016.[32] In addition, Governor Cuomo created the Energy Highway Task Force in 2012 to address the infrastructure needs of the energy system in New York. The Task Force issued a Request for Information (RFI) in April 2012 and received responses from 85 private developers, investor-owned utilities, financial firms and other entities with 130 ideas to upgrade and revitalize the State's aging infrastructure, totaling more than 25,000 MW. Among those responses, over 11,000 MW of new generation, dedicated transmission, and other upgrades could be applied toward a replacement for Indian Point.

There are a number of State and federal administrative processes and other pending issues that may affect the timing and advancement of relicensing or closure of the IP reactors. At the State level, such processes currently include activities at DEC and DOS. As part of the relicensing process, each of the IP reactors is required to obtain certain federal statutory approvals that are administered by the NYSDEC: a Water Quality Certificate and a SPDES permit. The NYSDEC denied IP's application for a Water Quality Certificate on April 2, 2010 and Entergy requested an adjudicatory hearing on the denial. The NYSDEC commenced hearings regarding the Water Quality Certificate and SPDES Permit for the IP reactors in October 2011. Additional hearings will be held during 2012. While the IP reactors need approval from both the NRC for the nuclear relicensing and NYDEC for Water Quality Certificate to continue to operate, absent a Water Quality Certificate, NRC may not issue or renew an operating license.

In addition, the New York State Department of State will conduct a review of any proposed action by NRC to relicense IP Units 2 and 3 to determine if the action is consistent with the State's federally-approved Coastal Management Program. The Coastal Management Program is based on a broad number of policies related to the various uses and functions of the State's coastal resources, including, but not limited to, fisheries, navigation, recreation, and aesthetic resources. The Department of State's consistency review assesses whether the proposed NRC action is consistent with all relevant Coastal Management Program policies, with a finding of consistency necessary for NRC to re-issue the IP licenses.

At the federal level, the nature, timing and issues involved in the NRC licensing procedures continue to evolve. For example, recent NRC activities initiated to examine issues that became known as a result of the disaster affecting the Fukushima Daiichi facilities may affect the timing and advancement of the relicensing process. Recently, the NRC identified the need to evaluate the potential environmental effects of on-site waste storage, in the absence of a permanent waste disposal facility. On August 7, 2012, the NRC, by unanimous decision, issued Memorandum and Order CLI-12-16 suspending issuance of new or renewed licenses for nuclear power plants until NRC completes a study of the environmental impacts of storing spent nuclear fuel on-site. The Memorandum and Order clarifies that all licensing reviews and proceedings should continue to advance, pending completion of such study. Also, the NRC initiated processes to examine the safety implications of seismic activity for all nuclear power reactors, including IP Units 2 and 3. The NRC is anticipated to issue guidance on compliance with new requirements based on these assessments. Finally, in 2012, NRC has issued various decisions requiring the IP Units 2 and 3 to comply with federal fire safety regulations in response to a petition from the New York State Attorney General for enforcement of those regulations, exemption requests, and facility inspections.

In sum, there are a number of State and federal issues that create uncertainty related to the continued operations of IP Units 2 and 3 beyond their respective license terms. The State is actively involved in the NRC relicensing proceedings and has mechanisms in place to address reliability impacts and implement solutions in the event the units do not receive their operating license renewals.

Generating Facilities at Risk of Retiring Due to Environmental Regulations - The 2010 RNA identified new environmental regulatory programs designed to improve air quality and address the impact of a power plant's cooling water systems on aquatic life as factors that could impact reliability. These regulatory initiatives, which are being promulgated by both state and federal environmental regulatory agencies,

[32] Proposed generation projects in the NYISO queue include: Cricket Valley Energy Center (1002 MW), NRG Astoria Re-powering (388 MW), and CPV Valley Energy (656 MW); proposed transmission projects include: TDI Hudson Power Express (1000 MW HVDC cable), NRG NY Power Pathway (1000 MW HVDC cable), and Anabaric West Point Transmission (Two 1000 MW HVDC cables).

cumulatively will require considerable investment by the owners of New York's existing thermal power plants to comply with these new regulatory requirements. In the 2010 RNA, the NYISO estimated that as much as 23,947 MW in the existing fleet, or 64 percent of existing NYCA capacity, will have some level of compliance requirements related to these new regulations. The magnitude of the combined investments required to comply with the four initiatives could lead to multiple unplanned plant retirements. As detailed previously, the primary programs assessed were:

- NO_x RACT – Reasonably Available Control Technology
- BART – Best Available Retrofit Technology for regional haze
- MACT – Maximum Achievable Control Technology for hazardous air pollutants
- BTA – Best Technology Available for cooling-water intake structures

NYSDEC promulgated revised regulations for the control of Nitrogen Oxides (NO_x) emissions from fossil-fueled electric generating units in June 2010. These regulations are known as NOx RACT (Reasonably Available Control Technology) for NO_X. Emission reductions required by these revised regulations must be in place by July 2014. Generators were required to file compliance plans by January 2012.

The class of steam-generating electric units constructed between 1963 and 1977 are subject to continuing emission reductions required by the Clean Air Act. The reductions are required to reduce their respective impacts on visibility levels at National Parks. In New York, 8,243 MW of capacity is affected. The owners of these units have submitted their visibility impact analyses and plans for Best Available Retrofit Technology (BART) to the NYSDEC and federal land managers for approval. Owners of oil-fired units are proposing alternatives that include maintaining the *status quo*, lower sulfur fuels, and low NO_x combustion systems. Two smaller coal-plant owners have planned to retire small boilers. Owners of plants are required to implement their plans by January 2014.

The U.S. EPA Administrator signed the Utility MACT Rule (also known as the Mercury and Air Toxics Standards (MATS) Rule) on December 16, 2011; as published in the Federal Register on February 16, 2012 with an effective date of April 16, 2012. Compliance with the rule must be achieved by April 2015. Under the Clean Air Act, the DEC can grant an additional year for technology installation and under an enforcement policy issued by U.S. EPA on December 16, 2011, a fifth year may be available for units to come into compliance. It is estimated that 32 units representing 10,844 MW of capacity are subject to the MATS Rule in New York. Two large coal units may need extensive emissions-control upgrades or may need to switch fuels to comply with the MATS Rule. Most of the affected oil-fired EGUs in NYCA would be subject the "limited-use oil-fired EGU" subcategory and likely will not require extensive retrofits.

The U.S. EPA has proposed new Section 316(b) rules providing standards for the design and operation of power-plant cooling systems. This rule will be implemented by NYSDEC, which has finalized a policy for the implementation of this rule known as Best Technology Available for plant cooling-water intake structures. New York power plant operators with open-cycle cooling systems must conduct studies to demonstrate that systems can be modified to achieve reductions in aquatic impacts equivalent to 90 percent of the reductions that could be achieved by the use of a closed-cycle cooling system, *e.g.,* using cooling towers. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4,000-7,000 MW of capacity could be required to retrofit closed-cycle cooling systems.

The cumulative effect of new regulatory requirements described above will increase operating costs for the affected units as well as demands for additional capital. These demands, when viewed in the competitive market place that is also occupied by cleaner more efficient generators that increasingly burn natural gas as well as low operating cost renewables, may influence some owners to curtail operations or retire certain plants.

A preliminary assessment of the new environmental regulatory initiatives coupled with unfavorable market conditions has resulted in the NYISO concluding that up to 1,600 MW of upstate New York coal plant capacity may be at risk of retiring in the near term.

The retirement of many of these units could result in local transmission reliability violations which would need to be mitigated. With respect to resource adequacy, the retirement of all these coal plants would result in a reduction of the NYISO's reserve margin by approximately five percent. Currently, New York has an adjusted capacity reserve margin of 29.7 percent for the summer of 2012; the five percent reduction would still result in a reserve margin that exceeds the current requirement of 16.0 percent by a significant amount.

The NYISO has recently issued the draft 2012 RNA, but the report will not be finalized for this publication. It should be noted however, the base case identifies potential transmission security issues due to facility overloads beginning in 2013 that will be addressed through NYISO procedures described in Section B. The draft 2012 RNA also identifies the need for new resources beginning in 2020, increasing to the need for an additional estimated 750 MWs of resources in 2022. The draft 2012 RNA found resource needs based upon new generator retirements, slightly increased load levels, and a slight decrease in expected demand response resources.

Future Environmental Initiatives - There are several future environmental initiatives that may impact the electric generation sector and thus reliability of the electricity grid. Discussions of the potential impacts of these initiatives are presented in the following paragraphs. The NYISO, NYSRC, DPS, and NYSDEC monitor future rulemakings by the U.S. EPA and meet on a regular basis to discuss regulatory initiatives by U.S. EPA and the NYSDEC and potential reliability risks.

