2009 Congestion Assessment and Resource Integration Study (CARIS) – Phase 1

Phase 1 - Study Phase

3RD DRAFT REPORT

October 20, 2009

For Discussion Purposes Only

Caution and Disclaimer

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Executive Summary

To be added at a later date.

1. Introduction

The New York Independent System Operator (NYISO) is undertaking a new process pursuant to its Attachment Y of the OATT (Open Access Transmission Tariff, or the Tariff from hereon, to assess both historic and projected congestion on the New York bulk power system and to estimate the economic benefits of relieving that congestion by integrating potential projects comprising transmission, generation or demand resources. This new process is entitled the Congestion Assessment and Resource Integration Study (CARIS). CARIS builds on the NYISO's existing reliability planning process previously known as the Comprehensive Reliability Planning Process (CRPP), and together with the Local Transmission Planning Process (LTPP), completes the NYISO's new overall Comprehensive System Planning Process (CSPP). The LTPP was developed to be the first step in the CSPP. When the reliability planning process of the CSPP is completed and approved by the NYISO board, the CARIS begins, starting from a reliable system as described in the approved Comprehensive Reliability Plan (CRP).

CARIS consists of two phases: Phase 1, the Study Phase, and Phase 2, the Project Phase. In Phase 1, the NYISO, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion, identifies, ranks and groups the most congested elements on the New York bulk power system based on the historic and forecasted congestion, and develops the three CARIS studies. Each of the three studies includes: i) the development of potential generic solutions to mitigate the identified congestion; ii) a benefit/cost assessment of each solution based on NYCA wide production cost savings; iii) and presentation of additional information on other related congestion metrics to all stakeholders, scenario analyses are then performed on the base case to assess the impact of potential factors to the top three groupings. Phase 1 results are presented in a written report to the NYISO's Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) for review. After that review, the draft report is presented to the NYISO's Business Issues Committee (BIC) and the Management Committee (MC) for discussion and action within the NYISO's Governance process before being submitted to the NYISO Board of Directors (NYISO Board) for approval.

This document is the NYISO's first CARIS report. It presents the Phase 1 study results and serves the crucial function of providing objective information on the nature of congestion in the New York Control Area (NYCA) that developers can use to decide whether to proceed with transmission upgrades or other resource additions (generation or demand response). This report does not make any recommendations of any kind and does not favor any type of resource addition or other actions. This process was developed specifically to not interfere with the present NYISO market, and provide information to potential Developers to assist them in deciding to invest in projects on their own, based on the economics of those projects in the NYISO's markets. Developers may also propose economic transmission projects for cost recovery under the NYISO's Tariff and proceed through the second phase of CARIS, the Project Phase, which will be conducted by NYISO staff in 2010. For these transmission projects, the NYISO will determine if they qualify as economic projects eligible for cost recovery, as defined by the Tariff. Eligible economic transmission projects that elect to pursue cost recovery under the NYISO's CARIS tariff provisions must be approved by at least 80% of the weighted vote of New York's Load Serving Entities (LSEs) that serve loads in those zones that the NYISO identifies as beneficiaries of transmission projects. The beneficiaries of the projects will be those load zones that experience net benefits measured over the first ten years from the proposed commercial operation for the project. Developers of economic generation or demand response projects may choose to pursue such projects on a merchant basis or to enter into contracts with LSEs or other parties**.** CARIS provides additional data and tools to assist in the development of policy and to provide information to potential developers in their investment decisions.

2. Background

2.1. The Evolution of Planning Processes at the NYISO

Since its formation in 1999, the NYISO has carried out two primary functions: (1) the reliable operation of New York's bulk power system and (2) the administration of New York's competitive wholesale electricity markets. The restructuring of the New York electric industry from vertically-integrated transmission, generation and distribution companies operating under traditional cost of service regulation to wholesale markets was designed to incent private investment in generation, transmission and other resources to foster competition. Additionally, this restructuring provided for the shift of the risk associated with these investments away from ratepayers to investors operating in economically-efficient and transparent wholesale markets. System planning, therefore, was initially restricted to conducting analyses for entities requesting transmission service which would require transmission upgrades and/or additions under Section 19 and 32 of the NYISO's Open Access Transmission Tariff (OATT). This system also allowed the New York Public Service Commission (NYSPSC) to request studies of transmission upgrades. In addition, NYISO had the responsibility for conducting analyses of any new generation or transmission facilities proposing to interconnect to the New York Bulk Power System to determine the necessary system upgrades for compliance with applicable reliability standards.

