

A Strategic Framework for a Future Transmission System in New York

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Introduction

Electricity is perhaps the most important commodity in modern society due to its widespread use in the economy. Modern life cannot exist without it, and even short periods without an adequate supply can create significant and widespread economic damage and social disruption. Widespread blackouts, or prolonged periods without electricity, often have societal costs in the billions of dollars.

Recent governmental policies regarding renewable electricity generation, energy efficiency and demand reduction, and constraints on carbon emissions reflect a philosophy of creating a sustainable economy and environment for the future while accommodating population growth and increased demand for energy. The high costs of oil, the increasing costs of natural gas and coal, and climate change concerns are driving these policies, and the need for additional “clean” electricity is a result. Because transmission is the crucial link between electricity generation and its use, the existing transmission system needs to be evaluated and then changed in a way that increases its capacity, maintains or improves reliability, and enables a sustainable future to be created.

New York, like many States, is facing a future of increasing demand for electricity due to an increasing population, new uses such as plug-in hybrid electric vehicles, policies to encourage economic development, environmental regulations to control pollution more stringently, and the tendency of new electric appliances and electronic equipment to incorporate more energy consuming features. Population growth will primarily occur in the New York City Metropolitan Area, while the other types of load growth will occur throughout the State. Meeting this increasing future demand for electricity will likely require a combination of increased energy efficiency, demand reduction and conservation efforts and new generation resources likely to be based on natural gas or renewable energy. The inter-relationship of these options to meet future electric load growth is complex and affects decisions about the transmission system.

The primary concern about increasing the capacity of the New York electric transmission system is cost - how to pay for it, and who should pay. These seeming straightforward questions are also complex, dependent on the issues indicated above, and further complicated by competing uses for natural gas as building and industrial process heat, the age and structural condition of the transmission grid, operations of the New York Independent System Operator (NYISO) markets, government policies which have de-regulated utility generation resources but left transmission regulated by the New York Public Service Commission (PSC), and the desire to encourage new privately financed transmission capacity.

This paper considers existing State energy policies, pertinent macro-economic and societal trends, new technologies, and alternative approaches to increasing transmission capacity to propose a strategic framework and design focus for increasing transmission capacity and improving system reliability. Several cost recovery and revenue allocation concepts are suggested, and possible alternative financing approaches are outlined. Next steps for detailed planning and evaluation of alternative options are recommended, and an example potential project for implementation is provided.

Transmission System Background

The existing electricity transmission system design reflects a long established central generation strategy implemented by vertically integrated utilities and the New York Power Authority (NYPA). Essentially, large electric generation facilities were built along major rivers, the Great Lakes and the coast where cooling water, transportation systems for fuel, land area and sufficient water flow and height differential for hydropower were available. The transmission system was constructed primarily to send this power to major load centers and to enable bulk power to be transmitted for interstate purposes. Because utilities were fully regulated during this period, all costs were recovered through charges imposed on ratepayers by the PSC or by NYPA. This system was largely completed by the 1970s, and little or no major new transmission (thermal) capacity has been constructed by utilities or NYPA in the past 30 years. The system was conservatively designed with excess thermal transmission capacity that has enabled load growth to occur over the past 30 years without major changes. The

original system has little if any excess to meet future electric demand, and new capacity is needed. A number of concepts to fully utilize system capacity over a 24 hour period have emerged, but no major thermal transmission capacity has been added by utilities or NYPA to the original system.

Broadly speaking, the transmission system can be viewed as having two principal parts. The extra high voltage (EHV) bulk power transmission system (345 KV – 765 KV lines) carries power from large central generating plants to major load centers. The high voltage (HV) transmission system (69KV – 230 KV lines) carries power from the EHV system to load centers not directly served by the EHV lines. In some cases the HV lines carry power from central generating plants directly to smaller load centers. HV system capacity is also used to interconnect smaller scale generation including wind power, small hydropower, and bio-power from wood and landfill gas.

HV transmission lines also provide capacity to accept power and re-route it along electrically parallel lines during emergencies to the EHV and HV system. In many electric grids in this country, the HV system capacity has excess capacity for use during emergencies. However, HV capacity on many lines in New York is being fully used for normal operations, and during emergencies HV system capacity is purposely overloaded for short periods of time to enable re-dispatching of generation to take place and correct the problem. In general, overloading transmission lines during emergencies should not be a permanent alternative policy in lieu of adding additional capacity. However, it is very difficult to place a value on improving reliability during emergencies by adding capacity or a cost on relying on overloading. Finally, the HV system infrastructure is older (much of it dates to pre-World War 2) and thus is more likely to have structural deterioration than the EHV system infrastructure.

Discounting infrastructure age, corrosion and structural condition, this transmission system is operated in a largely reliable manner, and is maintained and upgraded periodically to ensure high reliability. The New York Independent System Operator (NYISO) regularly conducts studies and recommends improvements to transmission owners to ensure voltage and frequency stability and other system reliability measures. But the system also has transmission capacity limitations that result in power congestion and higher energy prices, especially to downstate communities. This indicates an inability to accommodate significant future load growth, and an inability to accommodate large amounts of

future central generation – especially that which is located in upstate NY. The existing system is also vulnerable to terrorist attack and occasional grid emergencies due to extreme weather and high electric demand conditions.

Increasing the transmission system capacity in New York is difficult for several major reasons:

(1) Deregulation and competition ended the vertical integration of utilities, and forced them to sell most generation assets to private companies. The result was generation being operated under market based rules established by the NYISO, while transmission remains regulated and only partially subject to market forces.

(2) New or upgraded transmission lines usually create some additional capacity that typically will remain unused for some time. Unused capacity does not generate revenue, making financing and cost recovery difficult for transmission owners and adding to the cost of electricity for ratepayers.

(3) Capacity increases to the EHV system may require a concomitant increase to the HV system to maintain required levels of contingency capacity for reliability purposes even with the use of overloading. This is especially true if existing HV capacity in electrically parallel lines to new EHV capacity is being fully used for ordinary operations.

