

Energy Infrastructure Issue Brief
New York State Energy Plan 2009

December 2009

1 Overview

This Issue Brief addresses issues related to the current conditions of New York State’s energy infrastructure and the need for additional infrastructure over the planning horizon.¹ The Electricity, Natural Gas, and Petroleum Resource Assessments provide important background information supporting the issues explored in this brief. Key infrastructure issues are summarized below.

1.1 Electricity

Full and timely implementation of the State’s ‘15 by 15’ program is projected to eliminate the need for any major reliability-driven infrastructure additions. Major transmission additions, however, may be driven by resulting economic savings or by the State’s strong policy to increase its reliance on electricity generated by renewable resources.

Major capital expenditures will be required just in order to maintain the safety and reliability of the State’s existing, aging transmission and distribution infrastructure. Utilities’ implementation of their capital expenditure programs will likely exert significant upward pressure on retail rates. It will therefore be incumbent on the PSC to carefully scrutinize the utilities’ proposed expenditures.

Even based on the Starting Point reference case, which assumes that the State will meet only a fraction of its ‘15 by 15’ program objective, generation expansion to meet statewide reliability requirements is not projected to be necessary until after 2018. Full and timely implementation of the State’s ‘15 by 15’ initiative will likely push the need even further out in time. If substantial intermittent wind generation is installed, however, adequate load following generation capacity – or large scale energy storage - must be assured.

Uncertainty with regard to siting, interconnection delays, emerging environmental requirements, interregional coordination issues, and questions related to federal versus State regulatory jurisdiction can negatively impact the ability of the market to supply New York’s electricity needs effectively. These sources of uncertainty can be addressed by: enactment of a new power plant siting law; streamlined New York Independent System Operator (NYISO) and utility interconnection processes; a full vetting of proposed environmental regulations; and improved federal/State cooperation.

Optimizing system efficiency is an important approach for mitigating electricity costs, reducing potential environmental impact and providing for a secure electricity resource. The State’s commitment to demand response programs, cost-effective measures to reduce system losses, implementation of new system control technologies, and application of strategic energy storage concepts are critical components of a system efficiency optimization strategy. While optimizing system efficiency at all times is important, improvements that reduce system peak in relation to loads during off-peak periods will be most beneficial. Targeting infrastructure changes to reduce system peak loads can contribute to the State’s policy objectives.

¹ Infrastructure issues associated with the transportation sector are not included in this Issue Brief.

Multiple planning efforts are underway in New York State to assess the status and needs of the electricity infrastructure. Such efforts generally have used consistent assumptions, although further coordination may be appropriate. The Public Service Commission (PSC) should continue its systematic examination and evaluation of the State's transmission and distribution infrastructure and maintain its emphasis on appropriate replacement/upgrade of aging infrastructure to maintain safe and adequate service and also increase the efficient utilization of the electric system. Further, interregional planning and participation in the proposed Eastern Interconnection Planning Collaborative may be pursued, including addressing seams issues² in other forums.

1.2 Natural Gas

Overall natural gas supplies are expected to remain adequate to meet projected demand, both nationally and for New York State. However, adequate pipeline delivery capacity is critical to ensure that available gas supplies can be provided to the markets that require them.

To assess the adequacy of the natural gas delivery system properly, the combined natural gas requirements of the electricity generation, residential, commercial, and industrial natural gas customers must be considered together and compared to available pipeline delivery capacity at peak periods. Forecasts show that natural gas demand is expected to increase in the residential and commercial sectors, while remaining essentially flat in the electric generation and industrial sectors. Most of the growth in natural gas demand over the planning period is projected to be in the natural gas pipeline capacity-constrained downstate region.

Natural gas system modeling analysis, discussed in detail in the Natural Gas Assessment, has been conducted to assess the ability of the natural gas system to meet the future electric generation natural gas demand. Peak day demand analysis indicates that pipeline capacity is essentially fully utilized during the forecast period and that additional pipeline capacity would be needed to continue to meet demand reliably.

Modeling results indicate that some electric load may not be served due to the lack of natural gas delivery capacity. Further analysis will continue to assess the magnitude and the impacts to the electric system from this unserved load. Since the models assume that all elements of the gas system are operating as designed, the vulnerability of the State from pipeline or compressor failures should be examined as part of a separate contingency analysis.

Based on the natural gas modeling runs, the natural gas system appeared to be strained with conditions such as: (1) Indian Point being retired and replaced by a combined cycle natural gas plant; (2) a significant amount of repowering of downstate dual fuel units that use residual oil as a backup; (3) a much colder than normal winter; and (4) and a combination of the three. If any of these conditions occur, alone or in combination, various elements of the natural gas system and the electric system should be monitored and, if necessary, actions should be taken to mitigate the risks. Examples of the critical elements to monitor include: the natural gas storage drawdown rate; LNG imports into New England; both electric and natural gas imports from Canada; electric generation versus demand and the possible need to shed electric load; and electric generators' ability to continue to use distillate oil back-up beyond the limits of environmental permits.

² As defined by the NYISO, seams issues are barriers and inefficiencies resulting from equipment limitations and differences in market rules and designs, operating and scheduling protocols, other control area practices which inhibit or preclude the ability to transact capacity and energy across control area boundaries.

To address the vulnerability of the electric system on peak winter days due to the lack of natural gas delivery capacity, policies may be needed to encourage new combined cycle units to be equipped with back-up distillate fuel oil capability. New combined cycle units are significantly more efficient than existing steam units, thus lowering natural gas consumption per megawatt-hour generated. Pursuing a policy for back-up fuel capability provides the State the benefit of improved generation efficiency while mitigating risk by increasing fuel diversity.

The local distribution companies that serve the downstate market have identified a need to add pipeline delivery point capacity on their systems to continue to provide reliable service to customers in their service territories. If planned pipeline additions are constructed, they will help relieve existing system capacity constraints, increase gas system reliability, and lower natural gas prices, particularly in the downstate region. The new delivery points would benefit both the natural gas and electric ratepayers, and mechanisms to have all beneficiaries share the cost of expensive pipeline capacity additions should be explored.

The planning, regulatory approval, and construction processes for new pipeline and liquefied natural gas projects can take many years. Unexpected delays can represent significant obstacles to constructing the needed natural gas infrastructure to meet growing natural gas market demand. The State can reduce these barriers to investment in natural gas infrastructure, including liquefied natural gas facilities for meeting future downstate requirements, by: (a) providing project developers rigorous, pre-application, all-agency evaluations of State and local project siting, environmental and safety concerns; and (b) maximizing agency coordination during permitting proceedings.

2 *Electricity*

This section provides background information about the electricity industry, markets and regulatory institutions in New York State and describes how those institutions affect the maintenance and development of electricity infrastructure. Thereafter, the section identifies the various initiatives and processes used for planning of the electric system infrastructure in the State, while highlighting some of the issues now being confronted. The Electricity Resource Assessment provides additional information about the issues discussed here.

2.1 Status of Electricity Industry, Markets, and Regulatory Institutions

As described more fully in the Electricity Resource Assessment, the New York State electricity industry currently consists of investor-owned utilities, independent power producers, governmental utilities, transmission-only companies, energy service companies, and consumers of electricity. In general, the generation suppliers engage in wholesale sales, i.e., sales for resale, of energy, ancillary services and capacity through competitive markets administered by the NYISO. Electricity is then transported over the transmission and distribution lines to end-users throughout the State, as well as for bulk transactions with other energy market participants.

The PSC and the Federal Energy Regulatory Commission (FERC) share regulatory responsibility for the transmission system. FERC oversees the NYISO's reliability and economic planning processes, but has limited authority to direct the construction of additional infrastructure. The PSC, however, has authority to order construction of infrastructure facilities necessary to serve the public interest by the utilities under its jurisdiction.

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

The current competitive generation market began in August 1994 when the PSC instituted an investigation of the issues related to emerging competition in the electric industry. In April 1996, FERC issued Order 888, which requires public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves. As a result of these and other federal and State regulatory actions, a competitive wholesale electricity market was established and the NYISO was created in 1999. An integral part of the process was the separation of the ownership of transmission and distribution assets from the ownership of electric generation assets, with each sector having separate responsibility for maintenance and construction of its own infrastructure.

With the advent of the NYISO came a new system for pricing wholesale electricity, i.e., commodity pricing, known as Locational Based Marginal Pricing (LBMP). This system of pricing is designed to provide economically efficient price signals throughout the grid. Consequently, the NYISO operates both a day-ahead market and a real-time (or balancing) energy market and produces prices for both energy and ancillary services, e.g., operating reserves and regulation.³

To ensure resource adequacy, the NYISO also administers an installed capacity market. Load serving entities, i.e., transmission and distribution owners and energy service companies that supply electricity to end-use customers, are required to acquire capacity equal to their forecasted peak load plus the applicable reserve margin.⁴ Reserve margins, including specific locational requirements for New York City and Long Island, are redefined annually to account for changes in electricity system characteristics.

The NYISO has also developed tariff programs that foster demand-response⁵ within the State. Its programs grew fairly rapidly during their initial years as most of the low-cost and high payback (at current market prices) measures were deployed. Advanced meters, e.g., interval meters, that can record customer loads at intervals as short as one hour enable customers to take advantage of short-term prices by shifting their loads to off-peak periods or curtailing their loads during price spikes, thereby reducing their average rates. The NYISO has worked to refine its operating procedures and computer software to permit demand response resources to provide high-valued ancillary services to reduce the NYISO's reliance on expensive (and often relatively high-emitting) sources, such as quick-start generators.

Finally, reliability and security of the electricity system is a critical key concern for all market participants. While the cost of infrastructure investment to ensure reliability is high, the cost of losing electricity service is even higher. For example, the costs associated with the August 14, 2003 electricity system blackout in the northeast, which disrupted service in New York for 30 hours, was estimated to be between \$4 billion and \$10 billion.⁶ The cost for the nine-day power emergency in the Long Island City electric network in Queens in 2006 was about \$103 million,⁷ not including the costs that were absorbed by the many businesses, citizens, and community organizations during the event. The costs associated with most failures of the electric system, however, cannot be quantified just in dollars. Public health and safety are also at risk. While hospitals have backup generation at the ready, there is always the possibility

³ Regulation is defined as the capability of a specific generating unit with appropriate telecommunications, control and response ability to increase or decrease its output in response to a control signal every six seconds. This ensures the continuous balancing of resources (generation and interchange) with load variations in order to maintain scheduled interconnection frequency.

⁴ Reserve Margin is defined as generating capacity in excess of peak load requirements to be available in case demand is underestimated or normal supplies become unavailable due to repairs, refueling, etc.

⁵ Demand-response refers to customer load that can respond to short-term (day-ahead or real time) price signals. Demand-response resources reduce the need for new infrastructure and also discipline market prices and help ensure reliability. Customer response can take the form of reducing the use of supply or use of on-site resources. As such, demand-response is an important component in the energy industry and its markets, especially when it is used to reduce demand during peak periods, known as "peak-shaving". The PSC's System Benefits Charge (SBC) program administered by the New York State Energy Research and Development Authority (NYSERDA) has been the driving force in enabling demand-response to happen quickly in New York State.

⁶ In Canada, the gross domestic product was down 0.7 percent in August, there was a net loss of \$18.9 million work hours, and manufacturing shipments in Ontario were down \$2.3 billion in Canadian dollars." U.S/Canada Power System Outage Task Force. *Final Report on the Implementation of the Task Force Recommendations*. September 2006. <http://www.ferc.gov/industries/electric/indus-act/blackout/09-06-final-report.pdf>

⁷ Of this amount, about \$65 million was for restoration and about \$38 million was for system improvements that would not otherwise have been undertaken at this time. In addition to the approximately \$103 million, Con Edison spent another \$52 million for planned improvements. The figures given here are as of March 31, 2009 and include projections for expenditure through the remaining portion of 2009.

that the backup will fail. Elderly and vulnerable citizens who depend on air conditioning, electric heating and elevator service are immediately at risk in a blackout. When the power is off, public safety resources are stretched as personnel are dispatched to assist citizens. Continued vigilance in establishing and maintaining adequate reliability standards and practices and maintenance of facilities is important for protecting the health and safety of the residents of New York State and for fostering the health of the State's economy.

2.2 Regulatory Approaches

New York State now relies on both traditional regulatory and market approaches to attract the development of new infrastructure. This section describes and discusses infrastructure funding and the interactions between markets and infrastructure development.

It is important that New York's energy companies continue to have adequate access to capital markets. The energy industry is very capital intensive, and energy companies generally cannot fund all of their infrastructure needs through internal cash flows. This means that they must be attractive to debt and equity investors in order to raise the necessary external financing needed to meet their infrastructure needs. Recognizing this need, market mechanisms have been developed and are continually being monitored to provide economic incentives for developers to invest in infrastructure when and where such facilities may be needed. Similar mechanisms for transmission facilities, as discussed in more detail below, however, have not been as effective. Consequently, for most transmission investments, regulated and governmental utility companies that have the obligation to serve build and maintain such facilities using traditional funding approaches, e.g., rate-of-return for the regulated utilities, or via long term contracts with developers.