Climate Action Plans - Although a national climate program is not likely to be adopted by the current Congress, such a program could be developed subsequently. At this point, it is unclear how a national plan would affect RGGI and RGGI allowances auctioned prior to the start up of a national program. Regional initiatives, such as the Western Climate Initiative, could establish other CO_2 allowance auctions similar to the RGGI program. The use of RGGI allowances in programs that go beyond the program established by several north and Mid-Atlantic states can affect the price and supply of RGGI allowances. These impacts could adversely affect generators serving NYCA.

Revisions to National Ambient Air Quality Standards (NAAQS) - In June 2010, the SO_2 NAAQS was revised to a one-hour value of 75 parts per billion. U.S. EPA requires that some sources be modeled (by NYSDEC) to determine whether, in combination with all other significant nearby sources, they cause a violation of the NAAQS. The U.S. EPA has not yet provided guidance to NYSDEC regarding which sources must be modeled. If modeling indicates that sources cause or contribute to non-attainment, then affected sources may need to limit SO_2 emissions to allow the DEC to demonstrate attainment with the SO_2 NAAQS.

The U.S. EPA revised the ozone NAAQS in 2008 (eight-hour value of 0.075 parts per million). In August 2011, the White House announced that U.S. EPA would not be pursuing the reconsideration. The U.S. EPA will be designating areas in relation to compliance with the 2008 ozone NAAQS in May 2012. The New York City metropolitan area and the Jamestown metropolitan area do not attain the standard based on 2008 -2010 data. States and U.S. EPA will need to address air quality in non-attainment areas across the country and the transport of ozone and ozone precursors that significantly contribute to non-attainment or interfere with 2008 ozone NAAQS maintenance. Fossil-fuel-fired electricity generation units are likely to be required to further reduce NO_x emissions to help areas come into attainment. In addition, the U.S. EPA may revise (lower) the ozone and the $PM_{2.5}$ NAAQS over the next few years.

Compliance with this regulation and the loss-of-gas, minimal-oil-burn-reliability rule will be particularly challenging during the summer months with the existing fleet of units in the New York City area.

Cross-State Air Pollution Rule. The Cross-State Air Pollution Rule (CSAPR) was scheduled to take effect on January 1, 2012, but was stayed by a federal appellate court on December 30, 2012. The federal appellate court heard the case on April 13, 2012. The Court vacated the rule and remanded it back to the U.S. EPA on August 21, 2012. At the time of this publication, the U.S. EPA still had the option to appeal the ruling and it is unclear what the final determination will be. With this ruling, the U.S. EPA's prior Clean Air Interstate Rule (CAIR) remains in effect.

The CSAPR would have applied to 167 units in New York representing a total capacity of 23,275 MW. Many of these facilities would have been faced with compliance options ranging from equipment upgrades, buying allowances (if available) on the open market, or retiring units. The U.S. EPA estimated New York's allowance costs for the first year of the rule at $65 million. This rule addressed the 2006 PM2.5 NAAQS and the 1997 ozone NAAQS, but did not address the 2008 ozone NAAQS. The statewide SO_2 emissions cap would have decreased in 2016. Further NO_x reductions may be needed to address the 2008 ozone NAAQS.

The reliability risks associated with CSAPR are difficult to estimate at this time, since the legal process may not have concluded.

Federal Effluent Limitations - It was anticipated that the U.S. EPA would release a proposed revised effluent standard in July 2012 with a final rule to be released during the summer of 2013. The earliest compliance date would be in 2016. It is too early to estimate the impacts on central station power plants.

Coal-Combustion Residuals - The U.S. EPA proposed two options for regulating coal-combustion residuals in June 2010. If U.S. EPA selects the option whereby coal-combustion residuals are regulated as a "special waste" under Resource Conservation Recovery Act subtitle C, then the beneficial use determinations currently in place in New York for coal-combustion residuals may be terminated. Affected facilities in turn would face higher waste-handling and disposal costs for coal-combustion residuals.

Generating Facilities at Risk of Retiring Due To Changing Market Conditions - Changes in market conditions such as expiration of Public Utilities Regulatory Policy Act contracts, unfavorable capacity prices, or competition from new, more efficient power plants could result in a number of the older gas-fired units being retired.[33] Several of these units are run out of merit order for local reliability needs as dictated by local load conditions, primarily for voltage support. Retirement of these units could result in local transmission reliability violations. The NYISO estimates that there is approximately 1,800 MW of natural gas fired capacity that is in this category. This amount of capacity accounts for approximately 5.5 percent points of the current installed reserve margin. Moreover, as previously described, if both IP Energy Center units were shut down by 2016, more than 1,200 MW of replacement resources (transmission, generation, or both) would be necessary to have in place by 2016 and the need for additional resources would increase by 2020, even assuming no additional generator retirements in Southeastern New York, to meet reliability standards.

The question of when retirements will occur and in what amounts is a difficult one to answer with any certainty. Nevertheless, NYISO has several initiatives in place to monitor for retirements that will allow appropriate actions can be taken in a timely manner. These include:

- Ongoing evaluation of potential retirements due to environmental regulations
- Tracking of potential generator retirements
- Tracking of potential reliability solutions
- Coordination with the owners of the transmission system
- Processes to inform public officials and policy makers

The purpose of these initiatives is to:

- Anticipate potential retirements
- Identify any reliability needs that might arise as a result of the retirement
- Identify solutions that resolve any resulting reliability need in a timely manner

In December 2005 (Case 05-E-0889), the PSC issued its Order Adopting Notice Requirements for Generation Unit Retirements. That order requires all generators greater than 2 MW subject to Public Service Law jurisdiction to file notice with the Commission prior to retiring or otherwise removing units from service, such as through mothballing units that may or may not return to service. Generators equal to or greater than

[33] In addition to environmental regulations, coal fired units are also affected by market conditions when the spread between coal and natural gas decrease such as current conditions.

80 MW must provide notice at least 180 days in advance, while smaller units must provide at least 90 days prior notice before retiring. Once notice of a retirement is received, the effect of the retirement is analyzed by both the NYISO and the appropriate TO, and solutions are devised if it appears that system reliability would be jeopardized.

Fuel Mix Issues and Impacts of Diversity of Supply/Gas-Electric Interdependence - Although there is no industry standard for determining what exactly constitutes fuel diversity, historically the electric-supply fuel mix in New York State has been relatively diverse. The New York electric utility system relies on supply from numerous fuel sources, including water, wind, nuclear, coal, and natural gas, as well as interconnections with its neighbors and demand response resources to meet the needs of the over 19 million residents in New York State. Fuel diversity provides flexibility in terms of economics, reliability, and emissions, by being able to switch between fuels depending on price, availability, system reliability requirements, or to satisfy environmental constraints.

The New York fuel-diversity profile changes when viewed from an upstate verses downstate perspective. In this context, the diversity of the upstate region is much greater than that of the downstate region where, the fuel mix is dominated by natural gas- and dual fuel- (gas and oil) powered generators. The high dependence on natural gas in this region is largely driven by the need to meet clean-air regulations in a densely populated region. The relative lack of downstate diversity is mitigated partially by transmission connecting the downstate region to the more diverse upstate region of New York. The ability of the existing transmission system to transfer power from north to south has limits, and the continued growth in downstate demand for electricity primarily will rely on natural-gas and oil-fueled local resources until the transmission system is expanded or alternate resources are in place. These local solutions could include more demand response, energy efficiency, technologies such as HVDC transmission or "smart grid" that can optimize the existing transmission infrastructure and alternate fuel sources such as renewable energy.

Even these solutions have limitations, however. For example, intermittent renewable generation resources such as wind and solar require that conventional generating capacity equal to approximately 80 percent of the installed renewable generation nameplate be available as a backup. It is expected that natural-gas-fired generation will be the primary fuel for firing backup generation.

The discovery of and increased accessibility to large amount of new domestic natural gas has resulted in a potential abundance of natural gas-supply at relatively low prices. This supply abundance, in conjunction with some enhancement of pipeline infrastructure, more stringent environmental regulations to further reduce emissions, the ability to site single-cycle or combined-cycle natural-gas-fired plants close to load centers, and the repowering of existing power plants, all appear likely to result in increasing dependence on natural gas in the near term. Such an increased dependence on any one fuel source merits increased scrutiny with regard to potential reliability impacts.

Adverse reliability impacts resulting from an over dependence on natural gas, such as loss of gas supply, can be mitigated to a degree. The NYRC has local reliability rules (IR3 and IR5)in place designed to minimize disruption of electricity supply from loss-of-gas supply in New York City and on Long Island, which is known as the loss-of-gas minimum oil-burn rule (LOGMOB). This rule requires certain power plants to switch to the alternate fuel at prescribed load levels as a hedge against the occurrence of a gas contingency. The switch to the alternative fuel, however, will result in increased air emissions. Newer simple-cycle and combined-cycle plants can switch to alternative fuel "on the fly," thus eliminating the need to switch to alternate fuel in boilers. Such units can significantly reduce the need for cooling water. The addition of these types of plants to the New York power system has already reduced the amount of generating capacity that is required to have the capability to switch to an alternate fuel prior to a gas-contingency event.