(4) The transmission system is mostly owned by several different utilities and by the New York and Long Island Power Authorities. Getting agreement for system changes that often involve transmission segments with different owners is difficult for a variety of reasons. These include the possibility that ratepayers from one utility's or authority's territory can benefit from costs imposed on ratepayers from others.

(5) Use of the transmission system is governed by the NYISO, and its energy markets determine transmission congestion charges (TCC) that are paid to the utilities owning the lines. These market signals have resulted in the private financing of new transmission capacity, but only in two very special cases. These both involve underwater transmission from New Jersey to New York City and from Connecticut to Long Island. In both cases, generation is supplied from resources in adjacent electric grids (PJM and New England respectively). Since transmission congestion remains, it is unclear if current market signals are sufficient to encourage additional investment in new transmission capacity.

Changes to the transmission system must take into account these regulatory, market, financial, structural, and ownership realities, as well as concerns about infrastructure age, future generation strategies, system reliability, and meeting new load growth.

Transmission Capacity Alternatives

Major alternatives for increasing the capacity of transmission include: constructing new transmission lines in new rights-of-way, increasing capacity in existing rights-of-way, new central generation in major load centers to reduce use on the transmission system, and increasing energy efficiency and reducing demand to reduce use on the existing transmission system. All four options have advantages and disadvantages, and various combinations of these alternatives also need to be considered.

Generally speaking, the capacity of a given transmission line depends on several factors. The higher the voltage for a transmission line the greater its capacity (in megawatts). The size of the line (diameter and number of strands) and other factors, such as the composition of its structural core, also determine its capacity. In the case of overhead transmission, tower height, spacing and structural design are dependent on design voltage and current, type of conductor, and total weight or number of lines being carried. Overhead transmission corridors are land right-of-ways of various cross sectional width containing one to several transmission towers and having one or more different heights (or voltage levels). The full cross section (width and height) of many transmission corridors may not be fully utilized for various reasons, and understanding the maximum throughput capacity of each corridor is important when considering the alternatives.

New Transmission in New Corridors: Siting new transmission lines in new right-of-way corridors is very difficult due to public opposition, environmental concerns, legal and political concerns, land condemnation issues, court challenges etc., with resulting high upfront costs and typically very long lead times. The highly contested new overhead EHV transmission line proposed by New York Regional Interconnect, Inc. to bring power from Marcy south towards New York City is an example of these difficulties. In very congested places, with high land use and population densities such as the New York City Metropolitan Area and Long Island, adequate land for new transmission right-of-way may not exist or alternatively, development costs would be very high. To-date, the only new

transmission capacity in new corridors has been the two previously mentioned underwater projects.

Without strong government and political resolve, new transmission projects in new corridors have a low probability of success. However, some new transmission corridors may be necessary in the future to accommodate the potential for new large scale central generation or additional power imported from out-of-state.

Increasing Capacity within Existing Corridors: Increasing transmission capacity within existing right-of-way corridors can be accomplished in three ways: reconductoring lines, adding new lines in the existing right-of-ways, and adding energy storage devices at substations. Increasing transmission capacity, using existing rights-of-way and equipment, including towers and substations where structurally and electrically possible, is an approach that can avoid many of the issues associated with new rights-of-way, minimize cost and have a higher probability of success in a faster time frame.

One form of reconductoring involves replacing existing lines on existing towers with higher capacity or higher amperage lines at the same voltage. Because existing transmission towers have structural limitations due to design and age, the weight of the new higher amperage line usually must be equal to or less than the existing line. Higher amperage lines can use existing substations because the existing voltage level is maintained. New high temperature-low sag conductor technology can meet these structural constraints while effectively doubling existing transmission capacity. In many cases this can be accomplished with potentially lower costs than adding new transmission lines. Several new commercially available technology options exist for reconductoring that can result in more power being carried within existing transmission rights-of-way on existing towers. Because the structural conditions of towers must be considered before undertaking any project, reconductoring may be the best way of (simultaneously) addressing concerns about the age and structural condition of existing transmission infrastructure. Some towers may need to be replaced or reinforced.

In some cases, existing towers may have been built with a height that is greater than that needed for the voltage it currently is carrying. For example, 115 KV lines may have been placed on towers that are high enough to carry 230 KV lines. In these cases, reconductoring to a higher voltage is possible, although substation

transformers and other equipment will likely need to be changed, and potential structural limitations to towers need to be taken into account.

Adding new transmission lines in existing rights-of-ways depends on whether the entire cross sectional area of the corridor is fully utilized. Where right-of-way width (but not its height) is fully utilized, new lines may be restricted to lower voltage levels with lower height towers. Where the width of existing rights-of-ways are not fully utilized, new lines of equal or lower voltage levels can be installed without major new visual issues. Adding a new higher voltage line in corridors where the width is not fully utilized may require taller towers, and will create a new visual impact. In some instances, existing towers are not being fully used, and additional transmission capacity at the existing voltage level can be added by stringing new conductor on the unused arm of existing towers. Another possibility is the potential of double stringing towers that are structurally capable (with or without reinforcement) of carrying two sets of 3-phase lines but are currently carrying only one 3-phase set. In all of these cases, high temperature-low sag conductor should be considered to maximize the amount of added capacity.

While not physically adding new thermal transmission capacity, large energy storage devices such as batteries and compressed air technology located near substations in high load areas effectively increase the capacity of the connected transmission line by enabling it to be fully utilized on a 24 hour basis to provide additional peak power to the distribution grid when needed. These technologies are in the process of becoming commercial.

New Generation in High Load Centers: Adding significant amounts of new central generation in high load centers like New York City can avoid or minimize the need for increased transmission capacity, but likely can only be accomplished using natural gas as fuel. This is due primarily to environmental concerns about air quality and climate change, as well as practical considerations such as getting sufficient quantities of fuel into densely populated areas.

Large capacity new natural gas generation within New York City will likely require a new source of gas such as from a liquified natural gas (LNG) facility, a new pipeline, or some means of increasing the capacity of existing pipelines.