Utilities in New York have among the highest credit ratings of utilities in the country. Generally, they are "A" or "BBB+" rated. These ratings are strong relative to the industry as a whole in large part due to the fact that New York's utilities have divested their generation assets and also have risk reduction features in their rate plans. For instance, fuel costs are a large and volatile part of any utility's expenses. In New York, fuel adjustment clauses pass the cost of fuel along to customers, insulating utilities from fuel cost swings. Other major cost categories, such as pensions, other post-employment benefits, property taxes and environmental clean-up are also generally "trued-up" for New York utilities, reducing the potential impact on their income statements.

In addition, most New York regulated utilities now, or will soon, have revenue decoupling mechanisms (RDMs)⁸ in place. While such mechanisms are meant to moderate the revenue impacts of energy efficiency programs, they also maintain the utilities' cash flows at levels deemed necessary to attract investment capital. In addition to RDMs, some recent rate plans have included hyperinflation protection measures and deferral of costs related to turmoil in the auction rate security market. These proactive measures ensure that New York's utilities will remain less risky than the average utility elsewhere. This lower level of risk results in lower costs of debt and equity.

⁸ A RDM is a ratemaking approach designed to eliminate or substantially reduce the linkage between sales and utility revenues and/or profits. A RDM is used because existing utilities' delivery rate designs are, in most cases, not "optimal" in that they do not always collect fixed costs through fixed charges and variable costs through variable charges. RDMs remove the disincentive a utility has to promote energy conservation by removing the link between sales and profits.

2.2.1 Transmission

In the transition to competitive markets, stakeholders focused on the creation of wholesale generation markets for the purchase and sale of electricity, and the utilities divested the majority of their generation assets. Consequently, market rules were developed with the intent to allow the new owners of power plants opportunities to collect cash flows sufficient to support continued operation of the generation and to facilitate the building of new generation when required. Transmission infrastructure, however, was treated differently. Bulk transmission⁹ facilities were turned over to the NYISO for operation and monitoring, but the utilities retained ownership and ultimate responsibility for maintenance, hands-on operation (based on direction from the NYISO) and upgrades.

After the generation markets were determined to be functioning properly, however, the Department of Public Service (DPS) convened a meeting with the NYISO and its stakeholders to explore what market mechanisms might be developed to provide incentives for the construction of merchant transmission projects, similar to the way generation would now be expanded. The exploration, however, has so far been unsuccessful, primarily because of two major stumbling blocks: the lumpiness associated with building new transmission facilities and the potential loss of economic value affecting some market participants. As the construction of new transmission typically requires the acquisition of linear property rights to establish rights-of-way, which can result in environmental impacts and disruption of communities, and because they require major capital investments and usually require many years to site, license, design, and construct, new transmission lines must, by necessity, typically be planned to accommodate long-term use instead of just the immediate needs. Therefore, an immediate need of 200 MW of transmission capability might result in a desire to construct a 400 MW facility.

This lumpiness of development not only affects the cost and impacts of the planned facility, but it can lead to dramatic reductions in locational marginal price differences between the two ends of the new facility, diminishing, at least in the short-run, the value of any transmission congestion contracts (TCCs)¹⁰ that would be generated by the new line to help fund it. The devaluation of TCCs, however, will occur to some extent regardless of the size of the facility. Therefore, by default, continuation of traditional rate-of-return regulation of utilities with the obligation to serve appears, at least for now, to be the most practical approach to constructing most new major new transmission facilities, whether needed for reliability, economics, environmental, or public policy reasons.

The only transmission-specific provisions in the NYISO tariff that might be considered a transmission market mechanism to encourage developers to build such facilities are the rules providing for awards of incremental transmission congestion contracts for the transfer capacity of new projects. To date, the only major non-utility constructed projects have been the Cross Sound Cable between Connecticut and Long Island and the Neptune Line from New Jersey to Long Island, both of which have long-term contracts for the capacity backed by ratepayer funding. Looking forward, the costs of economic transmission expansion projects emerging from the NYISO's Congestion Assessment and Resource Integration Study (CARIS) process (described later in this Brief) will be able to be recovered through the NYISO's tariffs if approved by an 80 percent super-majority vote of the projects' identified beneficiaries.

While pure merchant-based transmission infrastructure may not soon materialize in New York, transmission infrastructure construction by non-utility entities is still possible under federal legislation. The Energy Policy Act of 2005 authorizes FERC to ensure cost recovery for transmission projects that

⁹ Bulk transmission is a functional or voltage classification relating to the higher voltage portion of the transmission system.

¹⁰ Transmission congestion contracts (TCCs) allow the holders to collect day-ahead market congestion rents based on the price differential between the point of injection and the point of withdrawal.

relieve congestion – regardless of ownership. The New York Regional Interconnect was the most recent independent project in New York to submit a siting application (since withdrawn); the project was seeking regulated rate treatment before FERC (rather than through the PSC as would a utility regulated directly by it).

2.2.2 Generation

Since electric industry restructuring was initiated, over 7,600 MW of generation has been added in New York. Most of the generation infrastructure added upstate (about 3,800 MW, primarily the Athens, Bethlehem and wind facilities) are merchant plants that rely solely on market-based revenue streams. Most of the plants added downstate (about 3,800 MW), however, have been added by New York Power Authority (NYPA) or supported by long-term contracts with Consolidated Edison (Con Edison), NYPA or the Long Island Power Authority (LIPA). The adequacy of market price signals to ensure adequate generation infrastructure is discussed below from reliability, economic, and environmental perspectives.

The principal source of revenues for investment in generation in NYISO markets is the wholesale electric energy market. Natural gas and oil plants are on the margin¹¹ in many of the hours in the year and set the market clearing energy price that is paid to all generators. The net energy revenues (market energy prices less marginal energy costs of suppliers) help to cover their non-fuel costs and potentially yield profits. Additional revenue sources include markets for installed capacity (particularly for generators with low capacity factors) and various ancillary services needed to ensure reliability. Suppliers' marginal energy costs, and hence wholesale electric prices, also incorporate certain environmental costs, especially for sulfur dioxide (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂), the latter via the Regional Greenhouse Gas Initiative (RGGI).¹² Generators that emit these pollutants must pay for emissions allowances at prices that reflect regional or national market values, thus increasing their operating expenses and potentially affecting their profitability and economic viability (particularly for the least efficient, most polluting units). Generators that reduce their pollutants may not need to pay for additional allowances and may be able to sell any of their own that are unused.

New York has historically had a diversified generation mix, with significant hydroelectric, nuclear, and coal-fired generation located upstate. New York's market prices have attracted new merchant generation infrastructure, primarily natural gas-fired combined-cycle plants, as well as imports from neighboring regions with surplus capacity. The NYISO's 2009 Comprehensive Reliability Plan (described later in this Brief) concluded that currently-proposed market-based solutions together with implementation of planned upgrades to the bulk transmission system and other assumptions would meet reliability requirements through 2018 without the need to trigger any backstop regulated solutions.¹³ This means that market

¹¹ The generating unit that produces the next increment of output is called the marginal unit (or the unit on the margin) at the point in time of that production. The marginal cost is the cost to produce that next increment of output.

¹² The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by 10 Northeast and Mid-Atlantic states to limit greenhouse gas emissions. It is the first mandatory, market-based CO₂ emissions reduction program in the United States. The states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are signatory states to the RGGI agreement. These 10 states will cap CO₂ emissions from the power sector, and then require a 10 percent reduction in these emissions by 2019. The RGGI approach involves: establishing a multi-state carbon dioxide emissions budget (cap) that will decrease gradually until it is 10 percent lower than at the start; requiring electric power generators to hold allowances covering their emissions of carbon dioxide; providing a market-based emissions auction and trading system where electric power generators can buy, sell, and trade carbon dioxide emissions allowances.

¹³ Additional solutions, however, could be needed if actual outcomes differ significantly from the assumptions of the analysis, such as unexpected unit retirements. Accordingly, the NYISO will continue to reevaluate its assumptions in future studies.

prices appear to be sufficient at this time to provide the resources needed to maintain reliability on a statewide basis.

The high price of natural gas in recent years has provided strong market incentives for building plants with cheaper fuel sources, such as hydro and other renewable resources, nuclear facilities, and coal plants, although development of some of these facilities in New York has been slow for various reasons.¹⁴ For example, the opportunity to get significantly more capacity from hydro resources within the State is limited. Also, most other renewable resources have relatively high capital costs and have required supplemental revenue support. With respect to new nuclear units, they would be expected to employ more advanced technologies and hence potentially have very high initial installed capital costs, thus offsetting the high gas price incentive. Some of the developers of new nuclear plants, however, are pursuing federal incentives to offset some of the technology risks they face. There is a proposal from a developer to build a new 1,600 MW nuclear plant in New York as a merchant plant (discussed in more detail later in this Issue Brief). The cheapest readily available fuel source is coal; however, siting new traditional coal plants in New York would be difficult due to increasingly stringent environmental regulations and the uncertain economics of coal in a carbon-constrained world. As a result, most of New York State's new non-renewable generation has consisted of natural gas-fired plants sited where generation is most valuable, close to the load centers of New York City and Long Island, minimizing the need for new transmission. The new natural gas-fired plants are cleaner and more efficient than most of the older natural gas-fired plants, and therefore have helped reduce market prices and emissions, but they have increased the State's dependence on natural gas.

To help address the State's public policy needs with regard to renewable resources and energy efficiency, the State has developed programs to support additional investment in those areas. For example, the PSC's Renewable Portfolio Standard (RPS) sets targets for new generation fueled by renewable resources and holds periodic procurements to meet this goal. The procurement price for renewable generation reflects the incremental cost of renewable resources, over and above the NYISO's wholesale market prices, that must be incurred to meet this public policy goal. Long-term benefits include greater fuel diversity and reduced reliance on natural gas, reduced emissions, and potential reductions in energy prices. The PSC's Energy Efficiency Portfolio Standard (EEPS) similarly sets targets for investment in customer energy efficiency measures, to reduce load and thus reduce the need for transmission and generation (and associated emissions from generation).

2.3 Regulatory Uncertainty

There is regulatory uncertainty about several matters that can affect the future of the State's utility infrastructure. Some of the most pressing concerns relate to: generation siting authority; interconnection authorizations; environmental requirements; inter-regional issues; and tension between the states and FERC with respect to resource adequacy. Elimination, or at least minimization, of such uncertainties is an appropriate State policy objective.

2.3.1 Generation Siting Authority

Currently, major generating facilities are subject to the State's Environmental Quality Review Act and must obtain appropriate approvals from multiple jurisdictions and authorities, any one of which could

¹⁴ The exception is large scale wind generation which has been spurred on by the State's Renewable Portfolio Standard (RPS) program and federal production tax credits.

reject the project or impose their own restrictions. A replacement or reenactment of the now-expired Article X of the Public Service Law, which previously provided a one-stop siting process under a State Siting Board, has been under consideration since the Article expired at the end of 2003. Although no additional major generation is needed until after 2018 for reliability purposes, the time period necessary to site and build such a facility can be extensive. Enactment of a comprehensive siting law to expedite approvals for needed and environmentally acceptable generation facilities would address the uncertainty that now exists in this regard.

2.3.2 Interconnection Authorizations

Uncertainty also exists with regard to the authorization process for interconnecting generation to the State's power grid. Whether a proposed generation project is a 10 kW wind turbine on a farm or a 1,400 MW nuclear power plant, there is an established process for that project to interconnect with the State's transmission and/or distribution system, but the process for the larger facilities can be lengthy. In general, the larger the project, the more complicated and costly the study and the longer it takes to progress through the process.

The NYISO interconnection process seeks to foster accurate and efficient allocation of the costs of facilities needed to interconnect new resources reliably and avoid the dedication of resources to study projects that are not ready to move forward. FERC estimates that it should take 490 days, or approximately 16 months, to complete the interconnection process if there are no delays or disputes. However, with over 33,000 MW of potential new generation and transmission interconnection projects currently in the NYISO's queue, few projects are being completed in that time frame. The NYISO has noted that the interconnection process in this State has been taking anywhere from 27 to 52 months with the average taking over three years. One reason for the delays is that developers sometimes are not able to submit their study funding and/or input data when needed to be included in the NYISO's class year studies, which means they must wait for the following class year studies.¹⁵ Disputes related to a class year study can and have delayed final resolution of the study and delayed the start of the next study. Even if excluded from a class year study, however, developers that do not foresee extensive costs being allocated to them had they been included in the study (typically small projects) may proceed with their projects. On the other hand, major projects are likely to have major impacts that could require significant and costly system modifications, so this is not a viable option for them. Both FERC and the NYISO, consequently, recognize that there are problems with the current queuing process and have been working to modify and streamline the process where opportunities exist.

