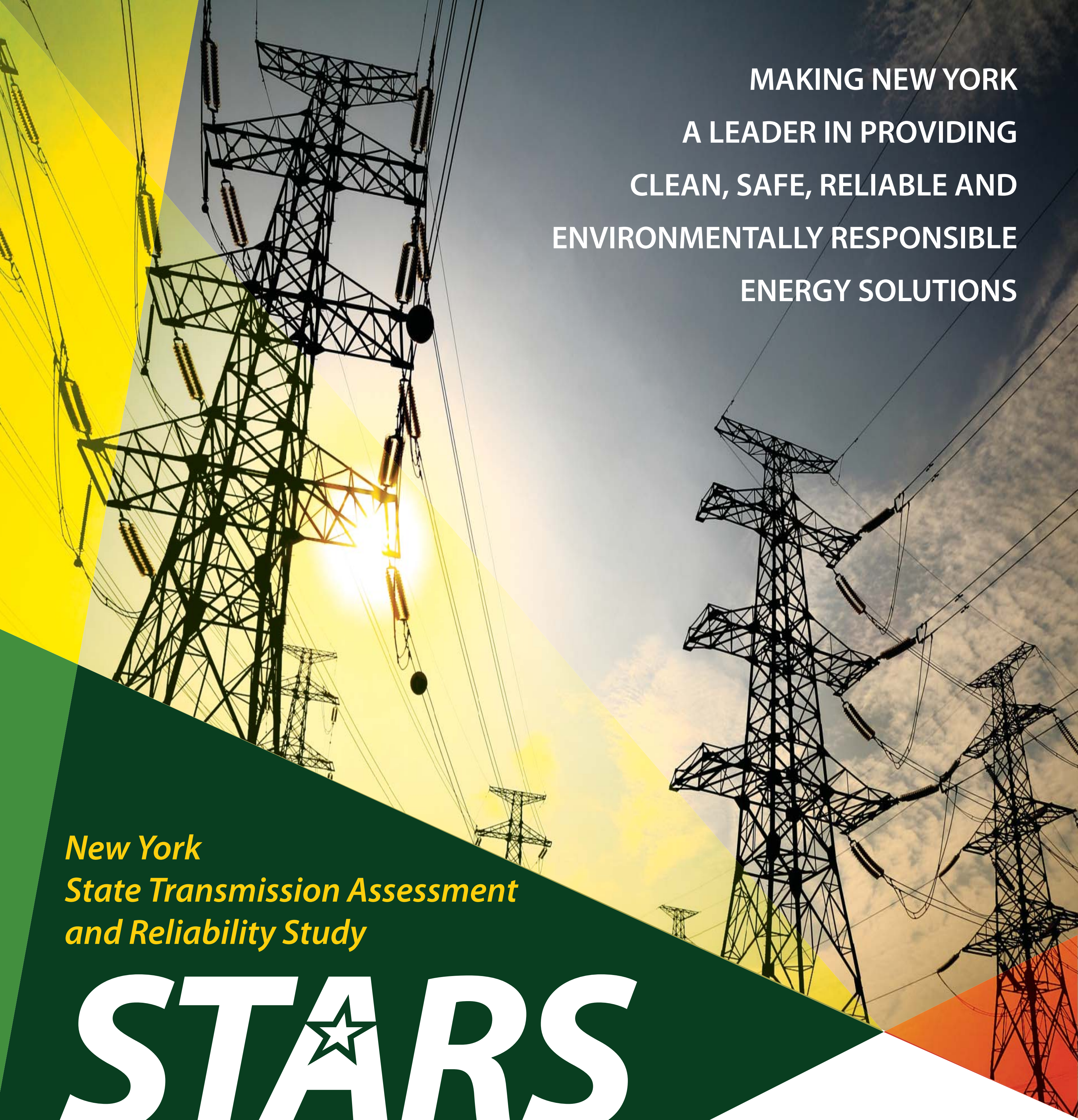

MAKING NEW YORK
A LEADER IN PROVIDING
CLEAN, SAFE, RELIABLE AND
ENVIRONMENTALLY RESPONSIBLE
ENERGY SOLUTIONS

New York State Transmission Assessment and Reliability Study

STARS

Phase II Study Report

Prepared by the STARS Technical Working Group
April 30, 2012

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Executive Summary

1.1 Executive Summary

Overview

Electric transmission plays a significant role in New York's "energy highway." However, the aging transmission system is making for a bumpy ride.

The last major cross-state transmission project was built in the 1980s; 85 percent of the state's transmission lines were built before 1980. And age is not the only challenge on the horizon:

CONGESTION

There is congestion along the 11,600 miles of high-voltage transmission lines in New York, with one-third of the state's electric load located in the proximity of New York City. The transmission pathways from upstate to downstate do not have enough capacity to carry all the electricity that could flow efficiently. The measured impact of this congestion for New Yorkers in 2010 was $1.1 billion.[1]

LINES NEED TO BE REPLACED

Based on a high level age based condition assessment nearly 4,700 miles of lines will approach end of life and may require replacement within the next 30 years.

COAL PLANTS MAY NEED TO CLOSE

Some coal and oil plants may no longer be viable due to a combination of factors which include low gas prices and a potential increase in the cost of environmental compliance.

GENERATION FLEET AGING

The state's electricity generation fleet is aging, with 42 percent of generation plants more than 40 years old.

In an effort to proactively address these looming issues, a new transmission planning study in New York was initiated — the New York State Transmission Assessment and Reliability Study, or STARS for short. The study, which began in 2008, is being conducted and funded by the state's transmission owners, with support from the New York Independent System Operator (NYISO)[2] and consultant ABB.

[1] NYISO 2011 CARIS Report

[2] The NYISO is a private, not-for-profit body that was formed pursuant to New York's deregulation of its energy system more than a decade ago. NYISO operates the transmission grid in New York and sets the price paid for wholesale energy through a complex set of rules and programs.

A team of engineers and experts — known as the STARS Technical Working Group — is thoroughly examining New York's electric transmission system, with a focus on identifying the system's infrastructure needs for the future. The study's long-term planning approach will help transmission owners develop an updated, more reliable system that meets New York Control Area requirements for the next 20 years and beyond.

Preliminary findings of the STARS effort indicate that $25 billion may be spent over the next 30 years if all of the transmission lines identified through the age-based condition assessment were to be replaced. Additionally, $2.5 billion worth of potential projects (including upgrades to existing lines as well as constructing several new lines) have been identified.

Who are the transmission owners in New York?

It's a public/private partnership that includes:

- **Central Hudson** (Central Hudson Gas & Electric Corp.)
- **Con Edison** (Consolidated Edison Company of New York, Inc.)
- **LIPA** (Long Island Power Authority)
- **National Grid**
- **NYPA** (New York Power Authority)
- **NYSEG** (New York State Electric and Gas Corp.)
- **O&R** (Orange & Rockland Utilities, Inc.)
- **RGE** (Rochester Gas & Electric Corp.)

The benefits: Issues lead to opportunities

With careful planning and a long-term approach to developing solutions to future energy needs, the energy issues that New Yorkers face can be turned into opportunities. Consider the good news:

EASE CONGESTION

Congestion in the transmission system can be reduced through expansion of the system, turning current energy "roadways" into "highways." This larger capacity can provide statewide economic benefits by increasing the transmission capability from upstate to downstate.

USE EXISTING RIGHTS-OF-WAY

Existing transmission lines' rights-of-way can be used; it offers the least cost and quickest solution, requires no new corridors, minimizes environmental impact associated with siting and construction, and offers an opportunity to upgrade rather than just replace in-kind key portions of the system.

IMPROVE RELIABILITY

Improving the robustness of the electric transmission system through upgraded and new lines improves the reliability of the system. This enhanced reliability has the potential to reduce the amount of generation necessary for the system to operate reliably.

CREATE JOBS & ECONOMIC GROWTH

Developing an improved energy highway will create jobs and economic growth. In addition to creating thousands of construction jobs, it will generate millions of dollars in additional property taxes and add to the regional gross domestic product (GDP). Every $100 million spent will generate $3 million annually in property tax revenue.

IMPROVE THE ENVIRONMENT

A more efficient energy system means a better environment. A more robust system can accommodate more upstate wind generation and displace less environmentally friendly energy generation such as coal and oil.

MEET CLEAN AIR AND PUBLIC POLICY GOALS

New York will be at the forefront in being prepared to address the impacts of upcoming federal clean air regulations.

Key public policy objectives (such as goals for renewable energy and energy efficiency), as well as the need for a contingency plan for the potential retirement of Indian Point Energy Center, will be advanced.

Overall, a more efficient system will reduce customers' electricity costs; and make New York a leader in providing clean, safe, reliable and environmentally responsible energy solutions.

Scope of the current NYISO system planning process

Compared to STARS' long-range planning horizon, the NYISO's system planning process utilizes a 10-year study horizon that may not identify potential longer-range transmission needs. The NYISO study — the Comprehensive System Planning Process, or CSPP — has two components:

1. **Comprehensive Reliability Planning Process (CRPP);**
2. **Congestion Assessment and Resource Integration Study (CARIS).**

The first component — the Comprehensive Reliability Planning Process (CRPP) — features a reliability needs assessment and a comprehensive reliability plan, which identifies the resources needed on the bulk power system[3] to fulfill federal, regional and state reliability rules, including sufficient capacity to meet New York State Reliability Council's Loss-of-Load Expectation (LOLE) criterion.[4]

One assumption in this planning process is that aging assets continue to operate reliably without consideration of the need for replacement.

The second component of NYISO's planning process — the Congestion Assessment and Resource Integration Study (CARIS) — uses analysis of past and projected congestion statistics to identify the power elements with the most congestion. A benefit/cost analysis of generic generation, transmission and demand-side solutions is performed; then, developers may submit specific transmission solutions for analysis, and beneficiary vote, to determine the project's eligibility for cost recovery under the NYISO Tariff.

When the NYISO's tariff-mandated planning process is augmented by a longer time horizon study such as STARS, additional effective and economical solutions for the state's mature power system (characterized by slower load growth and aging facilities) can be identified. The longer time horizon for planning is necessary to:

6 REASONS FOR A STUDY WITH A LONGER TIME HORIZON

1. **Evaluate whether higher transmission voltage or new technology is necessary and economical.**
2. **Incorporate the need to replace aging infrastructure (transmission lines and substations).**
3. **Address existing limited rights-of-way and siting issues.**
4. **Consider effective integration of renewable resources.**
5. **Meet reliability needs across the New York Control Area system for various resource expansion scenarios.**
6. **Consider emerging technological and regulatory issues with longer-term implications, such as plug-in electric vehicles.**

The above factors are overlapping in nature. Considering all of these factors at the same time will offer a significant number of alternatives and options. As the number of alternatives increase, the effort required for analyses increases substantially.

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[3] Bulk power system means high-voltage transmission (typically 115 kV and greater). It is the "backbone" that transfers electricity around the state to the various load centers. kV is the abbreviation for kilovolts.

[4] LOLE criterion is one day in 10 years, or an annual statewide Loss-of-Load Expectation of no greater than 0.1 days per year.

Long-range planning challenges

The longer planning horizon introduces significant challenges. One of the most challenging issues for long-range transmission planning under open market conditions is the uncertainty associated with new generating plants, including location, size, type, etc. as well as future generator retirements. If a new transmission project is built (including uprating, upgrading) and the new generation does not materialize at the location or in its anticipated size (or capacity), then the new transmission becomes an underutilized asset. Or, in a reverse situation, the transmission becomes limiting, potentially affecting the reliability and congestion of the power system.

Similar issues with respect to the degree of penetration and the location of demand-side resources also exist.

The STARS approach

In light of the uncertainties, the most practical approach is to advance various scenarios of future resource development, and to determine a range of transmission solutions and projects for the defined scenarios. The consideration of various future resource development scenarios significantly increases the amount of effort needed for analyses. However, using carefully considered scenarios, combined with appropriate sensitivity evaluations, assists in defining the transmission capacity requirements to meet reliability criteria and/or provide economic benefits.

Inclusion of aged facilities and renewable resource development to identify a robust mix of transmission alternatives further complicates the analyses. Therefore, the STARS Technical Working Group divided this study into two phases:

1. **PHASE I:** Identify the need for additional transfer capability to meet statewide LOLE with the existing transmission system.
2. **PHASE II:** Identify the most suitable, cost effective transmission alternatives to meet additional transfer capability while considering aged infrastructure and integration of renewable resources.

STARS findings: The details

Several key findings provide guidance for strategic long-range investment needs for the state's transmission system. These investments will ensure that aging infrastructure is replaced, and in some cases upgraded, in a prudent and coordinated manner to maintain and enhance system reliability. These findings take into account the value of utilizing existing transmission lines' rights-of-way, as well as projects that can assist in achieving New York State's Public Policy goals.

1. **40% of the existing transmission system will likely need to be replaced over the next 30 years:** The state's transmission infrastructure is well maintained, but aging. A high-level aged based condition assessment by the STARS TWG of this infrastructure has identified the potential need to replace, over the next 30 years, nearly 4,700 miles of transmission lines at operating voltages of 115 kV and greater. The estimated cost of this replacement is more than $25 billion.
2. **Study assumptions including generation location, type and fuel price forecasts significantly impact findings:** The longer time horizon of the study introduces uncertainty related to key assumptions including forecasted load levels, new generation resources including locations, size and type, as well as similar issues regarding the degree of penetration of and locations of demand side resources. The actual future mix of generation types, fuel costs, emission regulation and allowance prices, as well as the location of new generation additions can have a significant impact on the results of the study.
3. **Reliability needs are met under the statewide generation expansion scenario:** Based on the selected statewide generation expansion scenario, which assumed that

generation was added proportional to load growth, the system meets existing reliability criteria. This scenario did not include significant expansion of the capability of imports from external control areas, such as Hydro-Quebec. This statewide generation expansion scenario represents a conservative view of potential transmission needs. Analysis of other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily, show that the system does not meet established reliability criteria, increasing the need for more transmission.

4. **New transmission will unbottle wind resources:** The NYISO has identified as part of their 2010 Wind Generation Study that as part of the integration of 6,000 MW of wind resources nearly 9% of the wind energy production in three upstate areas would be "bottled" or be undeliverable to the transmission system. The study identifies and models the impacts of the underlying local transmission system upgrades that will allow for the nearly full unbottling of these resources. These upgrades allow for the full utilization of these resources which have been constructed under the State's Renewables Portfolio Standard. The STARS study assumed that these upgrades were in place. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed. No assumptions in the STARS study were made on how these projects would be developed, but they represent additional transmission investment opportunities.
5. **New transmission projects with economic benefits:** The study has identified several projects that provide economic benefits by increasing transfer limits on existing constraints within the state's grid. Projects such as the 3rd Leeds to Pleasant Valley line, a 3rd New Scotland to Leeds line and 2nd Rock Tavern to Ramapo line show promise. These lines would be located within or with minor expansion of existing rights of way. The estimated costs of these projects are slightly over $400M. These projects show annual net benefits based on production cost savings of $18M per year.
6. **Cost effective incremental transmission upgrades:** Based on the overlay of the condition assessment work and the STARS trials there are upgrade projects that provide increased transmission capability at a relatively modest cost. Projects such as the upgrade from 230 kV to 345 kV of the Moses to Marcy lines, Marcy to Rotterdam section of the Marcy to New Scotland line and the Oakdale to Fraser line are good examples. Again these lines would be located within or along existing transmission corridors. The replacement costs of these lines is approximately $1.0B, with the estimated additional upgrade costs of these projects slightly over $600M.
7. **Ancillary benefits of a more robust system:** The system transmission upgrades studied in STARS improve the robustness of the transmission system, which in turn have the potential to reduce the levels of generation reserves required to maintain system reliability.
8. **Upgrades to Moses South are further justified with increased Hydro Quebec imports:** The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit that can be realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.
9. **HVDC lines may help meet public policy objectives:** The HVDC lines from Pleasant Valley to NYC and Long Island that were analyzed as part of the study do not

appear to be justified based on either reliability or economic benefits, but may be justified based on Public Policy goals.

Recommendations

The following recommendations are supported by the analysis performed as part of the STARS effort.

1. Each Transmission Owner should continue to assess the condition of their assets to provide for the long-term reliability of the state's transmission infrastructure as part of their normal capital planning process.
2. Coordinated transmission studies (such as STARS) should be performed and updated on a periodic basis as they provide a mechanism to develop optimized, long-term investment strategies for the state's transmission infrastructure.
3. There are several projects that reduce congestion and provide economic benefits through lower production costs; these projects should be pursued. These 345 kV projects include the 3rd Leeds-Pleasant Valley line, 3rd New Scotland-Leeds line and 2nd Rock Tavern-Ramapo line. Construction of these lines leverages, to the extent possible, the use of existing rights-of-way.
4. To meet state public policy objectives of increased renewable resources, the underlying local upgrades identified in the NYISO 2010 Wind Generation Study should be constructed based on a review of the status of the development of the wind projects in the three upstate areas identified in that study. This would lead to greatly improved deliverability of wind resources and reduced emissions.
5. The export limit from Hydro-Quebec's Chateauguay station to New York is approved at 2,370 MW with all equipment in service, which includes four 765/120 kV transformers. The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection is, however, limited to 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1,380 MW. If there is a desire, from a public policy perspective, to increase the import capability of hydro generation from Quebec, additional analysis would be needed to determine how to best address the loss of single source contingency.
6. Specific projects were identified (3rd Leeds to Pleasant Valley line and 2nd Rock Tavern to Ramapo line) that can be a significant part of solving the reliability needs that would be created with the potential retirement of the Indian Point Energy Center. Several other projects such as the Marcy South Series Compensation and Staten Island Generation Unbottling projects were not evaluated as part of the study, but should be further considered since they appear to provide additional value in addressing this contingency.
7. Several transmission lines that are approaching the end of their useful life should be considered for upgrading to improve the strength of the transmission system backbone. These projects include the upgrade to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of Marcy to New Scotland line and the Oakdale to Fraser line. Upgrades of these lines leverages the use of existing rights-of-ways.

The STARS Study has been conducted in accordance with FERC Order 890 requirements. Periodic updates have been made and stakeholder input sought through the NYISO's Transmission Planning Advisory Subcommittee (TPAS). This report and its attachments are available at the following links:

http://www.nyiso.com/public/webdocs/services/planning/stars/Phase_2_Final_Report_4_30_2012.pdf
http://www.nyiso.com/public/webdocs/services/planning/stars/Phase_2_Final_Report_Attachments 4_30_2012.pdf

Through implementation of the above STARS recommendations, New York will reap the benefits of a more robust transmission system including reduced congestion, improved reliability, enhanced environmental benefits and support for other State Public Policy goals. This will make New York a leader in implementing a clean, safe, reliable and environmentally responsible energy future.

1.2 Abbreviations/Definitions

Base Transmission Plan (BTP): The Initial set of transmission system upgrade projects proposed by the TWG, sometimes referred to as Trial 0, or Initial.

BTP Trials: Subsequent sets of transmission system upgrade projects that are a subset of the BTP. Individual BTP Trials are identified by their trial number, i.e. Trial 1.

Technical Working Group (TWG): The group that performed the technical analysis associated with the STARS Study. Members included representatives from Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company Of New York, Inc. ("Con Edison"), Long Island Power Authority ("LIPA"), National Grid ("National Grid"), New York Power Authority ("NYPA"), New York State Electric And Gas Corporation ("NYSEG"), Orange & Rockland Utilities, Inc. ("O&R") and Rochester Gas & Electric Corporation ("RGE"), and the New York Independent System Operator ("NYISO"). The STARS TWG contracted with ABB to perform parts of the Study.

Reference Case: Used in the sensitivity analysis – base set of assumptions

Sensitivity Case: Adjustment to the base set of assumptions

Replacement Plan: Pre project case that includes underlying upgrades and wind projects

Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid).

Location Based Marginal Price (LBMP): A Locational Based Marginal Price (LBMP) consists of an energy, congestion, and loss component relative to a reference bus. LBMPs represent the incremental value of an additional MW of energy injected at a particular location.

Installed Capacity (ICAP): A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules.

Loss of Load Expectation (LOLE): LOLE establishes the amount of generation and demand-side resources needed - subject to the level of the availability of those resources, load uncertainty, available transmission system transfer capability and emergency operating procedures – to minimize the probability of an involuntary loss of firm electric load on the bulk electricity grid. The state's bulk electricity grid is designed to meet an LOLE that is not greater than one occurrence of an involuntary load disconnection in 10 years, expressed mathematically as 0.1 days per year.

Horizon Year: Planning Horizon for STARS Study. This corresponds to a 20+ year timeframe from now to the year 2030 or later. The NYCA peak load level in the Horizon Year is assumed to be 40,816 MW. See Section 5.1.

Intermediate Year: Halfway period between now and the Horizon Year. The NYCA peak load level in the Intermediate Year is assumed to be 37,130 MW. See Section 5.1.

