2013 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS – Phase 1

DRAFT

August 12, 2013

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1. Introduction

Pursuant to Attachment Y of its Open Access Transmission Tariff (OATT, or the Tariff), the NYISO performed the first phase of the 2013 Congestion Assessment and Resource Integration Study (CARIS).[1] The study assesses both historic[2] and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion. Together with the Local Transmission Planning Process (LTPP) and the Comprehensive Reliability Planning Process (CRPP), the CARIS is the final process in the NYISO's biennial Comprehensive System Planning Process (CSPP) (see Figure 1-1). The 2013 CARIS completes the CSPP process that began with LTPP inputs for the 2012 Reliability Needs Assessment.

CARIS consists of two phases: Phase 1 (the Study Phase), and Phase 2 (the Project Phase). Phase 1 is initiated after the NYISO Board of Directors (Board) approves the Comprehensive Reliability Plan (CRP). In Phase 1, the NYISO, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion and together with historic congestion identifies, ranks, and groups the most congested elements on the New York bulk power system. For the top three congested elements or groupings, studies are performed which include: (a) the development of three types of generic solutions to mitigate the identified congestion; (b) a benefit/cost assessment of each solution based on projected New York Control Area (NYCA)-wide production cost savings and estimated project costs; and (c) presentation of additional metrics for informational purposes. The four types of generic solutions are transmission, generation, energy efficiency and demand response. Scenario analyses are also performed to help identify factors that increase, decrease or produce congestion in the CARIS base case.

This final report presents the 2013 CARIS Phase 1 study results and provides objective information on the nature of congestion in the NYCA. Developers can use this information to decide whether to proceed with transmission, generation, or demand response projects. Developers of such projects may choose to pursue them on a merchant basis, or to enter into bi-lateral contracts with LSEs or other parties**.** This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

Developers may propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request and payment by a Developer. Developers of all other projects can request that the NYISO conduct an additional CARIS analysis at the Developer's cost to be used for the Developer's purposes, including for use in an Article VII, Article X or other regulatory proceedings.

[1] Capitalized terms not otherwise defined herein have the meaning set forth in Section 1 and Attachments Y of the NYISO's OATT.
[2] The NYISO began reporting NYISO historic congestion information in 2003.

For a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. Under CARIS, to be eligible for regulated cost recovery, an economic transmission project must have production cost savings greater than the project cost (expressed as having a benefit to cost ratio (B/C) greater than1.0), a cost of at least $25 million, and be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in Load Zones that the NYISO identifies as beneficiaries of the transmission project. The beneficiaries are those Load Zones that experience net benefits measured over the first ten years from the proposed project commercial operation date. After the necessary approvals, regulated economic transmission projects are eligible to receive cost recovery from these beneficiaries through the NYISO Tariff provisions once they are placed in service.

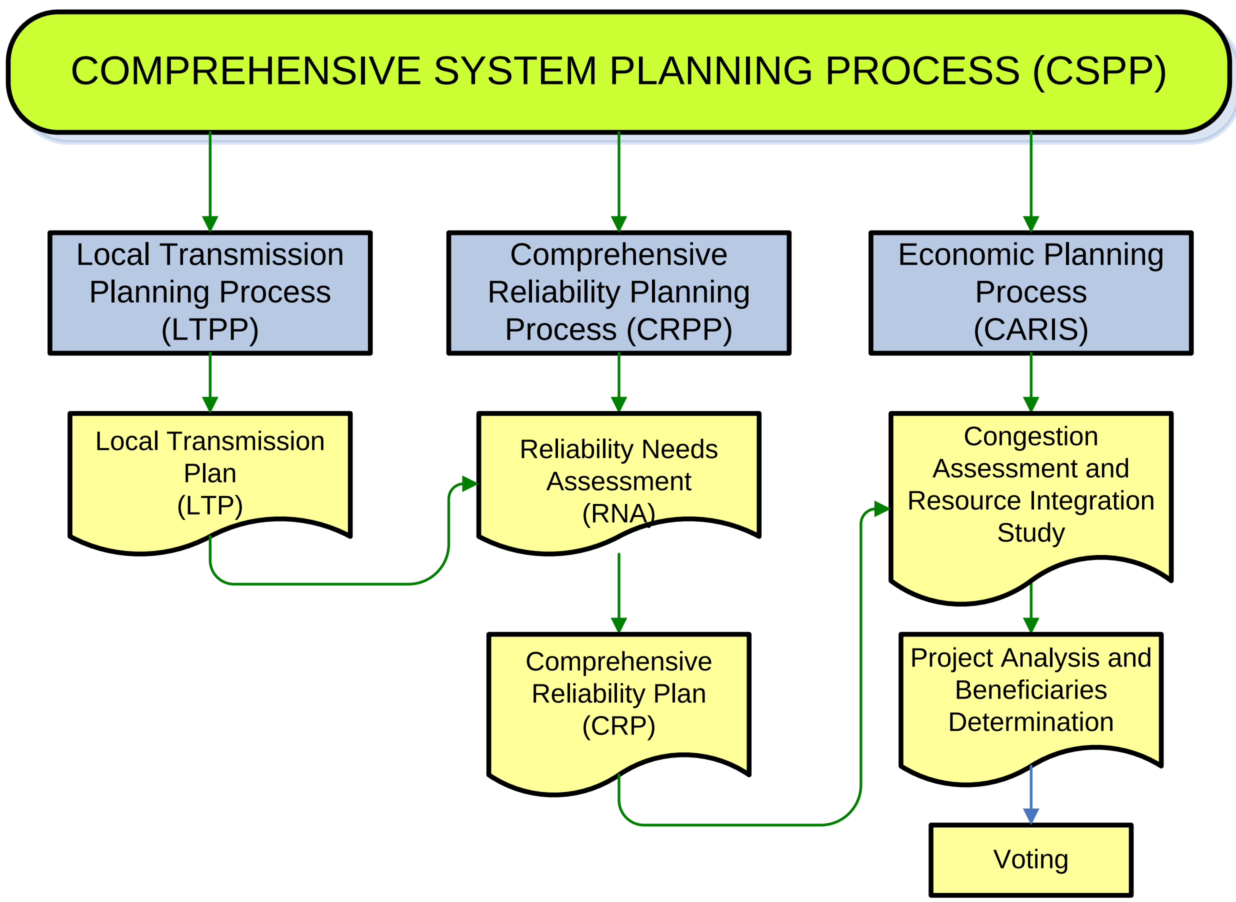

Figure 1-1: NYISO Comprehensive System Planning Process

This 2013 CARIS Phase 1 study includes intended enhancements to the 2011 CARIS Phase 1 study with respect to assumptions, modeling, and methodology for evaluating benefits. Such enhancements were discussed with ESPWG. Some of these changes reflect actual system changes while others are improvements. [to be updated with specific changes.]

The projected congestion in this report will be different than the actual congestion experienced in the future. CARIS simulations are based upon a limited set of long term assumptions for modeling of grid resources throughout the ten-year planning horizon. A range of cost estimates was used to calculate the cost of generic solution projects (transmission, generation, energy efficiency and demand response). These costs are intended for illustrative purposes only and are not based on any feasibility analyses. Each of the generic solution costs are utilized in the development of benefit/cost ratios.

The NYISO Staff presented the Phase 1 Study results in a written draft report to the ESPWG and the Transmission Planning Advisory Subcommittee (TPAS) for review. After that review, the draft report was presented to the NYISO's Business Issues Committee (BIC) and the Management Committee (MC) for discussion and action before it was submitted to the NYISO's Board of Director for approval.

2. Background

2.1. Congestion Assessment and Resource Integration Study (CARIS) Process

The objectives of the CARIS economic planning process are to:

a. Project congestion on the New York State Bulk Power Transmission Facilities (BPTFs) over the ten-year CSPP planning horizon;

b. Identify, through the development of appropriate scenarios, factors that might affect congestion;

c. Provide information to Market Participants, stakeholders and other interested parties on solutions to reduce congestion;

d. Provide an opportunity for Developers to propose solutions that may reduce the congestion; and

e. Provide a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff.

These objectives are achieved through the two phases of the CARIS process which are graphically depicted in Figure 2-1 below.

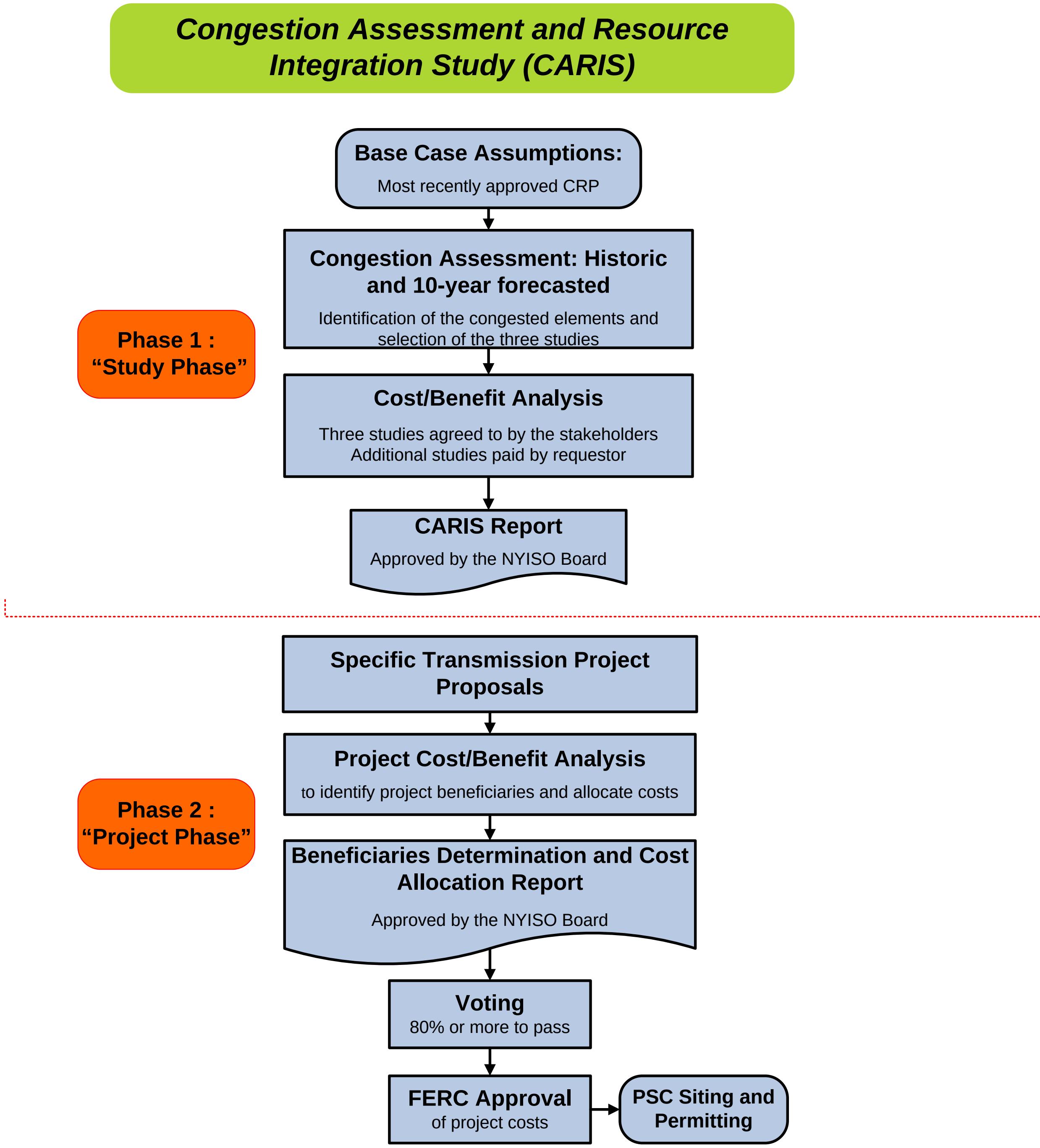

Figure 2-1: Overall CARIS Diagram

2.1.1. Phase 1 - Study Phase

In Phase 1 of the CARIS process, the NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts three transmission congestion studies based on those elements. In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the seven most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest projected production cost savings resulting from the relaxation. The top three ranked elements or groupings become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types - generation, transmission, energy efficiency and demand-response - are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, energy efficiency, demand response resources placed individually in the congested locations on the system to calculate their effects on relieving each of the three most congested elements and the resulting economic benefits.

The principal metric for measuring the economic benefits of each generic solution is the NYCA-wide production cost savings that would result from each generic solution, expressed as the present value over the ten-year planning horizon. The CARIS report also presents data on additional metrics, including estimates of reductions in losses, changes in Locational Based Marginal Pricing (LBMP) load payments, generator payments, changes in Installed Capacity costs, changes in emissions costs and changes in payments for Transmission Congestion Contracts (TCCs). The TCC payment metric in Phase 1 is simplified to include congestion rent calculations only, and is different from the TCC revenue metric contained in Phase 2. Each of the CARIS metrics is described in more detail in Section 3.

The NYISO also conducts scenario analyses to assess the congestion impact of various changes to base case assumptions. Scenario results are presented as the change in Demand$ congestion on the three study elements or groupings, as well as other constraints throughout NYCA.

2.1.2. Phase 2 – Project Phase

The Phase 2 model will be developed from the CARIS 1 database using an assumption matrix developed after discussion with ESPWG and will reflect all necessary system modeling changes required for a 10 year extension of the model. Updating and extending the CARIS database for Phase 2 of the CARIS is conducted after the approval of the CARIS Phase 1 report by the NYISO Board.

Developers of potential economic transmission projects that have an estimated capital cost in excess of $25 million may seek regulated cost recovery through the NYISO Tariff. Such Developers must submit their projects to the NYISO for a benefit/cost analysis in accordance with the Tariff. The costs for the benefit/cost analysis will be supplied by the Developer of the project as required by the Tariff. Projects may be eligible for regulated cost recovery only if the present value of the

NYCA-wide production cost savings exceeds the present value of the costs over the first ten years of the project life. In addition, the present value over the first ten years of LBMP load savings, net of TCC revenues and bilateral contract quantities, must be greater than the present value of the projected project cost revenue requirements for the first ten years of the amortization period.