The PSC has itself also undertaken efforts to address interconnection needs by establishing its own less onerous standardized interconnection requirements for distributed generation (2 MW or less), and specifically for small (25 kV or less) projects so as to expedite matters for those facilities. New York has a major interest in resolving the delays in the interconnection process for all resources, especially with regard to renewables. Over 8,000 MW of renewable projects are in the NYISO queue, representing generation that can help meet New York State's RPS program goal of 25 percent of the State's energy being supplied from renewable sources by 2013, which is being considered to be increased to 30 percent by 2015. New, clean resources that can assist in meeting environmental goals must be able to progress through the process without institutional delays.

¹⁵ Class year studies annually determine system upgrades required for generation and merchant transmission projects included in the class year to interconnect to the transmission system in compliance with the NYISO Deliverability Interconnection Standard.

2.3.3 Environmental Requirements

Emerging environmental requirements also raise uncertainty, especially with regard to the costs to comply with such requirements. Key requirements that would affect the electricity industry during the planning horizon include: RGGI and a potential federal climate change program; the Environmental Protection Agency's rules on continued or future use of once-through cooling systems; a regional NO_x trading program to replace the Clean Air Interstate Rule (CAIR); and a more specific NO_x reduction program driven by ozone problems and targeted at plants in southeastern New York.

Coal and oil-fired units could be especially vulnerable to cost increases as a result of environmental requirements associated with obtaining CO₂ and NO_x allowances. The combination of increased production costs due to the requirements to obtain emission allowances and decreased opportunities for energy sales will create economic challenges that may lead to retirement of some of these units, thus shrinking the pool of units available to follow load.

In southeastern New York, there are a number of old fossil-fueled generation units, known as High Electric Demand Day (HEDD) units that typically operate on the days of peak demand. Peak demands tend to occur on very hot days when ozone and PM_{2.5} air quality are at their worst. The HEDD units generally are the highest polluting and least efficient units in the system; however, these units supply needed capacity, energy and ancillary services for peak load hours. In addition to the cost for CO₂ and NO_x allowances described above, these and other units have been targeted by the Department of Environmental Conservation (DEC) to achieve NO_x emission reductions. Given the cost of back-fitting emission control equipment on these old units, the requirements to reduce NO_x emissions could lead to their retirements. If too many of the HEDD units are forced into retirement, it may lead to insufficient generation available to meet peak load and system load following and regulation needs, leading to reduced reliability and higher costs for New Yorkers to replace the capacity and energy.

2.3.4 Interregional Issues

Until recently, the NYISO and its neighboring control areas have not effectively coordinated their internal studies or jointly studied cross-border conditions and effects. Therefore, the full potential of such joint efforts has not yet been realized. It is likely that there are economic opportunities available for cross border solutions to issues affecting each system, but studies to provide the information have not been forthcoming. Although studies are being pursued, there are no certain timeframes for results. Even assuming results are achieved, the system operators have not begun to develop methods for measuring and quantifying levels of congestion that will help determine cost effectiveness and cost sharing approaches.

2.3.5 Resource Adequacy

In general, resource adequacy involves decisions concerning what levels or types of resources are sufficient to maintain desired levels of reliability or to achieve public policy objectives. Historically, issues concerning resource adequacy have been determined and enforced by the states. For example, New York has established the desired level of installed reserve margin (IRM), i.e., the amount of generation resources above peak load that should be available to avoid or minimize the possibility of a blackout. The calculation of reserve margin is based, as previously noted, on the criterion that the electric system not experience an outage more than one day in ten years due to a shortage of energy. However, because the IRM is currently enforced through obligations on load serving entities to purchase installed

capacity either bilaterally, or through a monthly market that is administered by the NYISO and regulated by FERC, the states have limited ability to determine how the IRM is enforced.¹⁶ In fact, FERC has recently imposed mandatory minimum bid requirements upon new generation and demand response resources in New York City that could prevent, under certain circumstances, new resources from receiving installed capacity payments or from counting toward the IRM. This treatment could adversely impact the State's ability to achieve legitimate public policy infrastructure objectives, such as phasing out the use of older and dirtier resources, and moving to more efficient and environmentally cleaner resources.

2.4 System Efficiency

Improving and optimizing system efficiency will mitigate electricity costs for consumers, benefit the environment, and promote the security of the State's energy resources. Several important approaches to improve system efficiency are now underway. Some of the more significant efforts involve establishing and expanding demand response programs, reducing system losses, implementing new control technologies, e.g., Smart Grid technology, and applying new energy storage options. While improving system efficiency at all times will be beneficial, improvements that modify the levels of system peak loads in relation to loads at other times will be most useful. Undertaking effective programs and infrastructure changes that will achieve such efficiency improvements is an important policy objective for the State.

As noted elsewhere in this brief and also in the Electricity Resource Assessment, demand response resources (which are primarily and most effectively used to moderate or shave peak loads) reduce the need for new infrastructure, discipline market prices, help ensure reliability, and promote efficiency of the system. As such, the impacts of demand response efforts can be profound and can influence both the need for new infrastructure and the need to call upon high-polluting peaking units. Application of emerging energy storage techniques, discussed in more detail elsewhere in this Brief, will also serve the demands on the system during peak periods and thus improve system efficiency when it will be most beneficial.

Reduction of system losses, primarily through addressing reactive power issues as the PSC is currently considering, might be achieved by such measures as installation of additional capacitor banks at certain locations, adjustment of voltage limits, and similar other measures. Also, modern control technologies, through Smart Grid applications, can improve the efficiency of the entire system from the generators through the transmission and distribution systems down to the customer level. The Smart Grid, which is described in more detail in the Electricity Resource Assessment provides specifically for information flow and actions that help to reduce demand and maximize the efficient use and distribution of electricity, which in turn can reduce costs and environmental impacts.

Energy storage is emerging as an important tool for improving system efficiency. Historically, electricity markets have been unique among major commodity markets in that they generally require instantaneous matching of supply and demand. Other energy commodities can be stored in large quantities providing a buffer between supply and demand. Without an effective means of storage, the electric grid has traditionally maintained excess capacity in generation and transmission. Although it is difficult to store

¹⁶ Installed capacity (ICAP) is a commitment of a resource (generation or demand-response) to bid energy into the Day-Ahead Energy market administered by the NYISO for which they receive payment. Resources are compensated through the energy market for any energy they may ultimately produce if selected to run by the NYISO.

electricity directly,¹⁷ electric energy can be stored in other forms, such as chemical and mechanical energy, and efficiently converted back to electricity as needed. Bulk electricity storage capable of providing hundreds of megawatts of power for several hours, and distributed energy storage capable of injecting and absorbing up to several megawatts for seconds or minutes, both provide economic benefits and can improve the stability and reliability of the grid, especially if applied during peak load periods. Emerging energy storage technologies include compressed air energy systems, batteries (including those used for plug-in electric vehicles), capacitors, and flywheels.

2.5 Electricity Infrastructure Planning Initiatives

Before 1999, each vertically integrated utility was responsible for planning its own system to meet its customers' requirements. The New York Power Pool was a forum where the utilities could screen their system plans with the other utilities to ensure that projects they were pursuing did not negatively impact the operations of the others. The Pool also provided the platform for discussion of mutually beneficial system upgrades. Through the Pool and the Northeast Power Coordinating Council (the regional reliability entity encompassing New York State, New England and the eastern half of Canada) studies were performed with neighboring entities to study regional intertie and other issues. While planning has always been an uncertain and difficult proposition, the utilities knew where major generation was to be built and could develop transmission plans to accommodate new generation and load growth. While planning was not optimized at the State level, this system was long established and produced a reliable electric system with few major disruptions.

With the restructuring of the electricity industry, many new stakeholders, each with their own market or policy interests, became involved in electric system planning. Many stakeholders are legitimately concerned about the protection of proprietary business information. Central planning by the utilities for their previous vertically-integrated systems was changed to focus on the needs of their local transmission systems and to consider interconnection studies. The discussion below identifies the entities, forums and infrastructure planning initiatives that now exist in New York, along with the issues being considered in these forums.

The establishment of the NYISO and competitive wholesale electricity markets changed planning for the utilities, the PSC. Prior to 1999, the utilities had an incentive (a rate of return on rate base) to bring both reliability and economic infrastructure projects to the PSC for approval. Given the utilities' command of future generation and transmission expansion plans, the utilities were in a position to justify future needed upgrades. With the development of competitive markets, however, utilities no longer planned for the siting and construction of generating facilities. Also, without an endorsement of need from the NYISO (which processes, as previously noted, by themselves may not adequately encourage new transmission projects), the utilities have not been proposing significant new transmission projects. The PSC must therefore encourage the development of economic infrastructure projects that would resolve congestion and support public policy goals.

In 2007, the PSC established a Renewable Portfolio Standard (RPS) to encourage the development of renewable generation and in 2008 released its Energy Efficiency Portfolio Standards (EEPS) Order to initiate planning and implementation activities to meet the State's electricity efficiency goal of reducing electricity use by 15 percent by 2015. In 2009, the PSC initiated a proceeding (Case 09-E-0115) to develop new or expanded demand response initiatives in New York City where demand response efforts would be expected to be

¹⁷ The exception is pumped storage hydroelectric generation facilities.

the most cost-effective.¹⁸ Also, DPS staff were instrumental in encouraging the NYISO to perform an updated wind study, described below, to determine system constraints and identify where system reinforcements will be required. In addition, the PSC ordered NYSEG and RG&E to perform bottled generation studies for their systems.¹⁹ Further, DPS staff participates in the nomination of scenarios studied in the NYISO's Congestion Assessment and Resource Integration Study (CARIS), also described below, and can request specific studies of the NYISO that it finds necessary.

2.5.1 NYISO

The NYISO has two planning processes in place: the Comprehensive Reliability Planning Process (CRPP) and the CARIS process. The NYISO will also undertake other studies as it considers appropriate; one significant study now underway is its Wind Integration Study. These three studies are described below.

Comprehensive Reliability Planning Process (CRPP)

The most current Comprehensive Reliability Plan (CRP) resulting from the CRPP was issued on May 19, 2009 and covered a 10-year planning horizon, 2009-2018. This plan will be the starting point for the new CARIS economic planning process. Until 2009, the CRPP had been an annual stand alone process, but it will now be part of a two year process with a CRPP issued in month 18 and the CARIS in approximately month 24. If the CRPP identifies infrastructure changes or additions needed for reliability purposes, the NYISO can direct utilities to pursue those changes or additions to the extent that market forces do not otherwise address the issue.

The CRPP, now with its fourth cycle completed, is functioning relatively smoothly. It encompasses a statewide approach designed to optimize planning at that level and provide a level playing field to evaluate all source solutions – generation, transmission and demand response based programs.

Congestion Assessment and Resource Integration Study (CARIS)

The CARIS is a new process for economic planning being initiated for the first time during 2009. The process calls for soliciting study suggestions from stakeholders and then combining and selecting at least three scenarios to study in two year planning cycles, with the output for each cycle to be the CARIS.²⁰ The initiative is to identify past and projected congestion levels in the study areas and suggest possible solutions to resolve the congestion. A high-level benefit and cost analysis is also to be included. Merchant developers, utilities and other stakeholders (including the PSC) bear the responsibility to determine if the studies should lead to system reinforcements and to propose specific projects.

¹⁸ PSC. *Case 09-E-0115: Proceeding on Motion of the Commission to Consider Demand Response Initiatives*. Issued February 17, 2009. <http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={1CE8543B-6AF8-4399-A45F-1783D707BE6C}>. The PSC also has a proceeding to identify transmission and distribution losses and to determine cost effective approaches to reducing them PSC. *Case 08-E-0751: Proceeding on Motion of the Commission to Identify the Sources of Electric System Losses and the Means of Reducing Them*. Issued July 17, 2008. As an outcome of the proceeding, the PSC recently ordered implementation of reactive power tariffs across all major utilities, with rates based on the cost of capacitor installations and with the same effective power factor threshold. Specific projects are under development. <http://documents.dps.state.ny.us/public/Common/ViewDoc.aspx?DocRefId={3B6709AF-7B38-4F67-8688-F21A73D05B93}>

¹⁹ These studies identify potential generation bottlenecks and costs of transmission upgrades needed, and they will be updated every three years.

²⁰ The details of the Congestion Assessment and Resource Integration Study process can be found in NYISO. *FERC Open Access Transmission Tariff Attachment Y*. 2007.