New York Independent System Operator (NYISO)

New York Control Area (NYCA)

Hydro-Quebec (HQ)

Congestion Assessment and Resource Integration Study (CARIS)

Hudson Transmission Project (HTP)

2

Phase I Summary

Phase I Summary

The STARS Phase I portion of the study focused on defining the long term, approximate 20-year horizon, electric transmission system needs within New York State.

Identifying the most economical and effective solutions for a mature power system, characterized by slower load growth and aging facilities such as exists in the State of New York power system, requires a longer time horizon than the 10 year period of CSPP. More specifically, the longer time horizon is necessary to:

1. evaluate whether a new transmission voltage or technology is necessary and economical
2. incorporate the need to replace aging infrastructure (transmission lines and substations)
3. address various existing limited rights-of-way and siting issues
4. consider effective integration of renewable resources (wind, solar)
5. meet varying reliability needs across the NYCA system in a coordinated manner
6. consider emerging technological and regulatory issues, such as smart grid and plug in electric vehicles, under a reasonable number of potential future scenarios

The above six factors are overlapping in nature. Considering all of these factors at the same time will expand the possibilities to a large number of alternatives and options. As the number of alternatives increase, the amount of effort required for analyses increases substantially.

Generation and transmission are intrinsically connected. One of the most difficult issues for long-range transmission planning under competitive market conditions, is the great uncertainty associated with future additions of new generation plants/units, including location, size, type etc. In theory, generation should be sited close to load centers. However, siting constraints and open market dynamics do not always bear that result. Therefore, transmission must often be built to access the electricity from the generation plant, but is not without risks. If a new transmission project is built and the new generation does not materialize at the location or in its anticipated size (or capacity); then the new transmission becomes an under utilized asset. In the case of reverse situation, the transmission becomes limiting, thereby potentially affecting the reliability and economics (congestion) of the power system. Similar issues with respect to the degree of penetration and the location of demand side resources also exist. In light of these uncertainties, the most practical approach is to postulate various scenarios of future resource development and to determine a range of transmission solutions or projects for the pre-defined scenarios. Even though the scenario approach considerably increases the amount of effort required for the analyses, using carefully considered scenarios combined with appropriate sensitivity evaluations will assist in defining the transmission capacity requirements for meeting the reliability criterion.

2.1 Load levels

In any planning study the starting point is to define a base forecasted load level. The load growth in New York for the past 30 years has been uneven and in recent years has declined; accordingly there is a high degree of uncertainty regarding future electric load within the state. When Phase I of the STARS study began, the most recent load forecast was in the 2008 NYISO Gold Book. Using the published 2018 50/50 non-coincident peak summer load forecast of 37,130 MW, and the corresponding annual growth percentages, in the STARS Study horizon year of 2030, the NYCA load level is projected to be 40,816 MW. This represents the base forecasted load level in the

STARS study. This level of load may happen earlier or later, depending upon the load growth that actually occurs. An example of a higher load growth scenario is a high penetration of plug-in electric vehicles. Conversely, slower load growth could occur due to aggressive energy conservation and efficiency programs, distributed generation etc. A load level of 37,130MW for the Intermediate Year (about half-way of the planning horizon) was assumed. As a reference, the summer peak load for the year 2009 was 30,844 MW; whereas the record peak load of 33,939MW occurred during the summer of 2006.

2.2 Capacity expansion scenarios

The STARS-TWG formulated four scenarios, as a "mix and match" of regional and statewide generation coupled with low and high import possibilities (Figure 2-1). Thus, the four scenarios (#1 through #4) span a wide range of future generation development possibilities and thus define boundaries or "book-end" possibilities. Further, with the Renewable Portfolio Standards (RPS) goals of the state in mind, two additional Scenarios (#5 and #6) explicitly including higher levels of wind generation have also been included. The total new generation capacity added by the Horizon Year for each scenario is based on the installed capacity reserve margin (IRM) of 16.5% that was in effect when the Study started, translating to 5,015MW for Scenarios #1 through #4. Due to lower and differing capacity factors associated with on-land and off-shore wind farms as well as non-coincidence of the maximum wind generation with the system peak load, the total new generation installed capacity requirement (to equal the effective or UCAP requirement of scenario's #1 thru' #4) is 6,834MW for Scenario #5 and 7,740MW for Scenario #6. Therefore, higher wind generation scenarios will likely require an increased IRM.

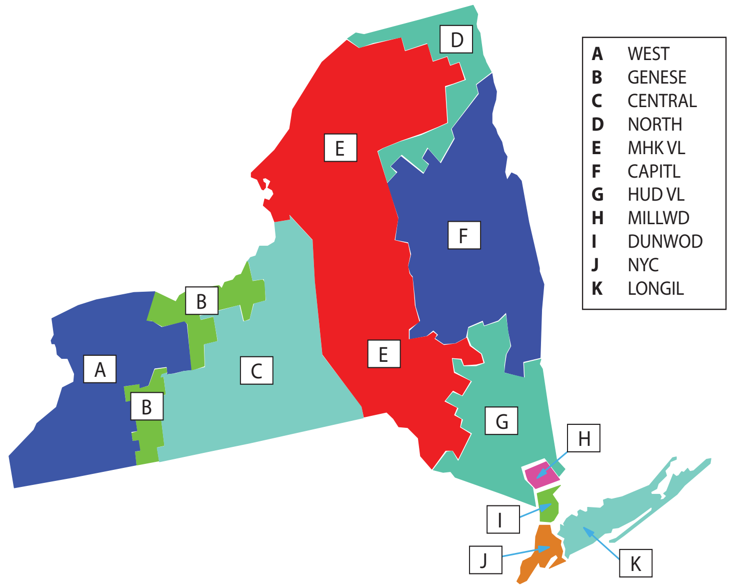
Figure 2-1 Generation expansion scenarios

Scenario	Future capacity scenario	Internally located capacity (as percentage of incremental capacity requirement)	Externally located capacity imports (as percentage of incremental capacity requirement)	Location of externally located capacity imports (as percentage of incremental capacity requirement)
1	Downstate capacity increased	85%	15%	10% ISONE (Zone K)
		Zones H-K		5% PJM (Zone J)
2	Upstate capacity increased	50%	50%	25% PJM (Zones A/C)
		Zones A-F		25% HQ (Zone D)
3	Statewide capacity — low imports	90%	10%	3.3% ISONE (Zone F/G)
		Zones A-K		3.3% PJM (Zone J)
				3.3% HQ (Zone D)
4	Statewide capacity — high imports	25%	75%	25% PJM (Zones I/J/K)
		Zones A-K		50% HQ (Zones D)
Scenarios with wind resources for 25% energy				
5	Downstate capacity	85%	15%	10% ISONE (Zone K)
	Renewables located downstate	Zones A-K		5% PJM (Zone J)
6	Upstate capacity	50%	50%	25% PJM
	50% of renewable capacity located upstate; 50% external	Zones A-F		25% HQ

2.3 Reliability criterion

The resource adequacy reliability criterion for the New York State bulk electricity system is a Loss of Load Expectation (LOLE) of one day in 10 years or 0.1 days per year. Emergency assistance available from external areas (PJM, ISO-NE, Ontario and Hydro-Quebec) is included for the calculation of LOLE. These external areas are also assumed, consistent with the NYISO Reliability Needs Assessment (RNA) assumptions, to achieve the target resource reliability criterion (LOLE of 1 day in ten years) on a multi-area or interconnected operation basis.

Figure 2-2 New York control area load zones



2.4 Methodology

The main methodology for this Phase-I Study is to determine the transmission capacity requirements for various scenarios to meet the above-mentioned LOLE. The primary tool used for LOLE calculation in this study is GridView[5]. In this model a full representation of the transmission network is used. In addition to the detailed transmission network representation, the GridView model contains various constraints for transmission lines, interfaces, contingency constraints, monitored lines, nomograms and emergency operating procedures (EOP).

Figure 2-3 Emergency transfer limits for LOLE calculations for the existing transmission system (intermediate year)

Interface	Limit MW
Dysinger East	2,504 (V)
West Central	1,134 (V)
Moses South	1,971 (V)
Volney East	3,952 (V)
Total East (Closed)	6,270 (V)
Central East	2,604 (V)
Central East + Fraser-Gilboa	2,916 (V)
CE Group	4,587 (V)
F to G	3,485 (T)
UPNY-SENY Open	5,124 (T)

(T) = Thermally constrained
(V) = Voltage constrained

Interface	Limit MW
UPNY-ConEd Open	5,392 (V)
Millwood South Closed	8,161 (V)
Dunwoodie South Plan	5,780 (T)
I to J	4,460 (T)
I to K (Y49/Y50) with Y49 flow set to 637	1,238 (T)
I to K (Y49/Y50) with Y49 flow set to 637 and Y50 RateA=653 MVA	1,293 (T)
I to J+K	5,413 (V)
LI import (with LIPA imports maximized)	2,851 (T)
LI import (with LIPA imports maximized and Y50 RateA=653 MVA)	2,905 (T)
Marcy South	1,686 (V)

[5] GridView is ABB's reliability analysis and market simulation software using Monte Carlo simulations. Gridview results benchmarked are very close to the values from GE Multi-Area-Reliability Simulation Program used by NYSRC and NYISO for LOLE studies

2.5 Transfer limits

The Interface Transfer Limits, which are defined as the amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules, for both Cross-State and External areas (Figure 2-3) were computed for the existing transmission topology and the intermediate year conditions and are close to the NYISO 2009 RNA assumptions and findings. These limits are used in the Gridview model for the LOLE calculations.

2.6 Calculated LOLE for the six scenarios

The LOLE index was calculated for each of the six scenarios (Figure 2-4. For Scenarios #1 and #5, the calculated LOLE values show that the postulated generation expansion plans combined with the existing transmission capability can meet the target reliability index of 0.1 days/year. This can be attributed to most of the new generation capacity (85%) being added in the downstate load zones for these two scenarios. In Scenario #3, the new generation (90%) was distributed proportionally to each zone across the state and resulted in an LOLE that did not meet the targeted reliability level. Scenario #4, with a heavy emphasis on out of state imports (75% of new capacity) shows that LOLE criterion cannot be met with the existing transmission system. The Scenarios #2 and #6 (with 50% of generation in the upstate zones and the other 50% from external imports) have the highest LOLE of the generation expansion scenarios studied and hence reliability criterion cannot be met with the existing transmission system. The LOLE value for Scenario #6 (similar to Scenario#2, but with more wind) is a bit higher, because the installed generation capacity considered for Wind Scenarios is in the up-state zones. Similar comparison can be made between LOLEs for Scenarios #1 and #5.

***Figure 2-4** Calculated LOLE values for six generation expansion scenarios (horizon year) with existing transmission*

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
NYCA LOLE days/year	**0.06**	**1.68**	**0.20**	**0.44**	**0.07**	**1.82**
Reliability criteria met?	YES	NO	NO	NO	YES	NO

2.7 Additional transmission capacity for scenarios 2, 3, 4 & 6

The study results have shown that the reliability criterion is only met for Scenarios #1 & #5 which assumes significant new generation being added downstate. However, the LOLEs for Scenario #s 2, 3, 4 and 6 (new upstate generation, low/high imports, more wind) are above the desired value. In order to estimate the additional transmission capacity needed to reduce the LOLE values to 0.1 days/year the GridView simulations were repeated for these four Scenarios to determine the additional transmission MW needed for each of the Interfaces (Figure 2-5) to achieve the reliability criterion. Because Scenarios #5&#6 are similar to Scenarios #1&#2, results for only the four primary scenarios are shown in Figure 2-5. The values in green color show the lowest amount of needed MW, the red color the highest amounts and the black color for in-between amounts. The MW need for each scenario (shown in each column) should be interpreted to be simultaneous, i.e. all the interface transfer limits need to be increased to the levels shown. In other words, increasing only one or a few of the interfaces to the shown MW levels is not sufficient to achieve the LOLE criterion. The actual upgrade to all the Interfaces will likely be somewhere between the boundaries of the low and high values in red, as they define the book end limits.

Figure 2-5 Additional transmission capacity need for the four scenarios (horizon year)

Additional transfer capability (MW) need

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
CE Group	0	1,460	150	1,185
UPNY-SENY	0	1,735	249	702
Volney East	0	1,314	492	648
Central East	0	1,047	279	1,106
I to J	0	1,135	386	424
Y49Y50	0	752	159	972
F to G	0	1,171	187	399
Total East	0	1,274	0	456
West Central	0	265	316	192
Marcy South	0	435	15	257
Moses South	0	0	0	228
HQ-D	0	0	0	550

The values in Figure 2-4 are shown to a precision of one MW. For practical purposes, the values will be rounded when considering the MW need in Phase II when transmission alternatives are being analyzed for those scenarios which require transmission reinforcements.

The values in Figure 2-5 are shown to a precision of one MW. For practical purposes, the values will be rounded to the nearest 25 MW when considering the MW need in Phase II when transmission alternatives are being analyzed for those scenarios which require transmission reinforcements.

2.8 Transition from Phase I to Phase II

The actual expansion of the NYCA transmission grid should be adapted to account for the constantly evolving load growth, location and magnitude of future resource capacity additions, and assumed emergency assistance from neighboring control areas. For example, additional resource capacity assumed Downstate (Scenario 1) was shown to mitigate or eliminate the need for transmission expansion for the study horizon, without consideration of aged infrastructure. Conversely, resource capacity assumed for Upstate (Scenario 2) showed a need to expand the transmission system to satisfy system reliability requirements. The reliability needs along with the aging infrastructure needs and the delivery of renewable resources are all considerations within Phase II of the study. In addition to the study objectives of satisfying system reliability needs, as well as establishing coordinated efforts to address aging infrastructure needs and identifying projects that achieve public policy objectives such as the deliverability of renewable resources, Phase II of the study also evaluated projects that provide economic benefits to the state by relieving known constraints that exist within the system. By considering all of these important objectives the study provides a holistic evaluation of the potential transmission projects best suited to achieve them. As with any study of this type, time will tell which scenario reflects more accurately the location of new generation and/or demand side resources. However, since timescales for constructing transmission reinforcements are in the five to ten year time horizons for large scale improvements, it will be necessary to identify those projects that can provide the overall best values for the state when considering all of the needs. Since generation expansion assumptions have a major impact on scenario analysis, and there have been some major changes in base generation assumptions since the start of this study, Phase II updated the power flow base case with likely new generation to be installed in the state in the next 5 years based on how far along they are in the current NYISO interconnection process. The updated power flow base case with economic dispatch was used for determination of new Interface Transfer Limits.

3

Transmission system condition assessment

3.1 Transmission system condition assessment

In preparation for the initiation of the Phase II portion of the STARS study a Condition Assessment Working Group was formed to determine the potential long term needs required to address the replacement of aging transmission system.

Subject matter experts were assembled from all the participant companies. The group utilized a high level screening criteria of 70 years for wood pole lines and 90 years for steel pole lines in establishing the potential time frames when transmission facilities would require replacement. It is recognized that an aged based criteria alone is not a sufficient justification for the replacement of assets and that detailed condition assessment analyses would be required prior to justifying a facility for replacement. If more detailed condition assessment information was available it was utilized in lieu of the 70 and 90 year aged based criteria.

The value of having the high-level condition assessment information was to provide input into the development of transmission reinforcement projects in Phase II. Opportunities were identified where it might be prudent to consider a thermal or voltage upgrade rather than simply replace a facility "in-kind" due to condition.

The Condition Assessment Working Group identified the potential need to replace nearly 4700 miles of transmission at operating voltages 115 kV and above over the next 30 years (Figure 3-1). The estimated cost to replace this infrastructure utilizing high-end pro-forma estimates from CARIS is over $25 billion. Figure 3-1 provides a breakdown of these transmission infrastructure needs by company and voltage class.

Figure 3-1 Future transmission infrastructure needs

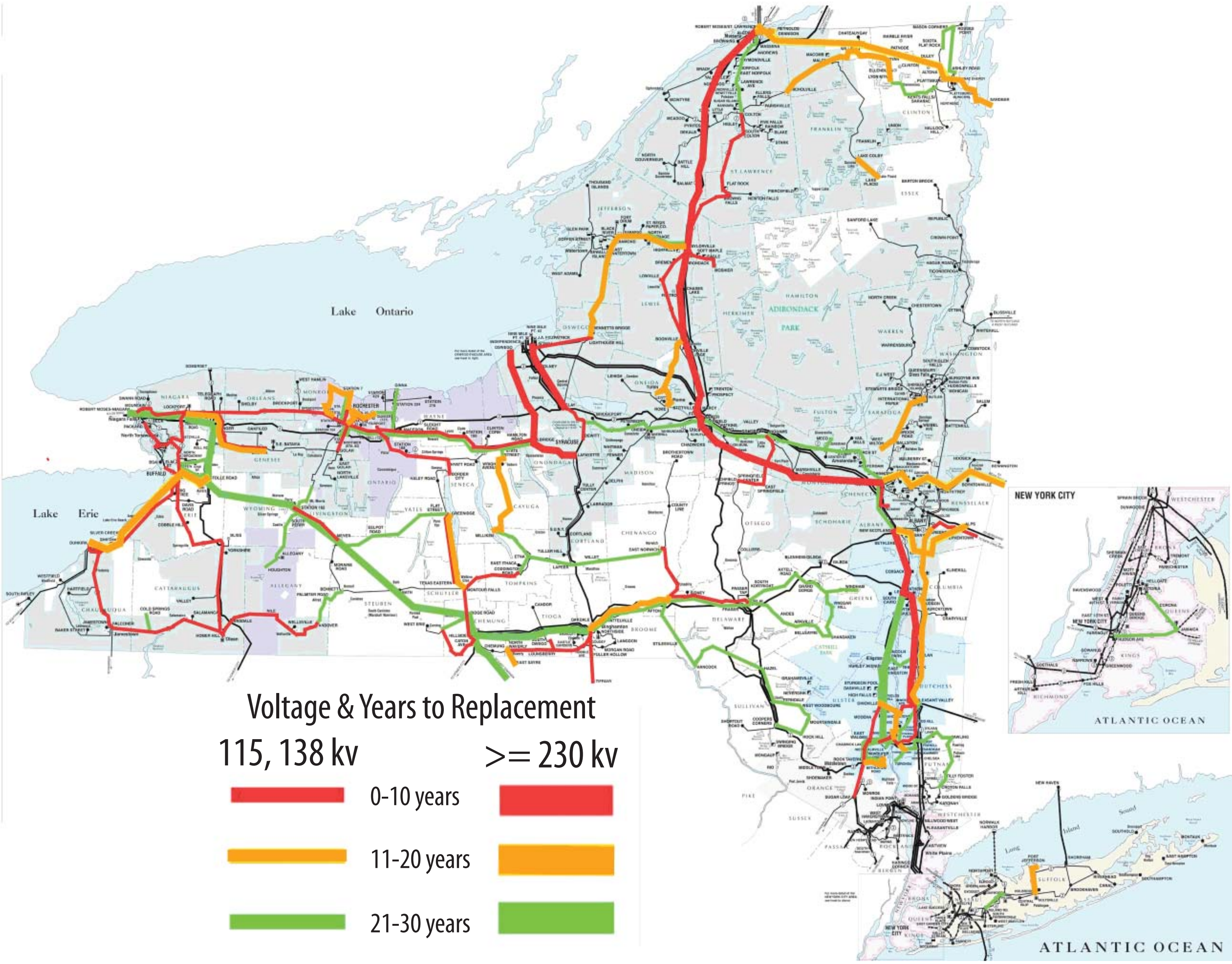
Voltage	Central Hudson	ConEd	LIPA	National Grid	NYPA	NYSEG	O&RU	RGE	Total miles replaced	Total miles
Overhead										
115/138kV	61.4%	0.0%	7.8%	42.5%	46.3%	64.1%	64.4%	87.3%	3,441	7,173
230kV	0.0%	0.0%	0.0%	53.4%	89.1%	99.6%	0.0%	0.0%	794	1,066
345kV	100.0%	0.0%	0.0%	43.8%	0.0%	0.0%	0.0%	0.0%	375	2,624
500kV	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0	5
765kV[1]	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0	155
Total OH system replaced	70.7%	0.0%	7.8%	43.5%	22.3%	52.5%	40.6%	87.3%	4,610	11,024
Underground										
Total UG system replaced	0.0%	11.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	45	602

[1]Lines constructed for but not operated at 765 kV

To highlight the replacement requirements, the STARS Condition Assessment Working Group created an overlay for the New York State Electric System map which depicts the corridors where transmission facility replacement work may be necessary (Figure 3-2).