Beneficiaries will be LSEs in Load Zones determined to benefit economically from the project, and cost allocation among those Load Zones will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon each zone's net LBMP load savings. The net LBMP load savings are determined by adjusting the LBMP load savings to account for TCC revenues and bilateral contract quantities; all LSEs in the zones with positive net LBMP load savings are considered to be beneficiaries. The net LBMP load savings produced by a project over the first ten years of commercial operation will be measured and compared on a net present value basis with the project's revenue requirements over the same first ten years of a project's life measured from its expected in-service date. LSE costs within a zone will be allocated according to the ratio of its load to all of the load in the zone - both expressed in MWh.

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow LSEs to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity (ICAP) costs, changes in emissions costs, and changes in TCC revenues. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC auction revenues and allocation of congestion rents to the TOs (for more detail on this metric see Section 3.2.2 of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual.[3])

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the Developer after discussions with ESPWG, regarding future uncertainties such as possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts such as improved system operations, other environmental impacts, and integration of renewable or other resources. Although this data may assist and influence how a benefiting LSE votes on a project, it will not be used for purposes of cost allocation.

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to the ESPWG for comment. Following that review, the NYISO

[3]http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/Economic_Planning_Process_Manual_Final_12-05-12.pdf

benefit/cost analysis and beneficiary determination will be forwarded to the BIC and MC for discussion and action. Thereafter the benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board of Directors and posted on the NYISO's website, the project will be brought to a special meeting of the beneficiary LSEs for an approval vote, utilizing the approved voting procedure (See Section 1.2.5 of the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual). The specific provisions for cost allocation are set forth in the Tariff. In order for a project to be approved for regulated cost recovery, the Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process will not relieve the Developer of the responsibility to file with FERC for approval of the project costs which were presented by the Developer to the voting beneficiaries and with the appropriate state authorities to obtain siting and permitting approval for the project.

3. CARIS Methodology and Metrics

3.1. CARIS Methodology

For the purposes of conducting the ten-year forward looking CARIS analysis, the NYISO, in conjunction with ESPWG, developed a production costing model database and utilized GE's Multi-Area Production Simulation (MAPS) software. The details and assumptions in developing this database are summarized in Appendix C.

In prior CARIS Phase 1 studies, the NYISO had utilized the Portfolio Ownership and Bid Evaluation (PROBE) production cost simulation tool, developed by PowerGEM LCC, to perform the NYISO historic congestion analysis. However, in January 2012, the NYISO adopted a new tool, Congestion Reporting for Off-Line SCUC[4] (CROS), to perform these analyses. Unlike PROBE, CROS utilizes the NYISO's production RANGER models as well as Day-Ahead Market (DAM) data to emulate the security constrained unit commitment (SCUC) operations. CARIS utilizes the most recent five years of historic data. Unlike MAPS simulation, CROS simulates virtual bidding and transmission outages and calculates production costs based on generation mitigated bids. While those additional attributes are important in capturing the real congestion costs for the past events, it is nearly impossible to model them with certainty in projecting future transmission congestion. Therefore, these attributes are not accounted for in the ten-year forward looking CARIS analysis. Actual future congestion will vary from projections depending on a number of factors. For more detail see Appendix D.

3.2. CARIS Metrics

The principal benefit metric for CARIS analysis is the NYCA-wide production cost savings that would result from each of the generic solutions. Additional benefit metrics were analyzed as well, and the results are presented in this report and accompanying appendices for informational purposes only. All benefit metrics were determined by measuring the difference between the projected CARIS base case value and a projected solution case value when each generic solution was added. The discount rate of 7.33% used for the present value analysis was the current weighted average cost of capital for the NYTOs, weighted by their annual GWh send-out in 2012.

One of the key metrics in the CARIS analysis is termed Demand Dollar congestion (Demand$ congestion). Demand$ congestion represents the congestion component of load payments. For a Load Zone, the Demand$ congestion of a constraint is the product of the constraint shadow price, the Load Zone shift factor (SF) on that constraint, and the zonal load. For NYCA, the Demand$ congestion is the sum of all of the zonal Demand$ congestion.

[4] SCUC refers to the NYISO's Security Constrained Unit Commitment process, described in Attachment C of the Tariff.

These definitions are consistent with what has been used for the reporting of historic congestion for the past nine years. Demand$ congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to payments by load.

3.2.1. Principal Benefit Metric[5]

The principal benefit metric for the CARIS analysis is the present value of the NYCA-wide production cost savings that are projected to result from implementation of each of the generic congestion mitigation solutions. The NYCA-wide production cost savings are calculated as those savings associated with generation resources in the NYCA and the costs of <u>incremental</u> imports/exports priced at external proxy generator buses of the solution case. This is consistent with the methodology utilized in the 2011 CARIS analysis. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

NYCA-wide Production Cost Savings = NYCA Generator Production Cost Savings -

$$\sum \sum [(\text{Import/Export Flow})_{Solution} - (\text{Import/Export Flow})_{Base}] \times ProxyLMP_{Solution}$$

Where $ProxyLMP_{Solution}$ is the LMP at one of the external proxy buses;

$(\text{Import/Export Flow})_{Solution} - (\text{Import/Export Flow})_{Base}$ represents incremental imports/exports with respect to one of the external systems; and the summations are made for each external area and all simulated hours.

3.2.2. Additional Benefit Metrics

The additional benefits, which are provided for information purposes only, include estimates of reduction in loss payments, LBMP load costs, generator payments, ICAP costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the ESPWG, determined the additional informational metrics to be defined for this CARIS cycle given existing resources and available data. The collaborative process determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual. An example illustrating the relationship among some of these metrics is provided in Appendix E.

[5] Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

Reduction in Losses – This metric calculates the change in marginal losses payments. Losses payments are based upon the loss component of the zonal LBMP load payments.

LBMP Load Costs – This metric measures the change in total load payments. Total load payments include the LBMP payments (energy, congestion and losses) paid by electricity demand (load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area.

Generator Payments – This metric measures the change in generation payments by measuring only the LBMP payments (energy, congestion, losses). Thus, total generator payments are calculated for this information metric as the sum of the LBMP payments to NYCA generators and payments for net imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs –The latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves are used for the calculation. The NYISO first calculates the NYCA MW impact of the generic solution on LOLE. The NYISO then forecasts the ICAP cost per megawatt-year point on the ICAP demand curves in Rest of State and in each locality for each planning year. There are two variants for calculating this metric, both based on the MW impact. For more detail on this metric see the Section 31.3.1.3.5.6 of the Tariff.

Emission Costs – This metric measures the change in the total cost of emission allowances for CO_2, NO_X, and SO_2, emissions on a zonal basis. Total emission costs are reported separately from the production costs. Emission costs are the product of forecasted total emissions and forecasted allowance prices.

TCC Payments – The TCC payment metric is calculated differently for Phase 1 than it is calculated for Phase 2 of the CARIS process, as described in the NYISO Tariff. In this CARIS Phase 1, the change in the TCC Payment is calculated as the change in load payment minus the sum of the generator payments and the net import payments. This is not a measure of the Transmission Owners' TCC auction revenues.

4. Baseline System Assumptions

The implementation of the CARIS process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2013 CARIS study process is conducted by updating the base case input assumptions provided in the 2012 CRP and aligns with the ten-year reliability planning horizon for the 2012 CRP.

4.1. Notable System Assumptions & Modeling Changes

The base case has been updated as of May 1, 2013 for this CARIS Phase 1 using the assumptions provided below. These assumptions were discussed with stakeholders at several meetings of the ESPWG. Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis. The key assumptions are presented below:

1. Power flow models – the 2012 CRP power flow base cases were updated for use in the 2013 CARIS study.

2. The load and capacity forecast was updated using the 2013 Load and Capacity Data Report (Gold Book) baseline forecast for energy and peak demand by zone for the ten year study period.

3. The transmission and constraint model utilizes a bulk power system representation for most of the Eastern Interconnection as described below. The model uses both the 2012 RNA/CRP transfer limits and actual operating limits.

4. The production cost model performs a security constrained economic dispatch of generation resources to serve the load. The production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed by the NYISO from multiple data sets including public domain information, proprietary forecasts and confidential market information. The model includes scheduled generation maintenance periods based on a combination of each unit's planned and forced outage rates.

5. In addition to the modeling changes listed below that can have significant impacts on the congestion projections, there are known NYCA events that have impacts on the simulation outcome, as summarized in Table 4-1.

Major Modeling Inputs

Input Parameter	Change from the 2011 CARIS
Load Forecast	Higher
Natural Gas Price Forecast	Higher by end of study period
Carbon Price Forecast	Lower
NOx Price Forecast	Lower
SOx Price Forecast	Higher

Modeling Changes

Description	Change from the 2011 CARIS
Central East Interface Limit	The nomogram to determine the voltage limit based on the commitment of the Oswego complex units was reviewed and enhanced.
Ramapo PARs	Modeling algorithm was adjusted to reflect revised NYISO-PJM Joint Operating Agreement, directing that 61% of AC flows occur across Ramapo PARS.
Fuel price forecast	Added additional natural gas pricing point for Midstate area (Zones F-I) with fuel costs proxied by Tennessee Zone 6 hub price. The Downstate natural gas price forecast also accounts in the near-term for the completed construction of the Spectra pipeline and the associated increase in supply to the region.
CRPP Market-Based and Reliability-Backstop Solutions	Incorporated MBS and RBS solutions from 2012 CRP required to maintain reliable system
PJM Representation Expanded	Expanded the modeled PJM system to include First Energy American Transmission Systems Inc. (FE-ATSI) and Duke Ohio and Kentucky (DEOK) which joined the PJM Market in 2011

Emission Modeling Refinement — Accounted for seasonal NOx Allowance Costs; Modeled Incremental Emission Rates; Refined Emissions Regions to the State Level.

Table 4-1: Timeline of NYCA Changes (including RBS and MBS)

Year	Year-to-Year Changes
2013	Danskammer 1 -6 retired; Montauk Units #2, #3 and #4 retired;Niagara Bio-Gen retired; Dunkirk 1 retired; Stony Creek Wind Farm in service (94.4 MW);Stewart's Bridge Hydro re-rate (3.0 MW); Naticoke Landfill re-rate (1.6 MW); HTP in service.
2014	No Changes
2015	Dunkirk 2 retired (June 2015)
2016	500 MW of Astoria Repowering project in service; approx. 100 MWs of Astoria GTs retired (MBS)
2017	No Changes
2018	500 MW of Astoria Repowering project in service; approx. 495 MWs of Astoria GTs retired (MBS)
2019	No Changes
2020	No Changes
2021	300 MW Generation (RBS) -- 100 MWs in G, J and K
2022	275 MW Increase in UPNY-SENY (RBS)

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS base case, provided in Table 4-2, was based on the 2013 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard (EEPS).

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Peak Load (MW)											
NYCA		33,279	33,725	34,138	34,556	34,818	35,103	35,415	35,745	36,068	36,355
Zone J		11,485	11,658	11,832	12,006	12,137	12,266	12,419	12,572	12,725	12,833
Zone K		5,421	5,471	5,514	5,592	5,616	5,663	5,729	5,802	5,878	5,958
Resources (MW)											
NYCA	Capacity	39,259	38,678	38,678	39,103	39,027	39,527	39,123	39,123	39,423	39,423
	SCR	1558	1558	1558	1558	1558	1558	1558	1558	1558	1558
	Total	40,817	40,236	40,236	40,661	40,585	41,085	40,681	40,681	40,981	40,981
Zone J	Capacity	9,515	9,515	9,515	10,015	9,939	10,439	10,034	10,034	10,134	10,134
	SCR	543	543	543	543	543	543	543	543	543	543
	Total	10,058	10,058	10,058	10,558	10,482	10,982	10,577	10,577	10,677	10,677
Zone K	Capacity	5,254	5,254	5,254	5,254	5,254	5,254	5,254	5,254	5,354	5,354
	SCR	127	127	127	127	127	127	127	127	127	127
	Total	5,381	5,381	5,381	5,381	5,381	5,381	5,381	5,381	5,481	5,481

Table 4-2: CARIS 1 Base Case Load and Resource Table [6]

Source: 2013 Gold Book baseline load forecasts from Section I.

[6] NYCA "Capacity" values include resources internal to New York, additions, re-ratings, retirements, purchases and sales, and UDRs with firm capacity. Zones J and K capacity values do not include UDRs with firm capacity.

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding WECC, FRCC, SPP, and Texas. Figure 4-1 below illustrates the NERC Regions and Balancing Authorities in the CARIS model. The CARIS model includes a full active representation for the NYCA, ISO-NE, IESO, and PJM.