Developers of infrastructure projects that desire cost recovery through the NYISO will have to submit the project for NYISO analysis and subject to a vote by the identified beneficiaries of the project. Unlike the CRPP discussed above, which is designed to ensure system reliability, the CARIS, designed for economic considerations, provides only for the voluntary nomination of projects and voluntary agreement to implement and pay for those projects by stakeholders who will benefit.

Wind Integration Study

In addition to its planning processes, as noted above, the NYISO is currently conducting a Wind Integration Study to address the statewide effects of additional wind generation interconnected to the grid. The study is considering various penetration levels of wind (2,500 MW, 4,250 MW, 6,000 MW, and 8,000 MW) added to the system over a 10-year period. The analysis is considering impacts on power system operations, system planning and the need for transmission, and energy production in terms of fuel mix, prices, reserves, regulation, and load following costs. A draft of this study is expected in 2010.

2.5.2 New York City

In May 2008, the New York City Economic Development Corporation retained a consultant to develop a plan for economic transmission projects to serve the New York City area. The final report, issued in May 2009, contains analyses that considered the economic costs and benefits, as well as the technical pros and cons, of various major transmission projects, including inter-zonal projects, in-City projects, and various approaches to expanding New York City's connection to PJM Interconnection (PJM). The results of the study are summarized in the "Need for Additional Electricity System Infrastructure" section.²¹

2.5.3 Transmission Owners

The State's transmission owners, including LIPA and NYPA, in addition to doing their own internal planning studies, are sponsoring a joint Statewide Transmission and Reliability Study (STARS). Early results of STARS are expected by the end of the fourth quarter of 2009. This project is designed to reestablish the long-term forward-looking transmission planning that has not taken place since pre-1999. The utilities are looking at the likely system needs 11 to 20 years out. The study will springboard from the NYISO's CRPP base case for 2018. It will model possible future system developments for generation and load, and determine what new transmission could be built to best accommodate those developments. As part of this effort, the utilities will evaluate the current age and condition of the bulk system infrastructure and factor in required replacements to their future planning efforts. The study has the potential to provide a future vision of how the system should develop to accommodate public policies to develop increased renewable resources and reduce the State's carbon footprint.

2.6 Electricity Infrastructure Planning Issues

While some of the sections so far in this Issue Brief have identified issues that can impact planning of the State's infrastructure, this section identifies several key planning issues that will be informed and addressed specifically by modeling studies and proceedings before the PSC. Issues associated with the siting of facilities are addressed in the Siting New Energy Infrastructure Issue Brief.

²¹ New York City Economic Development Corporation. *Master Electric Transmission Plan for New York City*. 2009. <http://www.nycedc.com/NewsPublications/Studies/MasterElectricTransmissionPlanforNYC/Documents/MasterElectricTransmissionPlanforNYC.pdf>

2.6.1 National Interest Electric Transmission Corridor

The Energy Policy Act of 2005 provided a role for federal backstop siting and cost recovery authority for new transmission lines that are proposed to resolve congestion. The Department of Energy (DOE) was given the authority and responsibility to designate corridors for transmission facilities appropriate to satisfy the national interest for such facilities. As a result of the first study to designate such a corridor, released in October 2007, 46 counties in New York, covering transmission interties with all neighboring systems, were included in what is referred to as the Mid-Atlantic Area National Corridor. A potential exists that federally-approved projects not selected through a New York planning initiative could be constructed under federal authority.

2.6.2 Energy Efficiency and Demand Response

In June 2008, the PSC released its EEPS Order to initiate the reduction of New York's electricity consumption by 15 percent by 2015. As an outgrowth of that decision, the PSC initiated a proceeding to consider approaches for demand response efforts in the New York City area where such activities might be the most effective. Both of these efforts can have significant impact on the need for additional infrastructure if implemented effectively.

Sound and effective program evaluation processes, focusing on measurement and verification, are critical to assessing the level of success achieved by energy efficiency and demand response program efforts. The New York State Energy Research and Development Authority (NYSERDA) has been a national leader in development of the program evaluation processes needed to support the State's System Benefits Charge programs over the past decade. NYSERDA will continue to expand its expertise in program evaluation to meet the challenges presented by EEPS.

2.6.3 Planning Studies

As mentioned in previous sections, multiple planning studies are being performed by or for the various industry stakeholders, including the NYISO, New York City, the utilities, the PSC and the State agencies participating in development of this Energy Plan. The NYISO, through a multi-stakeholder process, performs a 10 year reliability needs assessment (RNA) and develops a comprehensive reliability plan (CRP). As part of the CRPP, in 2009, it performed its first economic-based analysis of the impacts of various projects on the grid through the CARIS. Further, it also performs basic interconnection studies, is engaged in a wind energy study, and is performing a study to determine how losses can be reduced on the bulk electric system through lower system compensation.²² The utilities are moving ahead with their own long-term planning study, and NYSEG and RG&E are performing a bottled generation²³ study for their service territories. Several regional planning studies involving entities New York and other states are also underway. With regard to governmental studies, New York City is pursuing its own transmission plan, which will impact Con Edison's planning, and the PSC has instituted a proceeding to analyze the potential benefits of demand response activities including mitigation of emissions. Studies have also been performed for this State Energy Plan to examine possible policy initiatives.

The results of the on-going studies will provide valuable information regarding the current state of the bulk electric system and the infrastructure needs to support the State's policy goals. The PSC, NYPA and

²² Compensation is the addition of facilities to the electrical system to either produce or absorb reactive power.

²³ Bottled generation refers to generation that is located in areas without sufficient transmission to deliver the electricity output to load.

LIPA are well positioned to review the results, consider the views of various stakeholders, and determine how best to move forward to address the State's reliability, economic, and public policy goals. Verifying the results of the PSC's EEPS program with data will have a material impact on future infrastructures needs. And, unlike the NYISO under its current mandate, the PSC can account for public policy objectives in its planning and decision making processes.

2.6.4 Regional Planning (Inter-ISO/RTO)²⁴

The level of regional planning activities has been low for the past several years as the NYISO and neighboring control areas focused on establishment of market protocols and re-establishment of internal planning approaches. In December 2004, the NYISO, ISO-NE and PJM signed the Northeastern ISO/RTO Planning Coordination Protocol, which provides a platform to perform both coordinated and joint studies. Quebec, Ontario and New Brunswick utilities – while not signatories to the agreement – participated in the drafting and participate in the studies. Since the signing of the protocol, the parties have significantly increased the coordination and quality of inputs into each others' internal studies, jointly studied operational aberrations on the system, e.g., inter-area oscillations, evaluated cross-border resource adequacy, developed methodologies for consideration of environmental issues in the planning initiatives, evaluated levels of fuel diversity and performed some preliminary resource adequacy studies.

The full potential of the protocol, however, has not yet been realized. To date, studies have generally focused on reliability issues that cross seams between the ISO/RTOs.^{25, 26} Before new tie lines can be considered to more closely integrate the markets, studies need to be performed to identify benefits that could be derived from potential upgrades. This effort will assist the governments in New York and the New England and PJM states in determining if the region's ratepayers will be appropriately served by expanding transmission facilities across State borders.

The NYISO and its neighbors have taken initial steps to identify opportunities for economic transmission upgrades to relieve congestion on the system as required by FERC Order 890 and pursuant to the Protocol, and to develop and incorporate these opportunities through the established planning cycles. New York is starting to see the fruits of these efforts with the first study performed in 2009. It appears appropriate now to explore economic opportunities and market efficiencies that could be realized with our neighbors. Since the Quebec-New England high voltage direct current intertie was put into service, its full operation has been limited by constraints in both the New York and PJM systems. Quebec is expanding its resources to meet its own needs, but given seasonal diversity (Quebec's electrical needs peak in the winter months, while New York State's system peaks in the summer), there are likely economic opportunities to import excess energy when New York State needs it the most. Conversely, with New York's expanding investment in wind resources, excess wind energy could be sold to Quebec to provide expanded opportunities for pump storage and pondage of its hydro resources.

²⁴ Independent System Operators (ISOs) are entities that operate various electric control areas. They are responsible for guaranteeing open access, scheduling, system reliability and accounting. Regional Transmission Organizations (RTOs) are entities found by FERC to possess the characteristics and to be capable of fulfilling the functions required by FERC's Order No. 2000 and subsequent implementing regulations and orders. RTOs initially fulfilled the role of ISOs plus they also coordinate transmission planning, expansion and use on a regional and interregional basis; since FERC Order 890, however, the distinction between ISOs and RTOs has been diminished.

²⁵ The ISO/RTOs have all participated in the Joint Coordinated System Plan effort centered out of the Midwest ISO to examine the feasibility of a transmission overlay for the entire Eastern Interconnection to move the energy from yet to be developed wind resource in the Midwest to the east coast. This project, however, is visionary and ignores planning needs in the local areas.

²⁶ Consideration, however, has been given in this Plan to increasing the transmission capacity between Hydro Quebec and New York State. The impacts of such a connection are discussed in the Electricity Assessment: Modeling.

Portions of northern Vermont have long been supplied from New York, and with growth in Vermont load, the question of whether the increase can be more economically provided by upgrading the Vermont or New York system needs to be evaluated. Recent negotiations over the firmness of Con Edison's long-standing transfer of 1,000 MW of power through northern New Jersey have shown how dependent and fully used the two systems are. Interties with the State's neighboring systems are heavily used for the transfer of economic energy and emergency assistance. It is likely that there are economic opportunities available for cross border solutions, but studies to provide the information have not been forthcoming.

Each ISO/RTO has a full plate of internal studies that must be performed and those have been the focus of their planning efforts. As such, while study scopes have been developed to perform some level of cross-border studies and work progresses on those studies, there are no committed timeframes to produce results. Even if the studies eventually produce solid information on constraints and possible projects that could resolve congestion, the entities have not agreed to methodologies to measure and quantify the levels of congestion, which is required to judge the cost effectiveness of an economic system upgrade, nor have the entities embarked on negotiating a methodology to share costs of mutually beneficial projects.

It is understandable for an organization to pursue and satisfy its internal interests first, which has been the three ISO/RTOs' major focus. It appears reasonable, however, for New York to join with, at a minimum, the New England states, and possibly some of the PJM states, to identify common interests and direct entities to provide studies and congestion information that will aid in policy decisions for the future interconnections of the bulk electric system.

2.7 Need for Additional Electricity System Infrastructure

The Electricity Assessment contains a substantial discussion of the need to replace and update aging electricity infrastructure. The discussion here builds on that discussion and identifies major current developments relating to the need for additional new energy infrastructure.²⁷ It should be noted that while the State's preference is for new energy infrastructure to be built by merchant providers reacting to market forces, backup processes are in place to encourage the State's investor-owned and governmental utilities to provide infrastructure should reliability issues arise. The State's public policy goals and decisions will help shape how and when investments are made by utilities and market entities.

2.7.1 Aging Transmission and Distribution Facilities

Portions of the State's transmission and distribution system are in need of attention to ensure reliability in the future.²⁸ Consequently, the major investor-owned utilities have been required to inspect and report on the physical elements of their systems, and they have increased their plans for capital expenditures for the system. The investor-owned utilities propose to spend over \$13 billion over the five-year period between 2009 and 2013, an increase of about \$4.5 billion compared to the prior five-year period. It should be emphasized that while the utilities and the PSC can, and do, critically review capital investment programs to ensure that expenditures are made appropriately and may defer spending on projects as circumstances change, significant outlays are required to maintain and improve where possible the existing electric system. The reference case modeling in this Plan assumes that these facilities remain available, and

²⁷ The discussion of potential enhancements of the electricity system assumes that the natural gas and petroleum systems are maintained and adequate as well. Later sections of this Brief address the adequacy of the natural gas and petroleum systems.

²⁸ See the Electricity Assessment: Resources and Markets for further details about the aging transmission infrastructure.

future estimates of the rate impacts on customers of various initiatives must acknowledge these underlying electricity rate drivers.

2.7.2 Aging Generators

Just as the State’s transmission facilities are aging, so are many of its generation facilities. Table 1 identifies the range of ages of the major generation facilities in New York State.

Table 1. New York State Installed Generation Capacity Age Ranges

New York State Installed Generation Capacity Age Ranges (Generation 10 MW or Greater)		
Age Range	% of Total Installed Capacity (44,369 MW)	MW
More than 10 years old	84%	37,275
More than 20 years old	71%	31,368
More than 30 years old	63%	27,844
More than 40 years old	32%	14,250
More than 50 years old	12%	5,308
More than 60 years old	0.7%	320
More than 70 years old	0.3%	155
More than 80 years old	0.1%	60
More than 90 years old	0.02%	10
More than 100 years old	0%	0

Source: NYISO 2009 Gold Book, Name Plate Ratings

The NYISO, in its 2009 RNA analysis, considered the impact of retirements beyond what was assumed for the study. Rather than targeting specific units, however, the NYISO performed a “Zones at Risk” scenario.²⁹ In this study, the NYISO analyzed the Genesee (zone B), Hudson Valley (zone G), Millwood (zone H), and New York City (zone J) areas of the State. In the base case of the study, generation in each of these zones was decreased by 250 MW blocks until the loss of load expectation (LOLE) criterion of 0.10 days per year was violated. The results for study year 2018 are indicated in Table 2.