***Figure 3-2** New York state transmission condition assessment map*

STARS age-based condition assessment



4

Phase II scope

Phase II scope

4.1 Background

Phase I of the STARS study was completed in January 2010. The results of that study were based on resource capacity, other assumptions and data available at the time the study started in February 2009. Since then, there were substantial new resources proposed in the downstate as well as in the upstate zones. Several projects had completed the interconnection process, entered the class year and completed cost allocation. In the NYISO planning process, acceptance of class year cost allocation suggests a project with high likelihood of realization. In addition to the new resources, there were some transmission improvements (DOE stimulus projects including planned capacitor banks in NYSEG, RGE, NYPA, CHGE and NATIONAL GRID systems, local transmission improvements in LIPA system) that had been previously identified by the NYTOs. It was deemed that this new information, if included in the calculation of LOLE, will result in reduction of transmission needs. Based on the above situation and the information available (as of February 2010), the STARS Executive Committee and the STARS TWG considered it prudent to include the new information and re-compute the transmission MW needs. This is described under Section 4.2 below (Initial Analysis) and culminated in the summer of 2010. Subsequent analysis was performed after this period and included the following activities:

- Evaluation of Aging Infrastructure – Condition Assessment
- Selection of Generation Expansion Scenario
- Include projects recommended by the NYISO Wind Study
- Development of Base Transmission Plan (BTP)
- Economic Analysis of Base Transmission Plan (Production Cost / LBMP Analysis, ICAP Cost Savings)

The findings of these activities are described in subsequent sections of this report. As described previously, the actual expansion of the NYCA transmission grid should be adapted to account for the constantly evolving load growth, location and magnitude of future resource capacity additions, and assumed emergency assistance from neighboring control areas. In Phase I of the study transmission needs required to maintain system reliability were identified. Phase II will address the coordinated upgrade and new transmission infrastructure needs necessary to achieve public policy goals, deliver renewable resources and / or provide economic benefits to the state by relieving known constraints that exist within the system. By considering all of these important objectives the study will result in a holistic evaluation of the potential transmission projects best suited to achieve them.

4.2 Initial Phase II analysis

Initial analysis performed during 2010 included the following generation additions to the 2030 horizon year study models developed in Phase I of the STARS study (See Attachment #1):

- Astoria Energy II in Zone J (550 MW)
- Solar Farm in Zone K (50 MW)

In addition, generation retirements in Zone C (see Section 5.3 for details) were also reflected in the study models. Also included in the study models were the DOE stimulus projects, including planned capacitor bank additions as proposed by the NYTOs. In addition, some minor modeling changes were made to the power flow models based on input provided by the NYISO and NYTOs.

The capacity expansion scenarios assumed in the Phase I study were updated to include the modeling changes described above. The basis used by the STARS TWG for developing the four Scenarios (or book-end possibilities of new resources) is shown in Table 2-1 of the Phase I Report. The above-mentioned generation additions, noted earlier, are in Zones J and K. Because, the premise for Scenario 1 was that 85% of the new generation is to be located downstate, the two major generation projects are already included in Scenario 1 by default. Hence, it was deemed that there was no need to modify the Scenario 1 generation allocation and assumptions or to repeat LOLE calculations. Thus, the generation capacity additions and retirements were used to modify the three remaining Scenarios (Scenarios 2, 3 and 4). The new generation capacity for the horizon year was calculated as follows:

- With 65% capacity credit, the new Solar Farms have effective capacity of 32.5 MW
- Adding the new units and including retirements, reduced the new capacity requirement (Table 2-4, Phase I report) from 5,015 MW to 4,528 MW (=5015-550-32.5+53+42) (See generation expansion and retirement details in Section 5)

The new revised capacity requirement of 4,528 MW for the three Scenarios was allocated according to the Scenario definition in Table 2-1 of Phase I report. For example, in Scenario 3, the additional generation is 4,075 MW (i.e., 90% of 4,528 MW). Further, the additional generation was allocated to each zone in proportion to the zonal load. Generic 250MW units with 6% forced outage rate are assumed for the new generation, unless only smaller amounts are indicated. The new generation units assumed for the three Scenarios are shown in Figure 4-1. The updated scenarios are renamed 2A, 3A and 4A to avoid confusion with the original capacity expansion scenarios.

Figure 4-1 New generation capacity for scenarios 2A, 3A and 4A

Scenario-2A (50% upstate, 50% external)

50 % of requirement		2,264		2,264					**50% of requirement**			2,264	2,264
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	496	2	500	KINTI345	345	1	250	25%	PJM	ZONES-A&C	1,132	1,132
					DUNKIRK	230	1	250					
ZONE-B	2,365	376	2	500	ROCHESTER	345	2	500	25%	HQ	ZONE-D	1,132	1,132
ZONE-C	3,323	528	2	500	CLAY	345	2	500					
ZONE-D	971	154	0	-	MASS230A	230	0	-					
ZONE-E	1,600	254	1	264	EDIC	345	1	264					
ZONE-F	2,868	456	2	500	ATHENS	345	2	500					
ZONES-TOTAL	14,250	2,264	9	2,264			9	2,264					2,264
TOTAL NEW CAPACITY		2,264									TOTAL	2,264	

Scenario-3A (90% all zones, 10% external low import)

90 % of requirement		4,075		4,075					**10% of requirement**			453	453
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	312	1	250	KINTI345	345	1	250	3.3%	ISONE	ZONES-F&G	151	151
					DUNKIRK	230	0	-	3.3%	PJM	ZONE-J	151	151
ZONE-B	2,365	236	1	250	ROCHESTER	345	1	250	3.3%	HQ	ZONE-D	151	151
ZONE-C	3,323	332	2	500	CLAY	345	2	500					
ZONE-D	971	97	0	-									
ZONE-E	1,600	160	1	250	EDIC	345	1	250					
ZONE-F	2,868	286	1	250	ATHENS	345	1	250					
ZONE-G	2,948	294	1	250	HURLEY 3	345	1	250					
ZONE-H	782	78	0	-									
ZONE-I	1,753	175	1	75	PL VILLE	345	1	75					
ZONE-J	14,326	1,430	6	1,500	E 13TH ST	345	4	1,000					
					W 49TH ST	345	2	500					
ZONE-K	6,757	675	3	750	RULAND	138	2	500					
					HOLLBROOK	138	1	250					
ZONES-TOTAL	40,816	4,075	17	4,075			17	4,075					453
TOTAL NEW CAPACITY		4,075									TOTAL	453	

Scenario-4A (25% all zones, 75% external high imports)

25 % of requirement		1,132		1,132					**75% of requirement**			3,396	
			Conventional		**Locations for new generator**								
	Load	New gen	Units	MW	Bus name	kV	Units	MW					**Conventional**
ZONE-A	3,123	87	1	250	KINTI345	345	1	250	25%	PJM	ZONES I/J/K	1,133	1,133
ZONE-B	2,365	66	0	-				-					
ZONE-C	3,323	92	1	250	CLAY	345	1	250					
ZONE-D	971	27	0	-				-	50%	HQ	ZONE-D	2,267	2,267
ZONE-E	1,600	44	0	-				-					
ZONE-F	2,868	80	0	-				-					
ZONE-G	2,948	82	0	-				-					
ZONE-H	782	22	0	-				-					
ZONE-I	1,753	49	0	-				-					
ZONE-J	14,326	397	2	500	E 13TH ST	345	1	250					
					W 49TH ST	345	1	250					
ZONE-K	6,757	187	1	128	RULAND	138	1	128					
ZONES-TOTAL	40,816	1,133	5	1,128			5	1,128					3,400
TOTAL NEW CAPACITY		1,128									TOTAL	3,400	

Next, emergency transfer limits for key NYCA interfaces derived in the Phase I study were updated based on the above modeling assumptions. The updated emergency transfer limits were used in the subsequent LOLE analysis on Scenarios 2A, 3A and 4A.

GridView simulations were performed on scenarios 2A, 3A and 4A and the LOLE indices were recalculated. Results are shown in Figure 4-2. The results shows that with 550 MW added to zone J and 32.5 MW effective solar capacity added to zone K, the LOLE indices reduced significantly for all the three scenarios: from 1.68 to 0.96 days/year for Scenario 2A; from 0.20 to 0.08 days/year for Scenario 3A, and from 0.44 to 0.36 days/year for Scenario 4A.

Figure 4-2 Calculated LOLE values for scenarios 2A, 3A and 4A

	Horizon year's LOLE (days/year)		
Zones	**Scenario 2A**	**Scenario 3A**	**Scenario 4A**
A	-	-	-
B	0.34	0.03	0.12
C	-	-	-
D	-	-	-
E	0.82	0.06	0.32
F	-	-	-
G	0.80	0.08	0.30
H	0.00	0.00	0.00
I	0.88	0.07	0.30
J	0.97	0.07	0.33
K	1.02	0.08	0.38
NYCA	**0.96**	**0.08**	**0.36**

Since the updated Scenario 3A has an LOLE of 0.08 days/yr, it was deemed that only Scenarios 2A and 4A would need additional transmission capacity for reliability purposes. Using the methodology, described in Phase I report (Section 9.4), a series of sensitivity cases were simulated for Scenarios 2A & 4A. Additional transmission capacities were calculated (based on statistical average peak interface flow value). Results are summarized in Figure 4-3.

Figure 4-3 Additional transfer capability needs (MW)

	Scenario 2	Scenario 2A	Reduction	Scenario 3	Scenario 3A	Reduction	Scenario 4	Scenario 4A	Reduction
I to J	1,135	505	630	386	0	386	424	0	424
Marcy South	435	173	262	15	0	15	257	6	251
F to G	1,171	698	473	187	0	187	399	89	310
UPNY-SENY	1,735	933	803	249	0	249	702	142	560
CE Group	1,460	766	694	150	0	150	1,185	712	473
Central East	1,047	745	302	279	0	279	1,106	750	356
Volney East	1,314	916	398	492	0	492	648	256	392
West Central	265	102	164	316	0	316	192	0	192
Y49Y50	752	499	253	159	0	159	972	719	253
Total East	1,274	499	774	0	0	0	456	0	456
Moses South	0	0	0	0	0	0	228	0	228
HQ-D	0	0	0	0	0	0	550	300**	250
UPNY-CE	1,219	561	658	NA	0	NA	NA	0	NA

** based on HQ-D nonemergency limit of 1,200 MW

Figures 4-2 and 4-3 demonstrate how sensitive resource adequacy is to generation siting. In the generation expansion for Scenario 3A with 90% of the expansion located in the New York control area, the LOLE meets criteria and there is no additional transfer capability needed. For other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily the system does not meet established reliability criteria and there is an associated additional transfer capability need, thus a need for more transmission.

4.3 Generation expansion scenario selection

As was discussed in the Phase I portion of the study and as demonstrated in the updated Phase II analyses presented above the identified needs of the transmission system need to be adapted and account for the constantly evolving load growth, location and magnitude of future resource capacity additions and assumed energy assistance from neighboring control areas. Since the generation expansion assumptions have such a significant impact on resource adequacy and potential transmission expansion needs from a reliability perspective the study group sought guidance on the most appropriate assumptions to select for the detailed transmission planning analysis that would be performed in Phase II.

The study group during late spring and early summer of 2010 consulted with the executives of the study group companies as well as the NYISO and PSC staff in determining which generation expansion scenario would be most appropriate to select. By consensus it was agreed to utilize generation expansion scenario 3A in Phase II of the study. It was felt that this scenario represented the most probable view of generation additions. It should be noted that the utilization of this scenario represents a conservative view of potential transmission expansion needs during the studies time horizon since generation is assumed to be added proportional to load growth across the state, with minimal reliance on additional imports, and at a magnitude that maintains a reserve margin level consistent with current requirements.

4.4 Scenario update

Additional updates were made to Scenario 3A assumptions based on discussions between the STARS Executive Committee, STARS TWG and NYISO. These discussions resulted in the following modeling updates to the horizon year study models for Scenario 3A.

- Addition of Hudson Transmission Project (HTP): This is a 660 MW High Voltage Direct Current (HVDC) transmission link between New York City (Zone J) and PJM Interconnection. The PJM Interconnection Service Agreement (ISA) between PJM, Hudson Transmission Partners, L.L.C. and Public Service Electric and Gas Company , specifies that only 320 MW of the rated transmission capacity of the Hudson Transmission Project is available as Firm Transmission Withdrawal Rights (FTWRs), while the remainder is considered Non-Firm Transmission Withdrawal Rights (NFTWRs). The ISA clarifies that if TWRs above the allotted 320MW were to be requested that significant transmission upgrades would be necessary to reliably accommodate increased FTWRs. The STARS study has assumed that transmission upgrades, such as the Branchburg-Roseland-Hudson project proposed in the 2008 through 2010 PJM Regional Transmission Expansion Plans , will be constructed by year 2030, therefore the HTP was modeled to economically flow up to its full rated capacity. At this point the PJM upgrade (Branchburg-Roseland-Hudson project) has been canceled as noted in the published 2011 RTEP, and the HTP utilization may not be fully achievable by year 2030.

- Addition of 4,725 MW of Wind Generation in NYCA (for a total of 6,000 MW): See Section 5.5 of this report. Reference [2] provides additional information on the wind additions.

It should be noted that the above projects replace some of the generic generation assumed in Scenario 3A. Thus, the capacities of generic generators were reduced to keep the total added generation within the NYISO to 4,075 MW as specified by Scenario 3A. The adjustment took into account the typical capacity factors of the wind generation. Figure 4-4 shows details on the generic unit adjustments.

Figure 4-4 New generic generation capacities after scenario 3A update

Zone name	Zone ID	% of total internal MW addition	No. of generic units	Original generic generation capacity (MW)	% of generic generation addition	Original individual unit generic generation capacity (MW)	Individual unit adjustment for adding HTP (MW)	Adjust-memt for 4,725 MW wind additions (MW)	New individual unit capacity (MW)	New total zonal generic generation capacity (MW)
West	A	7.7	1	250	5.5	250	(36)	(26)	187	187
Genessee	B	5.8	1	250	5.5	250	(36)	(26)	187	187
Central	C	8.1	2	500	11	250	(73)	(52)	187	374
North	D	2.4	0	0	0	0	0	0	0	0
Mohawk Valley	E	3.9	1	250	5.5	250	(36)	(26)	187	187
Capital	F	7	1	250	5.5	250	(36)	(26)	187	187
Hudson Valley	G	7.2	1	250	5.5	250	(36)	(26)	187	187
Milwood	H	1.9	0	0	0	0	0	0	0	0
Dunwoodie	I	4.3	1	75	1.7	75	(11)	(8)	56	56
NY City	J	35.1	6	1,500	33.1	250	(219)	(157)	187	1,122
Long Island	K	16.6	3	750	16.6	250	(109)	(78)	187	561
Hydro Quebec	HQ	0	1	151	3.3	151	(22)	(16)	113	113
ISO New England	ISONE	0	1	151	3.3	151	(22)	(16)	113	113
PJM	PJM	0	1	151	3.3	151	(22)	(16)	113	113
Totals		**100**	**20**	**4,528**	**100**		**(660)**	**(473)**		**3,387**

The last column shows the calculated generic unit capacities (3,048 MW within NYCA and 339 MW outside NYCA). Also, the locations of some of the generic units in Zones F, G and J were changed based on the assumptions made in the economic analysis portion of the study. Figure 4-5 shows the updated generator locations. The Scenario 3A case as updated above is designated the Reference Case in the study.

Figure 4-5 Modified generic generator locations after scenario 3A update

	Locations of generic units				NYISO adjusted
	Bus name	kV	Units	MW	
Zone A	KINTIGH	345	1	250	187
	DUNKIRK	230	0	-	
Zone B	ROCHESTER	345	1	250	187
Zone C	CLAY	345	2	500	374
Zone D					
Zone E	EDIC	345	1	250	187
Zone F	NEW SCOTLAND	345	1	250	187
Zone G	ROCK TAVERN	345	1	250	187
Zone H					
Zone I	PLEASANTVILLE	345	1	75	56
Zone J	EAST 13TH ST	345	1	250	249
	GOWANUS N	345	1	250	249
	RAINEY	345	1	250	249
	WEST 49TH ST	345	3	750	374
Zone K	RULAND	138	2	500	374
	HOLBROOK	138	1	250	187
TOTAL			17	4,075	3,048

5 *Study assumptions*

Study assumptions

Attachment 3 lists the modeling assumptions used in the Phase II study effort (refer to study assumptions matrix). Additional details on some of the more significant assumptions are provided in the following subsections.

5.1 Load levels

When Phase I of the STARS study first began, the most up-to-date load forecast was in the 2008 NYISO Gold Book. Using the published 2018 50/50 non-coincident peak summer load forecast of 37,130 MW, and the corresponding annual growth percentages, the STARS Study horizon year NYCA load level was projected to be 40,816 MW. The STARS TWG is aware that with the latest forecasts, this load level may not be realized in 2030 (Figure 5-1).

Figure 5-1 *Load forecast year*

NYISO load forecast (all include EE impacts)	STARS equivalent study year using NYISO Gold Book	
	2010 load forecast	2011 load forecast
50/50 coincident summer peak	2035	2036
50/50 non-coincident summer peak	2033	2035
90/100 coincident summer peak	2029	2030

5.2 Planned facilities

Prior to the start of the Phase II study effort, the STARS TWG and the NYISO together identified a set of projects that were deemed to have a high likelihood of being commissioned within New York State within the next 5 years based on how far along they are in the NYISO interconnection process. These projects included the following facilities:

- Astoria Energy II (550 MW)
- LIPA Solar Farm (50 MW)
- Hudson Transmission Project (HTP, 660 MW)

The Bayonne project was not included in the study models because its status was deemed unknown at the time the Phase II study assumptions were finalized.

5.3 Generation retirements

The following generation retirements were included in the Phase II study. This is based on information contained in the 2010 NYISO Gold Book.

- Greenidge 3 (53 MW)
- Westover 7 (aka Goudey, 42 MW)

5.4 Generic generation expansion scenario units

Figure 4-1 shows the original expansion scenario units modeled in the Phase II analysis. The corresponding units in updated Scenario 3A are shown in Figure 4-5.

5.5 Wind generation

In September of 2010 the NYISO released a study titled "Growing Wind" that analyzes in great detail the reliability, economic, environmental, and regulatory aspects of increasing wind generation capacity in New York State. The study outlines three expansion scenarios where New York wind generation capacity is evaluated at 4,250 MW (New York State Renewable Portfolio Standard (RPS) Goal for 2013), 6,000 MW, and 8,000 MW capacity levels. The STARS base system model includes the 6,000 MW of wind generation and associated transmission upgrades necessary to deliver that generation to the bulk power system. Both the 4,250 MW and 8,000 MW wind capacity cases and their associated transmission upgrades were modeled in the sensitivity analysis phase of the STARS study.

Figure 5-2 NYISO nameplate wind generation by zone (MW)

NYISO zone:	West	Genesee	Central	North	Mohawk Valley	Capital	NYC & LI	Total
Base wind capacity:	1,291	281	1,593	1,068	1,647	70	0	5,949

Wind generators are modeled with fixed schedules and have the capability to curtail their output. Each generator is assigned a wind curve that represents historical geographical yearly wind patterns and is scaled to match the nameplate rating of the wind plant. The historical wind curves used were developed by AWS Truewind for the NYISO Wind Study.

The specific projects recommended by the NYISO wind study and included in the study are included in Section 6.6 of the report.

5.6 Transmission system model

The Horizon Year power flow models used in the Phase II study were derived from the Phase I study effort. See Reference [1]. Models were updated to reflect planned facilities, generation retirements, expansion scenario units and wind additions as described in the preceding sections.

5.7 Resource reliability model

The primary tool used for LOLE calculation in this study is GridView software. In this model a full representation of the transmission network (as in the power flow cases including external areas) is used. In addition to the detailed transmission network representation, the GridView model contains various constraints for transmission lines, interfaces, contingency constraints, monitored lines, nomograms and emergency operating procedures.

5.8 Interface limits

Horizon year emergency thermal transfer limits were calculated for key NYCA interfaces with the Base Transmission Plan projects and variations thereof (Trials 9 and 10; See Section 8.3.3). The Central East related interfaces have traditionally been voltage limited, whereas the other interfaces have tended to be thermally limited. So for purposes of this study, voltage transfer limits were only calculated for the Central East related interfaces. The lower of the two limits were used in the subsequent LOLE analysis.

5.9 Fuel forecast

The fuel forecasts used as inputs into the production cost model were developed using the publicly available forecasts made by the Energy Information Administration (EIA) from Spring 2011. The forecasts were adjusted for seasonality and monthly volatility based upon historical patterns in the NYCA.

5.10 HQ model update

The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.

As part of the production cost analysis a price sensitive model for HQ generation consisting of a thermal generator/load pair was created to produce an equivalent maximum generation amount. Historical HQ imports were used to develop an appropriate energy output pattern for the thermal generator/load pair. Additional details regarding this model are provided in Attachment 4.

5.11 Emissions forecast

The emissions price forecasts were created based upon the most up-to-date regional rules and regulations established at the time of the production cost database update (consistent with NYISO CARIS II 2010). The forecasts were driven largely by the Environmental Protection Agency's Clean Air Transport Rules.