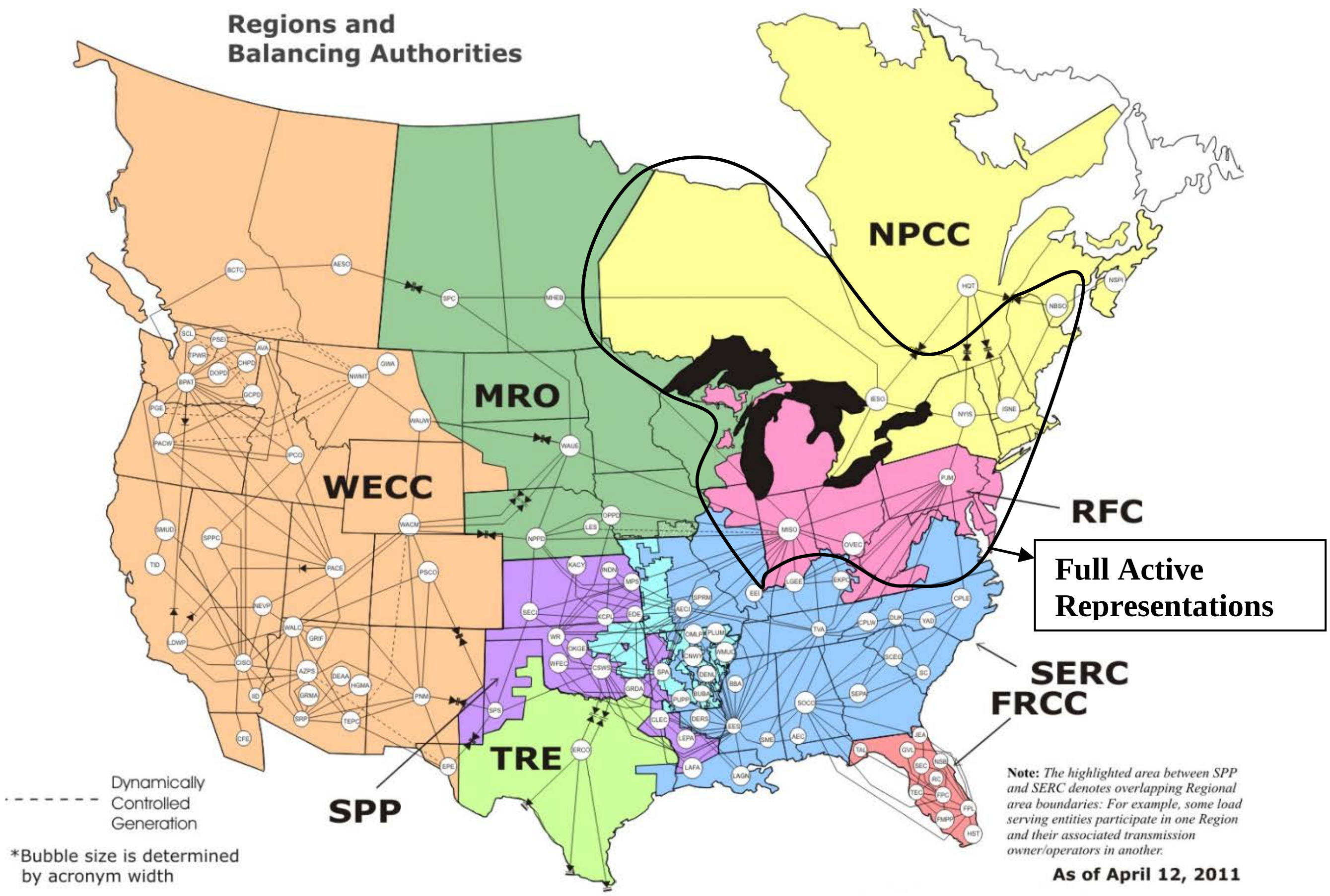

Figure 4-1: Areas Modeled in CARIS (Excluding WECC, FRCC, SPP, & TRE)

Source: NERC

4.3.1. New York Control Area Transfer Limits

CARIS utilizes normal transfer criteria for MAPS simulations, but it adopts emergency transfer criteria for MARS simulations and ICAP metrics. For voltage and stability based limits the normal and emergency limits are assumed to be the same. For NYCA Interface Transfer limits, the limits are consistent with the SCUC operating limits and operating nomograms with some exceptions as indicated in Table 4-3 below.

Table 4-3: Transmission System Normal Voltage Transfer Limits for Key Interfaces (in MW)

Note: Central East was modeled with a unit sensitive nomogram reflective of the operating nomogram.

Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Managing and Utilizing System Transmission (MUST) software application. Instead, CARIS uses the most limiting monitored line and contingency sets identified from MUST analysis. The resulting monitored lines and contingency sets used in the CARIS do not include lines that have less than a 5% impact on the NYCA cross-state transmission interfaces, or the lines that only impact local 115-138 kV transmission or sub-transmission constraints.

4.4. Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's (EIA)[7] current national long-term forecast of delivered fuel prices, which is released each spring as part of the Annual Energy Outlook (AEO). The figures in this forecast are in real dollars (i.e., indexed relative to a base year). Forecasted time-series of the GDP deflator published by EIA, as part of the AEO, were used to inflate the *real* values to *nominal* values.

4.4.2. New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect bases for fuel prices in New York. Key sources of data for estimating the relative differences or 'basis' for fuel prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[8] The base annual forecast series from the EIA 2013 annual energy outlook forecast are then subjected to an adjustment to reflect the New York 'basis' relative to the national prices as described below.

[7] www.eia.doe.gov

[8] Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html . These figures are published in Electric Power Monthly.

Natural Gas

Analysis of EIA's Short-Term Energy Outlooks from the past five years for the national average of delivered price of natural gas for electricity generation suggests that it is, on average, 10% higher than Henry Hub prices. The regional basis is then assessed against 110% of Henry Hub prices. The natural gas price for "Downstate" (Zones J and K), is the Transco Zone 6 (New York) hub-price[9], for "Midstate" (Zone F through I), is Tennessee Zone 6, and for "Upstate" (Zones A through E) the proxy-hub is the Tetco-M3. As of January 2013, the forecasted Downstate natural gas price is roughly 16.2% higher relative to the national average, the Midstate natural gas price is 21.6% higher than the national average and the Upstate natural gas price is 6.2% higher than the national average. The Midstate differential reflects recent trends and accounts for the impact of increased supply limitations and pipeline constraints on Tennessee Zone 6 and Algonquin Citygate prices. Reflecting an increase in supply due to the Spectra and Williams expansions, the Downstate differential with the national average is projected to gradually decrease from 16.4% in 2013 to 10% in 2018; increases back to 16.4% in 2021. Forecasted fuel prices for Upstate, Midstate and Downstate New York are shown in Figures 4-2, 4-3 and 4-4.

Fuel Oil

Based on EIA data published in Electric Power Monthly, price differentials across states and localities can be explained by a combination of transportation/delivery charges and taxes during the 24 month period ending May 2011. According to Electric Power Monthly, the trend of fuel-oil prices for New York implies that, on average, they are 5% below the national average delivered price. Based on this, the basis for both distillate and residual oils for Downstate are 0.95 (relative to the national average). The Upstate basis is 0.98 to reflect the additional transportation costs. For illustrative purposes, forecasted prices for Distillate Oil (Fuel Oil #2) and for Residual Oil (Fuel Oil #6) are shown in Figures 4-2, 4-3 and 4-4.

Coal

The data from Electric Power Monthly for the average cost of coal delivered for electricity generation was used to calculate a common basis for all NYCA Zones. Prices in New York are, on average, 36% higher than in the United States as a whole. (The published figures do not make a distinction between the different varieties of coal; *i.e.*, bituminous, sub-bituminous, lignite, etc.). EIA's 2013 AEO forecast is used for CARIS.

4.4.3. Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, NYISO estimated seasonal-factors using standard statistical

[9] The raw hub-price is 'burdened' by an appropriate level of local taxes.

methods.[10] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The 2013 data used to estimate the seasonal factors are as follows:

- Natural Gas: Raw daily prices from ICE (Intercontinental Exchange) for the trading hubs Transco Zone 6 (New York) - as a proxy for Downstate (Zones J and K) – Tennessee Zone 6 – as a proxy for Midstate (Zones F to I) – Tetco-M3 – as a proxy for Upstate (Zones A to E).
- Fuel Oils #2 and #6: The average daily prices from Argus, Bloomberg, and Platts.

The seasonalized time-series represents the forecasted trend of average monthly prices.

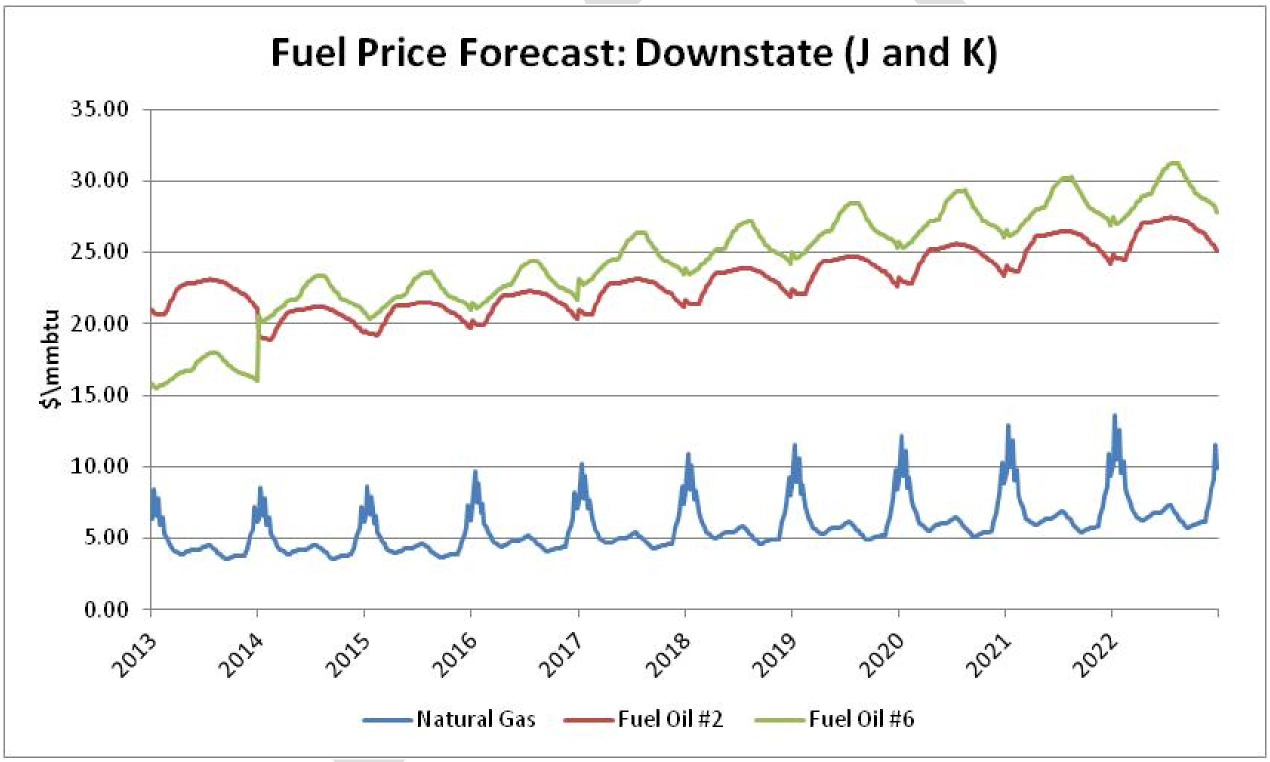

Figure 4-2: Forecasted fuel prices for Zones J & K (nominal $)

[10] This is a two-step process: First, deviations around a centered 12-month moving average were calculated over the 2008-2012 period; second, the average values of these deviations were normalized to estimate monthly/seasonal factors.

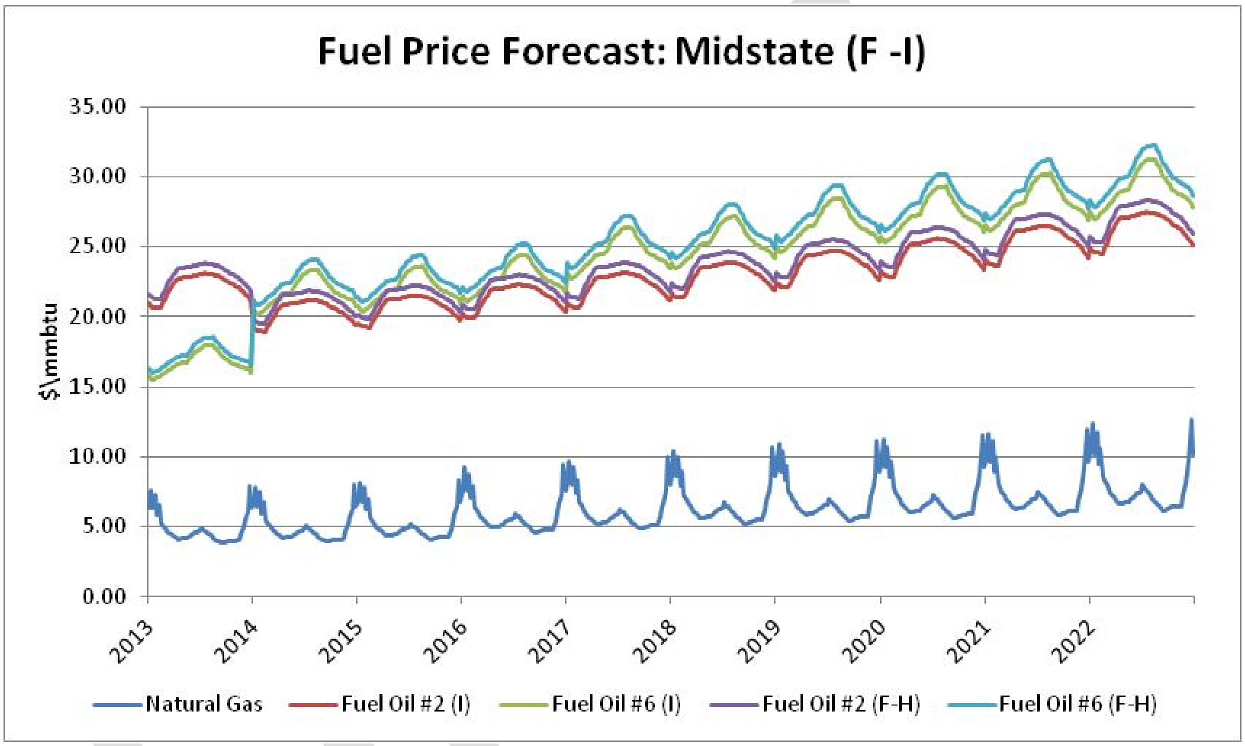

Figure 4-3: Forecasted fuel prices for Zones F-I (nominal $)