Additional actions to mitigate adverse impact from increasing dependence on natural gas as a generator fuel include: a higher level of gas-electric operations and planning coordination, the implementation of a requirement for some gas-fired plants to have dual fuel capability allowing them to switch between gas and oil during high system electric loads, and reviewing gas pipeline and electric system tariffs for changes that would facilitate electric-gas system interaction. The NYISO, in conjunction with New York utilities and ISO-

NE is undertaking a more detailed study of the interdependencies of electric and natural-gas systems, with the goal of enhancing electric-system reliability and operations going forward.

Another concern with increasing dependence on natural gas is the economic impact of the volatility of natural-gas prices. An abundance of supply coupled with the use of hedging strategies and longer-term contracting for gas supplies may help ameliorate the volatility of natural-gas prices to some degree. Increasing dependence on natural gas in the near term, however, will have positive impacts that may include significant environmental benefits and increased operating flexibility available with the new generation of natural-gas-fired units.

Natural Gas and Electric System Interdependencies and Coordination **-** NERC initiated a report titled 2011 Special Reliability Assessment - Gas and Electric Interdependencies: A Bulk Power System Reliability Perspective, issued on December 23, 2011 in which it stated:

> *"The majority of new North American generating capacity projected for the next ten years will rely on natural gas as its primary fuel.... However, increased dependence on natural gas for generating capacity can amplify the bulk power system's exposure to interruptions in natural gas fuel supply and delivery. Mitigating strategies, such as storage, firm fuel contracting, alternate pipelines, dual-fuel capability, access to multiple natural gas basins, nearby plants using other fuels, or additional transmission lines from other Regions, can contribute to managing this risk."*

The NERC Assessment, included: 1) a qualitative assessment and primer on gas and electric interdependencies, and; 2) a quantitative analysis representing gas pipeline vulnerabilities through contingency simulations. Among the key findings of the Assessment are:

- **Key differences exist between the electric and gas industries.** While the electric industry is somewhat functionally bundled between supply and delivery functions, the natural-gas industry is structurally unbundled between these functions. This difference makes long-term planning and communication important to operating successfully in different regulatory frameworks.
- **Increased coordination and communication are needed between the electric and gas industries.** Information sharing is needed for the reliable operation between both industries to ensure reliability of the bulk power system.
- **Storage solutions diminish interdependency issues.** Future natural-gas storage facilities must satisfy traditional fuel supply reliability demands, while taking into account day and night swings in demand.
- **Electric loads present unique challenges.** As the use of gas-fired generation increases, pipeline enhancements may be required to support large, concentrated, high-pressure, variable gas loads.
- **Ample gas supply expected.** In terms of supply, almost all future natural gas growth comes from the electric sector. Shale gas likely will make a significant contribution to the U.S. supply portfolio.
- **Pipeline expansion to accommodate the electric sector.** Pipeline infrastructure planning must take into account the long-term growth of gas-fired generation, as more pipeline capacity ultimately will be needed.

Recognizing both current and projected heavy dependence on natural gas for electric generation in the NYCA and the northeast and the unique issues and characteristics of the region, the NYISO took steps to enhance its operations and planning with expanded gas-electric coordination, including:

- Development of concepts for gas pipeline visualization
- With the NYPSC exploration of opportunities for increased natural gas delivery and storage capabilities, especially in the New York City market.
- Establishment of an Electric and Gas Coordination Working Group within the NYISO governance process to address joint operational and planning issues. Participation is open to all NYISO stakeholders, including TO, generators, and representatives of the PSC. The three objectives of the new working group are: (i)increase communication among gas and electric industries; (ii) increase

coordination of both industries' operations with respect to facility availability, outage scheduling, notification of supply disruptions and related matters; and (iii) joint long-term planning of natural gas and electric system infrastructure needs. Representatives of various sectors of the natural gas industry are being encouraged to participate with electric industry sectors.

In 2003, northeast U.S. ISOs/RTOs performed a multi-region assessment of the adequacy of the northeast natural gas infrastructure.[34] With increasing natural gas-electric interdependence, development of shale-gas resources close to northeast load centers, and increasing concerns regarding access to that natural gas. NYISO staff believes this is the appropriate time to conduct a comprehensive study of the growing interdependence of the gas and electric systems and the challenges that may be in the short- and long-term future.

In the spring of 2012, the NYISO issued a request for proposals to conduct a comprehensive technical analysis of the natural gas system's ability to meet electric generation needs. The expectation is that both steady-state and contingency analysis will be conducted to have the full understanding of the vulnerabilities of the electric system to the loss of key gas pipeline and local gas distribution facilities. It is possible that the ultimate scope of the analysis may be impacted or modified by complexity and projected costs, depending on the range and detail of the bids submitted. PJM, ISO-NE, and the Midwest ISO also may participate in this study. The study is expected to be completed by the end of 2013 and will have four objectives:

- Base line analysis of existing natural gas and electric systems in the northeast, including planning and current interactions
- Determining the adequacy of the gas pipeline system to supply aggregate natural gas requirements for electric generation over a 10-year study horizon
- Evaluating the benefits and costs of dual-fuel capability
- Analyzing contingencies on natural gas system that could adversely affect electric system and *vice versa*

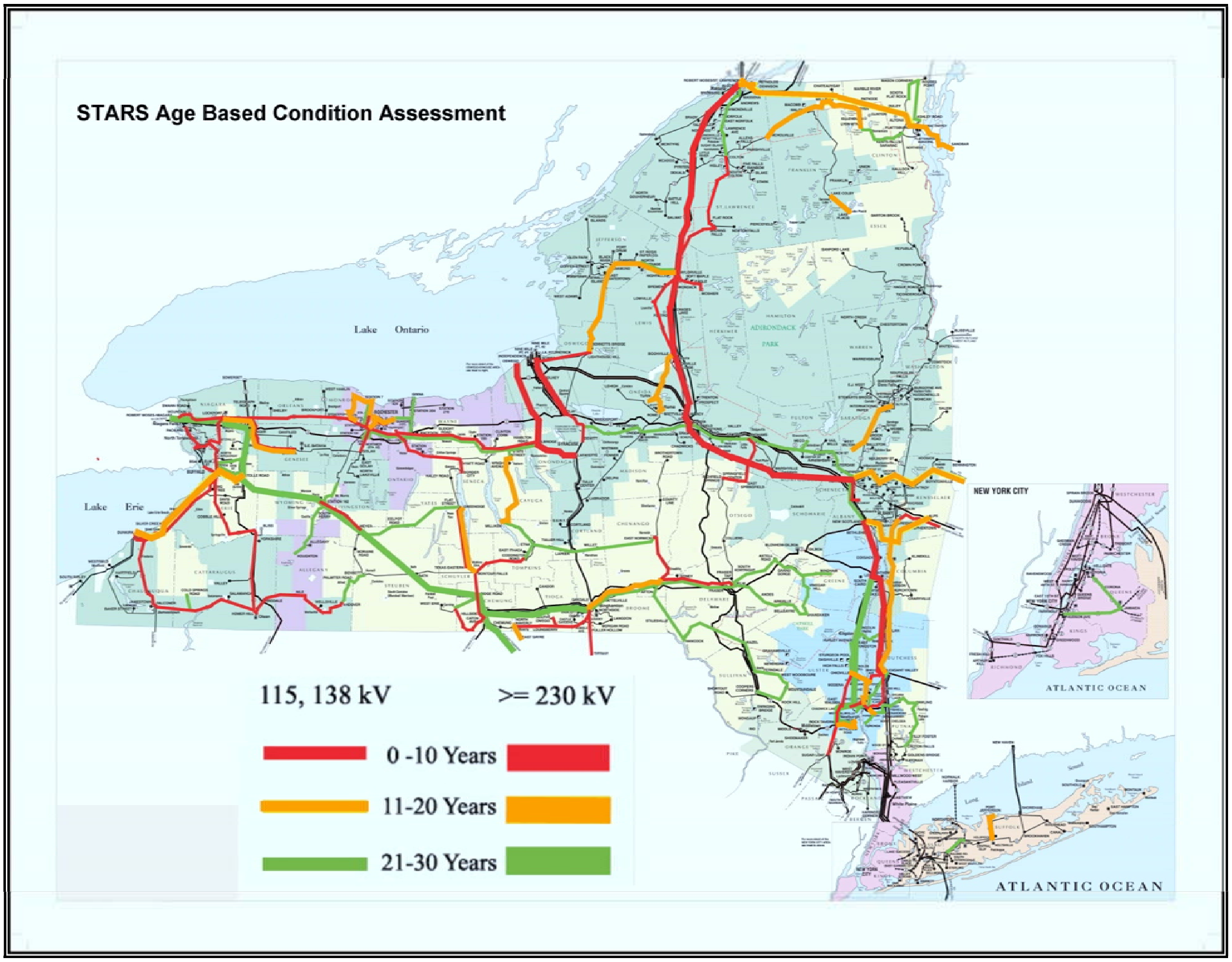
Aging of Transmission Lines

As described in Section B, the transmission infrastructure average age is more than 40 years with 70 years for wood poles and 90 years for steel-pole lines. By 2020, approximately 20 percent of the 11,000 miles of transmission lines of 115 kV to 765kV will reach the end of its useful life. Between 2020 and 2030, an additional 10 percent will reach this threshold. If these lines are not replaced, they will be more susceptible to failure and require more outage times for maintenance. This downtime could increase risk as more lines are out of service. Figure 19 illustrates the age of transmission lines by voltage that are approaching the end of their useful life.