5.12 Economic assumptions

The Replacement Plan for the STARS economic analysis was developed from the 2009 NYISO CARIS Phase I ABB GridView database and model. There were a significant number of changes and updates made to the database in order to align with the STARS assumptions, which are listed in Attachment 3. The major assumptions utilized in the economic database and production cost simulations are outlined below.

- 40,816 MW NYCA Peak Load
- Updated Generation & Transmission from NYISO Queue
  - Astoria Energy II
  - LIPA Solar
  - Hudson Transmission Project
- 4,528 MW of Generation Capacity Expansion
  - 90% Internal to NYCA = 4,075 MW
  - 10% External to NYCA = 453 MW

When adding additional wind generation to reach the 6,000 MW level prescribed in the NYISO Wind Study several adjustments to the case had to be made. First, numerous underlying sub-transmission upgrades had to be constructed to connect the wind generators to the bulk power system without causing overloads. Second, in order to stay true to the assumption of 4,528 MW of generation expansion to meet reliability criteria, generic generation expansion was reduced to accommodate the wind additions. Using a 10% capacity factor for land based wind generation and a 30% capacity factor for offshore, an equivalent amount of capacity was removed from the generic generators.

Upon completion of the model update for the STARS Replacement Plan, the Base Transmission Plan case was created by adding the transmission lines and elements listed in Attachment 7 to the economic database. Both the Replacement Plan and Base Transmission Plan case were simulated for 8,760 hours to simulate a single year of system operation.

6

Development of base transmission plan

Development of base transmission plan

The STARS TWG, selected projects for the Base Transmission Plan (BTP) that satisfied the identified MW needs. These needs included Condition Assessment MW Needs, Reliability MW needs and Unconstrained MW needs which were calculated on an interface basis.

6.1 Condition assessment MW needs

A high level screening criterion was used to identify transmission lines with a higher probability of replacement need based on condition. This was supplemented with a more detailed condition assessment of the National Grid transmission lines based on their assessment performed in 2009/2010. Since this was a screening assessment, no update has been made since the initial condition assessment performed by the study team. As indicated earlier, any decision to move forward with condition refurbishment work would be based on detailed analyses. Section 3 of this report provides a description of the condition assessment methodology. Figure 6-1 provides a summary of the Condition Assessment MW needs by interface. The columns represent transmission lines that meet the selection criteria. Although identified as meeting the criteria, a more detailed analysis of the two Leeds to Pleasant Valley 345 kV lines performed by National Grid indicated that the extent of mitigation only requires replacement of select towers.

Figure 6-1 Condition assessment replacement MW need summary

	Condition assessment needs (values in MW)									
	Pannel to Farminton 115 kV	Kattelville to Jenison 115 kV	East Spring-field to Inghams 115 kV	Rotterdam to Porter 230 kV (1)	Rotterdam to Porter 230 kV (2)	Leeds to Pleasant Valley 345 kV (1)	Leeds to Pleasant Valley 345 kV (2)	Moses to Adirondack 230 kV (1)	Moses to Adirondack 230 kV (2)	Total
West Central	206									**206**
Volney East		110								**110**
Moses South								348	348	**696**
Marcy South										**0**
Central East			80	440	439					**959**
F to G						1,331	1,331			**2,662**
I to J										**0**
I to K										**0**
HQ - D										**0**
CE Group										**0**
UPNY-SENY						1,331	1,331			**2,662**
Total East			80	440	439					**959**

Figures 6-2 through 6-8 provide detailed information for each line of each interface. Lines shaded in red will meet the selection criteria for replacement in 0-10 years. Lines shaded in orange will meet the selection criteria for replacement in 10-20 years. Lines shaded in yellow will meet the selection criteria for replacement in 20-30 years. The summer normal ratings of the orange and red shaded lines are summed to provide the Condition Assessment MW Need for each interface.

Figure 6-2 *West Central interface — condition assessment*

Interface	From name	From kV	To name	To Kv	CKT	RateA
WEST CENTRAL	STOLE230	230	MEYER230	230	1	430
WEST CENTRAL	STOLE230	230	SHLDN230	230	1	430
WEST CENTRAL	C708 LD	34.5	WOLCOT34	34.5	1	25
WEST CENTRAL	QUAKER	115	MACDN115	115	1	165
WEST CENTRAL	S121 B#2	115	SLEIG115	115	1	150
WEST CENTRAL	CLYDE199	115	SLEIG115	115	1	145
WEST CENTRAL	QUAKER	115	SLEIG115	115	1	150
WEST CENTRAL	ANDOVER1	115	PALMT115	115	1	79
WEST CENTRAL	STA 162	115	S.PER115	115	1	125
WEST CENTRAL	MORTIMER	115	LAWLER-1	115	1	129
WEST CENTRAL	MORTIMER	115	LAWLER-2	115	1	129
WEST CENTRAL	PANNELL3	345	CLAY	345	1	1033
WEST CENTRAL	PANNELL3	345	CLAY	345	2	1033
WEST CENTRAL	STA127	34.5	HOOKRD	115	1	75
WEST CENTRAL	CLYDE199	115	CLTNCORN	115	1	145
WEST CENTRAL	FARMNGTN	34.5	FARMGTN1	115	1	58
WEST CENTRAL	PANNELLI	115	FRMGTN-4	115	1	206
WEST CENTRAL	FRMNGT2	34.5	FRMGTN-4	115	1	58
WEST CENTRAL	S168	12	FRMGTN-4	115	1	56
WEST CENTRAL	CLYDE 34	34.5	CLYDE199	115	1	38
WEST CENTRAL						4658

THERMAL LIMIT 1877
VOLTAGE LIMIT 1134

Replacement MW due to condition assessment: 206
(Sum of Red & Orange RateA)

Figure 6-3 *Volney East interface — condition assessment*

Interface	From name	From kV	To name	To Kv	CKT	RateA
VOLNEY EAST	OAKDL345	345	FRASR345	345	1	1255
VOLNEY EAST	OAKDL115	115	DELHI115	115	1	161
VOLNEY EAST	WILET115	115	E.NOR115	115	1	108
VOLNEY EAST	KATEL115	115	JENN 115	115	1	110
VOLNEY EAST	CLAY	345	EDIC	345	1	1301
VOLNEY EAST	CLAY	345	EDIC	345	2	1301
VOLNEY EAST	VOLNEY	345	MARCY T1	345	1	1434
VOLNEY EAST	BRDGPORT	115	PETRBORO	115	1	116
VOLNEY EAST	LTHSE HL	115	BLACK RV	115	1	106
VOLNEY EAST	LTHSE HL	115	E WTRTWN	115	1	116
VOLNEY EAST	TEALL	115	ONEIDA	115	1	116
VOLNEY EAST	OMEGAWIR	34.5	CAMDEN	34.5	1	22
VOLNEY EAST	JA FITZP	345	EDIC	345	1	1434
VOLNEY EAST	W HILL_T	115	ONEIDA	115	1	146
VOLNEY EAST						7726

THERMAL LIMIT 4540
VOLTAGE LIMIT 3952

Replacement MW due to condition assessment: 110
(Sum of Red & Orange RateA)

Figure 6-4 Central East interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
CENTRAL EAST	E.SPR115	115	INGHAM-E	115	1	80
CENTRAL EAST	EDIC	345	N.SCOT77	345	1	1331
CENTRAL EAST	JORDNVLL	230	ROTRDM.2	230	1	440
CENTRAL EAST	PORTER 2	230	ROTRDM.2	230	1	440
CENTRAL EAST	PORTER 2	230	ROTRDM.2	230	2	439
CENTRAL EAST	INGMS-CD	115	INGHAM-E	115	1	167
CENTRAL EAST	MARCY T1	345	N.SCOT99	345	1	1487
CENTRAL EAST						4384

THERMAL LIMIT 3007
VOLTAGE LIMIT 2604

Replacement MW due to condition assessment: 959
(Sum of Red & Orange RateA)

Figure 6-5 F to G interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
F TO G	LEEDS 3	345	HURLEY 3	345	1	1395
F TO G	BOC 2T	115	N.CAT. 1	115	1	116
F TO G	BOC 2T	115	N.CAT. 1	115	2	116
F TO G	ADM	115	PL.VAL 1	115	1	119
F TO G	BL STR E	115	PL.VAL 1	115	1	119
F TO G	BLUES-8	115	PL.VAL 1	115	1	116
F TO G	LEEDS 3	345	PLTVLLEY	345	2	1331
F TO G	ATHENS	345	PLTVLLEY	345	1	1331
F TO G						4643

THERMAL LIMIT 3485
VOLTAGE LIMIT 3760

Replacement MW due to condition assessment: 2662
(Sum of Red & Orange RateA)

Note: Condition assessment has indicated select structure replacement is needed for the two existing Leeds to Pleasant Valley 345 kV lines.

Figure 6-6 Moses South interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
MOSES SOUTH	JAY12	46	NORTON46	46	1	33
MOSES SOUTH	ALCOA-NM	115	BRADY	115	1	128
MOSES SOUTH	ALLENS F	115	COLTON	115	1	119
MOSES SOUTH	DENNISON	115	ANDRWS-4	115	1	220
MOSES SOUTH	DENNISON	115	LWRNCE-B	115	1	220
MOSES SOUTH	GILPIN B	46	GILPINT	46	1	40
MOSES SOUTH	MASS 765	765	MARCY765	765	1	3975
MOSES SOUTH	MOSES W	230	ADRON B1	230	1	348
MOSES SOUTH	MOSES W	230	ADRON B2	230	1	348
MOSES SOUTH						5431

THERMAL LIMIT 2660
VOLTAGE LIMIT 1971

Replacement MW due to condition assessment: 696
(Sum of Red & Orange RateA)

Figure 6-7 Total East interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
TOTAL EAST	JEFFERSN	500	RAMAPO 5	500	1	1048
TOTAL EAST	HUDSON1	345	B3402 PAR1	345	1	536
TOTAL EAST	LINDEN	230	GOETHALS	230	1	645
TOTAL EAST	WALDWICK	345	SMAHWAH1	345	1	602
TOTAL EAST	WALDWICK	345	SMAHWAH2	345	1	602
TOTAL EAST	HUDSON2	345	C3403 PAR2	345	1	560
TOTAL EAST	LINVFT4	345	COGNTECH	345	1	500
TOTAL EAST	HCOR138	138	BURNS138	138	1	209
TOTAL EAST	SMAH138	138	RAMP138	138	1	249
TOTAL EAST	SMAH138	138	SMAHWAH1	345	1	484
TOTAL EAST	HCOR69	69	WNYA69	69	1	124
TOTAL EAST	MONTVALE	69	BLUHILL	69	1	67
TOTAL EAST	MONTVALE	69	BLUHILL	69	2	67
TOTAL EAST	MONTVALE	69	L491T	69	1	121
TOTAL EAST	SMAH69	69	HILB69	69	1	153
TOTAL EAST	HCOR34	34.5	PEARL34	34.5	1	20
TOTAL EAST	CRESSKIL	69	SPARKILL	69	1	131
TOTAL EAST	PLAT T#3	115	GRAND IS	115	1	262
TOTAL EAST	COOPC345	345	ROCK TAV	345	2	1554
TOTAL EAST	NEPTCONV	345	NWBRG	345	1	0
TOTAL EAST	COOPC345	345	MDTN TAP	345	1	1464
TOTAL EAST	FRASR345	345	GILB 345	345	1	1428
TOTAL EAST	E.SPR115	115	INGHAM-E	115	1	80
TOTAL EAST	W.WDB115	115	W.WDBR69	69	1	48
TOTAL EAST	EDIC	345	N.SCOT77	345	1	1331
TOTAL EAST	JORDNVLL	230	ROTRDM.2	230	1	440
TOTAL EAST	PORTER 2	230	ROTRDM.2	230	1	440
TOTAL EAST	PORTER 2	230	ROTRDM.2	230	2	439
TOTAL EAST	INGMS-CD	115	INGHAM-E	115	1	167
TOTAL EAST	MARCY T1	345	N.SCOT99	345	1	1487
TOTAL EAST						15258

THERMAL LIMIT 6696
VOLTAGE LIMIT 6270

Replacement MW due to condition assessment: 959
(Sum of Red & Orange RateA)

Figure 6-8 UPNY-SENY Open interface — condition assessment

Interface	From name	From kV	To name	To Kv	CKT	RateA
UPNY-SENY OPEN	CTNY398	345	PLTVLLEY	345	1	1195
UPNY-SENY OPEN	LEEDS 3	345	HURLEY 3	345	1	1395
UPNY-SENY OPEN	COOPC345	345	ROCK TAV	345	2	1554
UPNY-SENY OPEN	BOC 2T	115	N.CAT. 1	115	1	116
UPNY-SENY OPEN	BOC 2T	115	N.CAT. 1	115	2	116
UPNY-SENY OPEN	ADM	115	PL.VAL 1	115	1	119
UPNY-SENY OPEN	BL STR E	115	PL.VAL 1	115	1	119
UPNY-SENY OPEN	BLUES-8	115	PL.VAL 1	115	1	116
UPNY-SENY OPEN	LEEDS 3	345	PLTVLLEY	345	2	1331
UPNY-SENY OPEN	ATHENS	345	PLTVLLEY	345	1	1331
UPNY-SENY OPEN	COOPC345	345	MDTN TAP	345	1	1464
UPNY-SENY OPEN	W.WDB115	115	W.WDBR69	69	1	48
UPNY-SENY OPEN						8904

THERMAL LIMIT 5124
VOLTAGE LIMIT 6528

Replacement MW due to condition assessment: 2662
(Sum of Red & Orange RateA)

Note: Condition assessment has indicated select structure replacement is needed for the two existing Leeds to Pleasant Valley 345 kV lines.

6.2 Reliability MW needs

The STARS methodology to determine reliability needs requires a resource adequacy calculation of each of the generation expansion scenarios. This was performed in Phase I and in Phase II for scenarios 2A, 3A and 4A. Reliability based MW needs would then be determined on an interface basis as the increase in emergency transfer capability needed to insure reliability criteria are met. Based on the selection of Scenario 3A (see section 4), there are no Reliability MW Needs for the Base Transmission Plan.

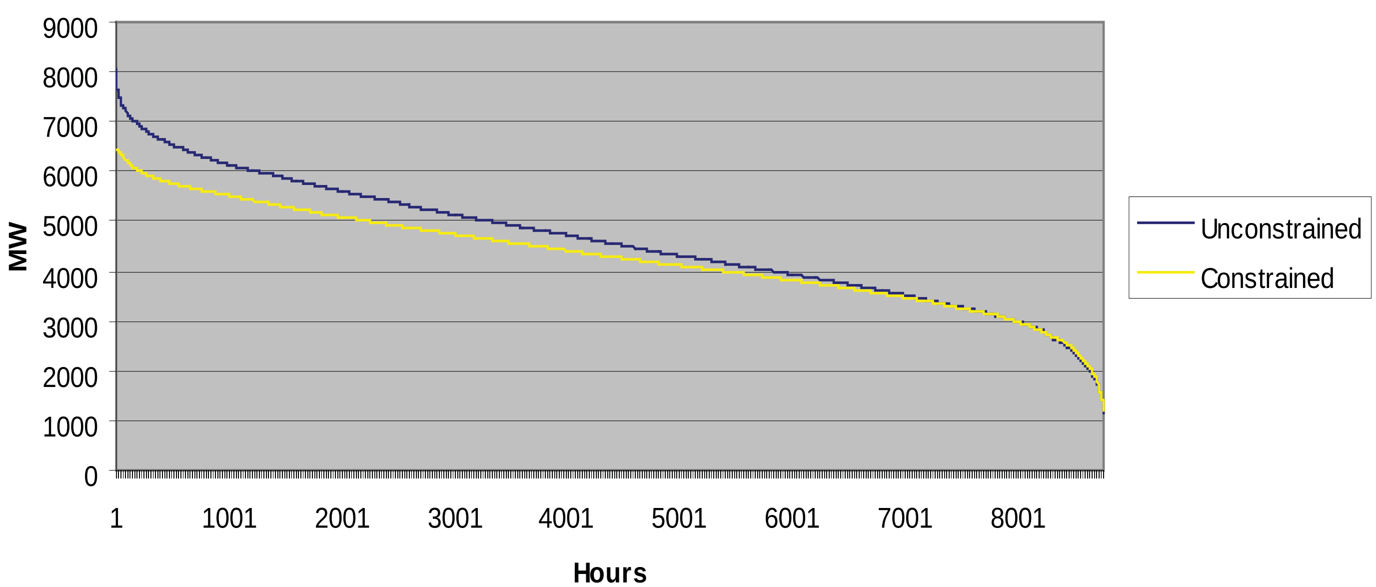
6.3 Unconstrained MW needs

An unconstrained system model was used to determine economic dispatch needs on an interface basis. In an unconstrained system all transmission limits are ignored resulting in a free flowing model. For this unconstrained case, the following was assumed:

- 6000 MW wind case
- All NYCA constraints removed
- Adjust HQ import schedule based on added capability of 2267 MW
- Added new 770 MW PJM-Zone J tie (free flow)
- Added new 363 MW PJM-Zone K tie (free flow)

Load duration curves of the unconstrained and constrained interface flow were developed. The following is an example for Total East (the remainder of the load duration curves can be found in Attachment #5).

Figure 6-9 Load duration curve for Total East



The Unconstrained MW Need value for the interface is calculated as the difference between the 100% unconstrained and the constrained. For Total East, the unconstrained value for 100% is 8,033 MW. The constrained value is 6,425 MW. Based on this, the Unconstrained MW Need is 1,608 MW. This indicates that the interface capability could be increased by 1,608 MW and still provide additional value toward lowering statewide production costs. The summary for all of the interfaces in the study is included in Figure 6-10.

Figure 6-10 Unconstrained MW need summary

	Unconstrained	Constrained	MW Need
WEST CENTRAL-OP	2334	1425	909
DYSINGER EAST-OP	2960	2550	410
Volney East-OP	5040	4001	1039
MOSES SOUTH-OP	2639	2237	401
TOTAL EAST	8033	6425	1608
CENTRAL EAST	4012	2800	1212
UPNY Seny-OP	8835	5800	3035
UPNY-ConEd-OP	6119	4059	2060
Spr/Dunwoodie So.-OP	5902	4866	1036
MILLW-SOUTH-OP	6797	5776	1021

6.4 Total MW need

The total MW need was calculated as the sum of the Condition Assessment MW Need, the Reliability MW Need and the Unconstrained MW Need for each interface (Figure 6-11). The total MW need becomes a target for the Base Transmission Plan project selection.

Figure 6-11 Total MW need summary by interface

	Condition assessment need	Scenario No. 3A LOLE need	Unconstrained need	Total need
West Central	206	0	909	1115
Dysinger East	0	0	410	410
Volney East	110	0	1039	1149
HQ - D	0	0	0	0
Moses South	696	0	401	1097
Total East	959	0	1608	2567
Central East	959	0	1212	2171
UPNY-SENY	2662	0	3035	5697
Marcy South	0	0	0	0
UPNY-ConEd	0	0	2060	2060
I to K (Y49/Y50)	0	0	0	0
PJME-J	0	0	0	0
PJME-K	0	0	0	0

6.5 Base transmission plan project selection

The STARS TWG, selected projects for the Base Transmission Plan (BTP) that satisfied the identified Total MW needs. This selection process provides for a high level first cut in terms of satisfying identified needs. The addition of transmission capacity occurs in large scale quantities. Although capacity ratings for new transmission lines can be fine tuned with the selection of the conductor size, the decision to add a transmission line introduces a step change for an interface. A "Delta" is identified for each project that identifies whether the proposed projects provide more capacity or less capacity, as measured by the increased thermal capability, than the identified need. A positive delta indicates that the proposed projects do not fully meet the identified need potentially leaving benefits unrealized. A negative delta indicates that the proposed project provides greater thermal capability than what was identified in the unconstrained case potentially resulting in headroom across the interface. It is recognized that transmission capacity changes for a line that crosses an interface and interface operating limits do not necessarily have a linear relationship. The following describes the project selection process results:

6.5.1 West Central

West Central has a Condition Assessment MW need of 206 MW and an Unconstrained MW need of 909 MW. The Condition Assessment need is met with the rebuild of the Pannell to Farmington 115 kV Line.

Figure 6-12 West Central condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(1) 115 kV Line Pannell to Farmington Rebuild (rating = 206 MW)	206	206	0

The Unconstrained MW need could be met with the reconductoring of four 115 kV transmission lines.

Figure 6-13 West Central unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 115 kV Line Mortimer to Hook Road #1, reconductor with 1033 ACSR	909	1284	-375
(1) 115 kV Hook Road to Elbridge #7, reconductor with 1033 ACSR			
(1) 115 kV Mortimer to Elbridge #2, reconductor with 1033 ACSR			
(1) 115 kV Line Geneva to Elbridge #15, reconductor with 1033 ACSR			

6.5.2 Dysinger East

Dysinger East has an Unconstrained MW need of 410 MW. The Unconstrained MW need could be met with the reconductoring of three 115 kV transmission lines.