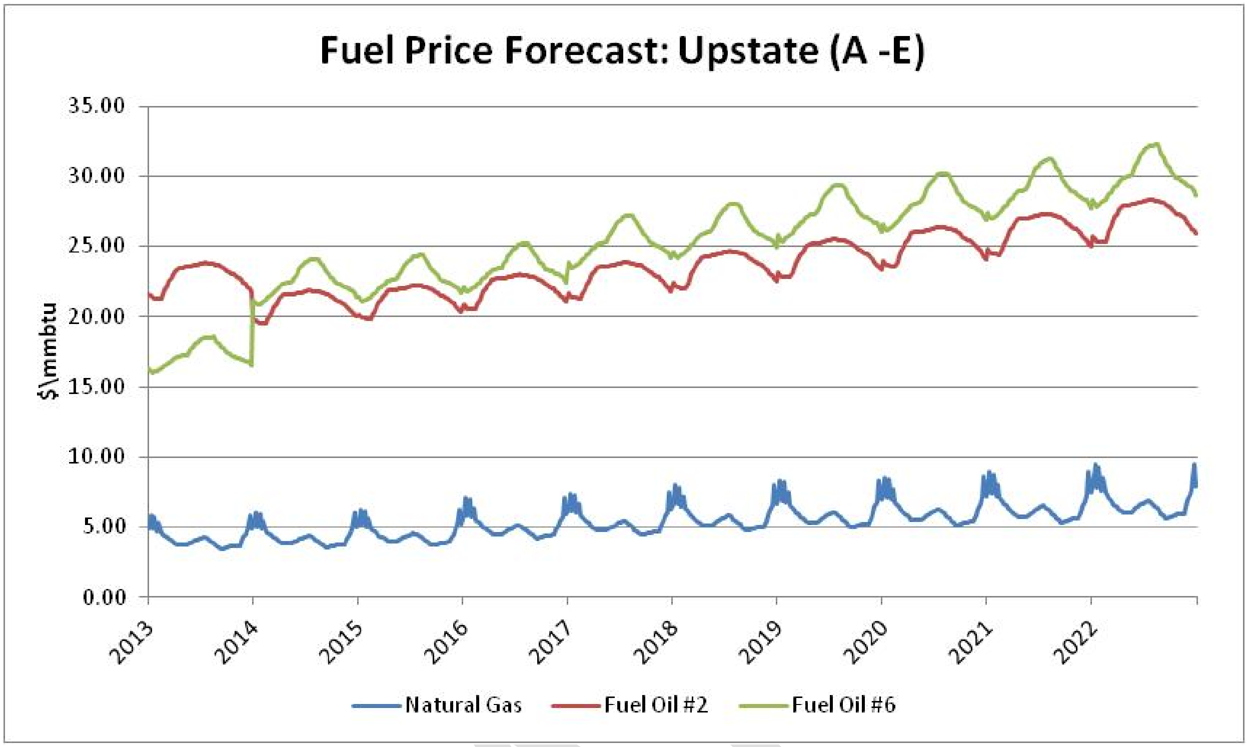

Figure 4-4: Forecasted fuel prices for Zones A-E (nominal $)

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external areas, ISO-NE, PJM, and IESO, were also developed. For each of the fuels, the basis for ISO-NE, PJM-East, and PJM-West were based on the state level data published in Electric Power Monthly. With respect to IESO, the relative prices were based on data from a recent publication.[11]

4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fueled generators greater than 25 MW and most generators in most surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

In July 2011 the USEPA finalized the Cross-State Air Pollution Rule (CSAPR) which would have required significant additional reductions of SO_2 and NO_X emissions

[11] Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2013 through October 31, 2014, Presented to Ontario Energy Board, March 28, 2013 by Navigant Consulting Inc., Toronto, Ontario.

beyond those previously identified. Before taking effect, the rule was stayed, and ultimately vacated, by the US District Court of Appeals for the District of Columbia. The USEPA has appealed the DC Circuit's ruling to the Supreme Court, which has accepted the petition and will begin hearing oral arguments during its next term, October 2013 – June 2014. Because of the uncertainty surrounding the CSAPR a decision was made, in consultation with the ESPWG, not to incorporate the rule. However, the impact of the CSAPR is analyzed as a scenario in this report.

Base Case allowance prices for annual and seasonal NO_X (throughout the study period) and SO_2 (2013-2015) are developed using prices representative of the currently traded Clean Air Interstate Rule (CAIR) NO_X and SO_2 allowances, escalated at nominally the same rate as natural gas prices.

USEPA's Mercury and Air Toxics Standard (MATS), requiring reductions in mercury, acid gas and particulate matter emissions, was finalized in December 2011. The standard will take effect in March 2015 with the option for an additional year to comply available to most generators. Compliance with the acid gas reduction portion of the standard may be achieved through an alternate SO_2 emission limit, as a reduction in one will invariably accompany a reduction in the other. While the rule takes a command and control approach to lowering emissions, USEPA posits in the rulemaking that the vast majority of the decreases in acid gas emissions required by MATS will be accomplished by the CSAPR SO_2 cap and trade program. For these reasons, USEPA's CSAPR SO_2 price projections are used as a proxy for the costs of MATS beginning in 2016.

The RGGI program for capping CO_2 emissions from power plants includes six New England states as well as New York, Maryland, and Delaware. Historically the RGGI market has been oversupplied, and prices have remained at the floor. In January 2012 several states, including New York, chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in a effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid program review in 2012 which, when effective in 2014, will reduce the emissions cap to roughly the level of CO_2 emitted in 2012. In each subsequent year the cap will be further reduced through various mechanisms.

As part of the mid-program review, RGGI forecast two different price scenarios. The CO_2 allowance price forecast applied to generators in RGGI states in the 2013 CARIS is the average of these two forecasts until 2020. Beyond 2020 the average of the forecasts exceeds the Cost Containment Reserve, which will trigger an increase in the cap to suppress the price. The forecast remains at the cost containment reserve for the final years of the study horizon.

A federal CO_2 program is assumed to take effect in 2020, and to be similar to the RGGI program. The implementation of the federal CO_2 program applies the RGGI allowance price forecast described above to states that are not currently participants in RGGI, as well as the Canadian province of Ontario. It is viewed as unlikely that a national CO_2 program in the United States would be implemented without a similar obligation made by Canada.

Emission costs, which are driven by the fuel type, efficiency and employed emission control technology of each unit, are calculated as the product of emission rate and emission allowance costs. Unit specific incremental emission rates developed from USEPA's Air Markets Program Data (AMPD) were used in the simulations.

Figure 4-5 shows the emission allowance forecast by year in $/Ton.

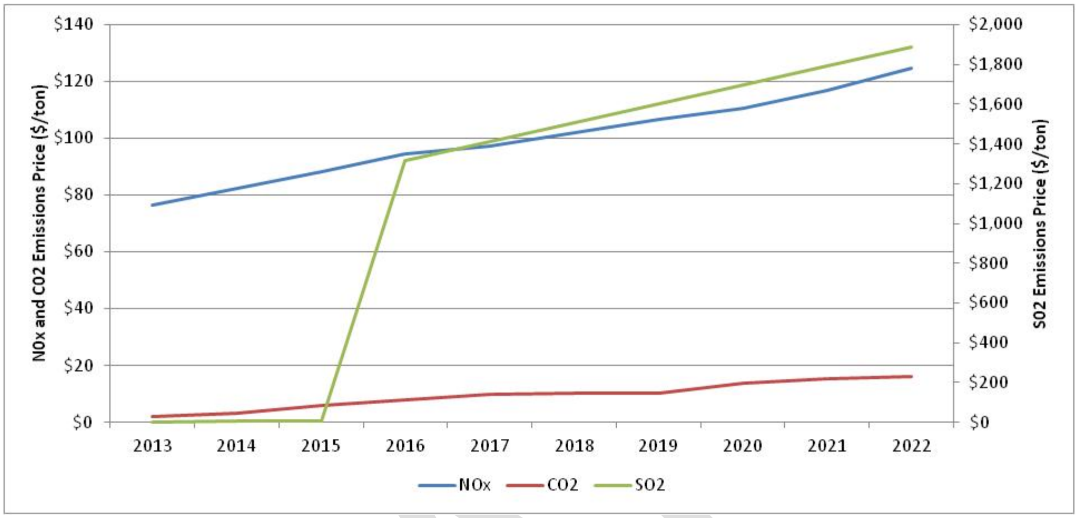

Figure 4-5: Emission Allowance Forecast

4.6. Generic Solutions

Generic solutions are evaluated by NYISO for each of the three CARIS studies utilizing each resource type (generation, transmission, energy efficiency (EE) and demand response (DR)) as required in Section 31.3.1.3.3 of the Tariff. The development of the generic solution representative costs was based on available public information with stakeholder input. This methodology utilized typical MW block size generic solutions, a standard set of assumptions without determining actual project feasibility, and order of magnitude costs for each resource type.

The cost estimates for generic solutions only are intended to set forth an order of magnitude of the potential projects' costs for Benefit/Cost ratio analysis. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these estimated costs or in the locations assumed.

4.6.1. Resource Block Sizes

Typical resource block sizes are developed for each resource type based on the following guidelines:

- Block size would be reflective of a typical size built for the specific resource type and geographic location;

- Block size is to be small enough to be additive with reasonable step changes; and
- Blocks sizes are in comparable proportions between the resource types.

The block sizes selected for each resource type are presented in Table 4-4 through Table 4-6.

Table 4-4: Transmission Block Sizes

Location	Line System Voltage (kV)	Normal Rating (amperes)[12]
Zone A-H	345	2228 (summer) 2718 (winter)

Table 4-5: Generation Block Sizes

Plant Location	Plant Block Size Capacity (MW)
Zone A-K	330[13]

Table 4-6: EE and DR Block Sizes

Location	Demand Response Quantity (MW)	Portfolio Type
Zone F-K	200	Energy Efficiency
Zone F-K	200	Demand Response

4.6.2. Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types was dependent on many different parameters and assumptions and without consideration of project feasibility or project-specific costs. A detailed list of assumptions utilized for each resource is included in the Generic Solution Cost Matrix, in Appendix C.

[12] Solution size is based on a double-bundled ACRS 795 KCmil conductor.
[13] Proposed generic unit is a Siemens SGT6-5000F(5).

The following guidelines and assumptions were used to select the generic solution:

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, then the two substations that have the shortest distance between the two are selected. Space availability at substations (i.e., room for substation expansion) was not evaluated in this process.

Generation Resource

- The generic generation solution consisted of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution terminates at the nearest existing substation of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements which meets the required criteria, the substation that has the highest relative shift factor was selected. Space availability at substations (i.e., room for substation expansion) was not evaluated in this process.

Energy Efficiency (EE)

- 200 MW blocks of peak load energy efficiency
- Aggregated at the downstream of the congested elements.
- Limited to whole blocks that total less than 10% of the zonal peak load
- If one zone reaches a limit, energy efficiency may be added to other downstream zones
- Goal to reduce congestion by at least 50%

Demand Response (DR)

- 200 MW demand response modeled at 100 peak hours
- Use the same block sizes in the same locations as energy efficiency

4.6.3 Generic Solution Pricing Considerations

Three sets of cost estimates which were designed to be reflective of the differences in labor, land and permitting costs among Upstate, Downstate and Long Island follow below. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Table 4-7.

Table 4-7: Generic Solution Pricing Considerations

Transmission	Generation	DR
Transmission Line Cost per Mile	Plant Costs	Energy Efficiency Programs
Substation Terminal Costs	Generator Lead Cost per Mile	Demand Response Programs
System Upgrade Facilities	Substation Terminal Costs	
	System Upgrade Facilities	
	Gas Line Cost per Mile	
	Gas Regulator Station	

Low, mid, and high cost estimates for each element were discussed with stakeholders. This establishes a range of cost estimates to address the variability of generic projects. The resulting order of magnitude unit pricing levels are included in the Generic Solution Cost Matrix in Appendix C.

5. 2013 CARIS Phase 1 Results

This section presents summary level results of the six steps of the 2013 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of three studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

5.1. Congestion Assessment

The CARIS process begins with the development of a ten-year projection of future Demand$ congestion costs. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. The results of the historical and future perspective are presented in the following two sections.

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements are taken into consideration. Whether congestion is positive or negative depends on the choice of the reference point. All metrics are referenced to the Marcy 345 kV bus near Utica, NY. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and any location with LBMP lower than the Marcy LBMP has negative congestion. The negative congestion typically happens due to transmission constraints that prevent lower cost resources from being delivered towards the Marcy bus.

5.1.1. Historic Congestion

Historic congestion assessments have been conducted at the NYISO since 2005 with metrics and procedures developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost (BPC) as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. The results of the historic congestion analysis are posted on the NYISO website quarterly. For more information or source of historical results below see:

http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Historic congestion costs by zone, expressed as Demand$, are presented in Table 5-1, indicating that the highest congestion is in New York City and Long Island.

Table 5-1: Historic Demand$ Congestion by Zone 2008-2012 (nominal $M)

Zone	2008	2009	2010	2011	2012
West	25	14	1	5	6
Genessee	9	4	6	6	3
Central	18	8	11	10	8
North	2	3	1	0	0
Mohawk Valley	10	4	5	5	3
Capital	143	53	62	47	34
Hudson Valley	175	57	73	78	39
Millwood	78	16	23	20	10
Dunwoodie	124	41	49	45	24
NY City	1403	503	560	548	261
Long Island	624	274	350	405	377
NYCA Total	2,611	977	1,141	1,169	765

Reported values do not deduct TCCs
NYCA totals represent the sum of absolute values
DAM data include Virtual Bidding & Transmission planned outages

Table 5-2 below lists historic congestion costs, expressed as Demand$, for top NYCA constraints* from 2008 to 2012. The top congested paths are shown below.