To plan major outages adequately, the NYISO requires annual coordination of all outages that include daily outages scheduled for three or more calendar days in succession for the current and next calendar year. All scheduled outages are evaluated to determine their impact on system reliability and transmission transfer capabilities. The NYISO has procedures to evaluate and change the approved schedule on a day-to-day basis should reliability be compromised. This process to date has been sufficient to maintain system reliability during maintenance. The aging infrastructure, if maintained rather than replaced, could pose scheduling challenges due to the expected volume of repairs.

[34] *Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to serve the Electric Power Generating Sector*, Levitan & Associates, Inc., 2003.

Figure 19. New York State Transmission Age Condition Assessment



Source: New York State Transmission Assessment and Reliability Study, 2012

Load Variations

As described in Sections A and F, unpredictable changes in load can create uncertainty on the generation resource requirements and consequently affect reliability. Smart grid and emerging technologies have the opportunity to create a more flexible system. If the load characteristics are not well understood, the benefits may not outweigh the risks. The following section describes the issues new technologies present to the system and actions being implemented that allow technology to progress without compromising reliability.

Smart Grid and Emerging Technologies - The concept of the "Smart Grid" encompasses use of advanced/enhanced technology and two-way communications to improve the operation and efficiency of the entire electric grid, from generation to end-use consumption. Such an approach seeks to:

- 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 use 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 modern technologies and approaches to control electricity flow and operations. Increased use of Smart Grid technologies in New York could result in significant improvements, including:

- Enhanced operator decision-making capability through faster communications and broader regional visualization, potentially avoiding events similar to the 2003 Northeast Blackout and 2006 Long Island City Outages
- Reduced power system losses
- Providing customers with greater demand response options and results
- Mitigating fault-duty issues, thereby enhancing distributed generation
- Improved outage-management systems
- Automated distribution system operation [35]
- Modernizing older utility systems
- Increasing dynamic reactive compensation and power-flow control in key parts of the system to maintain proper-voltages
- Increasing power flow-transfers or reduce power-transfer degradations
- Reducing effects of system disturbances[36]

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 implementation with an integrated approach and strategy through its work with utilities and on various task forces and consortiums.

Increased Use of Advanced Technology. New York's transmission and distribution system already has significant capability, using digital and enhanced communication technologies. On the bulk power system, monitoring and communication equipment used for transmission systems above 115 kV can be characterized as Smart Grid. Distribution facilities, however, are typically less sophisticated than transmission systems, particularly in remote areas of New York State. Recent enhancements include Con Edison's 14 kV auto-loop 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 currently is installing similar functionality on select 138 kV feeders.

The PSC has approved several projects in rate proceedings that 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.

Current Research and Development (R&D) and Pilots. Utilities in New York currently are undertaking several Smart Grid R&D activities. Orange & Rockland has a Smart Grid pilot project that will test increased monitoring and communication on two distribution circuits. Con Edison is using 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. DOE. Both Orange & Rockland and Con Edison are also participating in the EPRI Green Circuit program, an R&D effort directed at reducing distribution line losses. NYSERDA has issued several notices to support R&D projects for Smart Grid technologies.

The Advanced Energy Center at Stony Brook University is coordinating efforts to assist various Smart Grid businesses with R&D needs, as well as providing a center for validation and verification of product functions and capabilities. Advanced Energy Sector staff work with universities from around the State to provide a comprehensive array of services.

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

[36] These systems are generally referred to as Flexible AC Transmission Systems (FACTS). FACTS cover 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 (UPFC), Interline Power Flow Controller (IPFC), and Variable Frequency Transformer (VFT).

Smart Grid Implementation. The state is pursuing a comprehensive, integrated strategy to enable Smart Grid technology. DPS has several efforts under way to oversee the Smart Grid activities of regulated utilities, 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 created a Smart Grid Advisory Board, of which National Grid is a member, as well as a Smart Grid Task Force. EISA allocated funds to support the advancement of Smart Grid research and the Task Force has been working with the industry and interested stakeholders to increase focus on Smart Grid developments.

The 2009 American Recovery and Reinvestment Act (ARRA) created 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. The DOE issued a funding opportunity announcement for a Smart Grid Investment Grant (SGIG) to provide capital for Smart Grid projects and create jobs. As SGIG funding required states to provide 50 percent matching funds, New York recipients of ARRA projects were required to seek approval from the PSC. No funding was used for interactive customer meters.

The PSC approved matching funds of approximately $392 million for ratepayer-funded projects. New York utilities, including those not regulated by the PSC, received $571 million in ARRA grants for a number of projects. Con Ed received the largest portion for New York State with $251 million for SGIG projects and $92 million for its Smart Grid Demonstration Grant (SGDG) project. The Con Edison SGIG project primarily is for acceleration of a variety of distribution automation projects, including underground network sectionalizing devices and an underground network loop configuration. The Con Edison SGDG project is for a secure, interoperable open smart grid system that will demonstrate a scalable, cost-effective prototype that promotes cyber security, reduces electricity demand and peak-energy use, and increases reliability, and energy efficiency. The system will include renewable energy generation, grid monitoring, electric vehicle charging stations, transmission automation, and consumer systems that will help expand the use of renewable energy and lead to greater consumer participation in the electricity system.

Additional funding went to LIPA for a project to create a Smart Energy Corridor and NYPA for a project to evaluate instrumentation and dynamic thermal ratings for overhead lines. NYSEG was awarded funding for a project to develop a compressed-air energy-storage demonstration; an initial study to determine feasibility is in progress.

The NYISO, on behalf of TOs and itself, was awarded $37.4 million in DOE funding for a project to enhance deployment of synchrophasors (also referred to as phasor measurement units or PMUs) and expand the use of capacitors to make the bulk power system more efficient. With matching funds approved by the PSC for the investor-owned utilities, the total project investment in system monitoring and voltage control devices will be $75 million. The PMU potion of the project will help protect bulk-system reliability by providing additional system data more quickly; the capacitor project will reduce transmission losses.

New York's bulk electric grid requires the constant balancing of electricity supplies with demand on a moment-to-moment basis, which involve vast amounts of continuous data, calculations and analysis. Following the August, 14, 2003, blackout in the Northeastern United States and parts of Canada, a U.S.-Canada Power System Outage Task Force issued a report that called for the increased use of time-synchronized recording devices for better wide-area visibility of the grid and improved post-disturbance analysis of this type of event. In response to the 2003 Outage Task Force's recommendations, NERC and utility industry representatives agreed to accelerate the deployment of synchronized PMUs in the North American Eastern Interconnection. Several PMU owners and entities were involved in the project, including NYPA and NYISO.

PMUs can enhance the system operator capabilities significantly by providing essential data on the status of the grid thousands of times faster than previously used technologies. Time-synchronized phasor technology and dynamic data can be used locally, within substations for system protection and control, or to provide system operators and planners with greatly enhanced information into wide-area dynamic system behavior, greatly improving grid operators' visualization capabilities and situational awareness. In addition to helping avoid disturbances like the 2003 Northeast regional blackout, the PMU initiative and related technologies are providing a range of enhancements to overall grid operational reliability and efficiency, including improved system visualization and real-time awareness across multiple power systems, greater support for integration of renewable resources, and better asset use. Eventually, the NYISO's PMU network will connect with PMU networks in New England, the mid-Atlantic, the Midwest and Ontario, Canada, to create a North American Synchrophasor Initiative Network covering the eastern United States and Canada.