²⁹ As previously noted, the New York Control Area is divided for operational purposes into 11 areas or zones. They are identified geographically, generally from west to east across the State, with letters A through K.

Table 2. 2018 Loss of Load Expectations (LOLE) Due to Capacity Decreases

2018 Loss of Load Expectations Due to Capacity Decreases		
Zone	Capacity Decrease	Resulting Loss of Load Expectation
B	500 MW	0.13
G	750 MW	0.10
H	750 MW	0.10
J	500 MW	0.08
J	750 MW	0.15

Note that these amounts are not additive. The reduction of 500 MW in zone B (Genesee) alone by 2018 would place the entire State bulk electric system in violation of the resource adequacy reliability standard. Should events take place that force the retirement or shutdown of these levels of capacity, the State will need new capacity resources quickly to replace them.

The loss of existing generation could also have additional impacts on the system beyond pure resource adequacy. Today, these facilities provide fuel diversity, dual-fuel capability, load following, and voltage support in the system. Replacement with less flexible machines may require system upgrades to operate the system reliably, especially with regard to load following if there is a substantial build-out of intermittent wind capacity. These observations apply to the indicated capacity decreases regardless of the specific resource that goes off-line.

2.7.3 Nuclear Power

Potential Closure of Indian Point

The State has opposed the relicensing of Indian Point Units 2 and 3 due to specific concerns associated with that plant such as the adequacy of the evacuation plan in the event of a sudden, fast moving radiological event in an area of high population density; the risk of a terrorist attack on the spent fuel pools, which are located on site outside the containment structure; the impact of earthquakes on the integrity of the facility, the possibility of which are better analyzed with more modern geological methods than existed when the plants were first licensed; and the impact on aquatic life from the use of 2.5 billion gallons of Hudson River water each day, which is used to cool the facility and then discharged back into the Hudson River at higher temperatures.

The current relicensing proceeding could have a range of potential outcomes along with a range of potential consequences and challenges. The complete shutdown of the Indian Point units without adequate replacement infrastructure would have material adverse effects on the electric system, thus it is critical to begin considering what infrastructure would be required in the event that Indian Point is not relicensed. The NYISO's 2009 Reliability Needs Analysis contains a scenario that illustrates the impact on reliability if Indian Point Unit 2 and Unit 3 were to be shutdown in 2012 without any offsetting replacements. The LOLE in 2012 would immediately jump to 0.15 from below the 0.10 criterion, but then it would rise to 4.11 by 2018. A loss of load expectation of 4.11 represents the probability of 41 outages in a 10-year period. Beyond reliability considerations, the loss of the Indian Point units would

result in the loss of 2,065 MW summer rating of baseload capacity and its energy. The plant also provides 900 MVAR of reactive power capability needed to support lower Hudson Valley voltages, which in turn enable transfers into New York City and Long Island that could not otherwise occur.

As was assumed in the modeling discussed below, one possible replacement would be combined cycle gas-fired generating units interconnected at the Buchanan 345 kV substation, where Indian Point currently connects to the bulk power system. Similar generation located in New York City, with appropriate and possibly major modifications and upgrades to the transmission system, could also be effective in limiting increases in energy costs and restoring reliability. Generating units located across the river from Indian Point, without major transmission construction, including new river crossings, would not effectively counteract energy price increases or ensure reliability. New generation in upstate New York, without multiple new transmission circuits from upstate into Westchester and/or New York City, would not be a solution for mitigating energy costs in southeastern New York State. Neither new generation in New York City, nor new transmission into the lower Hudson Valley and New York City, has the ability to provide voltage control in the Westchester area. No other existing voltage control devices can adequately perform this function and therefore provide for a reliable system if Indian Point is closed.

In preparation for this Plan, a scenario was modeled for an assumption that the Indian Point nuclear facility will cease operations in 2015. To replace the 2,065 MW summer rating of lost capacity, from 700 to 1,800 MW of additional gas combined cycle capacity would be built. Generation output from nuclear facilities in 2018 would thus decline by 37 percent, while the output from combined cycle and combustion turbine natural gas units would be expected to increase by as much as 38 percent (which allows other fossil-fueled generation output to be reduced as well). Overall, natural gas usage could increase by as much as 25 percent. Net imports would also likely increase, between 14 and 50 percent, depending on the extent of achievement of the State's '15 by 15' energy efficiency program. CO₂ emissions would increase by as much as nine percent (3.6 million tons); CO₂ allowance prices would increase between 52 and 100 percent (also depending on the extent of the '15 by 15' program); and, similarly, average statewide wholesale electricity prices would increase by between five and eight percent (\$3.64 and \$5.46 per MWh). Construction of the new gas capacity that would be needed in the vicinity of Indian Point would also require a yet to be determined expansion of the gas system (to be reviewed in this Plan's gas modeling scenarios) in order to accommodate such loads, and it may also require new electric transmission facilities as well.

New Nuclear Plant in Oswego County

UniStar Nuclear Energy, a joint venture of Constellation Energy and EDF Development Inc. has proposed the construction of a new, technologically advanced 1,600 MW nuclear plant at the existing Nine Mile Point Nuclear Station site in Oswego County. Preliminary interconnection studies are being performed to provide a screening level indication of the impacts the project would have on the bulk electric system and what level of system upgrades would be required to integrate the plant into the New York State system. Because the plant location is west of the Central-East transmission constraint, injection of additional power in this area of the system will likely further exacerbate transmission congestion in the northern area of the State. Thus, it is anticipated that major transmission reinforcements would likely be required. The utilities' statewide study is simulating a scenario where future energy needs are met by generation west of the Central-East constraint and will, therefore, also provide information on transmission needs in this area of the system.

As with the Indian Point facility discussed earlier, modeling was also undertaken for this Plan to assess the impact of the addition of a 1,600 MW nuclear unit in Oswego in 2018. The results indicate that the output from nuclear generation in the State would understandably increase (by 30 percent 13,525 GWh). The output of natural gas, oil/gas, and coal units would consequently decrease (from as little as one

percent in the case of oil/gas units to as much as 10 percent in the case of natural gas fueled combined cycle and combustion turbine units). The output of natural gas fueled combined cycle and combustion turbine units would either decrease by eight to 10 percent, depending on whether or not the State's '15 by 15' efficiency program goals are achieved. Consequently, CO₂ emissions would decrease by from four to five percent, CO₂ allowance prices would decrease by 16 to 23 percent, and average statewide wholesale electricity prices would decrease by three to six percent. The 30 percent increase in nuclear output along with the potential change in output from combined cycle natural gas generation, would also significantly impact net imports: they would decrease by 43 to 78 percent, providing a better trade balance and allowing more future imports to occur.

2.7.4 Electricity Transmission Facility Expansion Considerations

Considerations of reliability, economics and public policy suggest that transmission expansion and replacement or upgrade of aging facilities should be evaluated for both the near term and long term. Statewide annual gross congestion costs (reflected as bid production costs) have risen from \$86 million in 2003 to \$243 million in 2008. As the State pursues low-carbon, low-emissions producing resources, transmission assets will likely need to be expanded to exploit fully New York's natural wind resources and hydro development in neighboring areas, including Quebec. However, the State currently lacks the information to determine what, if any, upgrades would be in the ratepayer and State's interest. For example, knowing the annual cost of congestion serves little purpose until it can be compared to the cost of a system upgrade to resolve the congestion. It is anticipated, however, that the NYISO's CARIS and wind integration study along with the utilities' statewide transmission and reliability study will produce information defining the problems, quantifying the congestion costs, and suggesting possible solutions. As these studies develop, the State will need to refine its infrastructure planning decisions. Further, successful implementation of the State's '15 by 15' program may impact future decisions on new infrastructure needs to accommodate the changing nature of New York's electric system topography.

Modeling for three separate transmission expansion scenarios that might be in-service in 2015 was performed for this Plan. One scenario examined the impacts of increasing transmission capability between Hydro-Quebec and upstate New York by 1,000 MW. Another scenario assumed the addition of 1,200 MW of new transmission capability from upstate New York directly to New York City. The third scenario combined the previous two scenarios. The 1,000 MW Hydro-Quebec to upstate New York scenario modeling results indicate that construction of a transmission facility to enable the 1,000 MW transfer would provide only small benefits, if any, for New York with regard to the variables studied. The tie would allow more electricity to flow into New York from Quebec in the summer, but in the winter an even larger amount of electricity would flow from New York to Quebec. The other two scenarios analyzed provide results for the variables studied that indicate there could be some economic and environmental benefits from such projects.

Economic analyses of possible future transmission development will be dependent on a number of factors, including precise locations, distances, sizing, engineering design, and integration with existing infrastructure and equipment. The net costs and/or benefits to ratepayers of actual projects could be highly dependent on negotiated long-term contractual agreements among specific parties, other generation, transmission, and natural gas infrastructure that is built or retired (both in New York and in neighboring regions), and significant additions to energy supply (such as potential large-scale hydro projects in Canada). Additions to the State's transmission system, while perhaps not called for to meet reliability needs, may be prompted by the clean energy policy objectives outlined in the State Energy Plan.

Needs of New York City

As load grows in New York City, either new generation needs to be built in the City, or new transmission needs to be constructed. The New York City Economic Development Corporation commissioned a Master Transmission Plan for New York City to determine whether new transmission facilities into the area would: decrease the cost of electric service to New York City ratepayers and reduce the costs of electricity production statewide; improve the reliability of bulk power supply to New York City; reduce the City's electricity carbon footprint; and, ensure a fair, competitive market for electricity generation and transmission in the City. The study identified and evaluated the costs and benefits of various proposed and conceptual generation and transmission options that have the potential to meet New York City's energy needs. Overall, the projects evaluated did not show significant net benefits either by production cost or consumer benefit standards. The analysis found that new capacity will be required in New York City in 2019 to meet reliability requirements, and that a gas turbine combined-cycle would be the economically optimal solution to meet the need. In addition, in-city generation would serve other public policy objectives, such as providing economic development benefits in the form of construction jobs and tax revenues, and reducing emissions, particularly if combined with repowering of an older higher pollution emitting generator. The addition of transmission facilities upstate, e.g. from Leeds to Pleasant Valley, would provide consumer benefits in New York City, but would potentially raise prices upstate. Other in-city options, which include a controllable cable between New Jersey and New York City and offshore wind generation, also showed projected New York City consumer benefits and additional analysis will be conducted. A key finding of the study was that the fact that there is not an immediate reliability need for additional capacity. Therefore, decision makers have adequate time to decide which projects to move forward with. The study recommended, however, that New York City seek ways to encourage clean, efficient in-city generation, pursue policies that reduce energy consumption, and pursue joint planning studies within New York and neighboring regions.

2.7.5 Increasing Renewable Development, Deliverability Issues and System Impacts

New York is committed to increasing renewable generation resources. Although there are multiple renewable technologies being supported by State programs, wind resources are the fastest growing of those under development. Wind generation facilities can present certain issues for the electrical system and impacts on the infrastructure that must be addressed. Due to the limited predictability of wind power when compared with conventional power plants, adequate reserve and balancing power must be available, and the transmission system must be adequate to deliver all necessary resources to load.

In an effort to examine concerns regarding the integration of wind resources, a March 2005 study conducted on behalf of NYSERDA found that 3,300 MW of new wind resources could be incorporated into the existing grid with some adjustments to operations but without requiring upgrades to the bulk electric transmission system. The NYISO is in the process of performing a follow-up study on wind integration that will revisit the issues of the 2005 study, but it uses as a starting point the actual location and performance characteristics of the wind turbines that have been built to-date. The new NYISO study will estimate the potential impacts of levels of wind resources that significantly exceed the 3,300 MW evaluated in the original study. The study will identify the level and location of constraints on the bulk system that could result from various levels of wind development based on projects currently in the NYISO's interconnection queue.

STARS, a statewide long-term (2018-2028) utility-sponsored study, will determine specific transmission upgrades that would support distribution of additional renewable energy throughout the State. NYSEG, RG&E and National Grid are analyzing their local transmission systems for the possibility of future congestion from the development of additional renewable generation. In addition, the PSC now requires

an energy deliverability study for each individual renewable project designed to identify the amount of energy that can actually be delivered from the plant without impacting the output of other renewable resources. The results of these studies will provide information and inputs to developers and policymakers on the most beneficial sites to develop additional renewable resources and where transmission system upgrades would be effective.