Figure 6-14 Dysinger East unconstrained project

Economic upgrade project	Unconstrained	Net Project capacity	Delta
(1) 115 kV Lines Lockport to Mortimer (#111, 113 and 114), reconductor with 795 ACSR	410	273	137

6.5.3 Volney East

Volney East has a Condition Assessment MW need of 110 MW and an Unconstrained MW need of 1039 MW. The Condition Assessment need could be met with the rebuild of the Kattelville to Jenison 115 kV Line.

Figure 6-15 Volney East condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(1) 115 kV Line Kattelville to Jenison Rebuild (rating = 110 MW)	110	110	0

The Condition Assessment MW need and Unconstrained MW need could be met by replacing the Kattelville to Jenison 115 kV Line with a new 345 kV Line from Oakdale to Fraser.

Figure 6-16 Volney East unconstrained project

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Oakdale to Fraser (replace Kattelville to Jenison 115 kV)	1039	1390	-351

The Oakdale to Fraser Line would reuse the right of way from Kattelville to Jenison and have a summer normal rating of 1500 MW. The Net Project Capacity of 1390 MW accounts for the 110 MW decrease in capacity associated with not building the Condition Assessment Project.

6.5.4 Moses South

Moses South has a Condition Assessment MW need of 696 MW and an Unconstrained MW need of 401 MW. The Condition Assessment need could be met with the rebuild of the two 230 kV lines from Moses to Adirondack to Porter.

Figure 6-17 Moses South condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(2) 230 kV Lines Moses to Adirondak to Porter Rebuild (rating = 348 MW each)	696	696	0

The Unconstrained MW need could be met by replacing the 230 kV lines from Moses to Adirondack to Porter with two 345 kV lines from Moses to Marcy.

Figure 6-18 Moses South unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(2) 345 kV Lines Moses to Marcy Replace Moses to Porter 230 kV	401	2304	-1903

The Moses to Marcy lines would reuse the right of way from Moses to Adirondack to Porter and have a summer normal rating of 3000 MW. The Net Project Capacity of 2304 MW accounts for the 696 MW decrease in capacity associated with not building the Condition Assessment Project.

6.5.5 Total East and Central East

Total East and Central East both share the same Condition Assessment MW need of 959 MW. The Unconstrained MW need for Total East is 1608 MW and the Unconstrained MW need for Central East is 1212 MW. The Condition Assessment need could be met with the rebuild of the two 230 kV lines from Porter to Rotterdam and the 115 kV line from East Springfield to Inghams.

Figure 6-19 Total East and Central East condition assessment projects

Condition assessment project	CA need	Project capacity	Delta
(2) 230 kV Lines Porter to Rotterdam Rebuild (rating = 440 MW each)	880	880	0
(1) 115 kV East Springfield to Inghams Rebuild (rating = 80 MW)	80	80	0

The Unconstrained MW need could be met by replacing the 230 kV lines from Porter to Rotterdam with one 345 kV lines from Marcy to Leeds.

Figure 6-20 Total East and Central East unconstrained projects

Unconstrained upgrade project		Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Marcy to Leeds Replace Porter to Rotterdam 230 kV	Total East	1608	620	988
	Central East	1212	620	592

The Marcy to Leeds lines would reuse the right of way from Porter to Rotterdam and have a summer normal rating of 1500 MW. The existing parallel 345 kV lines in this corridor allows for the replacement of two 230 kV lines with a single 345 kV line from a transmission security perspective. The Net Project Capacity of 620 MW accounts for the 880 MW decrease in capacity associated with not building the Condition Assessment Project associated with the two 230 kV lines from Porter to Rotterdam.

6.5.6 UPNY-SENY

UPNY-SENY has a Condition Assessment MW need of 2662 MW and an Unconstrained MW need of 3035 MW. The Condition Assessment need could be met with the rebuild of the two Leeds to Pleasant Valley 345 kV lines. It should be noted that a complete rebuild is not needed for this project. Although identified as meeting the criteria, a more detailed analysis of the two Leeds to Pleasant Valley 345 kV line performed by National Grid indicated that the extent of mitigation may only include replacement of select towers.

Figure 6-21 UPNY-SENY condition assessment project

Condition assessment project	CA need	Project capacity	Delta
(2) 345 kV Lines Leeds to Pleasant Valley Rebuild (rating = 1331 MW each)	2662	2662	0

The Unconstrained MW need could be met by adding a third 345 kV line from Leeds to Pleasant Valley.

Figure 6-22 UPNY-SENY unconstrained projects

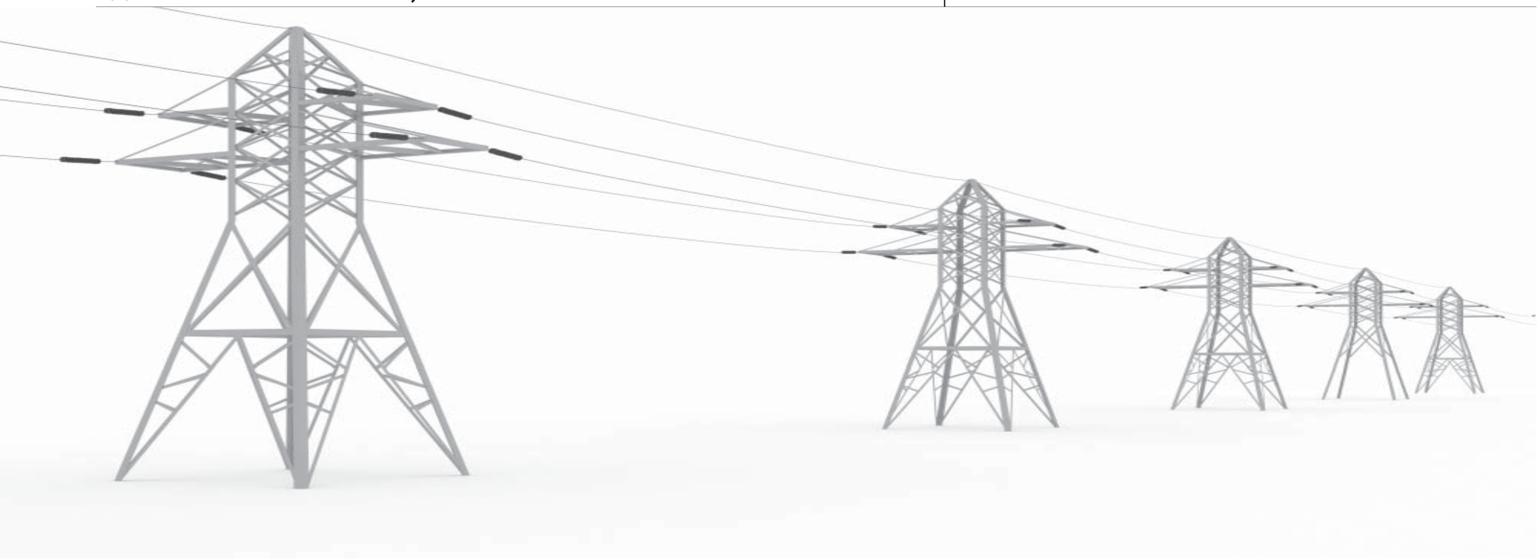
Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Leeds to Pleasant Valley Add Third Line	3035	1500	1535

6.5.7 UPNY-ConEd

UPNY-Con Ed has an Unconstrained MW need of 2060 MW. The Unconstrained need could be met with the addition of a second 345 kV Line from Rock Tavern to Ramapo, a 900 MW DC Line from Pleasant Valley to Sprainbrook, and a 600 MW DC Line from Pleasant Valley to Ruland Road.

Figure 6-23 UPNY-ConEd unconstrained projects

Unconstrained upgrade project	Unconstrained	Net Project capacity	Delta
(1) 345 kV Line Rock Tavern to Ramapo New Line	2,060	3,000	-940
(1) 900 MW DC Line Pleasant Valley to Sprainbrook New Line			
(1) 600 MW DC Line Pleasant Valley to Ruland Road New Line			



6.6 Wind deliverability projects

The NYISO Wind Study which was completed in September of 2010 analyzed the impact of the integration of varying amounts of winds resources ranging from a total of 3,500 MW to 8,000 MW. The primary finding of the report was that wind energy can supply reliable clean energy at a very low production cost to the New York power grid. While the study showed that the addition of wind generation to the resource mix resulted in significant reduction in production costs, the reduction would have been even greater if transmission constraints between upstate and downstate were eliminated. In addition the study determined that almost 9% of the potential upstate wind energy production would be "bottled" or not deliverable because of local transmission limitations. The study identified feasible sets of transmission facility upgrades that would greatly reduce or eliminate the transmission limitations. It should be noted that in many cases the transmission facilities that were analyzed for upgrade have also been identified as potentially requiring replacement based on condition assessment. Figure 6-24 provides a summary listing of projects that were included in the STARS Base Transmission Plan and all of the trials. The wind generators added to create the 8,000 MW wind case were primarily downstate offshore generators that resulted in no significant increases in bottled wind energy due to transmission congestion, therefore no additional transmission upgrades were required. Additional details on the wind projects are included in Attachment 2.

Figure 6-24 Wind deliverability upgrade projects

Transmission path or device	Voltage level	Upgrade
Moses-Willis	230 kV	Tower Reconfiguration
Canandaigua-Hillside& Hillside-Watercure	230 kV	Tower Reconfiguration
Oakdale-Fraser & Oakdale-Lafayette[1]	230 kV	Tower Reconfiguration
Montour Falls-Hillside	115 kV	Conductor
Hillside-North Waverly	115 kV	Conductor
Canandaigua-Avoca-Hillside	230 kV	Conductor
(2) Plattsburgh	230/115 kV	Transformers
Willis-Plattsburgh	230 kV	Conductor
Delhi-Colliers	115 kV	Conductor
Black River-Taylorville-Lowville	115 kV	Conductor
Bennett-Howard-Bath-Montour	115 kV	Conductor
Bennett-Moraine-Meyer	115 kV	Conductor
Moses-Willis	230 kV	Conductor
Lighthouse Hill-Mallory	115 kV	Conductor
Coffeen Street-East Watertown Coffeen Street-Black River Lyme Tap –Coffeen Street	115 kV	Conductor & Towers
Meyer-Eel Pot Rd-Ecogen-Flat St-Greenidge	115 kV	Conductor
Plattsburgh	230/115 kV	Transformers
Taylorville-Boonville	115 kV	Conductor & Terminals
Black River-North Carthage Black River-Taylorville North Carthage-Taylorville	115 kV	Conductor
Coffeen Street-Black River	115 kV	Conductor & Station
Indian River-Black River	115 kV	Bus & Station Connections
Rockledge Tap-Lyme Tap-Coffeen St Coffeen St-Black River	115 kV	Conductor
Coffeen Street-Adirondack	230 kV	New Circuit

[1]This project is currently under development.

6.7 Base transmission cost estimate

The cost estimate for most of the components of the Base Transmission Plan was based on pro-forma low, mid and high values of cost per mile from CARIS. Values were calculated in 2010 dollars. Line lengths represent routes along existing rights of way. In some cases, notably the third Leeds to Pleasant Valley Line and the second Rock Tavern to Ramapo Line, values were based on more detailed cost estimates. For the HVDC projects, values were based on discussions with vendors and comparisons to recent projects. Although costs estimates were calculated at the low, mid and high range values, only the mid range value was used in the economic analysis. The cost estimate for the Base Transmission Plan and the subsequent Trials (see Section 7 for information on Trials) is provided in Attachment #6.

Cost estimates were also developed for Replacement-in-Kind projects. For example, it was identified in Section 6.5.3 that the Oakdale to Fraser 345 kV Line will meet the Condition Assessment MW needs of Volney East, eliminating the need to rebuild the Kattelville to Jennison 115 kV Line. The cost estimate of the rebuild of the Kattelville to Jennison 115 kV line was calculated as a Replacement-in-Kind project. The net cost of the Volney East project is the cost estimate of the Oakdale to Fraser 345 kV Line minus the cost of the Kattelville to Jennison 115 kV Replacement-in-Kind project.

The economic analysis of the Base Transmission Plan (see Section 7) calls for a one-year analysis in the year 2030. The following was assumed for determining the costs in the year 2030:

- As studied the construction of the Base Transmission Plan would start in 2021 and be completed in 2030 with levelized construction costs over the 10 years. It is conceivable that project development could be advanced if it is warranted.
- Inflation through 2030 is 2% per year
- Depreciation is a straight line over 60 years.
- A carrying charge of 20% is applied to the depreciated "rate base" in 2030

Figure 6-25 Base transmission plan cost component summary ($M)

	Total	Replacement plan	Incremental	Carrying charge
Moses to Marcy	1035	842	193	48
Marcy to New Scotland	356	105	251	62
New Scotland Bus Upgrade	30	0	30	7
New Scotland to Leeds	96	0	96	24
Leeds to Pleasant Valley	195	0	195	48
Rock Tavern to Ramapo	113	0	113	28
Oakdale to Fraser	205	31	174	43
Pleasant Valley to Sprainbrook	411	0	411	102
Pleasant Valley to Ruland Road	946	0	946	235
115 kV Upgrades	514	514	0	0
BTP Total	3900	1492	2409	597
Sprainbrook to Ruland Road	535	0	535	133

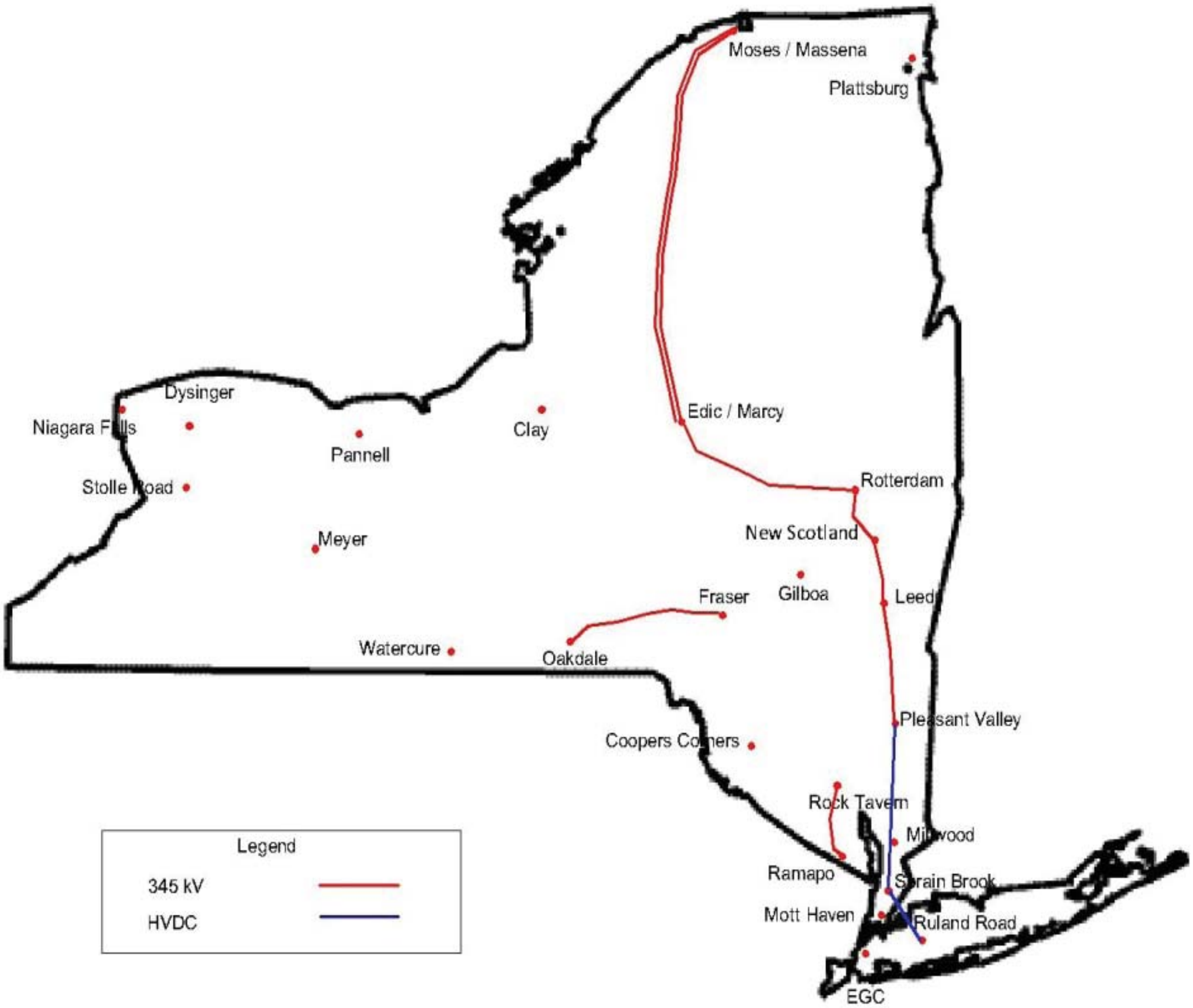
The New Scotland 345 kV Bus upgrade project is included in the Base Transmission Plan because it includes both the Marcy to New Scotland project and the New Scotland to Leeds project. Trials discussed in Section 7 include the New Scotland 345 kV Bus upgrade project only if both the Marcy to New Scotland project and the New Scotland to Leeds Project are included in the trial.

The Sprainbrook to Ruland Road project is a subset of the Pleasant Valley to Ruland Road project. This is used in Trial 5 as discussed in Section 7.

The cost estimates in Figure 6-25 do not include the costs for the Wind Deliverability Projects discussed in Section 6.6. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed.

A view of the location of the proposed Base Transmission Plan lines is included in Figure 6-26 shown below.

Figure 6-26 *Base transmission plan project locations*



7

Economic Analysis - Production Cost and Locational Based Marginal Price Savings

Economic Analysis - Production Cost and LBMP Savings

7.1 Economic analysis methodology

The proposed transmission projects included in the STARS Base Transmission Plan each serve to promote the transfer of energy throughout the New York Control Area. Projects, taken as individuals or in combinations, can provide varying amounts and types of benefits, which can be estimated through the forecasting, modeling, and the simulation of the electricity market. The primary benefit metric used to measure these economic benefits is system production costs. Production costs include the total cost that generators within a region incur in order to serve the energy demand while simultaneously maintaining system reliability. These can include fuel costs, maintenance costs, and emissions costs. The minimization of production cost is the primary objective function utilized in the linear programs that commit and dispatch energy in both the Real-Time and Day-Ahead Electricity Markets. Reduction in production costs generally provide a good indication of the societal benefits also realized when making a change to system topology.

7.2 Economic analysis assumptions

The Replacement Plan for the STARS economic analysis was developed from the 2009 NYISO CARIS Phase I ABB GridView database and model. The study economic assumptions are described in greater detail in Section 5.12 of the report as well as Attachment 3.

The production cost and LBMP savings estimates reflect a single year value which are estimated to represent a horizon year value of the year 2030. In addition, the annual carrying charges for the transmission investment, new and incremental investment, are for the same horizon year. As such the benefit/cost ratios that are provided in this report represent a one year snapshot which approximates the methodology included in CARIS.

It should be noted that the LBMP values that are provided are "non-adjusted" values. Since these values represent a forecasted value estimated to be approximately the year 2030 no attempt has been made to adjust them for the impacts of any future bilateral contracts or Transmission Congestion Contracts (TCCs) since it would be extremely difficult to estimate. Therefore ratepayer impacts will likely vary due to these among other factors.

7.3 Base transmission plan production cost & LBMP results

With a full year of simulation data from the Replacement Plan and Base Transmission Plan case the economic impacts of the transmission projects can be evaluated. The primary metric of production cost, which includes generator fuel & maintenance costs, import costs, and emissions costs for the New York system, is used to determine potential economic benefits. A secondary metric of LBMP payments by load can also be used. Figure 7-1 was pulled from Attachment 7 and shows the production and LBMP cost results for the Replacement Plan and Base Transmission Plan case and the resulting savings.

Figure 7-1 Reference case production cost results (nominal $)

STARS case	Production cost (M$)	Import cost (M$)	Emissions cost (M$)	Total NYISO production cost (M$)	Load LBMP payment (M$)
Replacement Plan	7,996	1,084	2,451	11,531	23,026
Base Transmission Plan	7,823	1,069	2,439	11,332	22,917
Base Transmission Plan Savings	172	14	12	199	109

The Base Transmission Plan provides a $199M annual decrease in production costs and a $109M annual decrease in Load LBMP Payments in the New York Control Area. This benefit is a direct result of freeing bottled economic energy throughout and into the state. The improved energy transfer can be seen in the utilization of the Base Transmission Plan elements that were added to the Replacement Plan, as shown in Figure 7-2. When reviewing the loading percentages for the BTP elements, it is important to note that for a line with a parallel circuit, the maximum flows on either of the circuits will be limited to the lowest rating of the two by the linear program optimization as part of the transmission security analysis. This could result in a reduced loading factor on one of the BTP elements being studied and was considered when analyzing the results.