The National Institute of Standards is leading the development of standard-based protocols for Smart Grid. Efforts to develop a strategy and approach to Smart Grid are complemented by the work of the New York Smart Grid Consortium (Consortium), comprised of representatives from the power generation, transmission, and distribution sectors, including utilities, transmission companies and independent providers; technology companies, the NYISO, State governmental entities; energy and grid technology researchers from universities; and Brookhaven National Laboratory. The Consortium has developed a work plan and vision statement to guide phased development of the Smart Grid. The agreement on a common vision among Consortium members allows stakeholders to understand their roles, responsibilities, and opportunities in a New York Smart Grid roadmap.

While expected benefits are commendable, transition to Smart Grid technologies poses both procedural and technical challenges. Ever-increasing amounts of data must be secured against hacking and cyber-security attacks. Available technologies for new and existing buildings are limited, and the value propositions for many owners remain inadequate or not well understood. Moreover, energy costs as a percentage of overall budgets remain relatively small in many situations, and the initial costs of performance enhancing technologies can be high. This gap is exacerbated by actual and perceived reliability, component compatibility, impact on end-users lifestyles and business practices, and uncertainty throughout the delivery chain associated with marketing, warranty, installer capabilities, and post-installation support. The unfamiliarity and complexity of transactions associated with verifying energy savings and selling negative load to a supplier and the challenges of modeling energy savings cash flow to facilitate financing are major barriers. These challenges maybe categorized as:

Procedural Challenges

- Broad set of stakeholders
- Smart Grid Complexity
- Transition to Smart Grid
- Ensuring cyber security Plans and Standards for systems
- Development and support of standards
- Consensus on standards
- Research and development
- Critical mass of acceptance for implementation

Technical Challenges

- Smart equipment
- Communication systems
- Data management
- Cyber security attacks
- Information/data privacy
- Software applications

Recognizing the benefits and challenges, the PSC has established guidelines to create a balanced and careful approach while smart-grid technology is still developing, yet creating conditions that will allow optimal technology solutions to flourish. The PSC encourages electric utilities to develop smart grid systems that integrate new intelligent technologies, while optimizing the use of existing facilities and resources, and maintaining just and reasonable rates for electric customers.

Energy Storage - Electricity in large interconnected power systems generally must be produced and delivered on a large scale and consumed instantly. From the standpoint of operational system reliability, as well as economics, there is substantial value in being able to store electricity at times when production and resources exceed demand, then being able to use that energy when consumption exceeds supply. Practically speaking, however, the capability to store electricity has been limited, costly, and complex.

The constant need to match the variability of the demand for electricity with the supply involves the processes of system "regulation" and "balancing" electron flow. Generally, this is achieved by a combination of having some conventional facilities running below normal output (spinning reserves) and others standing by, capable of being brought online within 10 to 30 minutes of notification. Such processes present many operational challenges and inherent inefficiencies that can impact reliability.

Issues associated with incorporating large amounts of variable renewable resources into the bulk grid have highlighted those challenges and created a renewed emphasis on the value and feasibility of energy storage. Conventional energy storage systems such as hydropower pumped storage, as well as an array of emerging storage technologies, have the potential to complement the integration of renewable energy, provide new tools to enhance overall system reliability, and create a more robust power grid.

Hydroelectric pumped storage has been the most widely used means of storing electricity for use by the bulk power system. In these systems, water flows or is pumped into reservoirs during off-peak hours and later released to produce electricity when demand is higher. Pumped storage accounts for approximately four percent of New York's generating capacity. While that level is twice the national average, it is not expected to expand due to the lack of sites where it may be permitted and economically constructed. New York has access to additional "storage" in the form of conventional hydroelectric power projects with large reservoirs, both within the New York State and Quebec.

New technologies and applications have begun to provide additional marketable, grid-scale energy storage resources, including flywheels, advanced batteries, compressed air, and potentially the off-peak use of plug-in electric vehicles for feeding power back into the grid.

New York has been a leader in promoting the implementation of new energy storage technologies. The New York Battery and Energy Storage Technology Consortium was formed in 2009 to accelerate the commercial introduction of energy storage technology in New York and build the human capital and expertise to sustain a vibrant commercial energy storage industry in New York.

Also in 2009, the NYISO became the first grid operator in the nation to have federally approved market rules to facilitate integration of new energy storage systems. These storage systems were enabled to participate in the markets as frequency regulation providers, delivering reserve capacity that helps grid operators maintain the balance between supply and demand.

In January 2011, Beacon Power began operations of a 20-megawatt flywheel energy storage plant in Stephentown, NY, the first full-scale flywheel energy storage facility to provide frequency regulation service on the U.S. electric grid. Beacon's flywheel systems are high-speed rotating mechanical devices that use the principle of kinetic energy to store and then discharge electricity to the grid. They also are capable of facilitating system balancing and regulation by taking or "absorbing" limited amounts of power from the grid.

When the first phase of the AES Energy Storage 20 MW energy storage-system in Johnson City, NY entered operation in December 2010, it became the first commercial grid-scale battery-based storage system to operate as a generator in the U.S. The AES Energy Storage facility uses advanced lithium-ion batteries that convert electricity into chemical energy for later release. The company is pursuing other opportunities for development of grid-scale battery storage facilities, primarily as a source of balancing and regulation services.

Consideration is being given to the role of batteries and other forms of energy storage in the development of "micro-grids," which are electrically isolated sets of power generators and/or other resources that supply the demand of a particular group of customers within a discrete location.

Electric Vehicles - As discussed in Section F, unexpected changes in load growth or patterns that are not reflected in the load forecast may potentially impact reliability. Plug-in-hybrid electric vehicles have the potential to help reliability, but if this technology changes load in an unpredictable manner, issues could arise.

Plug-in Electric Vehicles - In 2011, LIPA, Con Edison, and the NYISO each developed Plug-in Electric Vehicles (PEVs) forecasts. The NYISO, after consulting with LIPA and Con Edison, aggregated those forecasts and presented them to its Electric System Planning Working Group (ESPWG) in March, 2011. The ESPWG accepted the NYISO's forecast and by extension, those of LIPA and ConEd for their electric service territories. The forecast for the State of New York is for potentially moderate impact on system reliability in the long term with little impact occurring until 2020 and beyond.

Based on the NYISO's evaluation, PEV charging, even during peak-electric-demand periods, would not appear to create significant concern for electric transmission management unless and until either or both of the following circumstances occur:

- A significant number of PEVs begin charging at times other than off-peak
- Faster, higher voltage charging ("Stage 2" 240v, and "Stage 3" 480v, charging) becomes more widespread, creating more dramatic spikes in demand, both locally and system-wide

Should these circumstances arise, it may be possible to introduce policies designed to mitigate reliability impacts, such as incentivized rate structures or scheduled charging times. It has not been determined whether such incentives would be sufficient to change the charging patterns of early PEV owners so that reliability impacts could be avoided. Incentive policies under development should be flexible, as they may need to be adjusted over time to determine what approaches are the most efficient. Before large numbers of PEVs become the norm, it may be appropriate for policy makers to consider introducing mitigation efforts to proactively avoid impacts on the grid, such as incentivized rates for vehicle charging during off-peak periods or required charging technology.

Current PEV forecasts, provides policy-makers with sufficient latitude to monitor the implementation of these new modes of transportation, technological and other system developments, and assess the need for policy. Proper rate designs, impact on local distribution systems throughout New York State, promotion of in-city refueling sites, and other issues can be studied and evaluated to devise optimal strategies for promoting the adoption and managing the impacts of more environmentally friendly electric vehicles.

A study[37] of a radial and network circuits in the Con Edison service territory was conducted to evaluate the potential impact of PHEV. For the radial circuit, no near-term impacts were identified, although minor impacts, as with any load growth, cannot be ruled out. On the network circuit evaluated, however, transformer overloading would be expected at system peak, but the one percent or less of the transformers that were identified as needing upgrades was based on a model in which all PHEVs were being charged simultaneously.

External Forces

Security threats, geomagnetic disturbances, and aging workforce all pose a challenge to electric system reliability. Although impacts have been estimated and mitigating steps have been implemented, it is difficult

[37] *Transportation Electrification in New York State.*NYSERDA, Albany, NY: Technical Update No. 11-07. June, 2011

to determine the full effectiveness of those actions. All issues are being monitored and evaluated continuously. The issues are discussed in more detail in this section.

Security Threats - The high-voltage transmission portion of the grid is generally regarded as critical. As outages on the transmission system can have a significant impact over a widespread area, the lower voltage electric distribution portion of the grid is considered to be less critical because distribution level outages do not tend to have a significant adverse impact beyond the local area.

Among the several hundred electric substations in New York State, only 63 currently qualify as part of the bulk power system based on the NPCC performance definition where loss or incapacitation of such a substation would have a significant adverse impact outside the local area. With the new 100 kV bright line definition described in Section F, numerous additional substations will be included in this category within two years. Given the importance of these assets, security measures for physical and cyber attack are now in place.