LNG facilities are very difficult to site and are vulnerable to terrorist attack. LNG is a higher cost fuel than conventional natural gas and would add to the already

high cost of energy in New York City. It also would be imported from foreign countries, adding to our dependency on foreign fossil fuels and contributing more to the “fuel related” dollars already leaving New York.

New gas pipelines could be built within existing right-of-ways or in new pipeline corridors. The Millennium Pipeline across southern New York is in the final stages of completion and will bring significant quantities of natural gas towards New York City and Long Island. Given the very high density of development approaching and within New York City, the likelihood for new gas pipelines to deliver significant quantities of additional gas into the local distribution system is low or the cost would be very high. More likely is increasing the capacity of existing local distribution pipelines by increasing its operating pressure. This would tend to increase leakage (and escaping greenhouse gases) and likely increase the risk of explosion due to accident or terrorist attack.

Recent new natural gas sources found in shale formations in many states, including Pennsylvania and New York, mean that resource supply is more likely to be abundant in the future. But existing seasonal gas storage is fixed, and delivery of gas into the distribution systems of major load centers may be difficult and costly during winter periods with high gas demand for both electric generation and building heat.

Gas delivered via the Millennium Pipeline and existing pipelines will likely be used to fuel power plants on Long Island that switch from high cost oil. Coupled with any increased power generation in New York City and on Long Island, the cost of natural gas may increase for heating purposes throughout the State. Existing data already show that peak prices for natural gas occur during the winter due to competing needs for power generation and heat for buildings and industrial processes. Gas prices also peak during prolonged high temperature periods during the summer, and these episodes tend to draw down or slow down the storage of gas which has adverse impacts the next heating season. New York, including New York City and Long Island, uses a significant amount of oil for heating, but the very high cost of oil is driving consumers to switch to lower cost gas. This will exacerbate the winter heating cost problem. Increased use of natural gas for electricity generation will likely both increase the cost of electricity and increase the cost of heating, although the new gas supply and pipeline may tend to lessen the impact.

Finally, natural gas generation would add to carbon emissions, and further add to the cost of electricity in the future due to “cap and trade” emission regulations being planned through the Regional Greenhouse Gas Initiative (RGGI). If additional gas use requires the use of higher pressure in transmission and distribution lines, more leakage will occur, adding to costs and to levels of greenhouse gases emitted. If “cap and trade” programs are implemented by the Federal government as looks likely, and as environmental regulations to control emissions of nitrogen oxides and mercury are implemented, then the price of natural gas can be expected to increase over time as coal fired power plants in many parts of the United States switch to gas to stay competitive. Careful analysis of this alternative is needed to evaluate the future price of gas on a seasonal basis and to determine its impacts on both electric and heating costs to consumers.

Energy Efficiency and Demand Reduction Programs:

The New York 15x15 program to reduce electricity use by 15% by 2015 is absolutely essential in the effort to reduce use and congestion on the transmission system. The New York Systems Benefit Charge (SBC) program and more recently the Energy Efficiency Portfolio Standard (EEPS) program are in place to help fund this effort which is directed at a variety of energy efficiency, demand reduction and behind-the-meter distributed generation technologies to reduce peak demand and save energy.

The NYISO operates a demand reduction market that provides payments to cooperating participants to reduce demand upon signal during periods of high electricity demand. This program has the potential to increase in size. New opportunities include incentivizing large retail customers to add behind-the-meter electricity storage batteries or other devices. These batteries would charge at night and discharge daily to moderate levels to reduce customer peak demand and save battery life, and be subject to deep or higher discharge levels on signal from the NYISO during periods of high peak system demand.

These programs reduce stress on the transmission system, reduce congestion and reduce the need for new capacity. Similarly, reduced demand for electricity reduces the need for new local generation capacity. However, these programs also act to reduce the incentive to build new transmission or generation capacity because decreased system demand results in less future revenue to recover investment costs.

While critical to the success of any comprehensive energy plan, these programs may not be sufficient to counter load growth. Estimating the difference over time between the rate of load growth and the rate at which it is effectively reduced by efficiency and demand reduction programs is crucial to determining the rate at which new transmission capacity or new local generation resources need to be added.

Relevant Policy Issues

Electric Load Growth: A number of factors and trends are likely to contribute towards a significant increase in electric demand and energy use over time. These include:

- Population is expected to increase by 1 million in the next 10-15 years primarily in the New York City Metropolitan area,
- Efforts are underway to revitalize the upstate economy, with many new businesses such as computer chip manufacturing requiring significant amounts of electricity,
- The use of electric energy in new applications or for ever faster service with higher quality, more information storage and processing requirements and more features is likely to increase, and
- The use of electric energy is likely to increase for new purposes such as transportation, idle reduction, water and indoor air disinfection, and indoor and stack emission pollutant reduction.

High oil prices are likely to become the norm in the foreseeable future, providing an incentive for the transportation sector to move towards the use of electricity as an energy source. Anti-idling regulations for diesel trucks, buses, rail locomotives and ships are becoming more common as are technologies which replace diesel engine idling with electrical power. New advances in batteries will enable the next generation of hybrid-electric vehicles to be equipped with plug-in technology, and will improve prospects for all-electric vehicles.

Using electricity as a transportation fuel reduces oil consumption and CO₂ emissions. From a climate change perspective, the electric energy used to replace petroleum from transportation uses needs to come from renewable energy to realize maximum CO₂ reduction benefits. Also, if this replacement energy comes

from in-state renewable energy resources, the money that would have been spent on petroleum stays in the New York State economy.

Most of the “replacement” electricity for transportation needs will be required at night, but some new day-time and peak loads are likely. Locations that likely would be affected include all types of housing, large parking lots for businesses and commuters, truck stops, truck terminals, border crossings, large warehouses and retail stores, rail yards, airports and waterports. New load centers will be created and additional loads will be imposed on existing load centers throughout the State.

New day-time peak loads will be created by new economic growth (e.g., computer chip manufacturing, nano and biotechnology companies) and by increased population. Peak energy requirements also will likely increase due to associated future increases in the quantity of drinking water and wastewater effluent, for any mandated improvements to the purity of water and indoor air quality, and for a variety of new or faster or larger electronic equipment with more features. Increased urbanization will create additional stress on parts of the transmission system by transferring daytime and nighttime suburban electricity consumption to load centers in the State.