Table 5-2: Historic Demand$ Congestion by Constrained Paths 2008-2012 (nominal $M)

Rank	Constrained Path	2008	2009	2010	2011	2012	TOTAL
1	CENTRAL EAST	1,199	435	491	365	255	2,746
2	PLSNTVLY 345 LEEDS___345	667	149	232	161	137	1,347
3	DUNWOODIE_SHORRD_345	187	118	155	213	255	930
4	GREENWOOD LINES	114	87	132	95	51	480
5	MOTTHAVN 345 RAINEY 345	272	50	30	16	5	374
6	LEEDS 345 N.SCTLND 345	90	44	33	196	9	371
7	MOTTHAVN 345 DUNWODIE 345	33	63	52	87	22	256
8	RAINEY 138 VERNON 138	81	20	32	59	10	202
9	E179THST 138 HELLTP_W 138	34	13	20	38	9	114
10	SPRNBRK 345 EGRDNCTR 345	39	14	19	17	11	100

* Ranking is based on absolute values.

Table 5-3 summarizes the annual historic congestion results posted by the NYISO. NYISO reports the summaries of the calculated changes in the four historic congestion metrics: Bid Production Cost (BPC), Generator Payments, Congestion Payments, and Load Payments. The changes in these four historic congestion metrics were calculated using CROS as the constrained system values minus the unconstrained system values. Positive numbers imply savings while negative numbers imply increases in payments when all constraints are relieved. Unhedged Congestion is calculated as the total congestion represented by Demand$ congestion minus the TCC hedge payments (TCC auction proceeds). Total payments made by load adjusted for the TCC hedges, TCC shortfalls, and Rate Schedule 1 imbalances comprise the statewide Unhedged Load Payments. These adjusted statewide Unhedged Load Payments equal the total Generator Payments.

Table 5-3: Historic NYCA System Changes – Mitigated Bids 2008-2012 (nominal $M)

Year	Change in BPC	Change in Generator Payments	Change in Unhedged Congestion Payments	Change in TCC Payments
2008	243	(417)	1,525	1,143
2009	82	(102)	477	480
2010	94	(116)	640	515
2011	99	(86)	666	511
2012	106	(55)	457	319

Figure 5-1 below illustrates a cumulative effect of bid production costs savings over the past five years as a result of relieving all NYCA constraints.

Figure to be inserted.

Figure 5-1: Historic Cumulative BPC Savings, 2008-2012 (nominal $M)

5.1.2. Projected Future Congestion

Future congestion for the 10 year study period was determined from a MAPS simulation using a ten year base case developed with the ESPWG. As reported in Section 3.2, congestion is reported as Demand$ congestion. MAPS simulations are highly dependent upon many long-term assumptions, each of which affects the study results. The MAPS model utilizes input assumptions listed in Appendix C.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by CROS and MAPS. MAPS, unlike CROS, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) fixed load and price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee (BPCG) payments; and (f) co-optimization with ancillary services.

Discussion

Table 5-4 presents the projected congestion from 2013 through 2022 by Load Zone. The relative costs of congestion shown in this table indicate that the majority of the projected congestion is in the Downstate zones – NY City and Long Island. Year to year changes in congestion reflect changes in the model, which are discussed in Section 4.1.

Table 5-4: Projection of Future Demand$ Congestion 2013-2022 by Zone (nominal $M)

Demand Congestion (M$)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
West	$ 24	$ 29	$ 42	$ 42	$ 48	$ 47	$ 47	$ 48	$ 56	$ 55
Genessee	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 6	$ 4	$ 4	$ 4
Central	$ 20	$ 20	$ 24	$ 26	$ 29	$ 32	$ 36	$ 27	$ 35	$ 34
North	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
Mohawk Valley	$ 6	$ 6	$ 7	$ 7	$ 8	$ 9	$ 10	$ 8	$ 9	$ 9
Capital	$ 49	$ 53	$ 62	$ 52	$ 66	$ 69	$ 78	$ 57	$ 72	$ 70
Hudson Valley	$ 47	$ 49	$ 54	$ 43	$ 53	$ 53	$ 61	$ 50	$ 60	$ 57
Millwood	$ 15	$ 16	$ 17	$ 14	$ 16	$ 17	$ 19	$ 16	$ 19	$ 18
Dunwoodie	$ 31	$ 32	$ 35	$ 28	$ 34	$ 34	$ 39	$ 32	$ 39	$ 36
NY City	$ 283	$ 295	$ 321	$ 255	$ 310	$ 314	$ 367	$ 304	$ 374	$ 353
Long Island	$ 165	$ 168	$ 182	$ 161	$ 187	$ 204	$ 242	$ 225	$ 261	$ 269
NYCA Total	$ 643	$ 673	$ 749	$ 634	$ 757	$ 784	$ 906	$ 771	$ 929	$ 907

Note: Reported costs have not been reduced to reflect TCC hedges and represent absolute values.

Based on the positive Demand$ congestion costs, the future top congested paths are shown in Table 5-5 below.

Table 5-5: Projection of Future Demand$ Congestion 2013-2022 by Constrained Path (nominal $M)

Nominal Value ($)	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CENTRAL EAST	$ 306	$ 340	$ 396	$ 334	$ 427	$ 445	$ 506	$ 360	$ 465	$ 455
LEEDS PLEASANT VALLEY	$ 150	$ 148	$ 146	$ 103	$ 112	$ 101	$ 123	$ 132	$ 146	$ 109
DUNWOODIE SHORE ROAD	$ 19	$ 18	$ 20	$ 22	$ 23	$ 29	$ 36	$ 40	$ 44	$ 51
GREENWOOD	$ 2	$ 3	$ 4	$ 4	$ 6	$ 8	$ 11	$ 11	$ 14	$ 17
NEW SCOTLAND LEEDS	$ 22	$ 14	$ 10	$ 5	$ 2	$ 1	$ 5	$ 13	$ 8	$ 22
MOTTHAVEN RAINEY	$ 0	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ -	$ -	$ -
MOTTHAVEN DUNWOODIE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RAINEY VERNON	$ 0	$ 0	$ 1	$ (0)	$ -	$ -	$ 0	$ (0)	$ 0	$ 0
VOLNEY SCRIBA	$ 22	$ 22	$ 25	$ 31	$ 35	$ 41	$ 46	$ 34	$ 43	$ 41
HUNTLEY PACKARD	$ 13	$ 12	$ 18	$ 20	$ 23	$ 26	$ 24	$ 33	$ 40	$ 42

* The absolute value of congestion is reported.

5.2. Ranking of Congested Elements

The identified congested elements from the ten-year projection of congestion are lined up with the past five years of identified historic congested elements to develop fifteen years of Demand$ congestion statistics for each initially identified top constraint. The fifteen years of statistics are analyzed to determine recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system that may lead to exclusions. Ranking of the identified constraints is initially based on the highest present value of congestion over the fifteen-year period with five years historic and ten years projected.

Table 5-6 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East and Leeds - Pleasant Valley continue to be the paths with the greatest congestion. The top seven elements are evaluated in the next step for selection of the three studies.

Table 5-6: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the Fifteen Years Aggregate*

Present Value of Demand Congestion ($M)			
	Historic	Projected	Total
CENTRAL EAST	$ 3,591	$ 2,923	$ 6,514
LEEDS PLEASANT VALLEY	$ 1,770	$ 955	$ 2,724
DUNWOODIE SHORE ROAD	$ 1,137	$ 208	$ 1,345
GREENWOOD	$ 607	$ 52	$ 659
NEW SCOTLAND LEEDS	$ 462	$ 78	$ 540
MOTTHAVEN RAINEY	$ 516	$ 0	$ 516
MOTTHAVEN DUNWOODIE	$ 318	$ -	$ 318
RAINEY VERNON	$ 260	$ 1	$ 261
VOLNEY SCRIBA	$ 3	$ 241	$ 244
HUNTLEY PACKARD	$ -	$ 172	$ 172

*The absolute value of congestion is reported.

The frequency of actual and projected congestion is shown in Table 5-7 below. The table presents the actual number of congested hours by constraint, from 2008 through 2012, and projected hours of congestion, from 2013 through 2022. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Table 5-7: Number of Congested Hours by Constraint

[Table to be Inserted]

5.3. Three CARIS Studies

5.3.1. Selection of the Three Studies

Selection of the three CARIS studies is a two-step process in which the top ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints. Resultant grouping of elements for each of the top ranked constraints is utilized to determine the three studies.

In Step 1, both historic (5 years) and projected (10 years) congested elements for the fifteen- year period are ranked in ascending order based on the calculated present value of Demand$ congestion. In Step 2, the top congested elements from Step 1 are relieved independently to determine if any needs to be grouped with other elements that show significant congestion when a primary element is relieved. See Appendix E for a more detailed discussion.

In the first step, the remaining five congested elements with the highest present value ranking were utilized for further assessment. In the second step, the assessment was accomplished in multiple iterations to include additional elements that appear as limiting when each of the top five congested elements are relaxed by removing their limits. The assessed element groupings are then ranked based upon the highest change in production cost as shown in Figure 5-2.

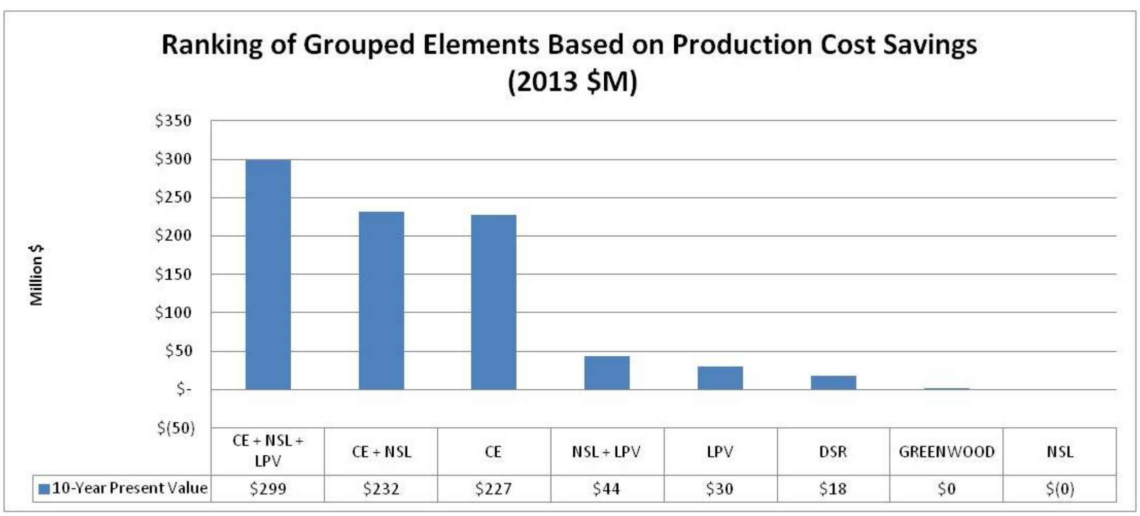

Figure 5-2: Production Costs Savings, 2013-2022 (nominal $M)

The three ranked groupings with the largest change in production cost are selected as the three CARIS studies: Central East-New Scotland-Pleasant Valley (CE-NS-PV), Central East – New Scotland (CE-NS) and Central East (CE). Table 5-8 has the base case congestion associated with each of the three studies. A detailed discussion on the ranking process is presented in Appendix E.

Table 5-8: Demand$ Congestion of the Top Three CARIS Studies (nominal $M)

Study	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Study 1: Central East - New Scotland-Pleasant Valley	479	503	552	443	542	548	633	507	619	586
Study 2: Central East	306	340	396	334	427	445	506	360	465	455
Study 3: New Scotland - Pleasant Valley	172	162	156	109	114	103	127	146	155	131

The location of the top three congested groupings, which define the three studies, along with their present value of congestion (in 2013 dollars) is presented in Figure 5-3.

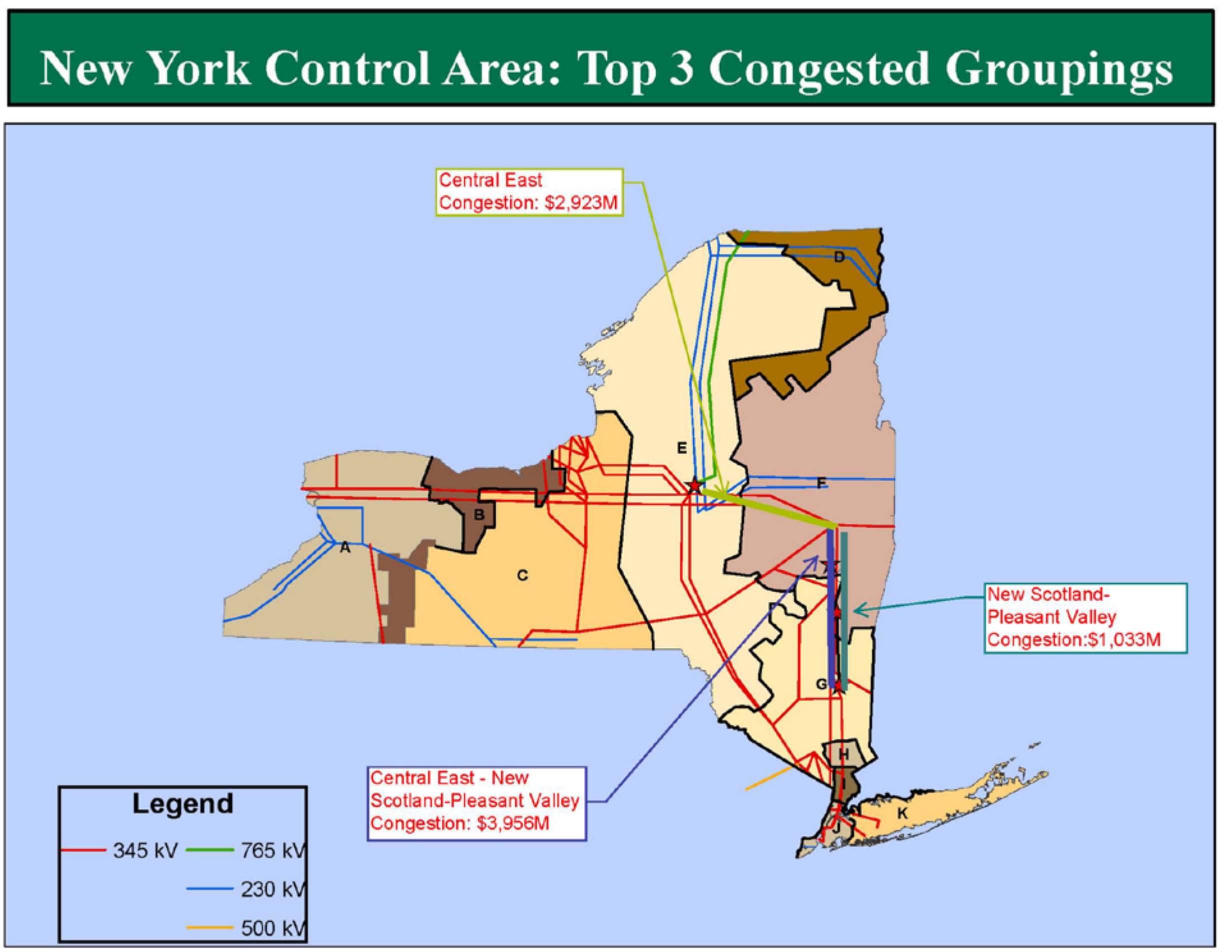

Figure 5-3: Base Case Congestion of Top 3 Congested Groupings, 2013-2022 - Present Value ($M)

5.3.2. Generic Solutions to Congestion

The congestion of each of the three groupings being studied is mitigated by individually applying one of the generic resource types; transmission, generation, energy efficiency and demand response. The resource type is applied based on the rating and size of the blocks determined in the Generic Solutions Cost Matrix included in Appendix C and is consistent with the methodology explained in Section 4 of this report. Resource blocks were applied to relieve a majority of the congestion. Additional resource blocks were not added if diminishing returns would occur.