Physical security systems include full coverage electronic intrusion detection, monitoring, and alert notification systems remotely monitored around the clock. TOs in New York have implemented such security systems at bulk power system substations or are currently in the process of upgrading systems to take advantage of the latest available security improvements. The most critical electric utility substations in New York have modern and reliable intrusion detection, monitoring, and alarming technologies in place. TOs are expanding installation of new state-of-the-art security systems at other important and vulnerable facilities.

In 2003, FERC charged NERC with developing industry-wide standards to ensure that all entities responsible for the reliability of the BES in North America undergo a process to identify and protect critical cyber assets that control or could impact BES reliability. NERC has adopted and FERC has approved mandatory and enforceable cyber-security regulations on the electric industry pursuant to the Energy Policy Act of 2005, including Section 215 of the Federal Power Act. After years of working group sessions, drafts, industry comments, and significant interest from Congress, the NERC Critical Infrastructure Protection Standards were adopted and became effective in 2010. Although NERC is in the process of revising its Critical Infrastructure Protection standards. Discussions continue between FERC and NERC concerning the appropriate depth and frequency of NERC cyber-security audits and compliance with its Critical Infrastructure Program. Additionally, FERC and NERC are engaged in discussions regarding their respective roles on this issue.

Since the early 1990s, a growing appreciation has been developing within the electric power industry that the advent of computerized Supervisory Control and Data Acquisition (SCADA) systems in the operation of the electric power grid is a vulnerable link for hackers and other possible unauthorized cyber intruders. The possibility of a remote intruder interfering with the operational engineering management of the power grid has become more fully understood.

To date, it does not appear that a bulk power system outage has been caused by a cyber security intrusion; however, a cyber attack capable of causing regional or widespread disruption lasting in excess of 24 hours is possible. The source for such an attack could be local or from the other side of the globe.

There is ample reason to be concerned that an outside organization or nation state with destructive goals could mount a structured cyber attack targeting utilities operations systems to cause widespread disruption to a given geographic region. Organizations have used structured physical attacks on utility infrastructure elements around the world to achieve a variety of goals. A number of studies and reports document thousands of attempted unauthorized intrusions into utility information systems every year with the number increasing annually. Though there is much discussion about the ease or likelihood of "cyber sabotage," it remains a possibility that an organization with sufficient resources, such as a foreign intelligence service or a well supported terrorist group, could conduct a structured cyber attack on the electric power grid.

The New York State Division of Homeland Security conducts a confidential review of critical infrastructure, including cyber security, every five years. The most recent review is due to be completed by the end of 2012.

Geomagnetic Disturbances **-** NERC characterizes a geomagnetic disturbance (GMD), occasionally referred to as a solar storm, as a high-impact, low-frequency event risk to North America. Earth has experienced numerous GMDs with only occasional impact to the electric system. A GMD in 1921 however, disrupted the telegraph system. In 1989, a GMD led to the collapse of the Hydro Quebec system impacting six million people for more than nine hours. Solar storms vary over a 24-year cycle. In the current cycle, solar storms or GMDs are expected to reach their peak in 2013.

A GMD is a large mass of charged solar particles consisting of electrons and ions that interact with the earth's magnetic field thereby creating electric currents in the order of millions of amperes. These geomagnetic-induced currents may interact with long conducting paths such as transmission lines, metallic pipelines, cables, and railways. On the electric system, the geomagnetic-induced current can damage BPS assets, typically transformers, and/or cause voltage instability possibly to the point of power system collapse due to changes in the reactive power profiles.

Transformers on the extra-high-voltage lines (ie. >345 kV) and those transformers nearing end-of-life are the most vulnerable to a GMD. Although the loss of a few extra-high-voltage transformers is unlikely to cause any problems, a widespread loss of extra-high-voltage transformers could impact the power system. The resulting restoration time could be lengthy *(i.e.,* months). Extra-high-voltage transformers are specific pieces of equipment that require long-lead time for design, engineering, and manufacturing. Due to cost and equipment specificity, spare transformers may not always be available.

Voltage instability occurs when a GMD creates distortions in the electric wave (in a system's current and voltage) that could result in malfunction of protection and control devices. This, in turn, causes a loss of reactive support that could lead to voltage collapse. System restoration from a voltage collapse would be much shorter than damage to extra-high-voltage transformers, lasting only hours to days rather than potentially months.

Both the U.S. and Canada have agencies that monitor and forecast solar and geophysical events. The NYISO receives GMD forecasts and alerts from three agencies that provide a 24-, 48-, and 72-hour predictions. In the event of a GMD, the NYISO has procedures to reduce the flows on the transmission system reducing, risk of damage to the system. The loss of power from transformer heating occurs over tens of minutes, where voltage instability occurs in seconds.

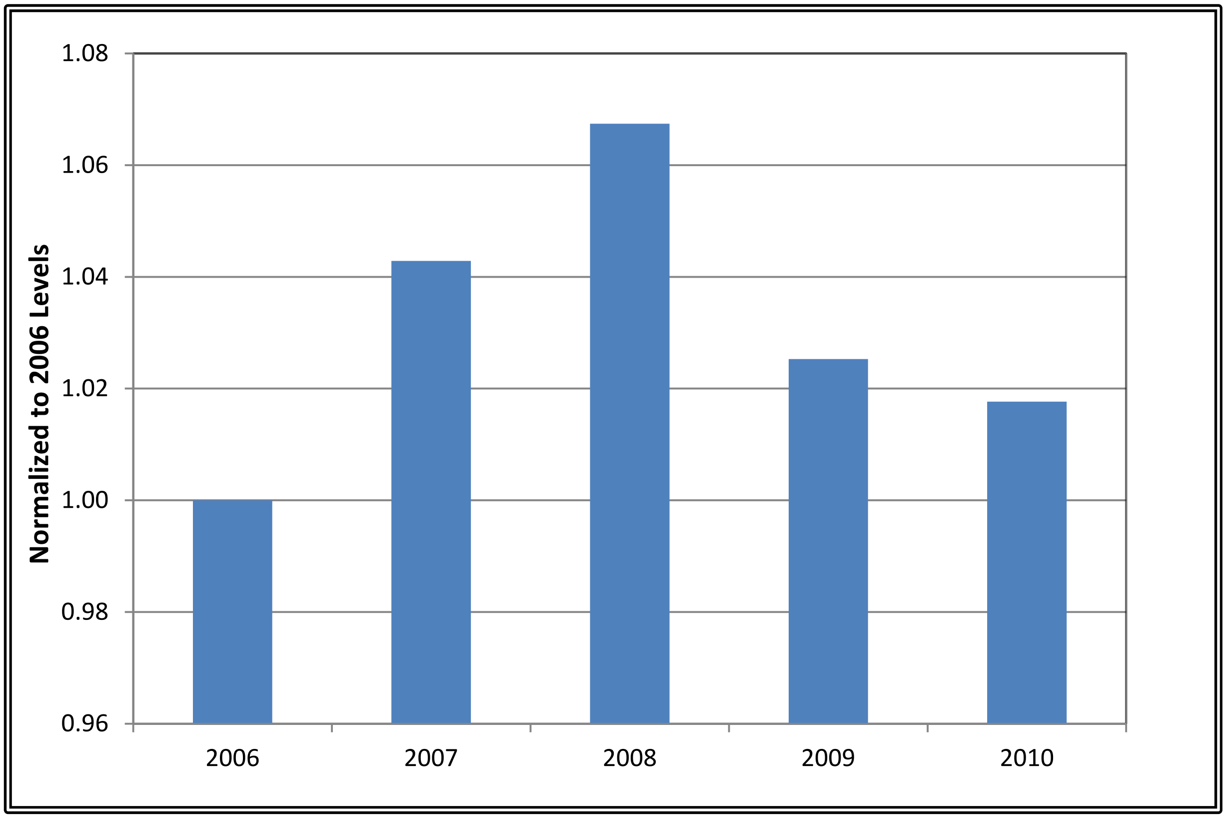
On April 30, 2012, FERC held a technical conference to discuss GMD vulnerability assessments and mitigating actions to protect the electric system. Panelist opinions on the magnitude of risk to the electric system varied, citing two reports-- NERC 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System, and FERC/DOE/DHS 2010 Report. In the event of a severe GMD, the NERC Interim Assessment Report suggests voltage instability could trip power equipment, thereby protecting the transformers and hence speeding recovery efforts. The FERC report estimates as many as 130 million Americans could be without power for several years due to widespread damage to extra-high-voltage transformers. NERC is continuing its vulnerability assessment, which is expected to be published in 2013.