In general, new daytime and nighttime electric loads in all urban areas in New York will lead to new stresses on the transmission system and higher congestion costs. These problems will be especially acute on Long Island, in the New York City Metropolitan Area and in upstate areas served by existing transmission lines that are at or near capacity.

Renewable Energy: Currently, about 18% of electricity generated and used in New York is from renewable energy resources – primarily from large scale hydropower using water from the Great Lakes, and from hydropower imported from Canada. Water levels in the Great Lakes are at or near historic lows, perhaps due to climate change influences, and less in-state hydropower might be expected in the near future.

Without a significant increase in renewable energy, more electricity consumed in New York will likely be generated using nuclear or fossil fuels, and more New York dollars will leave the State to pay for imported fuels to generate the electricity. Total costs to end users of electricity in New York were about \$20 billion in 2005. About 50% of this was due to fuel costs, most of which left the State to pay for

imported gas, oil, coal and nuclear fuels. In more recent years, with increasing electricity use and increasing energy prices, both the total amount spent for electricity and the percentage due to fuel costs have increased, resulting in even more money leaving New York to pay for imported fuel. Renewable energy generated within New York State keeps “fuel” dollars in-state that can be invested and circulated to improve the State’s economy.

The New York Renewable Portfolio Standard (RPS) program to achieve a 25% goal for renewable energy use has been a success to-date, but there is ample evidence that planned future wind farm construction and biomass fueled generation will slow or stop in many areas due to transmission capacity constraints. The RPS program was designed to provide developers of renewable energy resources with electricity production incentives under a competitive procurement process. No provisions were made to include incentives for new transmission capacity that might be needed to allow new renewable generation to be realized.

Most of the renewable energy being constructed in New York is wind power which is stochastic or statistically predictable in nature. Wind power is seasonal with the strongest winds in the late fall, winter and early spring period. This helps reduce the use of natural gas for electric generation during these seasons, and facilitates seasonal gas storage. In this way, wind power helps to keep the price of natural gas more affordable for process or space heating or for cogeneration purposes. The wind also tends to blow most strongly during the night providing electricity for new night-time loads such as for electric transportation, and for behind the meter battery storage to reduce day time peak demand.

Wind energy also has a very low marginal cost of production because its cost for fuel is zero. In the competitive New York market for electricity, this low marginal cost may translate to lower cost electricity during the fall, winter and spring (off-peak) periods if sufficient amounts of wind power are constructed.

Hydropower imported from Canada is transmitted into New York via a 765 KV transmission line from Chateaugay to Marcy. The 765 KV line is only operating at about 30% of its thermal capacity due to EHV transmission constraints from Marcy South and East, potentially higher system impedance at higher capacity levels, and because electrically parallel HV transmission lines that serve as contingent carriers for reliability purposes are operating at maximum thermal capacity. During emergencies, these HV lines are overloaded for short periods for

reliability purposes. As a consequence, significant new wind and biomass power plants in Northern New York which tend to interconnect with HV transmission lines, as well as additional hydropower from Canada will not be possible without increased HV transmission capacity and a resolution to other system constraints. The current Northern New York transmission situation may be the most restrictive in the State for additional renewable energy development, but other areas in the State face similar problems.

The lack of adequate transmission capacity will: prevent New York from achieving its renewable energy goal, cause more fossil fuel dollars to leave the state, and tend to keep electric energy and natural gas prices high. It will also result in less investment in upstate New York which otherwise would stand to benefit economically from wind and biomass power facilities. Renewable energy development helps strengthen the rural economy, provides jobs, keeps farms economically viable, and builds the property and income tax base.

Homeland Security: Much of current planning for Homeland Security to prevent terror attacks on critical energy infrastructure centers around “hardening” critical substations and central generation facilities. This reflects the difficulty of protecting thousands of miles of transmission lines that primarily carry electricity from large central generation sources to major load centers. The inability to protect transmission lines leaves the system vulnerable.

Heavy reliance on central generating facilities also contributes to potential security problems as an attack on these large plants can significantly disrupt the electric system.

An alternative might be to create a type of transmission system where total system transmission capacity is increased, more distributed and better interconnected, allowing the requisite re-routing of power during grid emergencies for longer periods of time while enabling smaller generation to be developed to supply power to load centers. Better interconnection between load centers would enable sections of the grid that come under attack or have grid emergencies to more easily be isolated, and be smaller in terms of affected load area. More small sized generation such as wind and biomass power plants (typically less than 150 MW) that are widely distributed will help reduce the impacts of losing large central generation to terrorist attack or unexpected emergencies. With the use of synchronous generators, this approach would help

facilitate re-starting the grid after a terrorist attack or unexpected emergency that affects the grid on a wide scale. This approach needs to have a more robust HV transmission system that has more capacity and upgraded interconnections.

Carbon Emission Constraints: The Regional Greenhouse Gas Initiative (RGGI) is a policy that will cap emissions of CO₂ from electric power plants with greater than 25 MW of capacity over the next 6-7 years, and then reduce them by 10% over the following 4-5 years. This goal needs to be accomplished during a period when electric energy loads are likely to increase significantly.

Significant behind the meter energy efficiency, distributed generation, peak demand reduction and small scale renewable energy programs are in place to help meet RGGI goals. But these may not be sufficient to counter future load growth and enable RGGI targets to be met. Transportation offsets, fuel switching from coal and oil to natural gas, additional non-fossil fuel electric generation (renewable and nuclear energy), and importing additional electricity from neighboring grids not a part of RGGI are possible alternative solutions. Each has its own set of problems, costs and new challenges for the transmission system or the State's economy.