In regard to the generic solutions, it is important to note the following:

- Other solutions may exist which will alleviate the congestion on the studied elements.
- No attempt has been made to determine the optimum solution for alleviating the congestion.
- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as studied.
- Generic solutions are not assessed for impacts on system reliability or feasibility.
- Actual projects will incur different costs.
- The generic solutions differ in the degree to which they relieve the identified congestion.
- For each of the base case and solution cases, HQ imports are held constant.

The discount rate of 7.33% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the NYTOs. The weighted average is based on the utilities' annual GWh sendout of energy for 2012.

Transmission has the greatest impact on reducing Demand$ congestion (42% to 97%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution reduced Demand$ congestion by 20% to 70%. A large portion of the production cost savings resulting from generation can be attributed to the efficiency advantage of the generic generation solution when compared to the system-wide heat rate. The demand response solution resulted in Demand$ congestion by -15% to + 2%, as expected, only affecting only the top 100 hours. The energy efficiency reduced Demand$ congestion by 19%% to 43%, yet shows the largest production cost savings because it directly reduces the energy production requirements.

The results of the three generic solutions are provided below with more detail in Appendix E. The following generic solutions were applied for each study:

Study 1: Central East – New Scotland – Pleasant Valley

The following generic solutions were applied for Central East – New Scotland - Pleasant Valley Study:

- Transmission: A new 345 kV line from Edic to New Scotland to Pleasant Valley, 150 Miles. The new line increases the Central East voltage transfer limit by 625 MW and the UPNY-SENY thermal capability by approximately 1200 MW.
- Generation: A new 1,320 MW Plant at Pleasant Valley
- Demand Response : 200 MW Demand Response in Zone F; 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K
- Energy Efficiency : 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K

Table 5-9 shows the Demand$ congestion of Central East – New Scotland – Pleasant Valley for 2017 and 2022 before and after each of the generic solutions is applied. The base Case congestion numbers, $542M for 2017 and $586M for 2022, are taken directly from Table 5-8 representing the level of congestion of the Study 1 before the solutions.

Table 5-9: Demand$ Congestion Comparison for Central East – New Scotland – Pleasant Valley Study (nominal $M)

CE-NS-PV	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	542	306	-43%	586	349	-41%
Generation - 1,320 MW	542	446	-18%	586	403	-31%
Demand Response - 1800 MW	542	532	-2%	586	551	-6%
Energy Efficiency - 1800 MW	542	416	-23%	586	418	-29%

Table 5-10 shows the production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the Central East – New Scotland – Pleasant Valley study after generic solutions were applied.

Table 5-10: Central East – New Scotland – Pleasant Valley Study: NYCA-wide Production Cost Savings (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Transmission	(31)	(24)	(22)	(23)	(22)	(20)	(22)	(17)	(19)	(17)
Generation - 1,320 MW	(24)	(21)	(18)	(20)	(16)	(13)	(17)	(31)	(33)	(38)
Demand Response - 1800 MW	(5)	(4)	(4)	(3)	(3)	(2)	(3)	(2)	(1)	(2)
Energy Efficiency - 1800 MW	(355)	(341)	(326)	(344)	(333)	(329)	(321)	(327)	(320)	(318)

The Edic – New Scotland – Pleasant Valley 345 kV transmission solution is projected to relieve the congestion across existing Central East – New Scotland – Leeds-Pleasant Valley transmission lines by 43% in 2017 and 41% in 2022 respectively, as shown in Table 5-9. As presented in Table 5-10, total ten year NYCA-wide production cost savings is $217 million (present value) as the result of better utilization of economic generation in the state and economic imports from neighboring regions made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to million (present value) are due to the uncongested location and the assumed better heat reduce congestion by 18% in 2017 and 31% in 2022. The ten-year production cost savings of $231 rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G, J and K Demand Response solution is projected to reduce congestion by 2% in 2017 and 6% in 2022, while the ten-year total production cost saving is $29 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the DR solution itself. DR solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions.

The Zones F, G, J and K Energy Efficiency solution is projected to reduce congestion by 23% in 2017 and 29% in 2022, while the ten-year total production cost saving is $3,315 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. For this reason EE solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 2: Central East

The following generic solutions were applied for Central East study:

- Transmission: A new 345 kV line from Edic to New Scotland, 85 Miles. The new line reduces the UPNY-SENY transfer capability by approximately 100 MW and increases the Central East voltage limit by 550 MW.
- Generation: A new 660 MW Plant at New Scotland
- Demand Response : 200 MW Demand Response in Zone F; 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K
- Energy Efficiency : 200 MW Energy Efficiency in Zone F; 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K

Table 5-11 shows the Demand$ congestion of Central East for 2017 and 2022 before and after each of the generic solutions is applied.

Table 5-11: Demand$ Congestion Comparison for Central East Study (nominal $M)

CE	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	427	249	-42%	455	253	-44%
Generation - 660 MW	427	387	-9%	455	311	-32%
Demand Response - 1800 MW	427	436	2%	455	450	-1%
Energy Efficiency - 1800 MW	427	345	-19%	455	351	-23%

Table 5-12 shows the NYCA-wide production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the Central East study after generic solutions were applied.

Table 5-12: Central East Study: NYCA-wide Production Cost Savings (Present Value in 2013 $M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Transmission	(13)	(11)	(11)	(12)	(12)	(16)	(14)	(7)	(11)	(9)
Generation - 660 MW	(3)	(4)	(2)	(5)	(3)	(3)	(4)	(10)	(10)	(13)
Demand Response - 1800 MW	(5)	(4)	(4)	(3)	(3)	(2)	(3)	(2)	(1)	(2)
Energy Efficiency - 1800 MW	(355)	(341)	(326)	(344)	(333)	(329)	(321)	(327)	(320)	(318)

The addition of the Edic-New Scotland line is projected to relieve the Central East congestion by 42% in 2017 and 44% in 2022. The total ten-year production cost savings of $116 million (present value) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the base case.

The generation solution is projected to reduce congestion by 9% in 2017 and 32% in 2022. The ten-year production cost savings of $57 million (present value) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Imports are significantly reduced in this solution. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G, J and K Demand Response solution is projected to increase congestion by 2% in 2017 and reduce congestion by 1% in 2022, while the ten-year total production cost saving is $29 million (present value).

The Zones F, G, J and K Energy Efficiency solution is projected to reduce congestion by 19% in 2017 and 23% in 2022, while the ten-year total production cost saving is $3,315 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation, transmission and energy efficiency solutions.

Study 3: New Scotland – Pleasant Valley

The following generic solutions were applied for the New Scotland-Pleasant Valley study, and the results are shown in Table 5-11:

- Transmission: A new 345 kV line from New Scotland to Pleasant Valley; 65 Miles. The new line increases the UPNY-SENY thermal capability by approximately 1200 MW and Central East voltage limit by 75 MW.
- Generation: Install a new 1,320 MW Plant at Pleasant Valley.
- Demand Response: 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K
- Energy Efficiency: 200 MW in Zone G; 1000 MW in Zone J; 400 MW in Zone K

Table 5-13 shows the Demand$ congestion of New Scotland-Pleasant Valley for 2017 and 2022 before and after each of the generic solutions is applied. Transmission has the greatest impact in reducing congestion and eliminated the entire congestion for the New Scotland-Pleasant Valley path.

Table 5-13: Demand$ Congestion Comparison for New Scotland-Pleasant Valley (nominal $M)

NS-PV	2017			2022		
Resource Type	Base Case	Solution	% Change	Base Case	Solution	% Change
Transmission	114	(0)	-100%	131	0	-100%
Generation - 1,320 MW	114	32	-72%	131	12	-91%
Demand Response - 1600 MW	114	91	-20%	131	98	-25%
Energy Efficiency - 1600 MW	114	60	-47%	131	53	-59%

Table 5-14 shows the NYCA-wide production cost savings expressed as the present value in 2013 dollars from 2013 to 2022 for the New Scotland-Pleasant Valley study after the generic solutions were applied.

Table 5-14: New Scotland-Pleasant Valley Study: NYCA-wide Production Cost Savings (Present Value in 2013$M)

Resource Type	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Transmission	(15)	(9)	(10)	(6)	(5)	(5)	(6)	(7)	(5)	(5)
Generation - 1,320 MW	(24)	(21)	(18)	(20)	(16)	(13)	(17)	(31)	(33)	(38)
Demand Response - 1600 MW	(5)	(3)	(4)	(3)	(2)	(1)	(2)	(2)	(1)	(2)
Energy Efficiency - 1600 MW	(315)	(298)	(286)	(302)	(294)	(290)	(282)	(288)	(282)	(280)

The addition of the New Scotland to Pleasant Valley 345 kV transmission line results in a projected total ten-year production cost savings of $72 million (present value). Elimination of the New Scotland-Pleasant Valley congestion allows the downstate load better access to upstate generation and economic imports from neighbors. It is also noted that relieving the congestion on the New Scotland- Pleasant Valley lines increases the congestion on the other two study groups.

The generation solution is projected to reduce congestion across NYCA for the planning horizon. The ten-year production cost savings of $231 million (present value) are due to the uncongested location and the assumed better heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones G, J and K Demand Response solution is projected to reduce congestion by 20% in 2017 and 25% in 2022, while the ten-year total production cost saving is $25 million (present value).

The Zones G, J and K Energy Efficiency solution is projected to reduce congestion by 47% in 2017 and 59% in 2022, while the ten-year total production cost saving is $2,918 million (present value). The relative large value of production cost saving is largely attributable to the reduction in energy use of the EE solution itself. EE solutions show greater reductions in production cost than the generation and transmission solutions.

The NYCA-wide production cost savings of the three generic solutions for the three studies are summarized and shown in Figure 5-4.

5.4. Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each of the three: Central East – New Scotland – Pleasant Valley, Central East, and New Scotland – Pleasant Valley. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 16% for transmission and generation solutions. Therefore, for a given generic solution pertaining to a constrained element, the carrying charge rate, in conjunction with an appropriate discount rate (see description in Section 5.3.2 above) yields a capital recovery factor, which, in turn, is used to calculate the benefit/cost ratio.

$$\text{Benefit/Cost ratio} = \frac{\text{Present Value of Production Cost Savings}}{\text{Overnight Costs x Capital Recovery Factor}}$$

The 16% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed O&M, and depreciation (assuming a straight-line 30-year method). The calculation of the appropriate capital recovery factor, and, hence, the B/C ratio, is based on the first ten years of the 30-year period,[14] using a discount rate of 7.33% , and the 16% carrying charge rate, yielding a capital recovery factor equal to 1.147.

5.4.1. Cost Analysis

Table 5-15 includes the total cost estimate for each generic solution based on the unit pricing included in Appendix C. The detailed cost breakdown for each solution is included in Appendix E. These are simplified estimates of overnight installation costs and do not include any of the many complicating factors that could be faced by individual projects. On-going fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital recovery factor.

[14] The carrying charge rate of 16% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.4.3.3.4.

Table 5-15: Generic Solution Costs for Each Study

Generic Solution Cost Summary ($M)			
Studies	Study 1: Central East-New Scotland-Pleasant Valley	Study 2: Central East	Study 3: New Scotland - Pleasant Valley
Transmission			
Substation Terminals	Edic to New Scotland to Pleasant Valley	Edic to New Scotland	New Scotland to Pleasant Valley
Miles (# of terminals)	150 (3)	85 (2)	65(2)
High	1,131	648	502
Mid	774	443	343
Low	312	179	139
Generation			
Substation Terminal	Pleasant Valley	New Scotland	Pleasant Valley
# of 330 Blocks	4	2	4
High	2,524	2,286	2,524
Mid	2,059	1,865	2,059
Low	1,595	1,444	1,595
DR			
Zone	F , G, J, and K	F , G, J, and K	G, J, and K
# of 200 MW Blocks	9	9	8
High	590	590	525
Mid	418	418	371
Low	299	299	266
EE			
Zone	F , G, J, and K	F , G, J, and K	G, J, and K
# of 200 MW Blocks	9	9	8
High	5,640	5,640	5,340
Mid	4,500	4,500	4,260
Low	3,360	3,360	3,180

5.4.2. Primary Metric Results

Map/Figure to be inserted.

Figure 5-4: Total NYCA-wide Production Cost Savings 2013-2022 (Present Value in 2013 $M)

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Table 5-16 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the three studies the DR solution produced the highest production cost savings because it directly reduces the energy production requirements. The next highest production cost savings resulted from generation followed by transmission. In the Central East to New Scotland to Pleasant Valley study the transmission solution produced higher production cost savings than generation.