Figure 7-2 Base transmission plan element utilization

From bus	To bus	Loading factor (%)
LEEDS 3	PLTVLLEY	43.1
JORDNVLL	PRINCETW	37.5
MARCY T1	JORDNVLL	35.2
ROCK TAV	RAMAPO	35.2
N.SCOT77	LEEDS 3	34.0
PRINCETW	ROTRDM.2	30.3
PRINCETW	ROTRDM.2	30.3
PRINCETW	N.SCOT99	22.7
CHASES L	MARCY T1	19.1
FRASR345	OAKDL345	18.9
PLTVLLEY	RULND RD	16.6
ADRON B2	EDIC	15.2
MOSES W	ADRON B2	12.9
ADRON B1	CHASES L	11.8
MOSES W	ADRON B1	11.8
PLTVLLEY	SPRBROOK	4.8

Not only did the Base Transmission Plan allow energy to flow more economically through the state it also allowed more inexpensive energy to flow into the state, as evidenced by the increase in import energy shown in Figure 7-3.

Figure 7-3 *Replacement plan and base transmission plan import energy*

External Interface	Replacement Plan Import Amount (MWh)	BTP Import Amount (MWh)	(BTP - Replacement) Import Amount (MWh)
IESO	-947,861	-437,004	510,857
Neptune	3,230,650	3,064,617	-166,034
HQ	4,110,265	5,214,219	1,103,953
CSC	861,862	805,611	-56,250
PJM	876,484	-220,716	-1,097,200
ISO-NE	1,533,988	1,313,402	-220,586
Total	9,665,388	9,740,128	74,741

There is a $14 million annual import cost decrease in the NYISO while increasing the actual amount of energy that is imported by about 75 GWh. The Base Transmission Plan permits more energy to flow from HQ and Ontario which is replacing more expensive imports from PJM and ISO New England.

It is also helpful to see where the savings (in red in Figure 7-4) is occurring within the state when the Base Transmission Plan is applied to the Replacement Plan, shown in the NYISO Zonal Savings Summary. As one can see, the majority of savings accrues to downstate locations.

Figure 7-4 *NYISO zonal savings summary*

Savings Due to the Base Transmission Plan by NYISO Zone and Import Area, Delta (BTP – Replacement)

Region/Area	Load LBMP Payment (M$)	Generation (MWh)
West	18	285
Genessee	12	31
Central	17	438
North	14	221
Mohawk Valley	14	36
Capital	14	333
Hudson Valley	(17)	(182)
Millwood	(7)	(0)
Dunwoodie	(14)	(16)
NYCity	(108)	(1,149)
Long Island	(51)	(828)
NYISO Total	(109)	(831)

( ) Savings indicated in red

As described in detail in Section 6 of the report the annual carrying costs of the Base Transmission Plan are estimated to be $597 M. The annual benefits of the full Base Transmission Plan as measured in production cost savings shown in Figure 7-1 are estimated to be $199 M. Therefore, from a strict economic perspective the entire Base Transmission Plan cannot be justified at this time solely from a production cost savings economic perspective. However, components of the this Plan are justified in response to other objectives such as reliability, aging infrastructure and improved integration of renewable resources.

For the purposes of specifically identifying purely economic projects in the plan the STARS TWG developed project trials which are described in more detail in subsequent sections of the report.

7.4 Development of transmission trials

While the primary production cost metric presented above provides a good indication of the economic benefits of the entire Base Transmission Plan, more information is required to choose subsets of the BTP for further study. A good indicator of how the Base Transmission Plan addresses transmission bottlenecks in the state is the Dollar Demand Congestion metric. This metric provides information regarding which transmission paths are causing increased production costs in New York. Details of the formulas used to calculate the metric can be found in NYISO OATT Attachment Y and the NYISO CARIS I 2011 Final Report.

Figure 7-5 shows the Dollar Demand Congestion for the Replacement Plan prior to the addition of the Base Transmission Plan. It should be noted that the Demand Congestion figures include results for not only the base set of study assumptions but for a number of sensitivities which are described in greater detail in Section 7.6 of the report.

Figure 7-5 Replacement plan demand congestion ($M annually)

	Contingency	Athens to Pleasant Valley	Pre Contingency		Gowanuss	Dunwoodie	Quenbrg_Verne	Pre Contingency	Marcy	Mothaven	Kinti Roch	Pre Contingency
STARS Scenario	**Constraint**	**Leeds to Pleasant Valley**	**Greenwood**	**Central East**	**Gowanuss**	**Dunwoodie**	**E179ST 15055SR**	**LIPA Cable**	**Coopers Frasier**	**Rainey**	**Niag Roch**	**Dunwoodie**
Reference Case	Replacement	993	35		22	22	20					
High Fuel Forecast	Replacement	1,275	38	28	25	34						
8000 MW Wind	Replacement	971	38	17	18		17					
4250 MW Wind	Replacement	786	32		28	19	23					
Shift 1000MW Upstate	Replacement	1,289	29		33		28	19				
Shift 1000MW Downstate	Replacement	856	40		18	21	17					
High Emissions	Replacement	2,355			47	239		162		72		

The red, orange, and yellow highlighted cells represent the first, second, and third rankings for the elements with the highest demand congestion in the Replacement Plan. Based on these rankings it can be concluded that the Leeds to Pleasant Valley transmission path currently produces the greatest congestion in the state. The Base Transmission Plan addresses Leeds-Pleasant Valley congestion as well as potential congestion in the paths up-stream and downstream to it. Figure 7-6 shows the Dollar Demand Congestion values after the Base Transmission Plan has been applied to the Replacement Plan.

Figure 7-6 Base transmission plan demand congestion ($M annually)

	Contingency	Athens to Pleasant Valley	Pre Contingency		Gowanuss	Dunwoodie	Quenbrg_Verne	Pre Contingency	Marcy	Mothaven	Kinti Roch	Pre Contingency
STARS Scenario	Constraint	Leeds to Pleasant Valley	Greenwood	Central East	Gowanuss	Dunwoodie	E179ST 15055SR	LIPA Cable	Coopers Frasier	Rainey	Niag Roch	Dunwoodie
Reference Case	BTP	20	45			48			73	37		
High Fuel Forecast	BTP		46			71			86	58	24	
8000 MW Wind	BTP		44						75	25	14	24
4250 MW Wind	BTP		37			35	19		26	22		
Shift 1000MW Upstate	BTP	53	35			47			90	48		
Shift 1000MW Downstate	BTP		44			44			66	33	16	
High Emissions	BTP	87				172		144	107	112		

The results of the purely economic analysis of the base transmission plan suggested that at a high level the full plan would not be justified solely on a production cost savings basis. As such the STARS TWG utilized the demand congestion data described in detail above as well as the element utilization information included in Figure 7-2 to help guide the development of transmission plan trials that were economically justified. The study group recognized that there were many permutations and combinations of projects that could be analyzed and as such agreed to evaluate a limited number of trials. Figure 7-7 below represents a summary of the trials that were evaluated. It should be noted that the summarized results included below were completed in an iterative fashion. As results from various trials were reviewed new trials were developed.

Figure 7-7 Phase II transmission trials

Trial	Pleasant Valley – Sprain-brook HVDC Line	Pleasant Valley – Ruland Road HVDC Line	Sprain-brook-Ruland Road HVDC Line	Marcy – Moses Lines	Oakdale – Fraser Line	Marcy – Princ-etown – New Scotland	Rock Tavern – Ramapo	New Scotland - Leeds	Leeds - Pleasant Valley	115kV Upgrades
Initial	X	X		X	X	X	X	X	X	X
T1		X		X	X	X	X	X	X	X
T2	X			X	X	X	X	X	X	X
T3				X	X	X	X	X	X	X
T4					X	X	X	X	X	X
T5			X	X	X	X	X	X	X	X
T6						X	X	X	X	X
T7							X	X	X	X
T8								X	X	X
T9									X	X
T10					X		X	X	X	X
T12						X		X	X	X
T14						X			X	X
T15						X	X		X	X
T16				X						X

Notes: 1) "X" indicates that the line(s) is included in the Trial.
2) Trial 13 was not included as it is the same as Trial 8, Trail 11 was not included as it only included the 115 kV Projects

7.5 Transmission trial production cost & LBMP results

The metrics analyzed for the full Base Transmission Plan were also calculated for each of the BTP Trials (Figure 7-8). Summaries showing the results for all of the Base Transmission Plan Trials can be seen in the tables below. Detailed results for each of the BTP Trials are found in Attachment 7. In addition, this analysis does not consider any potential ICAP savings which will be discussed and quantified in Section 8 of this report.

Figure 7-8 Transmission trial production cost and LBMP results

BTP Trial	Benefit Annual NYISO Production Cost Savings (M$)	Benefit Annual NYISO Load LBMP Savings (M$)	Cost Annual Project Carrying Charge (M$)	B/C Production Cost	B/C Load LBMP Payment
Initial	199	109	597	0.33	0.18
T1	197	103	456	0.43	0.23
T2	176	82	402	0.44	0.2
T3	175	77	261	0.67	0.3
T4	176	67	213	0.83	0.31
T5	192	103	394	0.49	0.26
T6	144	73	170	0.85	0.43
T7	126	58	108	1.17	0.54
T8	94	57	80	1.18	0.71
T9	75	28	48	1.55	0.58
T10	162	51	151	1.07	0.34
T12	117	67	142	0.83	0.47
T14	87	30	118	0.74	0.25
T15	107	35	146	0.73	0.24
T16	2	23	48	0.04	0.48

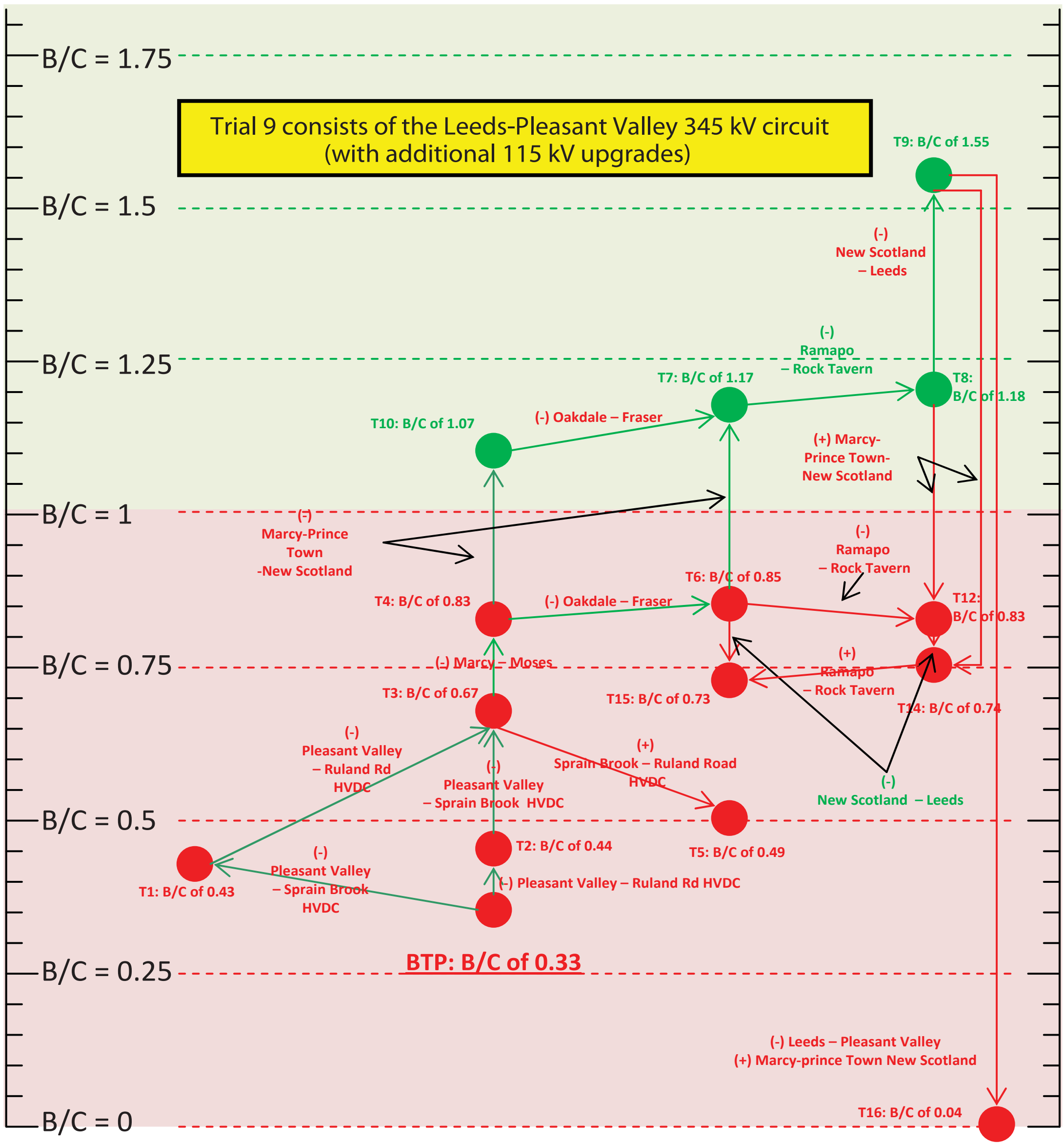
The Production Cost Benefit/Cost Ratio (B/C) results were used as the primary determinant as to whether a Trial is an economic solution. A B/C ratio greater than or equal to 1.0 is typically necessary for a project to be considered economically justified. The Base Transmission Plan provided the greatest benefit of all Trials but also had the highest cost, resulting in a 0.33 B/C ratio based on production costs. As Trials were being developed, specific attention was given to elements that provided incremental benefits, which allowed for the definition of additional Trials. Keeping transmission elements that provided incremental benefit and removing those that were economically detrimental increased the B/C ratios above 1.0 for Trials 7-10. Figures 7-9 and 7-10 show one of the methods used to develop additional Trials as results were being collected and analyzed (complete details can be found in Attachment 8).

Figure 7-9 Incremental benefit analysis

Trial	Benefit (M$)	Cost (M$)	B/C Ratio (M$)	Benefit-Cost (M$)	Inc Benefit (M$)	Inc Cost (M$)	Inc B/C Ratio (M$)
Initial (BTP)	199	597	0.33	-398	-	-	-
T1	197	456	0.43	-259	-	-	-
T2	176	402	0.44	-226	-	-	-
T3	175	261	0.67	-86	-	-	-
Incremental **Marcy-Moses** benefit (T3 to T4):					-1	48	-0.02
T4	176	213	0.83	-37	-	-	-
T5	192	394	0.49	-202	-	-	-
Incremental **Oakdale-Fraser** benefit (T4 to T6):					32	43	0.74
T6	144	170	0.85	-26	-	-	-
Incremental **Marcy/PT/N. Scotland** benefit (T6 to T7):					18	62	0.29
T7	126	108	1.17	18	-	-	-
Incremental **Ramapo-Rock Tavern** benefit (T7 to T8):					32	28	1.15
T8	94	80	1.18	14	-	-	-
Incremental **New Scotland-Leeds** benefit (T8 to T9):					19*	31	0.61
T9	75	48	1.55	27	-	-	-
T10	162	151	1.07	11	-	-	-
T12	117	142	0.83	-25	-	-	-
Incremental **New Scotland-Leeds** benefit (T12 to T14):					30	24	1.26
T14	87	118	0.74	-31	-	-	-
T15	107	146	0.73	-39	-	-	-
T16	2	48	0.04	-46	-	-	-
Incremental **Marcy/PT/N. Scotland** benefit (T4 to T10):					14	62	0.23
Incremental **New Scotland/Leeds** benefit (T6 to T15):					37	24	1.55
Incremental **Ramapo-Rock Tavern** benefit (T6 to T12):					27	28	0.97
Incremental **Marcy/PT/N. Scotland** benefit (T8 to T12):					-23	-62	0.37
Incremental **Marcy/PT/N. Scotland** benefit (T9 to T14):					-12	-70	0.17
Incremental **Oakdale-Fraser** benefit (T10 to T7):					36	43	0.83
Incremental **Ramapo-Rock Tavern** benefit (T14 to T15):					-20	-28	0.72

From the data in Figure 7-8, Trial 9 has the greatest B/C ratio of 1.55. While this provides evidence that Trial 9 is the most beneficial, the remainder of the Trials with a B/C ratio greater than 1.0 could also be justified (Trials 7, 8, and 10).

Figure 7-10 Incremental benefit graphical analysis



Notes:

1) Each trial is depicted as a node with red nodes denoting trials with B/C <1, and green with B/C>1.

2) A red arrow denotes that the B/C ratio decreased implying that more benefit than cost was removed, not a good outcome. A green arrow denotes the reverse, that more cost than benefit was removed, a good outcome.

7.6 Sensitivity analysis assumptions

To evaluate the robustness of the STARS Base Transmission Plan Trials, eight different production cost model sensitivities were developed. Each sensitivity represents a single change applied to both the Replacement Plan and the Base Transmission Plan Case. Decreases in production costs between the two cases indicates the varying economic benefits for the different transmission build-outs provided under alternate future forecasts. Figure 7-11 outlines the eight different sensitivities and the underlying assumptions used to create each of them. A detailed description and results for each of the sensitivities can be found in Attachment 9.

Figure 7-11 STARS sensitivity case assumptions

Sensitivity Case	Assumptions
4,250 MW Wind Generation	Model 4,250 MW Wind Generation from NYISO Queue as Prescribed by NYISO Wind Study
8,000 MW Wind Generation	Model 8,000 MW Wind Generation from NYISO Queue as Prescribed by NYISO Wind Study
Low Fuel Price Forecast	Set Fuel Price to 1 Standard Deviation Lower than Reference Case Forecast (see Attachment 9)
High Fuel Price Forecast	Set Fuel Price to 1 Standard Deviation Higher than Reference Case Forecast (see Attachment 9)
Low Emissions Price Forecast	CARIS I 2009 Values for CO2, SO2, & NOx
High Emissions Price Forecast	$100/Ton CO2 & 2x Reference Case SO2 & NOx Forecast
Shift 1,000 MW Generic Upstate	Remove 1,000 MW of Generic Generation Capacity From Zones J&K and Move to Zone C
Shift 1,000 MW Generic Downstate	Remove 1,000 MW of Generic Generation Capacity From Zone C and Move to Zones J&K

7.7 Sensitivity analysis

Numerous Trials were selected based upon B/C ratios and engineering judgment to evaluate in the sensitivity simulations. The specific trials that were selected for the sensitivity cases included the full BTP, Trial 3, Trial 4, Trial 9, Trial 12 and Trial 14. The changes in the production costs and production cost savings for the trials under each of the sensitivities are summarized in Figures 7-12 through 7-15. A complete set of sensitivity results for each of the Trials evaluated can be found in Attachment 9.