Transportation offsets will require more renewable or nuclear energy to realize an effective reduction of CO₂. More natural gas generation due to fuel switching will likely cause higher electricity costs and higher heating costs. New nuclear generation would likely require new EHV transmission lines to be constructed in order to get electricity from likely sites near the Great Lakes to major load centers in New York City and Long Island. The new EHV lines would also require additional HV transmission line "reserve" capacity for contingency purposes. Imported bulk power from States in neighboring grids that are not a part of RGGI will likely be generated by coal fired power plants, contributing significantly to CO₂ emissions. Additional imported hydropower from Canada requires both an increase in the HV transmission capacity of existing right-of-way corridors to meet additional contingency requirements and a resolution of long standing EHV segment capacity limitations from Marcy south and east. As previously noted, new wind and biomass power will require an increase in HV transmission capacity.

Thus, transmission capacity increases are likely to be needed in any scenario to meet RGGI goals and improve or protect future prospects for the State's economy.

Cost Considerations for Different Alternatives

The total cost of electricity from a ratepayer's perspective is the sum of the commodity cost of energy, demand charges if any, energy delivery charges and various charges for energy efficiency and renewable energy program subsidies. Commodity and transmission congestion costs are determined by markets operated by the NYISO. Demand charges and energy delivery through the utility owned transmission and distribution system are set by PSC regulation and depend on costs to utilities. Special program charges are also set by PSC regulation and are paid by most consumers. Power delivery charges to NYPA customers are set by NYPA.

The commodity cost of electricity reflects the variable cost of the different fuels used to generate electricity and the inherent fixed capital and other costs of generation. These costs can be different in the different NYISO zones. The markets operated by the NYISO use auctions to determine commodity prices that are paid to private generators who win bids in each zone.

The cost to deliver electricity to ratepayers through the transmission and distribution system reflects the need to meet high standards for reliability and power quality, and transmission congestion contracts (TCC). The TCC are dependent on load requirements in the various NYISO zones, differential generation costs in the various zones and the fixed amount of transmission capacity available in the different zones. The energy markets operated by the NYISO determine transmission congestion charges that are paid by ratepayers in high demand areas downstream of congestion points and paid to the regulated utilities who own the transmission lines upstream of the congestion points.

The TCC revenues paid to the utilities are used to offset power delivery costs to their respective ratepayers, creating a disincentive to build new transmission capacity. Thus, new transmission capacity would eliminate or minimize congestion, and some ratepayers would potentially be faced with increased power delivery charges that reflect both loss of congestion revenue and charges to recover investment in new transmission capacity. Regardless of who pays for new transmission capacity, equitable treatment for those ratepayers who will lose the financial benefit of congestion costs is likely necessary.

Looking to a future of significant load growth, the cost of electricity from a ratepayers perspective is likely to increase regardless of the options or

combination of options used to meet increased demand. Depending on the option, one or more components of a ratepayer's bill will likely increase.

For example, renewable energy such as wind and hydropower have low marginal costs of production due to zero fuel costs, and large amounts of renewable energy may result in lower energy commodity costs to ratepayers. But expanding its use requires increasing the capacity of the transmission system and thus increasing energy delivery costs to pay for new investment in electric transmission infrastructure. Some forms of renewable energy, including wind, also require subsidies due to high capital costs and relatively low capacity factors and this adds to ratepayer costs.

The major near term fossil fuel generation alternative is the use of natural gas. Expanding its use locally in high load growth areas risks increasing the marginal commodity costs of electricity due to competing needs for natural gas, but it minimizes the need for major transmission infrastructure improvements and thus minimizes future increases in electricity delivery costs.

Energy efficiency, demand reduction, and behind the meter renewable energy programs have zero marginal costs of electricity production, help reduce the total cost of delivery by reducing use of the transmission system and reducing congestion costs, but require subsidies to off-set high capital costs including those for advanced meters. These subsidies may increase in the future as lower cost targets like lighting changes are fully subscribed, and higher cost targets like air conditioning improvements remain. In addition, these programs result in less revenue being collected by utilities for energy delivery and potentially higher unit energy delivery rates in the future if an effective rate decoupling method for utilities (ensuring adequate revenue) cannot be developed.

Behind the meter combined heat and power programs often require subsidies to offset capital costs including interconnection to the electric distribution grid. Finally, electricity imported from out-of-state using new transmission capacity may result in higher energy delivery costs due to the need to recover the cost of capital investment.

Choosing a least cost approach between these major options is complicated by the need to recover the costs for new or upgraded gas pipeline infrastructure to accommodate increased use of gas, and by the likely increase in winter heating

costs to energy consumers due to the competing needs for gas to generate electricity and to provide building and industrial process heat.

Countering economic forces in society also complicate choices, create potential conflicts, and make investment decision-making complex. Thus ratepayers want low costs and high reliability for electricity and heat energy; utilities or private electric and gas transmission and distribution owners want a fair return on investment; power generators want to maximize profits; and government through a variety of policies wants to ensure system reliability, lower costs to encourage economic growth, protect the environment, ensure fuel diversity and encourage energy independence. No one wants the blame for power outages or gas shortages or explosions, but few are willing to pay for improved system reliability to avoid these occurrences.

The result of all these issues is difficulty in determining the amount of additional transmission capacity needed for the future and defining who should pay, because the economic, environmental and political implications of the various options to address electric load growth and system reliability go beyond these questions. A better set of questions might be to determine which option or combination of options minimizes the total cost of energy (electricity and heat) to ratepayers and improves system reliability in the future, with the allocation of the capital costs of improvements dependent on who benefits and the degree of benefit. But implicit in this set of expanded questions is that the analytical results will be at least partially and possibly highly subjective, due to the uncertainty associated with the need to predict future electric and natural gas demand, fuel costs, capital costs of equipment and other costs associated with the various alternatives.

Given these uncertainties, the age of the existing electric transmission system, the minimal investment in transmission capacity in the last 30 years, the possibility of new load growth overwhelming the capacity of the existing grid, the desire to meet State policy goals for renewable energy and reduced CO₂ emissions from power plants, the need to increase capacity for future contingency purposes, and the desire to reduce the risk of excessive future energy costs by diversifying energy delivery options, it seems highly likely that additional transmission capacity will be needed as part of a comprehensive strategy for new generation resources and expanded energy efficiency and demand reduction programs.