In the meantime, NERC has identified the following actions to mitigate vulnerabilities:

- System analyses to identify vulnerabilities
- Enhancement of system design and operating procedures; and, if required, addition of neutral current blocking
- Training programs for planners and operators
- Management of spare equipment inventories, especially transformer specifications

Aging Workforce - Workforce issues are under active scrutiny related to staffing levels, training, and measures intended to enhance the use and productivity of the electric utility industry workforce. While overall employment in the transmission and distribution segment of the industry has been declining in New York in past years, the size of the workforce has been relatively stable from 2006 to 2008, with a somewhat declining trend seen in 2009 and 2010, as illustrated in Figure 20. At the same time, significant improvements have been reported in workforce use to achieve higher levels of productivity through cross training, automation, and enhanced communications.

Figure 20. Electric Workforce Levels



Source: FERC Form 1 Annual Reports (2006-2010)

Normalized Transmission and Distribution Staffing Trends (1997 base year). Utilities have reported that continuing improvements in workforce productivity have allowed service of increased load levels with the same level of reliability and staffing. In addition to cross-training and outsourcing (*i.e.,* use of contractor services), utilities attribute productivity increases to new system equipment, tools, and work procedures. Some specific examples include:

- Improved automated communication techniques provide information to the operators on loading and status of facilities that were previously developed manually, reducing time spent gathering data
- Improved monitoring allows prediction of loading and possible contingencies that identify pressing needs and enable more efficient deployment of workforce to meet these needs
- Improved remote device monitoring, part of the Smart Grid concept, is helping utilities respond more quickly and appropriately to outages
- Newer transmission and distribution equipment frequently has proven to be more reliable than earlier designs, reducing maintenance requirements. Design revisions by manufacturers have resulted in more efficient operation and maintenance. Maintenance driven by diagnostic analyses rather than by time interval reduces the total applied time spent on maintenance
- New types of line materials are easier and quicker to install. Improved tools and work practices have reduced the time required for certain procedures

- Crew use has been improved by improved job site reporting, mobile network work status reporting, and anticipating needs based on weather forecasts

The impending retirement of large numbers of experienced electric utility workers is a concern. Their replacements will have to acquire the technical knowledge to handle today's technology as well as learning new methods and systems through the course of their careers. An example of this change is the evolving technology surrounding the evolution of the smart grid. A July, 2011 report by KEMA for the GridWise Alliance included the following:

As of 2008, approximately 53 percent of the electric industry workforce employed by utilities is aged 45 years or older. More recent survey results suggest that utilities will need to replace 46 percent of skilled technician positions by 2015 because of retirement or attrition. Approximately 50 percent of the engineering workforce will be eligible to retire by 2015.[38]

The referenced report looks upon this subject from the viewpoint of a national transition to smart grid. The replacement of experienced electric utility workers as they retire, however, will be a problem for New York State. Utilities and labor organizations are attempting to address this growing problem. One New York utility has partnered with several community colleges to offer coursework that will train people in basic electric-line-worker skills. These programs allow the utility to hire workers who can be qualified to do electric-line-work sooner than if they were to hire people without such educational background. Utilities and the Smart Grid Consortium are working with a number of colleges and universities to develop educational programs that will address the technological advances that smart grid and related digital and communication advances will bring to the industry.

Table 7. Utilities Workforce Transition 2009-2015

Job Category	Potential Attrition and Retirement	Estimated Number of Replacements
Technicians	50.7%	27,800
Non-Nuclear Plant Operators	49.2%	12,300
Pipefitters/Pipelayers	46.1%	8,900
Lineworkers	42.1%	30,800
Engineers	51.1%	16,400

Source: Center for Energy Workforce Development, 2009

[38] *The U.S. Smart Grid Revolution Smart Grid workforce Trends 2011*, KEMA, Inc., 2011.

H. Key Findings and Recommendations

As illustrated throughout the Study, transmission and distribution reliability is not something that is examined periodically. Rather, both short- and long-term reliability in planning and operations is continuously being assessed by numerous Federal, State, and Regional entities. Yet even with all the efforts to maintain reliability, the State has opportunities to support reliability improvements. The following highlights key findings and recommendations.

- As assessed using existing metrics, the electric system meets all current reliability standards and criteria. Mechanisms to maintain reliability are in place should a planning study identify potential reliability risks.

- To maintain reliability, understanding the components of the electric system (generation, transmission, distribution, and load) is essential. State and federal policies have changed the system topology through, among other things, RPS, promoting demand-side management through DR and EEPS, and promoting environmental regulations, all of which accelerated retirements in the existing generation fleet. Smart grid and advanced technologies are expected to introduce additional changes. To date, changes have been incorporated into the planning and operation of the electric system. However, the complexity of the electric system may limit how quickly the system can adopt new policies and technologies system wide.

- In light of the nature and age of much of the generation, transmission and distribution system within the State and the likelihood of the need for replacement of many of those facilities, as well as potential retirements of some such facilities in the near term, the State should support reasonable investment in electric system infrastructure to maintain reliability while considering rate impacts to customers. The Energy Highway Initiative is an opportunity to address these issues.

- In its policies and actions, the State should support a diverse mix of electric generation fuel sources that have access to robust delivery systems, particularly in light of likely increasing dependence on natural gas as a generation fuel, especially in the downstate region.

- The State should continue to monitor the growing interdependence of electric and natural gas industries and use such awareness to inform its legislative, regulatory, and planning decisions and processes.

- The State should encourage workforce development for technical utility workers and utility engineers, given the impending loss of large numbers of experienced electric utility workers to retirement.

- Support the development and implementation of distributed generation technologies through various initiatives aimed at making distributed generation compatible with the State's electric system infrastructure and more accessible to consumers. While supporting such actions, the State should consider the impact to the natural gas system and future gas pipeline and local distribution company infrastructure, and foster measurable and verifiable energy conservation, efficiency, and demand response programs in New York State.

- New York State should encourage the development of cost-effective measures that enhance the ability of the Electric System to withstand or mitigate the effects of severe storms, and enhance the ability to restore service and effectively communicate with customers following severe storms.

Appendix

Study Team

As permitted by legislation, this report was developed by staff from state agencies, the NYISO, and NYSRC. The state agencies included DPS, NYSERDA, NYPA, LIPA, and NYSDEC. The previous "Report on the Reliability of New York's Electric Transmission and Distribution Systems," issued in November 2000, hired a contractor overseen by a study team. Findings from this study are drawn from existing reliability assessments conducted by agency staff, planners, and utility staff who comprised the study team.

Environmental Regulation Capsules

NYSDEC Regulations

Air Regulations

Part 201, Permits and Registrations

Part 201 requires owners, operators, or both owners and operators of air-contamination sources to obtain a permit or registration certificate from the NYSDEC for the operation of such sources. In general, facilities subject to these regulations must apply for a permit or a registration certificate from the NYSDEC.

Subpart 219-2, Municipal and Private Solid Waste Incineration

Subpart 219-2 applies to any new or modified municipal solid-waste incineration facility or any new or modified private solid-waste incineration facility in the State of New York for which an initial permit to construct a source of air contamination is issued on or after April 1, 1989. Emission standards for NO_x, PM, and HAPs are included in this rule.

Part 222, Distributed Generation

The purpose of Part 222 is to establish emission standards and testing requirements for existing distributed generation sources located at minor facilities and new distributed-generation sources. It is anticipated that a proposed rule will be released for public review and comment in 2012.

Subpart 225-1, Fuel Composition and Use – Sulfur Limitations

Fuel-sulfur limitations are incorporated into Subpart 225-1 for distillate and residual fuel oils and coal. The NYSDEC anticipates that revisions to the sulfur limits for fuel oils will be proposed and adopted in 2012.

Subpart 227-1, Stationary Combustion Installations

Subpart 227-1 regulates particulate matter emissions from solid-fuel (*e.g.,* coal) and oil-fired sources. Opacity limits are also set forth in this rule. Distributed generation sources likely will not be subject to this rule upon adoption of Part 222.

Subpart 227-2, Reasonably Available Control Technology (RACT) for Major Facilities of Oxides of Nitrogen (NO_x)

Subpart 227-2 applies to facilities subject to a Title V permit due to their potential NO_x emissions. Emission standards are included in the rule for boilers and turbines (central station power plants) and engines (central station power plants and distributed-generation sources located at major sources of NO_x emissions). No future revisions to this rule are contemplated at this time.