In another analysis, the NYISO, using the base case developed for its 2009 RNA, modeled a scenario that decreased generation in the lower Hudson Valley and New York City by 1,500 MW and increased upstate generation by the same amount to simulate increased wind and/or hydro resources. Without any transmission upgrades, this change would result in a 2018 base case LOLE of 0.25 (loss of load for two and a half days in a 10-year period on average). If transmission capacity is increased into the lower Hudson Valley by about 800 MW, the expectation is reduced to the criteria of 0.10, i.e., improved to one day in 10 years, which is the minimum criterion for achieving a reliable system. This analysis provides further insight into the understanding that transmission additions may be needed to achieve the full benefits of renewable generation, depending on where the generation is located.

The potential benefits of expanding the PSC is RPS from a goal of 25 percent of New York's energy use by 2013 to a goal of 30 percent by 2015 were evaluated by modeling for this Plan. The modeling projects no discernable changes in the State's generation mix, net imports, CO₂ emissions, CO₂ allowance prices, and wholesale electricity prices when it is also assumed that the 15 by 15 program is implemented fully to yield a significant reduction in the 2015 expected load to which the 30 percent would apply. Again, as noted above, transmission additions may be required, depending on where renewable generation is located.

2.7.6 Plug-In Hybrid Electric Vehicles

To address some of the pollution impacts of automobiles, hybrid (electricity and petroleum fuel) engine technologies have been introduced to the market, and their use is expanding. Although the hybrid vehicle engines in commercial use today primarily charge their batteries when the engine is running on petroleum fuels, other charging technologies are in development. One that could impact the electricity system and its infrastructure involves charging the vehicle batteries through a plug-in arrangement with the local electricity system. While use of grid electricity would impose an additional burden on the system, such use (charging) during off-peak periods would increase the capacity factors of some generators and improve the overall load factor (efficiency) of the system.

Modeling of plug-in hybrid electric vehicle penetration for the year 2018 (assuming one million units in operation by that date distributed throughout the State, with charging during off-peak periods) was performed for this Plan. The results indicate that the output and fuel use for all generation resources, other than nuclear and hydro facilities, increase slightly as would be expected. CO₂ emissions, emissions allowances, and wholesale electricity prices would also increase slightly. Overall, the impacts on the studied variables from penetration of plug-in hybrid vehicles appears relatively small, given the expected off-setting load reductions projected from achievement of the State's '15 by 15' energy efficiency program.

2.7.7 Federal Carbon Policy

Modeling was also performed for this Plan to consider the effects on electricity costs and emission impacts from enactment of a national cap and trade program for CO₂ effective beginning in 2015. The analysis assumes that all CO₂ emissions from the electricity sector (nationwide) would be offset by the purchase of emission allowances valued at \$23 per ton in 2015, increasing to \$36 per ton by 2024. It was

also assumed that expectations of future prices would begin to change behavior before the program is implemented. The analysis focuses on 2024, significantly beyond the 10-year planning period normally addressed in the State Energy Plan, because focus on 2018 would not provide sufficient time for the effects of a hypothetical policy implemented in 2015 to become substantially evident.

The modeling indicated that for the United States as a whole, CO₂ emissions would be reduced by 764 million tons, i.e., about 37 percent less for that year, in 2024 than would occur for that year without implementation of the federal policy. The federal carbon policy modeled has the effect of approximately stabilizing U.S. CO₂ emissions at the 2009 level, equivalent to establishing a carbon cap at current levels of emissions. The analysis also found that with the federal carbon policy the cumulative new coal capacity in 2024 would be 72 percent lower compared to a scenario without it. Cumulative new natural gas capacity, however, would likely be 14 percent higher than the amount without it. The modeling also suggested that about 40,000 MW of additional new nuclear capacity would be economic and would be built. Coal generation output would be reduced by 24 percent, while gas combined cycle and nuclear generation would be increased by 27 and 44 percent, respectively, compared to what would be expected to occur without the policy. The average U.S. wholesale price of electricity would be \$21.33 per MWh, or 31 percent higher, as a result of the carbon policy than it would be without the policy.

With respect to projected impacts on New York alone, the modeling results indicate that a federal policy would have substantially lower impacts on New York than on other portions of the nation, especially if the goals of the '15 by 15' program are fully achieved. The analysis projects that by 2024 New York cumulative plant capacity retirements would be between 178 MW and 600 MW greater than without the federal policy; repowering of oil/gas steam units would be about 236 MW greater; and new nuclear unit capacity totaling between 530 MW and 1,100 MW would be added. Coal, natural gas combined cycle, and oil/gas steam unit generation would decrease by between 3,167 GWh and 3,966 GWh, 3,374 GWh and 4,183, and 1,416 and 1,586 GWh, respectively, while nuclear generation would increase by between 4,481 GWh and 9,299 GWh. In 2024, New York's CO₂ emissions would be reduced by 7.0 to 7.2 million tons, while the wholesale price of electricity would increase between about \$16.40/MWh and \$20.30/MWh (20 to 26 percent higher) as compared to not implementing the federal policy. The lower numbers in the identified ranges for capacity retirements, new nuclear unit capacity, and generation output from coal, natural gas, oil/gas, and nuclear units resulted from the effects of the '15 by 15' program being fully implemented. In other words, the '15 by 15' program alone achieved most of the benefits. The higher numbers were associated with achieving only 27 percent of the '15 by 15' program, allowing the Federal Program to have a greater effect. Similarly, the beneficially higher range value for CO₂ emission reductions was also due to the impact of the State's '15 by 15' program assumption, while the lower value assumed that the '15 by 15' program would not be fulfilled.

If the State's '15 by 15' program is fully implemented as well as the federal carbon policy, the price differential between New York and the nationwide average will be reduced. The modeling indicates that in 2024, without full implementation of the '15 by 15' program, New York's average wholesale electricity price would be \$14.69 per MWh (21 percent) higher than the national average. With the federal carbon policy enacted, the differential would reduce to \$9.81 per MWh (11 percent) higher than the national average. Contrasting this is a finding that by 2015 the combined impacts of the '15 by 15' program and the federal carbon policy could result in New York's average electricity price actually becoming lower than the national average price. Because the load forecast used for the analysis did not presume authorizations for continued funding of current or new energy efficiency programs beyond 2015 when the '15 by 15' program goal is to be met, the analysis assumes that load growth could return to the pre-funding levels and energy costs could again rise above the national average after 2015. This potential argues for continuation and possible intensification of funding and programming for energy efficiency after 2015 to ensure that New York's electricity prices remain lower than the national average prices.

2.7.8 Reactive Power Issues³⁰

Reactive power issues are being addressed in a PSC proceeding (Case 08-E-0751). One avenue of inquiry is to determine what infrastructure changes, e.g., installation of capacitor banks, could efficiently minimize the reactive flows on the bulk transmission system and thereby free up capacity for use to transfer real power. The parties in the proceeding are also looking at operational measures e.g., adjustment of voltage limits and revisions to reactive power demand tariffs that could be taken to minimize reactive flows on the system. The utilities have submitted reports addressing losses and reactive power tariffs, and the NYISO conducted a study using the Optimum Power Flow (OPF) software to help determine capacitor additions that could be made to help reduce losses and increase power transfer capabilities. These filings are all under review. The cost of these programs and infrastructure changes is likely to be small relative to other potential generation or transmission infrastructure additions, but may yield significant efficiency improvements.

³⁰ Reactive power is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. It is often compared to the pressure in a water system; pressure is not a commodity that is used by the customers, but it is required to deliver water at the tap. Unlike pressure, reactive power requires capacity on the electric system that could be used to deliver real power to the loads. Therefore, while reactive power is necessary, its use is ideally minimized. When a transmission system is lightly loaded, such as overnight, the system itself produces reactive power that must be removed from the system to keep voltages from rising too high. During periods of heavy line loadings, such as in the middle of a summer day, the system absorbs reactive power, requiring the addition of reactive power to keep voltages from sagging below limits. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers, and supplies the reactive losses of transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors. It directly influences electric system voltage and is usually expressed in kilovars (kVAR) or megavars (MVAR).

3 *Natural Gas*

This section of this brief provides background information on the natural gas industry, forecast gas supply and demand modeling results, as well as a discussion of natural gas infrastructure issues.³¹

3.1 Status of Natural Gas Industry, Market, and Regulatory Institutions

New York has approximately 4.7 million natural gas customers served by 11 major local natural gas distribution companies. The local natural gas distribution companies provide a natural gas delivery service to their customers, with those services provided on either a firm or interruptible basis. Firm deliveries are generally provided to residential and small commercial and industrial customers that do not have alternative fuel burning capability. Interruptible gas delivery service, on the other hand, is not guaranteed. It is used primarily by large customers that have alternate fuel burning capability, such as electricity generators.

The local natural gas distribution companies depend on the interstate natural gas pipeline infrastructure for the transportation of gas supply to the distribution systems. The interstate pipelines connect to the natural gas production regions of the country transporting natural gas supplies to the market areas where it is consumed. Major pipelines serving New York extend back to the natural gas production regions in Texas, Louisiana, and Canada, as well as others that access the Appalachian production region. An essential part of the interstate natural gas system is storage fields that are filled during the non-heating summer months: natural gas is withdrawn from storage during the winter season to meet the higher heating demands.

Under the Natural Gas Act, FERC has regulatory authority over the interstate natural gas pipelines and is responsible for regulating pipeline rates and services, the construction of interstate natural gas pipeline facilities, and overseeing related environmental matters. FERC also has regulatory authority over interstate natural gas storage facilities, located both in the producing regions and market areas, and liquefied natural gas import facilities. While FERC approves the certification of interstate pipeline, storage, and liquefied natural gas import facilities, such approval is conditioned on the applicant obtaining needed local permits. Thus, states maintain an important role in the building of new infrastructure.

The PSC regulates the local natural gas distribution companies in the State. The PSC's regulatory authority provides oversight of the retail rates and services of the local natural gas distribution companies, and it is responsible for ensuring that New York customers have access to reliable, safe, and reasonably priced natural gas distribution service. The PSC intervenes in proceedings before FERC that involve the interstate pipelines' rates and services, and FERC rule makings that may impact New York's local natural gas distribution companies and their customers.

³¹ The Natural Gas Assessment addresses these matters in more detail.

The pipelines that reach back to the production region are not sized to bring all the natural gas that is needed to meet winter loads. Storage fields, filled through the summer, are tapped during the winter to meet the higher demands. Substantial amounts of storage that serve New York's markets are located in Pennsylvania. There are also storage facilities located along the southern tier of New York and elsewhere connected to pipelines that bring natural gas to New York City and upstate markets.

Pipeline capacity is built to meet the needs of firm contractual requirements. Local natural gas distribution companies hold firm contracts for pipeline capacity to ensure delivery of their supplies, even on the coldest winter days. The pipelines also offer interruptible services, which is available when all of the capacity is not being used by the firm contract holders.

The Natural Gas Assessment contains a detailed discussion of the New York and national natural gas markets.

3.2 Adequacy of Natural Gas Delivery System

As explained in the Natural Gas Assessment, to assess the adequacy of the natural gas pipeline delivery system serving New York, the combined gas requirements of the State's residential, commercial, industrial and electric generation customers were considered together and compared to currently available pipeline delivery capacity at peak periods.³² This approach was taken because of the concern that the substantial reliance of the electric generation sector on natural gas, coupled with the almost total dependence on interruptible delivery services for that gas supply, raises reliability concerns regarding the adequacy of the natural gas infrastructure to support electric generation requirements. Pipeline infrastructure is designed to meet the requirements of residential, commercial and industrial customers that purchase gas with contracted firm delivery rights. The modeling analysis sought to determine whether this reliance of the generation sector on interruptible services would result in curtailments of natural gas deliveries to electric generators that would create electric reliability problems.³³ The forecast model examined a base or reference case and four scenarios, each representing a different level of gas usage: retirement of the Indian Point nuclear power plant and replacing the plant with gas-fired generation; re-powering existing downstate oil-fired units with gas-fired facilities; much colder than normal weather conditions; and a combination of the other three scenarios.

The Reference Case forecast shows that New York demand will increase in the residential and commercial sectors and will remain essentially flat in the electric generation and industrial sectors throughout the planning period. The Reference Case peak day modeling analysis shows that the interstate pipelines serving New York, while not having a problem on average days during the winter, will remain at essentially full capacity on a peak day and that there would be a relatively small level of unmet demand.

The modeling scenario where the Indian Point Nuclear power plant is retired and replaced by a gas-fired power plant shows pipeline flows similar to the Reference Case with most pipelines very full on peak days. Total unmet gas demand in New York increases to approximately two times that in the Reference

³² Currently, available interstate pipeline capacity is operated at full capacity on peak days to serve the needs of the downstate market and portions of the upstate market.