Financing Alternatives

There are at least three major alternatives to consider for financing new transmission capacity: all private, all regulatory and the power authorities, and a hybrid that might require re-regulation action by the PSC.

All Private Financing: This alternative uses all private funding (equity and debt) to respond to market signals of high prices for electricity. Private financing typically requires a long term contract with a supplier and buyer of electricity and a high capacity factor load for rapid and certain cost recovery.

In New York, high transmission congestion charges and high prices for natural gas in downstate areas including Long Island and New York City represent opportunities for private financing, and potentially lower costs to ratepayers. Two projects in new transmission corridors have been completed as previously noted. Neither has contributed to the upgrading of existing, aged transmission infrastructure within New York State.

Since the original transmission system in New York has not been deregulated, a true market based approach to increasing transmission capacity may only exist for new transmission in new corridors. With high levels of controversy associated with new transmission in new corridors, the opportunities for private financing may be very limited. Also, it is not clear whether private companies would add capacity on electrically parallel lines for contingency purposes or rely on overloading these lines during emergencies. In general, all private financing will likely do little to address the needs of New York's aging grid or improve its reliability. Also, since private financing generally will focus on high load, high capacity factor opportunities, it would likely not help New York meet its renewable energy goals, but could result in more Mid-West coal based electricity being used in New York (imports from the PJM grid) and make RGGI goals harder or more costly to achieve.

All Regulatory and Power Authorities Financing: This alternative for increasing transmission capacity would require the PSC to allow utilities to recover full costs from ratepayers while NYPA or LIPA would recover full costs from its customers. There are several approaches to implementing this alternative.

Approaching it on a utility by utility rate case basis would make it difficult for the PSC to estimate the costs to ensure that congestion would be reduced, system

reliability improved, and that future load growth in downstate New York would be served by upstate renewable resources because several utilities and NYPA or LIPA might be involved in specific efforts. While an all NYPA financing approach might be feasible in transmission corridors it owns, adding capacity in electrically parallel lines for reliability purposes might require the use of transmission corridors owned by several different utilities. LIPA would finance all capacity increases on Long Island, but would need to collaborate with other utilities and NYPA for new capacity outside of its territory. Determining which lines to focus efforts on, as well as determining optimal construction sequencing and scheduling, would be difficult with multiple utilities involved and the PSC making decisions on a utility by utility basis. Also, the problem remains of ratepayers from one utility or NYPA paying for new transmission capacity that benefits ratepayers from another utility or NYPA or LIPA customer.

A more equitable approach for all ratepayers might be to form a pool of funding based on the principles that beneficiaries and users should pay, and use some form of competition to determine which projects to fund.

Sources of funding could be direct charges to all ratepayers based on energy usage, energy delivery charges collected by utilities and power authorities on annual load growth beyond a pre-determined level in each NYISO zone, funds collected from sale of carbon emission allowances in the RGGI program, federal funds for homeland security or for energy infrastructure improvements, or some combination. (These sources are better described later on in the paper.)

A competitive process could award pooled funds to consortiums of utilities, NYPA and LIPA that would achieve specified goals such as delivering more renewable energy to downstate customers, improving system reliability, addressing aging grid issues, and other goals that would achieve benefits to ratepayers and the public. The utilities and power authorities would issue bonds to cover capital costs in their respective parts of the projects, and the pool funds would be used to pay bondholder interest over time and its face value at maturity.

These pooled funds would be managed by some unbiased third party such as the Energy Research and Development Authority (NYSERDA) or a new Transmission Authority. The NYISO might also be a candidate to manage the funds, although a separate governance, planning and program operations structure might be required for this type of activity to ensure fairness.

This approach might result in lower costs to ratepayers than an all private one because tax exempt bonds could be used and because rates of return on investment might be lower.

Hybrid Financing: This alternative for increasing transmission capacity would use consortiums of private companies, utilities and the power authorities to create projects that would combine funds from all three entities to finance projects meeting specified goals as noted above.

In this case, the utilities and power authorities might use capital from bonds to provide equity investments in renewable energy projects involving new transmission capacity. Pooled funds as noted above might be used to pay bondholders for the portion used for capitalizing new transmission capacity, while utility shareholders and the power authorities would take equity positions in the portion involving renewable energy generation (along with the private companies), and get paid back with funds from the New York RPS as well as energy sales and federal credits. This approach would require the PSC to “re-regulate” much like they did in the recent purchase of Energy East by Iberdrola.

In addition, to investments in renewable energy projects, there might be circumstances where private companies might make investments in portions of new transmission corridors that might be a distinct part of an overall hybrid financing project.

While the all market financing approach will likely not result in improving the reliability of the existing grid or addressing its age and structural condition, the latter two alternatives will. **Given a variety of pros and cons with each alternative, it seems reasonable to consider encouraging all three to be implemented simultaneously.** The all market approach would focus on new capacity in new transmission corridors, while the regulatory/power authority and hybrid approaches would focus on adding capacity in existing transmission corridors.

General Strategy and Conclusions

While determining an optimal, least cost approach to address future electricity needs and meet governmental policy and regulatory goals is very complex due to a host of inter-related factors, increasing transmission capacity appears to be one

of a combination of options that will be needed to achieve a future economy and environment that is sustainable.

Any conceptual approach to increasing electric transmission capacity needs to consider the total energy needs for the future, the need to invest in aged infrastructure, and the goals of pertinent governmental energy policies. Major considerations to consider include the characteristics of future generation resources, improving system reliability and addressing grid age and structural condition, investment cost recovery, and ease of constructing new transmission capacity.

Future Generation Resources and Improving Reliability: Load growth in New York, and especially in New York City, Long Island and downstate New York, will likely require some new central generation facilities sited in upstate New York or importing more bulk power from out-of-state resources. Either will likely require upgrading the EHV transmission lines to carry more power to downstate load centers or building new ones. One exception is the unused capacity on the 765 KV line from Canada. All options will require the need to add “reserve” capacity to HV transmission lines running electrically parallel to maintain system reliability under contingency situations (assuming that little excess capacity is available in existing HV lines and that continuing to overload lines during emergencies is not acceptable as a long term policy).