Part 231, New Source Review for New and Modified Facilities

Part 231 establishes the new source review preconstruction, construction, and operation requirements for new and modified facilities in New York State. Part 231 applies in areas of the State that are either in attainment or nonattainment with the national ambient air quality standards at new and modified facilities with emissions above applicable thresholds. Currently New York has areas classified as nonattainment for ozone, PM-2.5, and PM-10 and is in attainment or unclassifiable for all other regulated NSR contaminants. Requirements for new major facilities and major modifications at existing major facilities include the application of lowest achievable emission rate technology and offsetting of emissions for nonattainment contaminants and application of best-available control technology for attainment contaminants. Determination of control technologies is done on a case-by-case basis. Existing major facilities that perform minor modifications are required to meet record keeping and possibly monitoring requirements.

Part 242, CO_2 Budget Trading Program

Part 242 establishes the New York State component of the CO_2 Budget Trading Program under the Regional Greenhouse Gas Initiative. Part 242 applies to fossil fuel-fired generators with a nameplate capacity equal to or greater than 25 MW.

Part 243, CAIR NO_x Ozone Season Trading Program

Part 243 establishes the New York State component of the Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program, designed to mitigate interstate transport of ozone and nitrogen oxides, an ozone precursor. This rule was scheduled to sunset on December 31, 2011 and be replaced by the Cross-State Air Pollution Rule (CSAPR - see below under "Federal Regulations") effective January 1, 2012; however, CSAPR was vacated on August 21, 2012 and Part 243 remains in effect.

Part 244, CAIR NO_x Annual Trading Program

Part 244 establishes the New York State component of the CAIR NO_x Annual Trading Program, designed to mitigate interstate transport of fine particulates and nitrogen oxides by limiting emissions of NO_x from fossil fuel-fired electricity generating units. This rule was scheduled to sunset on December 31, 2011 and be replaced by CSAPR (see below under "Federal Regulations") effective January 1, 2012. Nevertheless, CSAPR was stayed on December 30, 2011 and Part 244 remains in effect.

Part 245, CAIR SO_2 Trading Program

Part 245 establishes the CAIR SO_2 Trading Program, designed to mitigate interstate transport of fine particulates and sulfur dioxide. This rule was scheduled to sunset on December 31, 2011 and be replaced by CSAPR (see below under "Federal Regulations") effective January 1, 2012; however, CSAPR was stayed on December 30, 2011 and Part 245 remains in effect.

Part 246, Mercury-Reduction Program for Coal-Fired Electric Utility Steam-Generating Units

Part 246 applies to coal-fired central-station power plants with nameplate capacity greater than 25 MW. Mercury emission caps apply to 13 existing facilities and emission standards apply to new coal-fired units. It is anticipated that the monitoring requirements in Part 246 will be modified as a result of the U.S. EPA's adoption of the Utility MACT (40 CFR 63, Subpart UUUUU).

Part 249, Best-Available Retrofit Technology (BART)

The purposes of the Best-Available Retrofit Rule (BART – Part 249) are to reduce regional haze and improve visibility in Federal Class I Areas (*e.g.,* National Parks). Fossil fuel-fired steam-electricity-generating units with heat inputs greater than 250,000 mmBtu/h and a potential to emit more than 250 tons per year of NO_x, SO_2 or PM_{10} are potentially subject to Part 249. The units specifically affected by Part 249 are those that were not in operation prior to August 7, 1962 and were in existence on August 7, 1977, or underwent reconstruction between August 7, 1962 and August 7, 1977.

Part 251, CO_2 Emission Limitations for Combustion Installations and Gasification Sources.

Part 251 will apply to new power plants with a nameplate capacity of 25 MW or greater and to existing generation plants that add 25 MW or more of capacity. CO_2 emission standards will be established based on emission rates achievable by new natural gas-fired plants.

<u>Water</u>

Subpart 750-01, Obtaining a SPDES Permit

The requirements for applying for a SPDES Permit as well as the content of SPDEC permits are set forth in Subpart 750-01.

Subpart 750-02, Operating in Accordance with a SPDES Permit

The compliance obligations including reporting, monitoring and incident reporting are set forth in Subpart 750-02 along with the penalties for non-compliance with SPDES permits.

Best Technology Available (BTA Policy)

Through this policy, the NYSDEC identifies closed-cycle cooling or the equivalent as the performance goal for the BTA to minimize adverse environmental impacts (injury and mortality to fish and shellfish via impingement at the intake or entrainment through the cooling system) pursuant to Section 704.5 of 6 NYCRR and Section 316(b) of the federal Clean Water Act (see below under "Federal Regulations") in SPDES permits issued by the NYSDEC. A copy of the policy is available online at:

http://www.dec.ny.gov/docs/fish_marine_pdf/btapolicyfinal.pdf

Materials Management

Part 360

Permitting, landfill construction, and operational requirements for solid wastes are addressed in the Part 360 regulations. There are provisions, referred to beneficial used determinations, in the regulations to exempt certain materials from being classified as solid wastes. Coal combustion bottom ash and fly ash have qualified for BUDs under Part 360-1.15(b) under certain conditions.

Parts 370 - 374

The definitions of hazardous waste and the requirements for hazardous waste storage, transport, and disposal are set forth in Parts 370 through 374.

Petroleum Bulk Storage

Parts 612, 613 and 614

Parts 612 through 614 address the permitting, engineering controls, and record keeping requirements for facilities with a combined petroleum storage capacity greater than 1,100 gallons. These regulations pertain to both above ground and underground tanks.

Environmental Justice

Part 487, Analyzing Environmental Justice Issues in Siting of Major Electric Generating Facilities Pursuant to Public Service Law Article X

The purpose of Part 487 is to put the requirements set forth in the Power NY Act of 2011 into regulation. As part of an Article X application, applicants must submit:

An evaluation of significant and adverse disproportionate environmental impacts (if any) that may result from the construction and operation of the facility.

An evaluation of the cumulative impact from the facility and other relevant sources within a half-mile radius of the proposed or modified facility.

A comprehensive demographic, economic, and physical description of the impacted community compared to adjacent communities and to the county in which the project would be located.

Air

40 CFR 51, 52, et. al., Cross-State Air Pollution Rule (CSAPR)

This rule establishes NO_x and SO_2 emission budgets for fossil fuel-fired electricity generating units with nameplate ratings greater than 25 MW in 27 states (including New York) in the central and eastern portions of the United States. Annual and ozone season NO_x allowances and annual SO_2 allowances will be allocated to central-station power plants. If a facility emits more NO_x or SO_2 than the number allowances allocated, that facility must obtain allowances from another facility in New York or, to a limited extent, in another state. There are corresponding state-specific emission caps (or emission budgets) in addition to the facility-level emission caps. This regulation will be implemented by the U.S. EPA. The rule was to take effect on January 1, 2012, but was stayed on December 30, 2011.

40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression-Ignition Internal Combustion Engines

This rule sets forth emission standards (NO_x, CO and PM_{10}) for new compression-ignition (diesel-fired) engines. The standards differ by model year. The rule addresses engines manufactured through the 2015 model year. These standards will apply to new distributed-generation sources of such engines until Part 222 is adopted.

40 CFR 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

This rule sets forth emission standards (NO_x and CO) for new spark ignition (natural gas-fired) engines. The standards differ by model year. The rule addresses engines manufactured through the 2015 model year. These standards will apply to new distributed generation sources of such engines until Part 222 is adopted.

40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

This rule sets forth NO_x emission standards and fuel-sulfur limits for new turbines.

40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal-Combustion Engines

This rule covers the same sources as 40 CFR 60, Subpart JJJJ and establishes standards for emissions of hazardous air pollutants.

40 CFR 63, Subpart UUUUU, Utility MACT

The U.S. EPA proposed this rule on May 3, 2011, to establish national emission limitations and work practice standards for hazardous air pollutants emitted from coal- and oil-fired electric utility steam generating units. In accordance with a consent decree, a final rule was signed by the U.S. EPA administrator on December 16, 2011. The anticipated compliance deadline is early2015. Facilities may be granted an additional year (until 2016) to comply with this rule.

Water

40 CFR 122 & 125, Cooling Water Intake Structures

These rules were promulgated to implement Section 316(b) of the Clean Water Act. A revised rule was proposed in 2011. A final rule is expected in 2012. This rule is also addressed in the NYSDEC's BTA Policy.

40 CFR 423, Steam Electric Power Generating Point Source Category

The effluent limitations for coal-, natural gas- and oil-fired and nuclear central station power plants are set forth in this rule. This rule was last updated in 1982; a proposal for a revised rule may be released in mid-2012.

Materials Management

40 CFR 257, 261, 264, et al., Coal Combustion Residuals Rule

The U.S. EPA released a proposed rule on June 21, 2010 to regulate coal-combustion residuals (bottom ash and fly ash) as either a special hazardous waste (Subtitle C) or as a non-hazardous waste (Subtitle D). A final rule is expected in 2012.

NEW YORK STATE ENERGY PLAN

New York State Transmission and Distribution Systems Reliability Study and Report

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State of New York

Andrew M. Cuomo, Governor