³³ Additional factors that contribute to demand for natural gas for electric generation include: reduced use of oil for power generation during periods of elevated air pollution levels; the decreased use of oil and coal resulting from Federal carbon emission limitations; and a significant shift toward natural gas in end-use applications.

Case. For the modeling scenario that examined the re-powering of existing downstate power plants that burn heavy (#6) oil as an alternate fuel, the analysis shows a significant decrease in gas demand upstate, offset by a significant increase downstate. Total unmet gas demand is slightly lower than in the Indian Point retirement case. The much colder than normal scenario forecasts total unmet demand at levels less than the Indian Point retirement and repowering scenarios, but greater than the unmet demand reflected in the Reference Case. However, only about 10 percent of the unmet demand is projected to occur in the New York market area. The combination scenario indicates a higher unmet demand of about 900 millions of cubic feet per day (mmcf), of which about 375 mmcf occurs in the New York market area. About 330 mmcf or nearly 90 percent of the New York unmet demand is in the downstate region.

Additional MAPS modeling was conducted for the Reference Case, Indian Point Retirement Scenario, and the Repowering Scenario to assess the impact of this unmet demand to the electric system. Electric generators were made unavailable based on the unmet demand schedule from RIAMS and adjusted to account for uncertainties of the unmet demand allocation between New York and New England and among sectors within New England. The additional MAPS modeling indicates that some electric load would not be served due to insufficient gas delivery capacity. On an annual basis, this unserved electric load would be considered negligible, given the level of precision of the model and modeling assumptions. However, if this unmet demand all occurred on the same day, the impact to the electric system may be significant. Further analysis will continue to assess the magnitude and the impacts to the electric system from this unserved electric load due to insufficient natural gas delivery capability.

The results of the Reference Case and the four scenarios examined reinforce the need for adding additional pipeline capacity for overall reliability purposes (as well as reducing the cost of delivered gas supplies). While the analyses provide a New York and New England regional unmet demand estimate, they were not able to identify location and gas flows associated with specific electric generation demand on the natural gas system. Further analysis is needed to determine to what degree the reliance of electric generation on natural gas and use of interruptible services for the supply of that gas impacts the natural gas system's ability to continue to support electric generation requirements reliably.

3.3 Natural Gas Pipeline Infrastructure Development

Additional pipeline capacity will be needed to meet growing natural gas loads in the New York and northeast regions. The region has physical capacity constraints on its natural gas system, particularly into the New York downstate area (New York City and Long Island). As new pipeline capacity is built into the region, it will help relieve existing constraints by increasing deliverability, flexibility, and reliability of the natural gas system and will help to reduce the cost of gas into the region. Another very important benefit to be considered is that new interstate pipeline capacity could increase the diversity of gas supply to the region. For example, a new pipeline may provide access to new supply basins, such as the developing Marcellus shale. A new pipeline connection may also improve the diversity of pipeline capacity that serves the downstate region, a potentially critical security and reliability consideration.

The natural gas market has been responding to the firm capacity needs of its customers, and several new interstate pipeline projects have been completed in the northeast region in recent years.³⁴ The most important recent projects directly related to New York's firm demand requirements are the Millennium pipeline and associated pipeline projects that provide about 525 million cubic feet per day of new pipeline capacity to the New York market (of which 300 million cubic feet per day is deliverable directly to the

³⁴ Table 6, Recently Completed (2007 to 2009) Major Northeast Pipeline Expansions, of the Natural Gas Assessment provides a summary of the major gas pipeline projects completed in New York and the northeast from 2007 to 2009.

downstate New York City and Long Island markets).³⁵ Another project, put into service in 2007, that directly provides 100 million cubic feet per day of new pipeline capacity for the downstate New York City market was the Leidy to Long Island expansion on the Transcontinental Gas Pipeline Corporation pipeline system. Even with the addition of these projects, capacity into the downstate New York market is essentially full on peak demand days.

The level of pipeline construction in the northeast is likely to increase in the next few years to meet growth in firm customer requirements and as long-planned system expansions take place and flows from new supply areas and imports such as the Rockies Express Pipeline (REX) and LNG commence.³⁶ Pipelines are proposed to bring Rocky Mountain gas supplies to northeast markets, through interconnections with, and expansions of, the major pipelines serving New York area markets. These pipeline expansions will also provide access to supplies from the Marcellus Shale, providing a significant source of supply close to the market area. Also, two major pipelines are proposing new delivery points directly into the constrained downstate market area. Several of the planned projects are competing for the same market, and not all of the projects will be constructed and put into service. The projects that are ultimately certified and constructed will likely enhance the region's access to natural gas supplies to meet existing and future loads and will be critical to ensuring reliable, competitively-priced supplies to New York in the future.

The planned projects to bring new delivery capacity directly to the New York City market are of particular importance. During peak natural gas demand periods, pipeline capacity into the New York City market area is constrained. Both National Grid and Con Edison have identified a need to add delivery capacity into certain areas of their respective New York territories. In addition, the distribution system's ability to absorb additional interstate deliveries at a particular point must be considered in planning interstate capacity additions. Con Edison has identified a need to add delivery capacity in lower Manhattan as the optimal point. National Grid has identified a need to add delivery capacity in the Jamaica Bay (Rockaway Peninsula) area to service growing demand on its distribution system.

Transco has proposed a new delivery pipeline lateral from its offshore pipeline in the Lower New York City Bay area to an interconnection with National Grid facilities on the Rockaway Peninsula (FERC Pre-filing Docket PF09-8). Transco is also considering a new pipeline lateral from its pipeline in northern New Jersey to interconnect with Con Edison's facilities in lower Manhattan. Texas Eastern Transmission is considering a similar proposal by extending its system from its existing Goethals delivery point in Staten Island to a new delivery point with Con Edison in lower Manhattan. The two competing lower Manhattan proposals are preliminary and have not been filed with FERC. Only one of the lower Manhattan projects will be built, and before proceeding with final plans, either pipeline will need a commitment from Con Edison or other potential customers, e.g., Local Distribution Companies, LDCs, or electric generators, for a sufficient level of capacity to make the project economical. Con Edison is in the process of evaluating the merits of each proposal.

New delivery points at those New York City market locations would significantly relieve existing capacity constraints, increase the reliability of the gas system and reduce both the volatility of spot market gas prices in the downstate market and the delivered price of natural gas into that market. Additional

³⁵ The associated projects are the Empire Connector, Algonquin Ramapo Expansion, Iroquois' Market Access Expansion, and Iroquois' 08/09 Expansion. The Millennium, Empire Connector, Ramapo Expansion, Market Access, and Phase I of the 08/09 Expansion were put into service in 2008. Phase II of the 08/09 Expansion was put into service in early 2009 and Phase III should be in service by the fall of 2009.

³⁶ Table 7 of the Natural Gas Assessment provides a summary of some of the major planned gas pipeline projects for New York and the northeast region.

pipeline capacity into the downstate region would provide a direct benefit, not only to the natural gas ratepayers but also to electric ratepayers. Therefore, mechanisms for having all beneficiaries share the cost of these expensive pipeline capacity additions should be explored.

New liquefied natural gas (LNG) terminals and the pipeline expansions necessary to provide delivery of regasified LNG into the natural gas pipeline system are being developed in the New York and northeast market areas. Several LNG projects in New England have been completed or are near completion. Also, there are three projects in the early planning stages that would locate LNG terminals near large market areas off the coast of New Jersey and New York. A large volume of imported LNG entering the northeast market close to load centers would increase the competitiveness of the market, reduce price volatility, and could lower prices.

3.3.1 Other Potential Actions Affecting Natural Gas Infrastructure Needs

The New York City Department of Environmental Protection (NYCDEP) has circulated a draft proposal as part of its PlaNYC, which would prohibit the use of No.4 and No.6 fuel oil in the City. From an air quality perspective, equipment burning No.4 and No.6 fuels represents a significant portion of emissions in the City. The rule is not intended to be imposed on existing customers or equipment, but instead on new or replacement oil burning equipment. At present, it does not appear that the proposal applies to electric utilities, which have DEC Title 5 permits.

The NYCDEP estimates that approximately 85 million gallons of No.4 and 220 million gallons of No.6 fuel oil are used by the customers that would be subject to the rule. It is estimated that as many as 10,000 customers could be impacted by these rules. It anticipates a replacement/turnover rate of approximately three to five percent per year, as old equipment is replaced. At the time the boilers are replaced, the customer will essentially have three options: use No.2 oil; use natural gas primarily, as an interruptible customer with No.2 oil as the backup fuel; or become a firm gas customer. Each of those choices has pros and cons that a customer would have to consider. A customer choosing to remain on oil or be an interruptible customer with No.2 oil as backup, may not be able to use the existing tanks, so new oil tanks may be required. If new oil tanks are required, the customer may decide to forego the oil installation altogether and become a firm gas customer. Also, some locations on the utility gas system may not be able to accommodate firm service for these large volume customers, without substantial upgrade for which the customer would be responsible to pay. So, individual circumstances, and the resultant economics, will dictate whether customers go to No.2 oil, interruptible or firm gas service. NYCDEP has assumed that most customers will use interruptible gas service, and it has estimated this could impact the gas system throughput with increased usage of one quarter to one half percent per year. However, there are several areas of concern: whether the existing natural gas infrastructure can handle the change; and whether the petroleum distribution industry has the capacity to supply new interruptible gas service accounts having dual fuel requirements.

The gas system depends on the availability of interruptible dual fuel customers to manage gas supply and manage system peaks. The gas system was not designed to provide firm service to dual fuel customers, and further, some of the existing No.4 and No.6 fuel oil users do not currently use gas at all. There are concerns regarding the possible need to retrofit some portions of the existing local distribution system infrastructure if this rule becomes final, for instance, some streets in the City do not have existing gas lines. However, customers that typically use No.4 and No.6 fuel oil are large customers. In these circumstances, there may be a greater propensity for the local distribution companies to make the necessary system improvements.

NYCDEP anticipates that customers who continue with petroleum would switch to No.2 oil, from No.4 and No.6. Issues related to greater dependence on the refined petroleum products would be similar to the

questions raised on the gas system impacts of these additional loads, including what the impact would be on the petroleum providers and infrastructure. The petroleum industry is very likely to make the necessary infrastructure and transportation investments to supply those customers that switch to No.2 oil. However, it is unknown how much investment will be made by the petroleum industry to service the sporadic, limited oil demand of interruptible natural gas service dual fuel accounts.

3.3.2 Difficulty in Siting New Natural Gas Pipelines and Liquefied Natural Gas Facilities

The planning, regulatory approval process, and construction of new pipeline facilities is difficult and can take many years. For example, the Millennium pipeline project's application was first filed with FERC in December 1997. The project experienced significant delays due to major issues involving routing and environmental concerns. In December 2001 and September 2002, Millennium received FERC approval. However, the Department of State (DOS) determined that construction of the pipeline was inconsistent with the Coastal Zone Management Act due to the pipeline crossing the Hudson River in an environmentally sensitive area. Millennium filed an amended application with FERC that addressed the DOS' concerns in August 2005 and received final FERC approval in December 2006. Subsequently, authorization to begin construction was received in June 2007. The project commenced service in December 2008, over 11 years from when it was first filed. Such delays, although often necessary and appropriate, can represent significant obstacles to constructing the needed natural gas pipeline infrastructure to meet growing natural gas market demand.

As with new pipeline infrastructure, LNG projects are also difficult to site. There has been a great deal of opposition to such facilities, particularly when the facilities are proposed to be located near more densely populated areas. Also, the issue of consistency with the Coastal Zone Management Act has been a major area of controversy associated with these facilities.

The Broadwater Liquefied Natural Gas project, proposed to be located offshore of Long Island, was publicly announced by Broadwater Energy in November 2004 and filed with FERC in January 2006. It took over two years for the project to receive FERC approval; even so, it did not receive the necessary Coastal Zone Management Act approval from New York due to unacceptable environmental issues involving the location of the facility in an environmentally sensitive area. Broadwater filed an appeal with the U.S. Department of Commerce in June 2008, but the appeal was denied in April 2009.

There is a moratorium on the location of new LNG facilities in New York City. State regulations (6 NYCRR Part 570) also currently do not permit the siting of new intrastate LNG facilities. For the siting and construction of such intrastate facilities upstate, the regulation would need to be revised. This matter is also discussed in the Transportation Issue Brief.

Even though demand for natural gas is expected to grow, siting and building new incremental infrastructure are expected to continue to be difficult. If New York is to have adequate natural gas to meet future needs, it becomes critical to overcome the obstacles to getting facilities sited. New York agencies involved in permitting energy infrastructure need to have a coordinated approach and work with developers early in the process to identify appropriate locations where natural gas facilities stand the best chance of being built.