Additionally, upgrading existing EHV transmission lines will require that they be disconnected for periods of time during off-peak seasons to allow construction to occur. This load would need to be re-routed onto electrically parallel HV lines during these periods, but there would be no guarantee that sudden demand increases due to weather changes would not occur. To maintain power and reliability, increasing the capacity of these HV lines may be necessary as a first step.

Meeting this new future load with a REGGI cap on CO2 emissions as well as meeting Renewable Portfolio Standard goals will require much more renewable energy. Most of the potential for renewable energy is located in upstate New York. With the exception of additional hydropower from Quebec using the existing 765 KV transmission line, this type of generation typically would interconnect to HV transmission lines. Given system reliability requirements and a

lack of existing HV transmission capacity in many areas of New York, additional capacity would need to be added to the HV system.

The rate of load growth and new generation can be controlled to a certain extent by the timing of RGGI and RPS offset policies, and by the timing of regulations for anti-idling and new environmental mandates that cause increases in energy use . Controlling the rate of new load growth would facilitate the scheduling of construction for additional transmission capacity.

Transmission Capacity Design and Construction Sequence Focus: Given the likely characteristics of future generation resources, grid reliability considerations, the older age of the HV system and the need to maintain grid operations during construction, **any strategy to increase the capacity of the existing transmission system in New York must include an initial focus on the HV transmission system.**

Thus, it seems logical to focus first on increasing the capacity of the HV system, second on upgrading weak segments of the EHV system, and third on building additional EHV capacity.

Fourth, as they become commercially available, large energy storage devices such as batteries and compressed air technology located near substations could be used to enable transmission lines to be fully used on a 24 hour basis and to provide power to high load pocket areas.

Ease and speed of construction considerations indicate that initial efforts to increase transmission capacity should focus on reconductoring lines in existing transmission corridors. Using high temperature – low sag technology, this could lead to a doubling of transmission capacity while simultaneously addressing concerns about system age and structural condition.

Given policy goals and more immediate energy needs, priority should be given to increasing transmission capacity into downstate New York and New York City, and increasing transmission capacity to interconnect upstate renewable resources where needed.

Investment Cost Recovery: Key to any strategy is to recognize that new electric loads will be created in the future. New daily off-peak load might be accommodated by existing transmission capacity, while new daily on-peak load will require additional transmission capacity. However, the new incremental annual power delivery revenues that transmission and distribution system owners

will receive as a result, can either be “used” to reduce the unit power delivery cost of electricity to ratepayers or increase the transmission capacity and reliability of the electric system. Also as previously indicated, the beneficiaries and users of transmission capacity increases should pay investment costs. While all ratepayers benefit from system reliability improvements, ratepayers in NYSISO market zones affected by congestion and more rapid load growth should expect to pay more. All ratepayers will likely be affected by higher energy costs if RGGI and the RPS fail. The success of both policies depends in part on additional transmission capacity.

Using this guidance, the investment costs of new electric transmission capacity would be paid with a combination of: (1) new energy delivery revenue collected by utilities and power authorities on annual electric use growth beyond a pre-determined level in each zone of the NYISO (2) a charge to ratepayers who benefit from reduced transmission congestion costs with transfer payments to those who are currently benefitting from transmission congestion, (3) a portion of funds obtained from the sale of RGGI carbon emission allowances, (4) federal funds for homeland security or energy infrastructure improvements and (5) a general charge to all ratepayers, based on energy use, who would normally pay for gradual structural improvements to an aging grid in any event, and who would receive benefits from increased transmission capacity in several ways.

These ratepayer benefits include savings from: improved system reliability and possible reduced outage costs, reduced electric energy costs in off-peak hours due to renewable energy and during peak hours from additional electricity from remote resources, and a reduction in the future cost of energy for heating needs in winter due to a reduction in the need for fossil fuel electric generation resulting from increases in renewable energy.

Further justification for a general charge to all ratepayers are the public benefits from energy dollars kept in New York by developing renewable energy to create construction, operation and maintenance jobs, stimulate the economy and build the tax base. With proper timing and incentives, additional public benefits can result from creating new manufacturing jobs to take advantage of infrastructure upgrades and technology to accommodate new electric loads. These cost savings need to be estimated and publicized.

An evaluation would be required to determine the magnitude of funding needed from each source over time to ensure that a sufficient amount of pooled funding would be available to provide for meaningful changes to the transmission system and enable goals to be met. Any matching dollars needed to secure potential federal funds would come from the other four payment categories put into a pool for financing purposes.

Benefits: The benefits of an upgraded transmission system include the savings from reduced congestion costs and from reduced natural gas peak prices. The additional investment in wind power will help ratepayers and the economy by lowering the price of electric energy during fall, winter and spring periods. Public benefits from renewable energy accrue from creating a property tax base, jobs, taxable royalties, corporate and salary taxes, and by keeping “fuel” dollars spent on energy in-state where they can circulate to help the economy.

A more difficult benefits calculation is estimating the value of improved reliability and security to ratepayers. Expected reductions in the costs of avoiding or reducing the number and severity of terror attacks and grid emergencies including major blackouts, and expected savings to consumers from reduced losses due to fewer transmission outages are difficult to estimate for these low probability events.

Additional benefits would be created by fully developing this concept and trying to attract a major manufacturer to New York to make the new conductor here for use in New York and other states that will need new transmission capacity. With opposition to new right-of-way transmission corridors in all states, and aging infrastructure in all states, reconductoring with high temperature-low sag lines will be attractive. Typically, a combination of tax incentives and enhancing the prospects of selling plant output are needed to entice new manufacturing where large investments by a private company in manufacturing capacity are needed. The location for this new manufacturing facility would likely be in upstate New York, further helping to improve its economy. New businesses and jobs would also be created for manufacturing, installing and servicing vehicle anti-idling and plug-in technology, as well as energy storage technology and devices to improve water and indoor air quality.

New York would be the first state to implement such an integrated policy and would have a very good chance of attracting the new manufacturing capacity.