Figure 7-12 Average percent change in NY system production costs by sensitivity

Sensitivity	Average New York System Production Cost Change When Sensitivity is Applied
4250 MW Wind	4%
8000 MW Wind	-6%
Low Fuel Forecast	-9%
High Fuel Forecast	8%
Low Emissions Forecast	-24%
High Emissions Forecast	46%
Shift 1000 MW Upstate	0%
Shift 1000 MW Downstate	-1%

Figure 7-13 Base transmission plan trials sensitivity results by production cost savings percent change

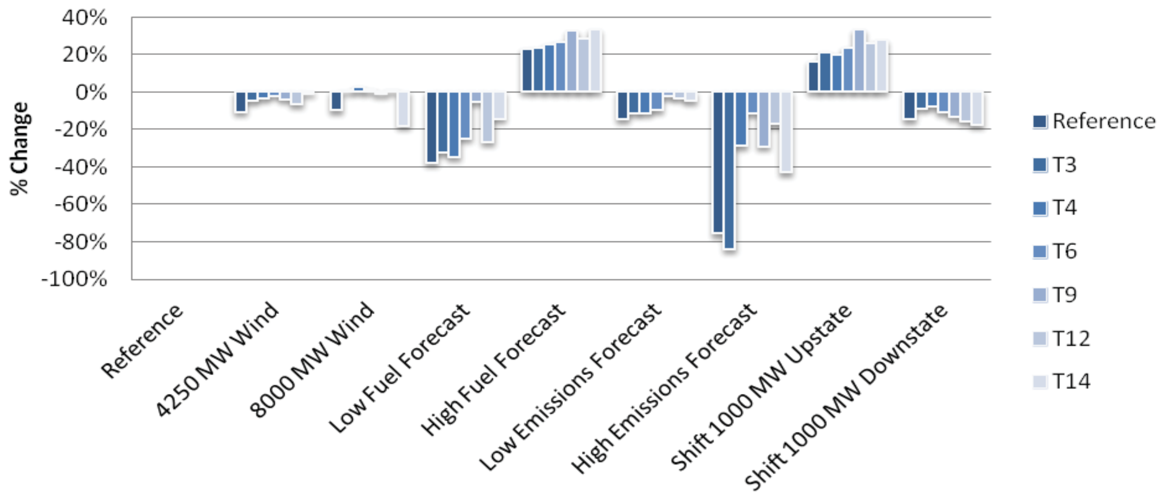
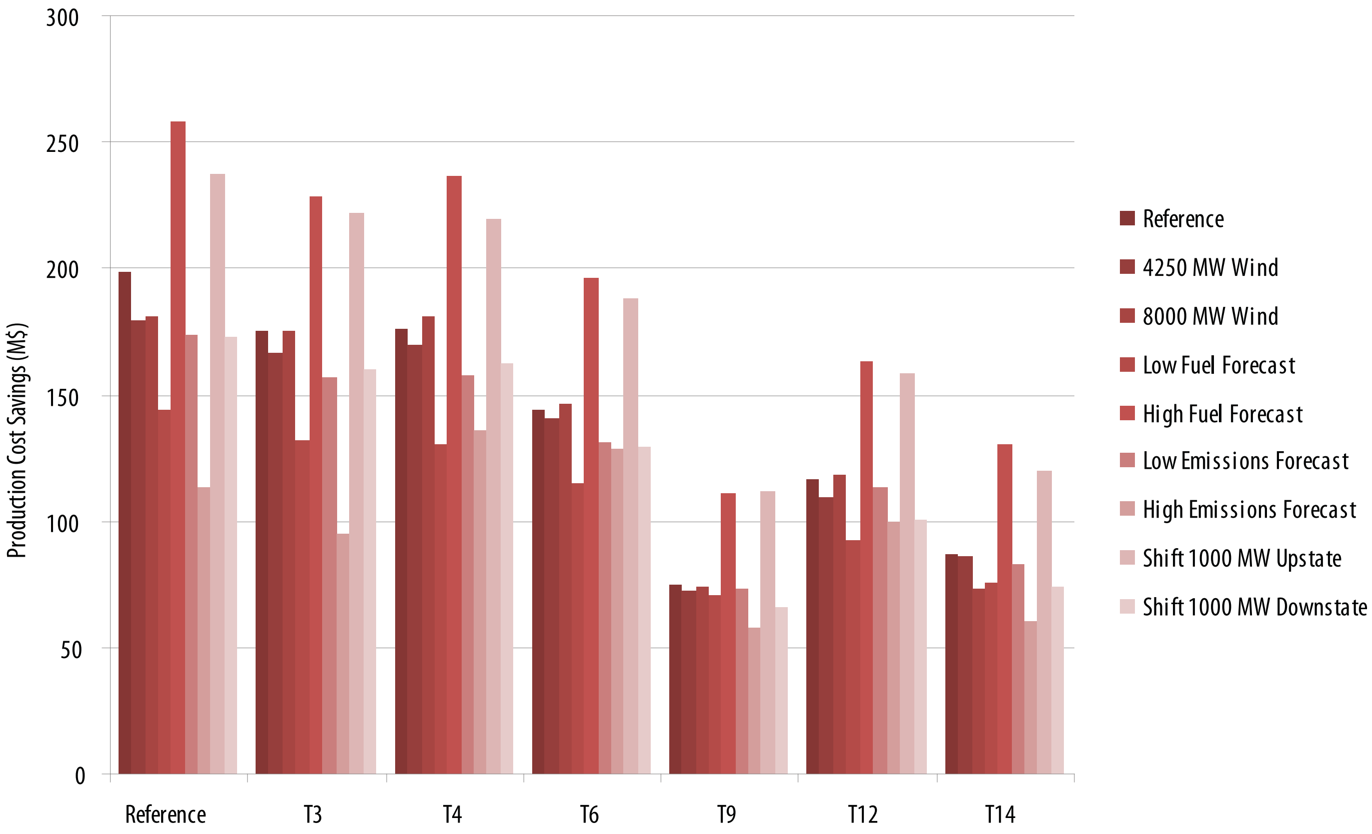


Figure 7-14 Base transmission plan sensitivity results by production cost magnitude



Using Figure 7-15, the general effects of the sensitivities on the STARS BTP Trials can be observed. The generation resource mix upstream and downstream to the transmission projects being evaluated has a significant impact on how each Trial responds to the sensitivities. Figures 7-16 and 7-17 show the upstate (NYISO Zones A-F) and downstate (NYISO Zones G-K) generation resource mix being modeled in the STARS Reference Case:

Figure 7-15 Average percent change in production cost savings by sensitivity

Sensitivity	Average BTP Trial Production Cost Savings Change
4250 MW Wind	-5%
8000 MW Wind	-3%
Low Fuel Forecast	-25%
High Fuel Forecast	27%
Low Emissions Forecast	-8%
High Emissions Forecast	-42%
Shift 1000 MW Upstate	24%
Shift 1000 MW Downstate	-13%

Figure 7-16 NYISO upstate generation resource mix

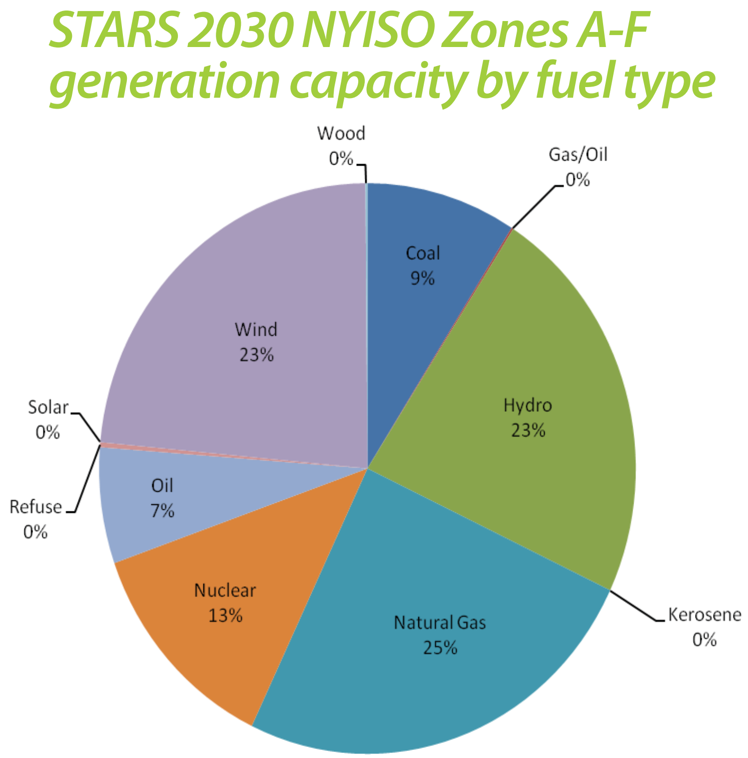
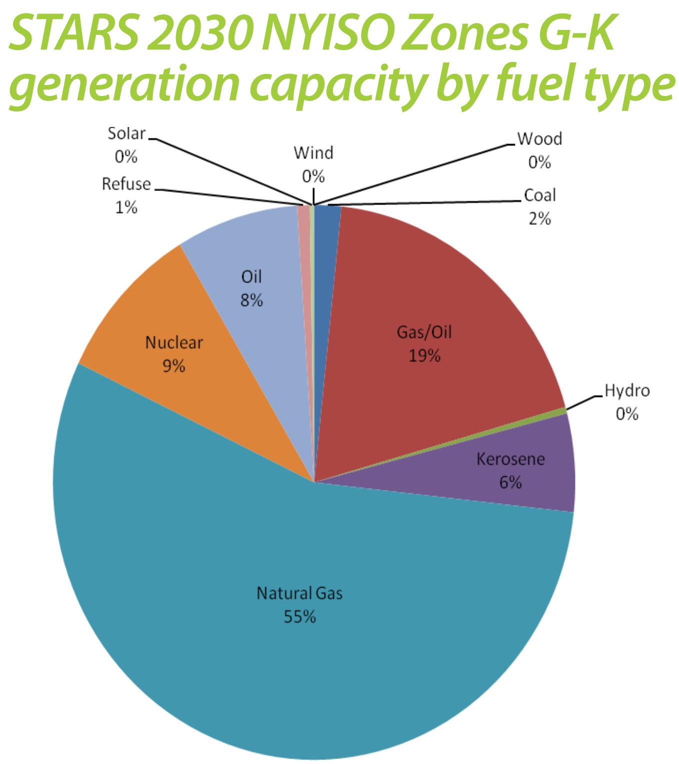


Figure 7-17 NYISO downstate generation resource mix



Because the upstate area generation is comprised of a large percentage of cheaper renewable and nuclear generation compared to the downstate area which contains mostly fossil fuel based generators, the impacts of fuel and emission price sensitivities will be drastically different between those areas. Reactions of sensitivities involving the addition or relocation of generation are highly dependent upon the exact locations of the generation changes.

When reviewing the results of the sensitivities it is important to note that both hydro and wind generators operate based on a fixed pattern throughout the study year. The energy pattern is based on the geographic location, unit operating limits, and historical data. Fixed output units do have capability to curtail generation if their output causes congestion but curtailed generation was minimal in this study. The fixed units limit the ability of generation in each zone to adjust to changes made to the Base case, including the application of the BTP and the sensitivities. Table 7-18 identifies the wind generation capacity for each NYISO zone for the three different wind generation amounts studied.

Figure 7-18 NYISO nameplate wind generation by zone (MW)

Wind Case	West	Genesee	Central	North	Mohawk Valley	Capital	NYC & LI	Total
4250	917	86	1110	717	1397	0	0	4227
6000	1291	281	1593	1068	1647	70	0	5949
8000	1492	418	1861	1068	1647	70	1400	7955

7.7.1 4,250 MW wind generation sensitivity

This sensitivity represents a decrease in the amount of wind generation capacity from the reference case, which contains 6,000 MW. Figure 7-18 shows the zonal variations in wind generation capacity for each of the wind related sensitivities. The wind generation reductions in this sensitivity occur in zones A-F, which are upstream to transmission bottlenecks. The production cost savings, as a result of reducing the amount of wind generation capacity, is reduced. The benefit of installing transmission in the BTP Trials is diminished as inexpensive generation upstream to the projects and transmission congestion is reduced.

7.7.2 8,000 MW wind generation sensitivity

A majority (70%) of the generation added to the reference case to create the 8,000 MW wind sensitivity was installed in zones J and K based on a proposed New York City / Long Island offshore wind project, with the remainder located in zones A, B, and C. In most BTP Trials there was a negligible change in savings when the sensitivity was applied, with the exception of the Reference Case and Trial T14. When the Reference Case wind generation is increased to 8,000 MW the production cost savings due to the BTP is reduced. With 1,400 MW of new wind generation installed in zones J & K the benefits provided by the BTP are decreased. In Trial 12 there is also a noticeable reduction in savings. The only difference between T12 and T14 is the exclusion of the New Scotland to Pleasant Valley segment of the Marcy-New Scotland-Leeds-Pleasant Valley transmission path. It appears that the removal of this line segment negatively impacts the production cost savings in this sensitivity.

7.7.3 Low fuel price forecast

In the Low Fuel Price Sensitivity prices were set to one standard deviation lower than the base forecast (See Attachment #9). The general effect of reducing fuel prices was to diminish the benefit of each of the BTP Trials that were studied. Lowering fuel prices allows downstate generators to be more competitive against imports from upstate generation and reduces the need for additional transmission capacity to transport energy across the state. Because the fuel forecast sensitivity largely affects oil and natural gas generation, the effect is even more compounding considering the large percentage of these types of generators in downstate zones (see Figures 7-16 and 7-17).

7.7.4 High fuel price forecast

In the High Fuel Price Sensitivity prices were set to one standard deviation higher than the base forecast (See Attachment #9). In contrast to the Low Fuel Price Sensitivity, production cost savings increase when fuel prices are raised. Upstate generation costs increase less than those in the downstate area, due to differing fuel sources as shown in Figures 7-16 and 7-17, therefore indicating that generation is more economic to be transferred from upstate to downstate. The Base Transmission Plan provides more benefit as the price separation between these areas grows, such as in the case of increased fuel prices.

7.7.5 Low emissions price forecast

The low emission price sensitivity reduces the emissions prices by more than 500% for each of the three emissions types. This is a very large decrease in prices and essentially eliminates any emissions adders to generator cost in commitment and dispatch decisions. Without emissions adders, fossil fuel generation in the downstate area is more competitive with upstate generation and produces more energy in this sensitivity as compared to the Reference Case. When the BTP and the BTP trials are added to the low emission Replacement Plan the resulting savings is less than the non-sensitivity case. This is due to the fact that a smaller amount of downstate generation is replaced with upstate generation and less energy transfer is required across the transmission buildout.

7.7.6 High emissions price forecast

The high emissions price sensitivity increases each emissions price forecast by nearly 100%. With emissions cost increases, generation in upstate New York becomes more economic than downstate New York as it is affected less by emissions price changes, with the exception of the coal generators in Western New York. Upstate coal generation provides a portion of the incremental energy beyond hydro, wind, and nuclear to create a production cost savings when the BTP and BTP Trials are installed. With increased CO2 prices, this coal generation incurs much higher costs, and is no longer an economic alternative to downstate generation. Generation in New England increases significantly in this sensitivity, which essentially replaces the Western New York coal generation, increasing the imports cost from New England. For this reason there is a decrease in the production cost savings that the BTP and the BTP Trials provide when emission costs are increased.

7.7.7 Shift 1,000 MW generic generation upstate

In this sensitivity 1,000 MW of generic generation capacity was re-located from NYC and Long Island to the Central zone in upstate New York. As shown in Figure 7-15 there is a material impact on New York production costs when shifting this generation. With more inexpensive generic generation placed on the upstream side of the studied transmission elements the production cost savings provided by the BTP and BTP trials increases by an average of 24%.

7.7.8 Shift 1,000 MW generic generation downstate

In this sensitivity 1,000 MW of generic generation capacity was re-located from the Central zone in upstate New York to NYC and Long Island. As shown in Figure 7-15 there is a minimal impact on New York production costs when shifting this generation. With more inexpensive generic generation placed on the downstream side of the studied transmission elements the production cost savings provided by the BTP and BTP trials are diminished by an average of 13%.

8

Economic analysis -Installed Capacity (ICAP) Savings

Economic analysis-ICAP Savings

8.1 Savings methodology

The calculation of the Installed Capacity Market Savings Metric was performed in accordance to Section 31.3.1.3.5.6 of the NYISO OATT Attachment Y. This requires the approximation of the capacity impact that a transmission project has on the study system through LOLE calculations. The capacity "MW Impact" is then used to determine the monetary benefits associated with a future capacity market, which is an escalated version of the current capacity market, directly from the demand curve. The OATT Attachment Y specifies two calculation "variants" for ICAP savings that represent differing philosophies on the potential benefits that can be obtained in the ICAP market. Both versions of the calculation were performed in the STARS analysis.

8.2 Development of BTP projects and trials

Section 6 of this report described the development of the Base Transmission Plan. Results of economic analysis and transmission utilization warranted evaluation of modifications to the Base Transmission Plan. Some projects in the Base Transmission Plan were removed, modified and/or some projects were added. This resulted in several potential alternatives to the Base Transmission Plan. Section 7 of this report describes the development of these alternatives (trials) and benefit-to-cost ratio calculations associated with each trial. In particular, trials with a B/C ratio greater than 1.0 are justifiable under current NYISO rules for economic projects. Based on these results, the STARS Executive Committee and the STARS TWG recommended further evaluation on the following transmission plans:

- Base Transmission Plan
- Trial 9
- Trial 10

Evaluation of the above plans involved the following analyses. First, a steady-state analysis was performed to evaluate system performance with the proposed plans. The analysis is performed under all-lines in and contingency case conditions to check for potential thermal and/or voltage violations and the results are compared against New York State Reliability Criteria to determine whether the system would be secure with the proposed transmission additions. In addition, emergency transfer limits are established for use in the subsequent LOLE analysis. Next, reliability analysis is performed to determine the impact of the transmission plans on the statewide LOLE. The resulting LOLEs are compared against the Reference Case LOLE (without transmission upgrades). Since the Reference Case LOLE is 0.08 days/year, it can be expected that the LOLEs with the transmission additions will also be ≤ 0.08. Analysis is performed to quantify the excess generation capacity to bring the LOLE back to 0.08. Generation is reduced in all NYCA zones proportionally on the basis of zonal unforced capacity (UCAP) until the base system LOLE of 0.08 is achieved. That amount of reduced generation is the NYCA MW Impact. Finally, the ICAP cost savings are calculated on the basis of the MW Impact.

8.3 Power flow and transfer limit analysis

8.3.1 Case development

The Scenario 3A power flow case for horizon year summer peak conditions was updated with the Hudson Transmission Project (HTP) and the NYISO wind additions (See Section 4.4). Also, the locations of some of the generic units in Zones F, G and J were changed based on the assumptions made in the economic analysis portion of the study as shown in Figure 4-5. The Base Transmission Plan projects were then added to the case. See Attachment 10 for details. The base case generation dispatch inside NYCA was derived from the horizon year BTP Economic Study database prepared by the NYISO (security constrained economic dispatch at the peak load hour). Minor adjustments were made to generation dispatch to mitigate marginal base case and post-contingency violations seen on bulk power system facilities. This case is referred to as the BTP Case.

In addition to the BTP Case, two trial cases were developed:

The Trial 10 Case was developed from the BTP Case by removing the following transmission projects: Pleasant Valley - Sprainbrook HVdc, Pleasant Valley - Ruland Road HVdc, Moses - Marcy 345 kV lines (replaced the existing Moses - Adirondack - Porter 230 kV lines), and Marcy - Princetown - New Scotland 345 kV lines (replaced the existing Porter-Rotterdam 230 kV lines). Trial 10 therefore includes the following BTP facilities only:

- Oakdale-Fraser 345 kV line #2
- New Scotland-Leeds 345 kV #3
- Leeds-Pleasant Valley 345 kV line #3
- Rock Tavern-Ramapo 345 kV line #2
- National Grid 115 kV transmission upgrades

The Trial 9 Case was also developed from the Trial 10 Case by removing the following transmission projects: Oakdale-Fraser #2, New Scotland - Leeds #3, and Rock Tavern - Ramapo #2. Trial 9 therefore includes the following BTP facilities only:

- Leeds-Pleasant Valley 345 kV line #3
- National Grid 115 kV transmission upgrades

8.3.2 Power flow analysis

Power flow analysis was performed on the above-mentioned cases using the same methodology as in the earlier Phase I and Phase II work. For the purposes of this analysis, transmission facilities rated 100 kV and above within NYCA (and tie-lines out of NYCA) were monitored. For thermal overloads, each branch element (transformer, transmission line, or feeder in the monitored system) was monitored and electrical flows above the applicable branch rating (normal continuous rating - Rate A) under system intact conditions, LTE rating (Rate B) under contingency conditions for overhead transmission lines and STE rating (Rate C) for underground feeders were flagged. Bus voltages were monitored for range violations and voltage collapse. Phase angle regulators (PARs), switched shunts and LTC transformers are modeled as regulating pre-contingency and non-regulating post-contingency.

The following types of contingencies were simulated based on the contingency files provided by NYISO and NYTOs:

1. Outage of branches connected between buses with a base voltage of 100 kV and above (these included outages based on "automatic" N-1 contingency specification in MUST and specific pre-defined branch outages)

2. Generation contingencies
3. Series element contingencies
4. Bus contingencies
5. HVDC contingencies

In addition to these contingencies, other contingencies provided by National Grid associated with wind generation in the North Country were simulated. No stuck-breaker or tower contingencies were simulated.

Results of the power flow analysis on the above-mentioned cases showed some thermal overloads and voltage violations. These violations were reviewed by the STARS TWG. Several of the violations were dismissed as local area issues that have nothing to do with contingencies on the NYS Bulk Power System. Mitigation for these violations will be established through the local area planning process performed by the NYTOs. In addition, local area generation adjustments and/or SPS action can be used to mitigate other violations seen in this study.

8.3.3 Transfer limit analysis

After completing the power flow analysis, emergency transfer limits were calculated for key interfaces in the NYCA system. See Attachments 10 through 12. Figure 8-1 compares the calculated thermal transfer limits between the three cases. Figures 8-2 through 8-5 show the limiting facilities associated with the emergency transfer limits in each of the cases.