4 Petroleum Fuels

This section of the Energy Infrastructure Issue Brief provides background information, with references to the separate Petroleum Fuels Assessment of this Plan, about the petroleum fuels industry, fuel supply distribution operations, and regulatory institutions that indirectly impact petroleum markets. The discussion briefly describes how the workings of those components affect the adequacy of the petroleum fuels system infrastructure. A more in-depth and detailed discussion of the petroleum industry in New York is contained in the Petroleum Fuels Assessment of this Plan.

4.1 Status of Petroleum Fuels Industry, Market, and Regulatory Institutions³⁷

Petroleum fuels, such as gasoline, diesel fuel, home heating oil, propane, and residual fuels, are major components of New York's overall energy supply profile. Numerous multi-national, national, and independent energy companies supply refined petroleum products to the State through an extensive distribution system. The Port of New York, with large petroleum storage terminals located on both the New York and New Jersey sides of the harbor, is an important component of this system. These deep water terminals receive a steady flow of refined petroleum products and crude oil into the New York area from domestic and foreign sources. New York also receives petroleum products from several pipeline systems that connect terminals located throughout the State to the major refining centers located along the Gulf and East Coasts. Additionally, crude oil is used by refineries located in the mid-Atlantic region to produce refined products for the northeastern United States. Once refined fuels arrive at these facilities or are produced at the regional refineries, they are distributed by pipeline, barge, and truck transport to smaller coastal and inland terminals for further distribution to customers through retail distribution channels. The continued, uninterrupted operation of this complex distribution system, with its ability to receive, store, and distribute millions of gallons of the various fuels per day, is of critical importance to New York users.

4.2 Adequacy of the Petroleum Fuels Industry Infrastructure

New York is a major market for petroleum fuels such as motor gasoline, home heating oil, diesel fuel, propane, and residual fuel oil. The State is the fifth largest petroleum fuel market in the United States, exceeded only by Texas, California, Florida, and Louisiana.³⁸ Petroleum fuels are vital to New York's economy and remain the single largest source of energy used in the state. It is critical that the supporting petroleum infrastructure required to store, handle, blend, and dispense the wide range of petroleum and petroleum blended fuels be adequate to meet customer demand. This includes retail refueling outlets and large primary and secondary bulk storage facilities. This is particularly important as liquid fuel composition evolves to include higher percentages of biofuels (B100) such as bio-diesel, bio-heating oil,

³⁷ Transportation fuels are addressed in the Transportation Issue Brief.

³⁸ U.S. Energy Information Administration (EIA). *State Energy Consumption Estimates: 1960 – 2006, Table S2*. 2006.

and ethanol for gasoline blending. The significant construction costs, space limitations, multiple fuel types, and potential local siting considerations make it imperative that New York ensures that adequate storage facility capacities are available for evolving fuel blends on a regional and statewide basis.

For a number of years, petroleum product distribution companies throughout the State have expressed concern over the long-term decline in the number of storage terminals and associated storage capacity. They note that this reduction has increased the risk of impairing the operational flexibility needed to satisfy consumer oil demand. Petroleum storage terminal facilities face many of the same environmental, land use, and economic pressures that affect many other businesses. Operators note the costs associated with meeting environmental regulations, increased insurance costs, greater carrying costs associated with holding petroleum products, local siting concerns, and the lack of market incentives to build new facilities as impediments to adding storage capacity in the State. However, beginning in 2007, the amount of New York storage capacity dedicated to distillate fuels has increased. In certain parts of the State, including Long Island, the petroleum distribution industry has responded to market signals and added tank capacity to meet demand.

As a result of oil supply disruptions and oil price spikes that occurred in January 2000, the PSC issued regulations that require natural gas customers that select interruptible service and use petroleum fuels as backup to enter the winter season with seven to 10 days worth of fuel supply in storage tanks. Alternatively, customers with insufficient on-site storage to cover this requirement must have firm supply arrangements with petroleum fuel distributors to cover the remaining volume requirements. Large contract customers, such as electric generators with interruptible gas contracts, are required to maintain, or have on call, the equivalent of five days of petroleum fuel at the maximum winter burn rate.

Subsequently, following the severe distillate fuel (home heating oil, kerosene, and diesel fuel) supply shortfalls and the large number of interruptions of gas service to interruptible customers that occurred during the 2002 to 2003 winter, the PSC and local distribution companies took the following additional steps to help mitigate the impacts of high demand for heating fuels:

- Requiring natural gas local distribution companies to notify customers, the petroleum supply industry, and selected state agencies as soon as possible by email of impending, weather induced, interruptions.
- Having some local distribution companies with interruptible service hold two preseason test interruptions to verify the ability of interruptible customers to switch to backup fuel;
- Issuing regulations that require local distribution companies to move interruptible customers to firm service for 12 months if they fail to interrupt use when appropriate.

In November 2003, the PSC ordered that a study be performed of the domestic heating oil industry's infrastructure, with particular emphasis on those facilities used to serve interruptible gas customers in the New York City metropolitan area and Hudson River corridor. The main purpose was to help determine if the PSC's regulations pertaining to interruptible customers required any modification.³⁹ The consultant

³⁹ Interruptible gas customers that have distillate oil or residual fuel back-up must have oil storage capacity and sufficient alternate fuel on hand to withstand interruption of gas service for at least seven days (in the case of Temperature Control customers), and 10 days (for on-demand, fully, interruptible customers). Customers lacking sufficient storage space to hold either seven or 10 days of supply are required to enter the heating season with oil tanks filled and a contract for replenishment of oil storage inventory. Local distribution companies must alert their interruptible customers of the potential need to replenish oil storage inventories whenever, prior to February 15, accumulated gas service interruptions exceed a total of five days.

found that, although no major changes to PSC regulations were required, there were some issues that required ongoing monitoring.⁴⁰

The PSC issued a “Notice Soliciting Comments” on the study in March 2007. Comments were received from seven local distribution companies, three oil associations, the Northeast Gas Association, Multiple Interveners, and the New York State Reliability Council. Based on the comments received, a notice was published in December 2007 posing seven questions for interested parties to address:

- Should the PSC’s rules and regulations, applicable to interruptible gas customers having distillate oil as their alternate fuel, be expanded to include residual oil or all alternate fuel users
- Should on-site oil storage be preferred, or required, versus contract commitments or arrangements
- Should on-site oil storage requirements differ by geographical location
- Should interruptible gas customers be required to burn their alternate fuels during certain specified periods during the winter months
- For new applications for interruptible gas service, should on-site oil storage be required, and if so, how much
- Should the number of days of required on-site oil storage, or contracted amounts, for electric generators that burn gas on an interruptible basis be modified
- Should there be regular and periodic reporting by utilities and/or the PSC of the price and inventory levels of natural gas?

Comments from the parties were received in January 2008. The PSC may modify its regulations in the future as circumstances dictate.

4.3 Adequacy of Propane Storage and Supply Infrastructure

Propane fuel is a small volume, essential source of energy for New York residents and business owners. Often referred to as “bottled gas” or “LP-gas,” propane is used in the residential sector for heating homes and water, cooking, drying clothes, and fueling fireplaces. In the commercial, industrial, and agricultural sectors it is used for heating and to drive manufacturing processes. It also has a small, but growing use as a transportation fuel with both on and off-road applications.

Propane inventory capacity is generally classified by three levels of storage capacity: primary, secondary, and tertiary. At the primary level, in central New York, there are several underground salt dome storage caverns that hold large volumes of propane. These caverns are emptied as the heating season unfolds to meet demand. At the secondary level, there are many large scale pressurized above-ground tanks located at terminals and retail dealers around the State. These facilities may include any number of 90,000 gallon

⁴⁰ For example, the distribution of heating oil from storage terminal to end-users during high demand periods or during inclement weather conditions is sometimes problematic. Distribution bottlenecks, such as heavy coastal icing conditions or high seas, may delay or curtail barge resupply efforts, particularly on Long Island. The closure of several petroleum storage facilities over the past two decades because of operational inefficiencies or for economic and environmental considerations has resulted in a lengthening of distances between supply sources and end-users.

tanks grouped together at one location or may simply be one 30,000 gallon tank located in a local community. Secondary storage tanks are repeatedly refilled during the heating season with fuel from primary terminals to meet local demand. Finally, end user storage tanks, including residential homeowners, represent final tertiary storage capacity.

The smaller, secondary storage facilities play a critical role ensuring adequate propane supply during high demand periods. Winter season cold temperature induced demand often exceeds the resupply capacity of the propane distribution system. The secondary storage terminals are the last line of supply for a locality before a distributor must send large transport trucks to distant primary terminals to secure resupply. This effort is time consuming and significant costs may be incurred. During the normal average cold 2008 - 2009 winter season, a combination of strong, season long demand, an early drawdown of primary level storage cavern inventories, and resupply delays at New England ocean terminals, forced many northeast companies to send transport trucks to distant supply sources as far away as Indiana, Kansas, and Michigan to secure fuel. The added transport costs of this effort resulted in higher retail prices for many New York consumers as distribution companies passed along the additional costs.

For many years some local propane distribution companies have stated they have had difficulty siting additional storage tanks to meet demand within the communities they serve. As demand for propane has grown the supply pressure on the existing storage facilities has increased. At this point it is not possible to determine if the ratio of storage capacity to peak winter demand has reached a critical point. The supply difficulties experienced during the 2008 to 2009 heating season suggest a closer examination is warranted. The NYS Department of Agriculture and Markets, Bureau of Weights and Measures has begun to collect data on secondary storage tank capacity around the state. Once completed, this data, coupled with the known capacity of primary level storage caverns and pipeline flow rates, will allow for the development of a better understanding between storage capacities and demand.

5 Steam System

Con Edison supplies steam to approximately 1,800 customers in Manhattan from Battery Park north to 96th Street on the West Side and 89th Street on the East Side. Its steam system provides an important contribution to New York City's energy requirements. The system serves approximately 1,800 customers with steam for space heating and hot water and provides about 363 of those customers with steam for cooling equipment. Use of steam provides customers with energy options, especially in those cases where alternatives are not practicable. For example, where gas boilers and chimney flues for heating a building cannot be installed due to lack of space, building restrictions, or environmental concerns, or because the space would be more valuable for other uses, steam heating is a desirable choice for the building owners. In addition to its appeal as an alternative heating source, use of steam, especially during the peak summer period for such things as water chilling, reduces the need for electric generation capacity (for air conditioning), as well as for electric and natural gas delivery infrastructures, thus benefiting all electricity and natural gas customers in southeastern New York.

The Con Edison steam system is subject to regulatory oversight by the PSC. On September 20, 2006, the PSC approved a two-year steam rate plan that was structured to promote the preservation and growth of the steam business and ensure reasonable system planning. That rate plan also required the Con Edison to file an annual Strategic Plan to address steam business development and production planning efforts over a 10-year timeframe, and a Steam Resource Plan to identify and justify future supply options, including re-powering of the Con Edison's existing steam boilers, construction of new steam generation or cogeneration capacity, and competitive resource options. The annual strategic plan and Steam Resource Plan were filed accordingly.

On September 17, 2008, the PSC approved a two-year steam rate plan, which among other things required the Con Edison to conduct customer focus groups and customer satisfaction surveys, and prepare reports on such efforts for submission to DPS. It also sets forth several safety performance measures, including performance measures for emergency response to steam vapor conditions control. In addition, the Con Edison in collaboration with DPS and interested parties selected a consultant to review the thermal efficiency studies performed by the Con Edison since 1995 and to develop a detailed action plan that would prioritize implement and maintain economic projects for reducing overall steam losses.

The 2008 Order required that the Con Edison convene a collaborative of interested parties to consider: (1) the market potential for steam energy efficiency programs for steam customers proposed for rate year two; and (2) customer and Con Edison incentives associated with such programs. This process is to ensure that the Con Edison's energy efficiency plan will be fully developed and will increase the potential for success of the program.

Lastly, the 2008 Order required that the Con Edison complete an investment grade study evaluating adding a cogeneration plant of up to 500 MW at the Hudson Avenue Station, and then file a supplement to the Steam Resource Plan (SRP) on or before December 31, 2008 that incorporates updated fuel and energy price forecasts and includes the results of the Cogeneration Study. In approving the 2008 rate plan, the PSC envisioned that it would establish a procedure for parties to file comments on the supplemental plan and explore other steam system planning issues.

Consequently, on January 15, 2009, the PSC initiated a new proceeding to consider several additional matters, including the Con Edison's Steam Resource Plan, potential energy efficiency opportunities, the East River Re-powering cost allocation and the expected impact upon the Con Edison's steam rates of its capital improvement plans. That proceeding is developing a record on the Con Edison's proposed capital improvements, including replacement of the Hudson Avenue Station, expected upgrades at the Ravenswood Steam Station, expected upgrades to the Con Edison's steam distribution steam, and the costs and benefits of any steam energy efficiency programs that might be ordered by the PSC. The PSC's consideration of the comments and its actions are likely to occur later in 2009.