This strategy is not meant to imply that the alternatives of local generation in load centers and aggressive energy efficiency and demand reduction programs are not needed. Rather, a diversified portfolio approach is needed to meet a wide set of policy goals, to keep future total energy costs low, and to stimulate the economy in a future having a high load growth potential.

Recommendations

A general design strategy and conceptual framework for increasing transmission capacity has been developed by understanding the common linkages between governmental energy policies and the relationship between these policies and the need to provide for new load growth, improve grid security, maintain or improve reliability, and address grid age and structural condition. Linking policies of the RPS, EEPS, REGGI, Homeland Security, regulating and enforcing diesel anti-idling, encouraging plug-in hybrid electric vehicles and accommodating other new electric loads utilizing new technologies creates the potential for a synergy that will enable the State to meet its policy goals while improving the State's environment and economy in a sustainable manner.

Developing a more specific plan for increasing the capacity of the whole transmission system requires more in-depth economic and technical analysis which looks at all the costs, savings, new revenue and economic and environmental benefits to better understand the comparative total value (costs and benefits) that would result from different alternatives for upgrading the transmission system. The viability of the different financing methods that were proposed as well as others also needs to be evaluated. Equally important is an evaluation of the impact to the New York economy and environment if transmission capacity is not increased.

To conduct these economic and technical analyses, more information is needed about the current state of transmission infrastructure and right-of-way capacity, estimates of load growth and energy prices, and estimates of the savings and public benefits associated with renewable energy generation. Specifically, detailed studies are needed to provide information regarding:

- The maximum throughput capacity of every transmission corridor in the State needs to be determined. This would result in an inventory of the

existing capacity, and the ability to estimate incremental maximum transmission capacity potential for all existing transmission right-of-ways. The entire potential cross section of each right-of-way corridor needs to be considered in making this determination, along with the structural capabilities of existing towers and methods for reinforcing them, and new reconductoring technologies to maximize incremental capacity potential.

- A listing of all planned renewable energy generation in New York and discussions with Hydro Quebec to determine the potential of purchasing under contract additional renewable energy from Canada. A contract to purchase additional renewable energy by the New York Power Authority or another company may facilitate the Canadian effort.
- An estimate of expected future natural gas prices as additional electric generation capacity is added along with growth in gas demand for heating due to population and economic growth and switching from oil because of high oil prices. This study should include the alternative of meeting future electric load without increasing electric transmission capacity.
- An estimate of the annual electric use level in each NYISO zone beyond which would constitute new load, taking into account existing energy conservation and efficiency program reductions.
- An estimate in each NYISO market zone of the rate that new electric demand would be added and how individual load centers in each zone would be affected. Load growth rates should reflect scenarios with and without policy and regulations that would encourage new demand. Energy delivery revenue estimates associated with the new load in each zone are also needed. Estimates of peak, off-peak and seasonal variations in zonal demand should be included.
- An estimate of the cost of meeting expected load growth by implementing each of the four major alternatives for increasing transmission capacity on an individual basis versus a portfolio approach. The cost of addressing the age and structural condition of the existing grid without any increase in transmission capacity should be estimated separately.
- An evaluation of the costs of different approaches to finance transmission upgrades including tax implications and costs to ratepayers.

- An evaluation of the magnitude of funding needed from each cost recovery source over time to ensure that a sufficient amount of pooled funding would be available for increasing transmission capacity.
- A listing of commercially available technology for reconductoring transmission lines, large scale battery storage and their estimated range of installed costs.
- A thorough understanding of the public benefits from the economic impact of keeping energy dollars in New York through renewable energy generation and new manufacturing potential.
- Estimates of the reduction in congestion costs, energy prices and other savings and public benefits noted above.
- An estimate of the cost to utilities and the public of a range of blackout scenarios attributable to terrorism, major weather related emergencies or major increases in electric demand due to weather if nothing is done to change the existing transmission grid, and
- The potential for using new and any remaining (already allocated but not spent) Federal Homeland Security funds to increase transmission capacity, and starting a new federal Energy Department program to fund energy transmission infrastructure projects. Pooled funds from the other cost recovery sources could be used to meet any cost sharing requirements.

This detailed information will reveal the need for and the costs and benefits of a portfolio approach to meeting future energy needs. It will provide an estimate of the cost of addressing concerns about the age and structural condition of the existing grid and the costs of potential blackouts in the future if nothing is done. It will also allow a variety of specific alternative transmission upgrade projects to be proposed and evaluated on a cost and benefit basis, enabling competing projects to be rank ordered for pooled funding purposes in a competitive process.

An example of a potential project is attempting to increase the amount of renewable energy generated in Northern New York and purchased from Quebec, and transmitting it to downstate load centers in the New York City Metropolitan Area and Long Island. This scenario would likely require increasing the capacity of existing HV lines running electrically parallel to the existing 765 KV line from

Quebec to Marcy. The increased capacity of these HV lines would be used to interconnect additional amounts of wind and biomass renewable energy from Northern New York and accommodate the increased contingency requirement associated with increasing the amount of hydropower purchased from Canada and transmitted on the unused capacity of the 765 KV line. Getting the power from Marcy south towards New York City would require increasing capacity on (well known) weak segments of existing EHV lines and increasing capacity on existing HV lines for contingency purposes. In this type of project, a consortium of utilities, NYPA, and private equity would be needed. The privately financed, proposed New York Regional Interconnect project might provide an alternative path from Marcy south to New York City.

Quebec is in the process of its increasing wind power generation, and provinces adjacent to Quebec are considering better interconnections to facilitate the inter-provincial transfer of renewable energy. Increasing the amount of energy purchased from Quebec and transmitted on the existing 765 KV line might facilitate this effort.

Reconductoring these HV lines using commercially available new high temperature-low sag technology should be a first consideration. Increasing electric demand through scheduled transportation offsets in the RGGI program and anti-idling law enforcement during construction phases should be considered. This scenario would minimize concerns about one of the major financing obstacles – creation of unused transmission capacity – as new renewable energy and increased contingency requirements would likely absorb most or all incremental transmission capacity, and new electric demand created from transportation offsets and anti-idling regulations would help generate revenue for cost recovery.