Table 5-16: Production Cost Generic Solutions Savings 2013-2022: Present Value in 2013 ($M)

Study	Ten-Year Production Cost Savings Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East -New Scotland-Pleasant Valley	217	231	29	3,315
Study 2: Central East	116	57	29	3,315
Study 3: New Scotland-Pleasant Valley	72	231	25	2,918

5.4.3. Benefit/Cost Ratios

Figure 5-5 shows the benefit/cost ratios for each study and each generic solution.

Figure to be inserted (once B/C analysis is complete).

Figure 5-5: B/C Ratio (High, Mid, and Low Cost Estimate Ranges)

5.4.4. Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Table 5-17, Table 5-18, and Table 5-19 to show the ten-year total change in: (a) generator payments; (b) LBMP load payments; (c) TCC payments (congestion rents); (d) losses; (e) emission costs/tons; and (f) ICAP MW and cost impact, after the generic solutions are applied. The values represent the generic solution case values less the base case values for all the metrics except for the ICAP metric. Details on the calculations are in Appendix E.

While all but the ICAP metric are from the production cost simulation program, the ICAP metric is computed using the latest available information from the installed reserve margin (IRM), locational capacity requirement (LCR), and ICAP Demand Curves.[15] For Variant 1, the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the sum of the megawatt impact. For Variant 2, the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by fifty percent (50%) of the assumed amount of NYCA Installed Capacity available. Details on the ICAP metric calculations and 10 years of results are provided in Appendix E.

[15] Insert citation from latest ICAP data.

Table 5-17: Ten-Year Change in NYCA Load Payments and Export Payments (Present Value $M)

		LOAD PAYMENT	EXPORT PAYMENT	LOAD + EXPORT PAYMENT
TRANSMISSION SOLUTIONS				
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	$93	$134	$227
Study 2: CE	Edic-New Scotland	$75	$194	$269
Study 3: NS-PV	New Scotland-Pleasant Valley	$14	($52)	($38)
GENERATION SOLUTIONS				
Study 1: CE-NS-PV	Pleasant Valley	($1,023)	$750	($273)
Study 2: CE	New Scotland	($406)	$324	($81)
Study 3: NS-PV	Pleasant Valley	($1,023)	$750	($273)
DEMAND RESPONSE SOLUTIONS				
Study 1: CE-NS-PV	F (200), G(200), J(1,000), K(400)	($208)	$43	($166)
Study 2: CE	F (200), G(200), J(1,000), K(400)	($208)	$43	($166)
Study 3: NS-PV	G(200), J(1,000), K(400)	($196)	$40	($155)
ENERGY EFFICIENCY SOLUTIONS				
Study 1: CE-NS-PV	F (200), G(200), J(1,000), K(400)	($4,576)	$588	($3,988)
Study 2: CE	F (200), G(200), J(1,000), K(400)	($4,576)	$588	($3,988)
Study 3: NS-PV	G(200), J(1,000), K(400)	($4,106)	$414	($3,692)

Note: A negative number implies a reduction in payments

Table 5-18: Ten-Year Change in NYCA Generator and Import Payments (Present Value $M)

		GENERATOR PAYMENT	IMPORT PAYMENT	GENERATOR + IMPORT PAYMENT
TRANSMISSION SOLUTIONS				
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	$1,251	$150	$1,401
Study 2: CE	Edic-New Scotland	$608	$136	$744
Study 3: NS-PV	New Scotland-Pleasant Valley	$291	$25	$316
GENERATION SOLUTIONS				
Study 1: CE-NS-PV	Pleasant Valley	$407	($402)	$5
Study 2: CE	New Scotland	($214)	($153)	($367)
Study 3: NS-PV	Pleasant Valley	$407	($402)	$5
DEMAND RESPONSE SOLUTIONS				
Study 1: CE-NS-PV	F (200), G(200), J(1,000), K(400)	($92)	($48)	($140)
Study 2: CE	F (200), G(200), J(1,000), K(400)	($92)	($48)	($140)
Study 3: NS-PV	G(200), J(1,000), K(400)	($90)	($50)	($140)
ENERGY EFFICIENCY SOLUTIONS				
Study 1: CE-NS-PV	F (200), G(200), J(1,000), K(400)	($2,749)	($787)	($3,536)
Study 2: CE	F (200), G(200), J(1,000), K(400)	($2,749)	($787)	($3,536)
Study 3: NS-PV	G(200), J(1,000), K(400)	($2,399)	($799)	($3,198)

Note: A negative number implies a reduction in payments

[Table of Loss and TCC Metrics to be Inserted]

Table 5-19: ICAP MW Impact

Table to be Inserted (once ICAP Metric is complete.).

The ten-year changes in total emissions resulting from the application of generic solutions are reported in Table 5-20 below. The base case ten-year emission totals for NYCA are: CO_2 = 335,319 thousand- tons, SO_2= 121,164 tons and NOx = 208,730 tons. The study results reveal that all of the generic solutions impact emissions by less than 10%. The current Installed Capacity in NYCA as reported in the 2013 Gold Book is 37,920 MW. The generic generation solutions of 1,320 and 660 MWs represent the equivalent of a 3.4 % and 1.7% increase, respectively, in Installed Capacity. The generic demand response solutions of 1,800 MW and 1,600 of DR and EE and could be considered as an additional resources which would be equivalent to 4.7% and 4.2%, respectively, of Installed Capacity. The capability of the generic transmission solution is 1,200 MVA, which would be utilized to shift dispatch patterns of several hundred MW of capacity, or something on the order of 1% of Installed Capacity. The three generic solutions can be considered to change the fleet emission characteristics on the order of 1-5%. The comparison of the relative emission changes among solution types and across locations provides insight about the relative air related impacts if the emissions assumptions come to fruition. The emissions results include only emissions from NYCA units. The external emissions impacts associated with changes in NYCA imports are not reported. [analysis to be inserted]

Table 5-20: Ten-Year Change in NYCA CO2, SO2 and NOx Emissions (Dollars in Present Value)

		SO2			CO2			NOx		
Study	Generic Solutions	Tons	% Change	Cost ($M)	1000 Tons	% Change	Cost ($M)	Tons	% Change	Cost ($M)
	Transmission									
Study 1: CE-NS-PV	Edic-New Scotland-Pleasant Valley	8,485	7.0%	$5.4	-404	-0.1%	$1.9	1,460	0.7%	$0.1
Study 2: CE	Edic-New Scotland	5,245	4.3%	$3.6	734	0.2%	$5.3	2,211	1.1%	$0.1
Study 3: NS-PV	New Scotland-Pleasant Valley	1,158	1.0%	$0.9	-1,575	-0.5%	-$6.8	-1,333	-0.6%	-$0.1
	Generation									
Study 1: CE-NS-PV	Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
Study 2: CE	New Scotland	-3,895	-3.2%	-$2.2	4,223	1.3%	$27.9	-2,198	-1.1%	-$0.2
Study 3: NS-PV	Pleasant Valley	-6,445	-5.3%	-$3.6	9,463	2.8%	$68.4	-6,558	-3.1%	-$0.4
	Demand Response									
Study 1: CE-NS-PV	F (200), G (200),J (1000), K (400)	-622	-0.5%	-$0.5	644	0.2%	$3.6	-61	0.0%	$0.0
Study 2: CE	F (200), G (200),J (1000), K (400)	-622	-0.5%	-$0.5	644	0.2%	$3.6	-61	0.0%	$0.0
Study 3: NS-PV	G (200),J (1000), K (400)	-289	-0.2%	-$0.2	738	0.2%	$4.3	36	0.0%	$0.0
	Energy Efficiency									
Study 1: CE-NS-PV	F (200), G (200),J (1000), K (400)	-8,191	-6.8%	-$5.2	-23,674	-7.1%	-$131.4	-10,535	-5.0%	-$0.7
Study 2: CE	F (200), G (200),J (1000), K (400)	-8,191	-6.8%	-$5.2	-23,674	-7.1%	-$131.4	-10,535	-5.0%	-$0.7
Study 3: NS-PV	G (200),J (1000), K (400)	-6,228	-5.1%	-$3.9	-20,395	-6.1%	-$112.4	-8,931	-4.3%	-$0.6

5.5. Scenario Analysis

Scenario analysis is performed to explore the impact on congestion associated with variables to the base case. Since this is an economic study and not a reliability analysis, these scenarios focus upon factors that impact the magnitude of congestion across constrained elements.

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the magnitude of congestion costs. The CARIS scenarios were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these analyses was to examine the impact of the full amount of the resources added through the State Renewable Portfolio Standard (RPS) combined with the full achievement of the State Energy Efficiency Portfolio Standard (EEPS), fuel price and load forecast uncertainties, costs of emissions, and removing the Athens SPS in service. The objective of the scenario analysis is to determine the change in the costs of congestion that is caused by variables that differ from their base case values. The simulations were conducted for the entire 10-year study period.

5.5.1. Scenario Analysis

Table 5-21 summarizes the scenarios studied in CARIS Phase 1. The scenarios consider the effects of changes to the base case model. These changes are described as “Variables” in the table below.

Table 5-21: Scenario Matrix

Scenario	Variables
Implementation of Cross-State Air Pollution Rule (CSAPR)	Increases in NO_x and SO_2 costs as projected by EPA
Higher Load Forecast	4% higher
Lower Load Forecast	5% lower
Full MainTier RPS and Full EEPS Goals Achievement	Add renewables from Interconnection queue and reduce 2015 coincident peak load to 32147 MW
Athens SPS Out of Service	2013-2022
Higher Natural Gas Prices	One standard deviation
Lower Natural Gas Prices	One standard deviation
Lower CO_2 Emission costs	$5/ton Ceiling
Higher Natural Gas cost differential	Midstate & New England / Upstate differential doubled.

Table 5-22 presents the impact of nine scenarios selected for study. Those impacts are expressed as the change in congestion costs between the base case and the scenario case.

	2017 Scenarios: (Change in Demand$ Congestion from Base Case) (Nominal $M)								
Constraints	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Cost Differential
CENTRAL EAST	(12)	(15)	48	390	(17)	181	(180)	19	402
LEEDS PLEASANT VALLEY	3	17	(28)	(20)	48	15	(21)	11	(26)
DUNWOODIE SHORE ROAD	1	14	(3)	0	(1)	5	(3)	(1)	0
GREENWOOD	(0)	5	(4)	(4)	0	1	(1)	(1)	(2)
NEW SCOTLAND LEEDS	1	1	0	2	(1)	1	5	1	(2)
MOTTHAVEN RAINEY	0	0	0	0	0	0	0	0	0
MOTTHAVEN DUNWOODIE	0	0	0	0	0	0	0	0	0
RAINEY VERNON	0	0	0	0	(0)	0	(0)	(0)	(0)
VOLNEY SCRIBA	3	3	(4)	(9)	1	5	(7)	(0)	(10)
HUNTLEY PACKARD	5	1	1	1	1	(1)	7	3	(1)
Central East – New Scotland – Pleasant Valley	(7)	3	20	372	31	198	(195)	31	374
Central East	(12)	(15)	48	390	(17)	181	(180)	19	402
New Scotland-Pleasant Valley	4	18	(28)	(19)	48	16	(15)	12	(28)

Constraints	2022 Scenarios: (Change in Demand$ Congestion from Base Case) (Nominal $M)								
	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Cost Differential
CENTRAL EAST	(1)	11	19	238	(42)	46	(196)	81	355
LEEDS PLEASANT VALLEY	(8)	22	(39)	(25)	84	12	(30)	13	(22)
DUNWOODIE SHORE ROAD	(1)	67	(13)	(10)	(2)	6	(11)	(1)	0
GREENWOOD	(1)	8	(12)	(12)	1	5	(5)	2	(5)
NEW SCOTLAND LEEDS	0	(2)	(2)	(2)	(7)	(5)	2	(4)	(17)
MOTTHAVEN RAINEY	0	0	0	0	0	0	0	0	0
MOTTHAVEN DUNWOODIE	0	0	0	0	0	0	0	0	0
RAINEY VERNON	(0)	0	(0)	(0)	0	0	(0)	0	(0)
VOLNEY SCRIBA	(0)	(0)	(3)	(9)	1	4	(16)	(4)	(7)
HUNTLEY PACKARD	0	(3)	(3)	(9)	1	(16)	9	(17)	(6)
Central East – New Scotland – Pleasant Valley	(9)	32	(22)	211	35	52	(224)	90	315
Central East	(1)	11	19	238	(42)	46	(196)	81	355
New Scotland-Pleasant Valley	(8)	20	(41)	(27)	77	6	(28)	9	(39)

Table 5-22: Comparison of Base Case and Scenario Cases, 2017 and 2022 (nominal $M)

Table 5-23 below presents a summary of how each of the three transmission groupings chosen for study is affected by each of the scenarios.

Constraints	Scenarios: (Aggregate Change in Demand$ Congestion from Base Case) ($2013M)								
	CSAPR	Higher Load Forecast	Lower Load Forecast	Full RPS/EEPS Achievement	Athens SPS Out of Service	Higher Natural Gas Prices	Lower Natural Gas prices	Capped Carbon Prices	Higher Natural Gas Cost Differential
Central East – New Scotland – Pleasant Valley	(232)	45	(66)	1,424	255	1,089	(1,487)	165	2,189
Central East	(218)	(113)	150	1,563	(153)	956	(1,354)	120	2,432
New Scotland-Pleasant Valley	(14)	158	(217)	(139)	408	133	(133)	46	(243)

Scenario 1: EPA Projected NOx and SO_2 Costs

Emissions of SO_2 and NOx have costs that are determined by various cap and trade programs currently in effect in New York and in most of the surrounding regions. Forecasts used in the base case for these allowance costs were developed using various private and public data such as some proprietary forecasts, and EPA's allowance price. To examine factors that might produce or increase congestion, the forecast costs of NOx and SO_2 emissions were modeled based on EPA projections for 2017 and 2022, resulting from the Cross-State Air Pollution Rule.