Figure 8-1 Comparison of emergency thermal transfer limits for horizon year between BTP, Trial 10 and Trial 9 cases

Interface	Intermediate Yr. Summer Peak Case Without BTP	Limiting Facility Table 8-2	Horizon Year Summer Peak Case With BTP	Limiting Facility Table 8-3	Horizon year Summer Peak Case Trial 9	Limiting Facility Table 8-4	Horizon year Summer Peak Case Trial 10	Limiting Facility Table 8-5	T9-BTP		T10-BTP	
									MW	%	MW	%
Dysinger East	3225	1	2950	1	2975	1	2975	1	25	1%	25	1%
West Central	1825	1	1775	1	1800	1	1825	1	25	1%	50	3%
Volney East	4550	2	4300	2	4100	2	3875	2	-200	-5%	-425	-10%
Moses South	2650	7	4200	3	2325	3	2325	3	-1875	-45%	-1875	-45%
Total East (Closed)	6700	2	7750	2	7575	4	7550	2	-175	-2%	-200	-3%
Central East (Note 1)	3000	3	4175	4	2975	4	3550	4	-1200	-29%	-625	-15%
Central East + Fraser-Gilboa (Note 1)	3200	2	3725	2	3350	4	3325	2	-375	-10%	-400	-11%
CE Group (Note 1)	5175	2	5650	2	5275	4	5250	2	-375	-7%	-400	-7%
F to G	3475	4	5250	5	4525	4	5425	5	-725	-14%	175	3%
UPNY-SENY Open (Note 2)	5225	4	7275	2	6950	4	6950	2	-325	-4%	-325	-4%
UPNY-ConEd Open	5800	5	7525	6	6825	5	7400	6	-700	-9%	-125	-2%
Millwood South Closed (Note 3)	9775	8	11275	6	10850	5	11250	6	-425	-4%	-25	0%
I to J	4450	6	4475	7	4450	6	4475	7	-25	-1%	0	0%
Dunwoodie South Open	5725	6	5700	7	5675	6	5675	7	-25	0%	-25	0%
I to K	1275	9	1275	8	1275	7	1275	8	0	0%	0	0%
LIPA Import	2875	9	3475	8	2900	7	2900	8	-575	-17%	-575	-17%

Notes:

1. Excludes Plattsburgh-Sandbar 115 kV line
2. Excludes Jefferson-Ramapo 500 kV line
3. Horizon year definition of this interface includes the Hudson Transmission Project (HTP)
4. Interface limits rounded down to the nearest 25 MW to be consistent with NYISO practices

Figure 8-2 Limiting facilities for emergency thermal transfer limit calculations (Intermediate year case without BTP projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Stolle-Meyer 230	430	Pre-disturbance
2	Coopers Corners-Frasers 345	1207	Pre-disturbance
3	New Scotland77-Leeds 345	1724	L/O New Scotland99-Leeds 345
4	Pleasant Valley-Leeds 345	1725	L/o Athens-Pleasant Valley 345
5	Middletown Tap-Coopers Corners 345	1793	L/O Rock Tavern-Coopers Corners 345
6	Dunwoodie-Mott Haven 345	783	Pre-disturbance
7	Moses-Adirondack 230	440	L/O Massena-Marcy & Massena-Chateaguay
8	Roseton-Fishkill 345	1935	Pre-disturbance
9	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line
2. Excludes Jefferson-Ramapo 500 kV line
3. The limiting transfer for the I-to-K and LIPA Import interfaces is Y50 (Dunwoodie – Shore Road 345 kV). The limit is based on the MW rating for Y50 (653 MW)

Figure 8-3 Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with BTP projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Wethersfield - Meyer 230	430	Pre-disturbance
2	Fraser - Coopers Corners	1207	Pre-disturbance
3	Marcy 765/345 T2	2338	L/O Marcy 765/345 T1
4	New Scotland 77 - Leeds 345	1724	L/O New Scotland - Leeds #3
5	Leeds - Pleasant Valley #1 (existing)	1724	L/O Leeds - Pleasant Valley #3
6	Roseton-Fishkill 345	1935	Pre-disturbance
7	Dunwoodie-Mott Haven 71	783	Pre-disturbance
8	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Horizon year definition includes PV - Sprainbrook HVdc (900 MW) and PV - Ruland Road HVdc (600 MW)
4. Horizon year definition includes PV - Sprainbrook HVdc (900 MW) and PV - Ruland Road HVdc (600 MW) and the Hudson Transmission Project (HTP)
5. Horizon year definition includes PV - Ruland Road HVdc (600 MW)
6. The limiting transfer for the I-to-K and LIPA Import interfaces is Y50 (Dunwoodie – Shore Road 345 kV). The limit is based on the MW rating for Y50 (653 MW)

Figure 8-4 Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with Trial 9 projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Niagara-Rochester 345	1685	L/O Kintigh-Rochester 345
2	Fraser - Coopers Corners 345	1207	Pre-disturbance
3	Marcy 765/345 AT1	1756	L/O Marcy 765/345 AT2
4	New Scotland 77 - Leeds 345	1724	L/O New Scotland 99 - Leeds 345
5	Roseton-Fishkill 345	1935	Pre-disturbance
6	Dunwoodie-Mott Haven 71	783	Pre-disturbance
7	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Includes Hudson Transmission Project (HTP).

Figure 8-5 Limiting facilities for emergency thermal transfer limit calculations (Horizon Year case with Trial 10 projects)

Limiting Facility		Limiting Rating MVA	Contingency
1	Niagara-Rochester 345	1685	L/O Kintigh-Rochester 345
2	Fraser - Coopers Corners 345	1207	Pre-disturbance
3	Marcy 765/345 AT1	1756	L/O Marcy 765/345 AT2
4	Marcy - New Scotland 345	1792	L/O Edic - New Scotland 345
5	Leeds - Pleasant Valley #1 (existing)	1725	L/O Leeds - Pleasant Valley #3
6	Roseton-Fishkill 345	1935	Pre-disturbance
7	Dunwoodie-Mott Haven 71	783	Pre-disturbance
8	Dunwoodie-Shore Rd 345	653	Pre-disturbance

Notes:
1. Excludes Plattsburgh-Sandbar 115 kV line.
2. Excludes Jefferson-Ramapo 500 kV line.
3. Includes Hudson Transmission Project (HTP).

In addition to these limits, emergency voltage transfer limits were calculated for the Central East, Central East + Fraser-Gilboa and Central East Group interfaces. These interfaces have traditionally been voltage limited, whereas the other interfaces have tended to be thermally limited. So for purposes of this study, voltage transfer limits were only calculated for the Central East related interfaces. Figure 8-6 compares the voltage limits between the three cases.

Figure 8-6 Comparison of voltage transfer limits for Central East interfaces, BTP case vs. Trial 10 Case vs. Trial 9 Case

	Horizon year limit with BTP		Horizon year limit with BTP Trial 10				Horizon year limit with BTP Trial 9			
	Voltage transfer limit	Limiting facility	Voltage transfer limit	Limiting facility	T10-BTP		Voltage transfer limit	Limiting facility	T9-BTP	
					MW	%			MW	%
CENTRAL EAST	3275	3	2800	1 & 2	-475	-14.5	2775	1 & 2	-500	-15.3
CE + FRASER-GILBOA	3700	3	3225	1 & 2	-475	-12.8	3150	1 &2	-550	-14.9
CE-GROUP	5550	3	5000	1 & 2	-550	-9.9	4875	1 & 2	-675	-12.2

Additional details on the transfer limit calculations and comparison against previously derived limits are given in Attachments 10 through 12. The more limiting of the two transfer limits (thermal vs. voltage) is used in the LOLE calculations. This is described in the next section.

8.4 Reliability analysis

The Scenario 3A GridView model used in the initial Phase II analysis was updated with the HTP project and NY-ISO wind additions as described in Section 4.4 of this report. Three separate models were then developed by adding the BTP, Trial 10 and Trial 9 projects. The models were updated with the corresponding emergency transfer limits derived in Section 8.3.3. Voltage transfer limits were used for the Central East interfaces as these are more limiting than the corresponding thermal limits.

Results of the reliability analysis on the BTP Case show that the statewide LOLE is 0.070 days/year. As expected, it is below the statewide LOLE of 0.080 days/year from the Reference Case. The corresponding LOLE in the Trial 9 and 10 Cases is 0.074 days/year.

Figure 8-7 compares the zonal and statewide LOLEs between the BTP Case, Trial 10 and Trial 9 Cases.

Figure 8-7 Comparison of zonal and statewide LOLEs between BTP, Trial 10 and Trial 9 cases

	Horizon year's LOLE (days/year)		
Zones	BTP case	Trial 10 case	Trial 9 case
A	-	-	
B	0.017	0.021	0.018
C	-	-	
D	-	-	
E	0.044	0.040	0.045
F	-	-	0.002
G	0.068	0.071	0.063
H	-	-	
I	0.064	0.063	0.070
J	0.061	0.074	0.074
K	0.066	0.073	0.075
NYCA	0.070	0.074	0.074

8.5 ICAP MW impact analysis

ICAP MW Impact analysis was performed on the BTP and Trial 9 Cases to quantify the impact of the added transmission. Since the Trial 9 and Trial 10 cases showed the same LOLE (0.074 days/year), it can be assumed that both Trials will have similar MW Impacts – therefore the analysis that was performed on the Trial 9 case should apply to the Trial 10 case.

8.5.1 BTP case

In order to determine the MW capacity impact of the BTP projects, new generation capacity was reduced and LOLE recalculated. Zonal generation unforced capacity (UCAP) was used as a basis for the generation reductions. In other words, new generation capacity in each zone was reduced in proportion to the unforced generation capacity (UCAP). Because LOLE varies in a non-linear fashion with the generation capacity (or load), this LOLE calculation is an iterative process involving reduction of generation capacity until the NYCA's LOLE of 0.08 days/year (as in original Replacement Plan case) is reached. Then, the amount of capacity that was backed off is the "MW Excess".

After several iterations, with 400 MW new generation capacity reduction, the NYCA LOLE reaches 0.08 days/yr. See Figure 8-8. The new generation capacity reductions are shown in Figure 8-9. So the MW Impact of the BTP projects is 400 MW(See Attachment 13).

Figure 8-8 Calculated LOLE for BTP cases with and without generation reduction based on zonal UCAP proportion

	Horizon year's LOLE (days/year)	
Zones	Base Transmission Plan case	BTP case with reduced new generation
A	-	-
B	0.02	0.02
C	-	-
D	-	-
E	0.04	0.05
F	0.00	0.00
G	0.07	0.07
H	-	-
I	0.06	0.07
J	0.06	0.07
K	0.07	0.08
NYCA	0.07	0.08

Figure 8-9 New generation capacity in BTP case based on zonal UCAP proportion (from NYISO)

Zones	UCAP using 2011 translation factors (MW)	MW reduction
A	4,743	48
B	866	9
C	6,421	65
D	1,679	-
E	972	27
F	3,679	37
G	2,813	28
H	2,227	-
I	93	23
J	9,758	98
K	6,425	65
Total	39,676	400

8.5.2 Trial 9 case

In order to determine the MW capacity impact of the projects in both trials, new generation capacity was reduced and LOLE recalculated. Zonal generation unforced capacity (UCAP) was used as a basis for the generation reductions. In other words, new generation capacity in each zone was reduced in proportion to the unforced generation capacity (UCAP). Because LOLE varies in a non-linear fashion with the generation capacity (or load), this LOLE calculation is an iterative process involving reduction of generation capacity until the NYCA's LOLE of 0.08 days/year (as in the Scenario 3A case) is reached. Then, the amount of capacity that was backed off is the "MW Impact". This MW Impact would be identical for both Trials 9 and 10 based on the reported LOLE findings in Section 8.4.

Figure 8-10 *Calculated LOLE for T9 case with and without generation reduction, based on zonal UCAP proportion*

	Horizon year's LOLE (days/year)	
Zones	T9 case	T9 case with reduced new generation
A	-	-
B	0.02	0.02
C	-	-
D	-	-
E	0.04	0.05
F	0.00	0.00
G	0.06	0.08
H	-	-
I	0.07	0.08
J	0.07	0.08
K	0.08	0.08
NYCA	0.07	0.08

Figure 8-11 *New generation capacity in Trial 9 case, based on zonal UCAP proportion*

Zones	UCAP using 2011 translation factors (MW)	MW reduction
A	4,743	32
B	866	6
C	6,421	44
D	1,679	0
E	972	18
F	3,679	25
G	2,813	19
H	2,227	0
I	93	16
J	9,758	66
K	6,425	44
Total	39,676	270

After several iterations, with 270 MW new generation capacity reduction, the NYCA LOLE reaches 0.08 days/yr. See Figure 8-10. The new generation capacity reductions are shown in Figure 8-11. So the MW capacity impact of the projects is 270 MW(See Attachment 13).

8.6 Installed capacity savings of MW impact

The results for the annual ICAP savings calculation variants for the three trials studied are presented in figures 8-12 and 8-13. Three levels of demand curve escalation are included as sensitivities to the growth rate of the ICAP market prices.

Figure 8-12 Variant No. 1 installed capacity savings

ICAP Demand Curve Escalation Sensitivity	BTP Savings (M$)	Trial 9 & 10 Savings (M$)
1%	56	38
3%	82	55
5%	117	79

Figure 8-13 Variant No. 2 installed capacity savings

ICAP Demand Curve Escalation Sensitivity	BTP Savings (M$)	Trial 9 & 10 Savings (M$)
1%	150	101
3%	218	147
5%	314	212

A detailed description of how the ICAP savings calculations are performed can be found in the NYISO CARIS Phase I 2011 Appendix E.1.2.6. Additional results, including the projected demand curve prices and savings by ICAP locality can be seen in Attachment 14.

9
Conclusions

Conclusions

This study has been performed over three years. It is recognized that over time, conditions change. Accordingly, the STARS TWG has made every effort to update assumptions as practical.

As with any study of this nature, periodic updates will be required. Despite changing conditions, the findings and recommendations provided in this study are sufficiently robust and supported by the analytical work included in the report and its attachments. The following are identified as key findings of this study which provide guidance into strategic long range investment needs into the State's transmission system. These investments will ensure that aging infrastructure is replaced and in some cases upgraded in a prudent and coordinated manner to maintain and in some cases enhance system reliability. It also supports the fact that there are projects that can deliver economic benefits by reducing congestion as well as projects that can help to achieve the State's public policy goals of enabling the integration of greater amounts of renewables.

KEY FINDINGS THAT PROVIDE GUIDANCE INTO LONG-RANGE INVESTMENT NEEDS

1. **40% of the existing transmission system will likely need to be replaced over the next 30 years:** The state's transmission infrastructure is well maintained, but aging. A high-level aged based condition assessment by the STARS TWG of this infrastructure has identified the potential need to replace, over the next 30 years, nearly 4,700 miles of transmission lines at operating voltages of 115 kV and greater. The estimated cost of this replacement is more than $25 billion.
2. **Study assumptions including generation location, type and fuel price forecasts significantly impact findings:** The longer time horizon of the study introduces uncertainty related to key assumptions including forecasted load levels, new generation resources including locations, size and type, as well as similar issues regarding the degree of penetration of and locations of demand side resources. The actual future mix of generation types, fuel costs, emission regulation and allowance prices, as well as the location of new generation additions can have a significant impact on the results of the study.
3. **Reliability needs are met under the statewide generation expansion scenario:** Based on the selected statewide generation expansion scenario, which assumed that generation was added proportional to load growth, the system meets existing reliability criteria. This scenario did not include significant expansion of the capability of imports from external control areas, such as Hydro-Quebec. This statewide generation expansion scenario represents a conservative view of potential transmission needs. Analysis of other generation expansion scenarios where more generation is sited upstate or where imports are relied on more heavily, show that the system does not meet established reliability criteria, increasing the need for more transmission.
4. **New transmission will unbottle wind resources:** The NYISO has identified as part of their 2010 Wind Generation Study that as part of the integration of 6,000 MW of wind resources nearly 9% of the wind energy production in three upstate areas would be "bottled" or be undeliverable to the transmission system. The study identifies and models the impacts of the underlying local transmission system upgrades that will allow for the nearly full unbottling of these resources. These upgrades allow for the full utilization of these resources which have been constructed under the State's Renewables Portfolio Standard. The STARS study assumed that these upgrades were in place. The approximate cost of these upgrades ranges from $75 million to $325 million, depending upon the scope of the upgrades constructed. No assumptions in the

STARS study were made on how these projects would be developed, but they represent additional transmission investment opportunities.

5. **New transmission projects with economic benefits:** The study has identified several projects that provide economic benefits by increasing transfer limits on existing constraints within the state's grid. Projects such as the 3rd Leeds to Pleasant Valley line, a 3rd New Scotland to Leeds line and 2nd Rock Tavern to Ramapo line show promise. These lines would be located within or with minor expansions of existing rights of way. The estimated costs of these projects are slightly over $400M. These projects shows annual net benefits based on production cost savings of $18M per year.
6. **Cost effective incremental transmission upgrades:** Based on the overlay of the condition assessment work and the STARS trials there are upgrade projects that provide increased transmission capability at a relatively modest cost. Projects such as the upgrade from 230 kV to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of the Marcy to New Scotland line and the Oakdale to Fraser line are good examples. Again these lines would be located within or along existing transmission corridors. The replacement costs of these lines is approximately $1.0B, with the estimated additional upgrade costs of these projects slightly over $600M.
7. **Ancillary benefits of a more robust system:** The system transmission upgrades studied in STARS improve the robustness of the transmission system, which in turn have the potential to reduce the levels of generation reserves required to maintain system reliability.
8. **Upgrades to Moses South are further justified with increased Hydro Quebec imports:** The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection was modeled at 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1380 MW. The thermal capability of the Chateauguay substation, with four 765/120 kV transformers placed in service, is approximately 2370 MW. The operating limitation on the Chateauguay-Massena 765 kV line as a single source limited the benefit that can be realized by the Moses South 230 kV to 345 kV upgrades in the STARS Base Transmission Plan.
9. **HVDC lines may help meet public policy objectives:** The HVDC lines from Pleasant Valley to NYC and Long Island that were analyzed as part of the study do not appear to be justified based on either reliability or economic benefits, but may be justified based on Public Policy goals.

Building off the findings described in detail above the STARS TWG makes the following recommendations as to the long-term action plans that would best address the maintenance and selected upgrades of the State's electric transmission infrastructure. These recommendations can help to achieve the goals of continued safe and reliable service of this infrastructure which is critical to the economic viability of the state. In addition known historical congestion points on the system can be addressed in a responsible manner and projects which will able full deliverability of the State's renewable resources can be achieved.

1. Each Transmission Owner should continue to assess the condition of their assets to provide for the long-term reliability of the state's transmission infrastructure as part of their normal capital planning process.
2. Coordinated transmission studies (such as STARS) should be performed and updated on a periodic basis as they provide a mechanism to develop optimized, long-term

investment strategies for the state's transmission infrastructure.

3. There are several projects that reduce congestion and provide economic benefits through lower production costs; these projects should be pursued. These 345 kV projects include the 3rd Leeds-Pleasant Valley line, 3rd New Scotland-Leeds line and 2nd Rock Tavern-Ramapo line. Construction of these lines leverages, to the extent possible, the use of existing rights-of-way.
4. To meet state public policy objectives of increased renewable resources, the underlying local upgrades identified in the NYISO 2010 Wind Generation Study should be constructed based on a review of the status of the development of the wind projects in the three upstate areas identified in that study. This would lead to greatly improved deliverability of wind resources and reduced emissions.
5. The export limit from Hydro-Quebec's Chateauguay station to New York is approved at 2,370 MW with all equipment in service, which includes four 765/120 kV transformers. The NYCA import limit from the Quebec Chateauguay-Massena single 765 kV interconnection is, however, limited to 1,380 MW per current NYISO operating criteria, which prevents a single external NYCA source from exceeding the largest internal contingency, in this case Nine Mile Point Station #2 at a projected capacity of 1,380 MW. If there is a desire, from a public policy perspective, to increase the import capability of hydro generation from Quebec, additional analysis would be needed to determine how to best address the loss of single source contingency.
6. Specific projects were identified (3rd Leeds to Pleasant Valley line and 2nd Rock Tavern to Ramapo line) that can be a significant part of solving the reliability needs that would be created with the potential retirement of the Indian Point Energy Center. Several other projects such as the Marcy South Series Compensation and Staten Island Generation Unbottling projects were not evaluated as part of the study, but should be further considered since they appear to provide additional value.
7. Several transmission lines that are approaching the end of their useful life should be considered for upgrading to improve the strength of the transmission system backbone. These projects include the upgrade to 345 kV of the Moses to Marcy, Marcy to Rotterdam section of Marcy to New Scotland line and the Oakdale to Fraser line. Upgrades of these lines leverages the use of existing rights-of-ways.

While the STARS study was initially envisioned to include three phases, with the emergence of the Governor's State Energy Highway Task Force, the Phase III work will not be performed at this time. It is felt that the analyses work performed by STARS could be a key input into the work of the Task Force and could help to provide a road-map for the development of projects to meet the Governor's objective of establishing a State Energy Highway.

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References

References

[1] New York State Transmission Assessment and Reliability Study (STARS) Phase 1 Study Report – "As Is" Transmission System. Report issued by ABB, January 13, 2010.
[2] Growing Wind – Final Report of the NYISO 2010 Wind Integration Study, September 2010.