Scenario 2: Higher Load Forecast

This scenario examined the impact of the higher load forecast on the cost of congestion. The high load forecast is obtained from the 2013 Gold Book, and is 4% higher than the 2013 Gold Book Baseline load forecast used in the 2013 CARIS base case. The high load forecast is 36,142 MW and 38,369 MW respectively in 2017 and 2022. All other assumptions were kept the same as in the base case.

Scenario 3: Lower Load Forecast

This scenario examined the impact of the lower load forecast on the cost of congestion. The low load forecast is derived from the 2013 Gold Book, assumed the full achievement of the EEPS initiative and is 5% lower than the 2013 Gold Book Baseline load forecast used in the 2013 CARIS base case. The low load forecast is 33,097 MW and 34,558 MW respectively in 2017 and 2022. All other assumptions were the same as in the base case.

Scenario 4: Full RPS and EEPS Goals Achievement

This scenario adds renewable generation projects from the NYISO Interconnection queue to achieve the renewable goal of 9,870 GWh by 2015, and models load reductions which achieve the goal of 15% load reduction resulting in a peak load projection of 32,447 MW in 2015. This scenario only models the Market-Side component of the RPS program which comprises greater than the 95% of the MW target.

Scenario 5: Athens SPS Continued In Service

This scenario assumed that the Athens SPS is not in service throughout the study period from 2013 -2022. The 2011 base case assumed that Athens SPS was in service. The Athens SPS system impact study in 2006 indicated a 450 MW increase in the transfer capability of the UPNY-SENY interface with the SPS in service.

Scenario 6: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than the base case levels by one standard deviation. The standard deviation figures represent, for a given fuel, the typical volatility of daily prices around the monthly average based on an assessment of a 5-year history. The volatility of natural gas prices varies across the year such that it is most volatile in winter months. Consequently, as compared to the base case, the low price case uses January prices around 32% lower for Downstate, 28% for Midstate and 20% lower for Upstate, while remaining about the same in August in all cases.

Scenario 7: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than the base case levels by one standard deviation. The standard deviation figures represent, for a given fuel, the typical volatility of daily prices around the monthly average based on an assessment of a 5-year history. The volatility of natural gas prices varies across the year such that it is most volatile in winter months. Consequently, as compared to the base case, the low price case uses January prices around 32% lower for Downstate, 28% for Midstate and 20% lower for Upstate, while remaining about the same in August in all cases.

Scenario 8: Lower CO_2 Emission Costs

To simulate the potential impact of carbon emission costs lower than those modeled in the base case, this scenario assumed the price of CO_2 allowances to not exceed $5/ton throughout the 2013-2022 study period.

Scenario 9: Higher Differential in Natural Gas Prices

To simulate the potential impact of an extension in recent trends in higher Capital zone and New England natural gas prices, this scenario assumed the differential in natural gas prices between Midstate/New England and West was double the Base Case differential throughout the 2013-2022 study period.

6. 2011 CARIS Findings – Study Phase

The CARIS identified three study areas by considering monitored elements that have historically displayed high levels of congestion after adjusting for the effects of volatile fuel price changes and also considering the installation of new resources and transmission system improvements contained in the 2012 CRP. In order to estimate the economic impact of alleviating the identified congestion, the three generic solutions were applied to each of the three study areas and production costs savings were calculated based on the three different ranges of generic costs.

Table 6-1 shows the projected congestion for each of the three transmission groupings: Central East-New Scotland-Pleasant Valley, Central East, and New Scotland-Pleasant Valley.

Table 6-1: Base Case Projected Congestion 2013-2022

Study	Ten-Year Congestion ($M)	
	Nominal	Present Value ($2013)
Study 1: Central East-New Scotland-Pleasant Valley	5,409	3,823
Study 2: Central East	4,034	2,825
Study 3: New Scotland-Pleasant Valley	1,374	998

The application of the generic solutions to the three study areas all result in production cost savings expressed in 2013 present values, as shown in Table 6-2.

Table 6-2: Production Cost Savings

Study	Ten-Year Production Cost Savings			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East -New Scotland-Pleasant Valley	(217)	(231)	(29)	(3,315)
Study 2: Central East	(116)	(57)	(29)	(3,315)
Study 3: New Scotland-Pleasant Valley	(72)	(231)	(25)	(2,918)

2013-2022, Present Value in 2013 $M

In Phase 1, CARIS compares the present value of the production cost savings benefit over the ten-year study period to the present value of fixed costs based on a 16% carrying cost charge, for transmission and generation solutions, to determine a benefit/cost ratio, as presented in Table 6-3. A 16% carrying cost charge does not apply to demand response solutions. See Section 5.5 for a detailed explanation.

Table 6-3: Benefit/Cost Ratios

To be inserted once B/C is complete.

In conclusion, this CARIS Phase 1 study provides: (a) projections of congestion in the NYCA system; (b) present value of ten-year production cost savings ranging from $25M to $3,315M resulting from the application of various generic transmission, generation, energy efficiency and demand response solutions; and (c) the Benefit/Cost ratios as high as *** and as low as *** depending on the high-medium-low generic project cost estimates.

Additionally, the scenario analyses provide information on new or increased projected congestion costs resulting from changes in variables selected for scenario analyses (see Table 5-22 in Section 5).

7. Next Steps

In addition to the CARIS Phase 1 Study, any interested party can request additional studies or use the CARIS Phase 1 results for guidance in submitting a request for a Phase 2 study.

7.1. Additional CARIS Studies

In addition to the three CARIS studies, any interested party may request an additional study of congestion on the NYCA bulk power system. Those studies can analyze the benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs.

7.2. Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board of Directors. The model for Phase 2 studies would include known changes to the system configuration that meet base case inclusion rules and would be updated with any new load forecasts, fuel costs, and emission costs projections upon review and discussion by stakeholders. Phase 2 will provide a benefit/cost assessment for each specific transmission project that is submitted by Developers who seek regulated cost recovery under the NYISO's Tariff.

Transmission projects seeking regulated cost recovery will be further assessed by NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff[16]. To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority (≥ 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. Additional details on the Phase 2 process can be found in Appendix F.

7.3. Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a Developer seeks cost recovery, will determine beneficiaries and conduct cost allocation calculations. The results of the

16 Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated cost recovery, and therefore are not obligated to follow the requirements of Phase 2. Cost recovery of market-based projects shall be the responsibility of the Developer.

Phase 2 analyses will provide a basis for beneficiary voting on each proposed transmission project.

The next CARIS cycle is scheduled to begin in 2015.

Appendix A – Glossary

TERM	DEFINITION
Ancillary Services	Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. [FROM SERVICES TARIFF]
Bid Production Cost	Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). [FROM SERVICES TARIFF]
Bulk Power Transmission Facility (BPTF)	Transmission facilities that are system elements of the bulk power system which is the interconnected electrical system within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area.
Business Issues Committee (BIC)	A NYISO committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to bidding, Settlements and the calculation of market prices.
Capacity	The capability to generate or transmit electrical power, or the ability to reduce demand at the direction of the NYISO.
Chicago Climate Futures Exchange (CCFE)	A derivatives exchange that offers standardized and cleared futures and options contracts on emission allowances and other environmental products.
Clean Air Markets Division (CAMD)	A division of the U.S. Environmental Protection Agency responsible for various market-based regulatory programs that are designed to improve air quality by reducing outdoor concentrations of fine particles, sulfur dioxide, nitrogen oxides, and mercury.
Comprehensive Reliability Plan (CRP)	A biennial study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point. It is the second step in the Comprehensive Reliability Planning Process (CRPP)
Comprehensive Reliability Planning Process (CRPP)	The biennial process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a ten-year period and evaluates solutions to meet those needs. The CRPP consists of two studies: the RNA, which identifies potential problems, and the CRP, which evaluates specific solutions to those problems.

Comprehensive System Planning Process (CSPP)	A transmission system planning process that is comprised of three components: (1) Local transmission planning; (2) Compilation of local plans into the Comprehensive Reliability Planning Process (CRPP), which includes developing a Comprehensive Reliability Plan (CRP); (3) Channeling the CRP data into the Congestion Assessment and Resource Integration Study (CARIS)
Congestion	Congestion on the transmission system results from physical limits on how much power transmission equipment can carry without exceeding thermal, voltage and/or stability limits determined to maintain system reliability. If a lower cost generator cannot transmit its available power to a customer because of a physical transmission constraint, the cost of dispatching a more expensive generator is the congestion cost.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions.
Contingencies	Electrical system events (including disturbances and equipment failures) that are likely to happen.
Day Ahead Market (DAM)	A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.
DC tie-lines	A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.
Demand Response	A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.
Eastern Interconnection Planning Collaborative (EIPC)	A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.
Economic Dispatch of Generation	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.
Electric System Planning Working Group (ESPWG)	A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's Comprehensive Reliability Planning Process (CRPP), the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.
Energy Efficiency Portfolio Standard (EEPS)	A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.

Exports	A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. [FROM SERVICES TARIFF]
External Areas	Neighboring Control Areas including HQ, ISO-NE, PJM, IESO
Federal Energy Regulatory Commission (FERC)	The federal energy regulatory agency within the US Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.
FERC Form 715	An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.
FERC Order No. 890	Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 is intended to provide for more effective competition, transparency and planning in wholesale electricity markets and transmission grid operations, as well as to strengthen the Open Access Transmission Tariff (OATT) with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.
Grandfathered Rights	The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert those rights to TCCs. [FROM SERVICES TARIFF]
Grandfathered TCCs	The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. [FROM SERVICES TARIFF]
Heat Rate	A measurement used to calculate how efficiently a generator uses heat energy. It is expressed as the number of BTUs of heat required to produce a kilowatt-hour of energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel, so when this is compared to the actual energy produced by the generator, the resulting figure tells how efficiently the generator converts that fuel into electrical energy.
High Voltage Direct Current (HVDC)	A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.
Investment Hurdle Rate	The minimum acceptable rate of return.
Imports	A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area.

Independent Market Monitoring Unit	Consulting firm retained by the NYISO Board pursuant to Article 4 of the NYISO's Market Monitoring Plan.
Independent System Operator (ISO)	An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single US State, but sometimes encompassing multiple states.
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.
Installed Reserve Margin (IRM)	The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet New York State Reliability Council (NYSRC) resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.
Load	A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. [FROM SERVICES TARIFF]
Locational Capacity Requirement (LCR)	Locational Capacity Requirement specifies the minimum amount of installed capacity that must be procured from resources situated specifically within a locality (Zone K and Zone J). It considers resources within the locality as well as the transmission import capability to the locality in order to meet the resource adequacy reliability criteria of the New York State Reliability Council (NYSRC) and the Northeast Power Coordinating Council (NPCC).
Load Serving Entity (LSE)	Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. [FROM SERVICES TARIFF]
Load Zones	The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.
Local Transmission Planning Process (LTPP)	The first step in the Comprehensive System Planning Process (CSPP), under which stakeholders in New York's electricity markets participate in local transmission planning.
Locational Based Marginal Pricing (LBMP)	The price of Energy at each location in the NYS Transmission System.
Market Analysis and Portfolio Simulation (MAPS) Software	An analytic tool for market simulation and asset performance evaluations.
Multi-Area Reliability Simulation (MARS) Software	An analytic tool for market simulation to assess the reliability of a generation system comprised of any number of interconnected areas.

Market Based Solution	Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response Programs.
Market Participant	An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO tariffs, power exchanges, TOs, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.
New York Control Area (NYCA)	The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 zones.
New York Independent System Operator (NYISO)	Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a 11,009-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.
New York State Reliability Council (NYSRC)	A not-for-profit entity whose mission is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator (NYISO) and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.
Nomogram	Nomograms are used to model relationships between system elements. These can include; voltage or stability related to load level or generator status; two interfaces related to each other; generating units whose output is related to each other; and operating procedures.
Northeast Coordinated System Planning Protocol (NCSPP)	ISO New England, PJM and the NYISO work together under the Northeast Coordinated System Planning Protocol (NCSPP), to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.
Operating Reserves	Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. [SERVICES TARIFF TERM]
Overnight Costs	Direct permitting, engineering and construction costs with no allowances for financing costs.
Phase Angle Regulator (PAR)	Device that controls the flow of electric power in order to increase the efficiency of the transmission system.
Proxy Generator Bus	A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface.
Regional Greenhouse Gas Initiative (RGGI)	A cooperative effort by ten Northeast and Mid-Atlantic states to limit greenhouse gas emissions using a market-based cap-and-trade approach.

Regulated Backstop Solution	Proposals required of certain TOs to meet Reliability Needs as outlined in the RNA. Those solutions can include generation, transmission or Demand Response. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap solution should be temporary and strive to ensure that market-based solutions will not be economically harmed. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.
Regulation Service	An Ancillary Service. See glossary definition for Ancillary Services.
Reliability Need	A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (OATT TERM)
Reliability Needs Assessment (RNA)	A biennial report that evaluates resource adequacy and transmission system security over a ten-year planning horizon, and identifies future needs of the New York electric grid. It is the first step in the NYISO's CRPP.
Security Constrained Unit Commitment (SCUC)	A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.
Special Case Resource (SCR)	A NYISO demand response Demand Response program designed to reduce power usage by businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up to serve as SCRs are paid in advance for agreeing to reduce power consumption upon NYISO request.
Stakeholders	A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.
Thermal transfer limit	The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.
Transfer Capability	The amount of electricity that can flow on a transmission line at any given instant, respecting facility rating and reliability rules.
Transmission Congestion Contract (TCC)	The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (SERVICES TARIFF TERM)
Transmission Constraint	Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.
Transmission District	The geographic area served by the Investor Owned Transmission Owners and LIPA, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (SERVICES TARIFF TERM)
Transmission Interface	A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas. (SERVICES TARIFF TERM)

Transmission Owner (TO)	A public utility or authority that provides Transmission Service under the Tariff
Transmission Planning Advisory Subcommittee (TPAS)	A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.
Unhedged Congestion	Congestion payment (congestion component times load affected) minus the TCC hedge.[Add definition]