The NYISO, in collaboration with its stakeholders, developed a CRPP in 2003-2004 to identify the Reliability Needs of the bulk power system looking out ten years and seek market-based solutions to the identified Reliability Needs. In December 2004, the FERC approved the CRPP filing, including the addition of a new Attachment Y to the NYISO's OATT, and the NYISO immediately began its implementation in early 2005. The CRPP is a long-range assessment of resource adequacy and transmission reliability over a ten-year planning horizon. It includes the development of a Reliability Needs Assessment ("RNA"), an evaluation of proposed solutions, and the development of the CRP to address the identified needs. For each Reliability Need identified in the RNA, the NYISO contemporaneously requests market-based solutions from the marketplace as well as regulated backstop solutions from the identified Responsible Transmission Owner(s). If no viable market-based solutions are developed in time to satisfy the Reliability Needs, the NYISO will initiate the second step of the solicitation process by requesting alternative regulated responses to Reliability Needs All types of solutions may include generation, transmission, or demand response resources. Once it receives the market-based and regulated backstop proposed solutions, the NYISO assesses these solutions and reports in the CRP whether the projects submitted will meet the identified Reliability Needs. If the NYISO deems a Responsible TO's regulated backstop solution necessary to meet the Reliability Needs, then the costs incurred by the Responsible Transmission Owners in planning, developing, and implementing the regulated backstop solutions are recoverable under the NYISO Tariff. The principal objective of the CRPP is to maintain reliability by providing an opportunity for developers to invest in new, market-based projects before triggering a regulated backstop solution. To date, the NYISO has completed four annual cycles of the CRPP. Most recently, the NYISO staff, in collaboration with its stakeholders, developed the 2009 CRP which was approved by the NYISO Board in May, 2009. The Plan identified no Reliability Needs through 2018 — provided system conditions do not change — and evaluated the risks that could give rise to Reliability Needs before that time. The 2009 CRP forms the foundation for this first CARIS study.

In Order No. 890 (Order 890), the FERC expanded the planning responsibilities of the NYISO and the New York Transmission Owners (NYTOs) setting forth nine principles that all planning processes are required to meet. The NYISO and the NYTOs submitted a joint compliance filing in December 2007, which proposed tariff changes creating a three-stage CSPP which will span a two-year cycle. First, each NYTO conducts a LTPP for its respective transmission system and provide the input assumptions and results to interested parties through the NYISO stakeholder process for review and comment. Second, the LTPP provides input into the CRPP, which remains largely unchanged from the process first implemented in 2005. Third, the NYISO conducts the CARIS to a) identify the most constraining elements on the New York bulk power system and study the potential benefits and costs associated with relieving that identified congestion, and b) provide that information to stakeholders in order to facilitate the development of solutions to the identified congestion from private developers who, as an alternative to recovering transmission projects costs through contractual obligations/arrangements, can now be eligible for transmission project cost allocation and regulated cost recovery through the Tariff if such project is approved by a supermajority of voting beneficiaries. The NYISO CSPP is illustrated in Figure 2-1 below.

The joint NYISO/NYTO compliance filing was conditionally approved by the FERC on October 18, 2008. The NYISO and the NYTOs have made three subsequent compliance filings, and final approval of the CSPP remains pending at the FERC (Placeholder - FERC Approval). Based on the FERC's conditional approval and the expectation that economic planning proceeds as filed with the FERC, the NYISO and the NYTOs commenced implementation of CARIS with its stakeholders using the 2009 CRP as the basis.

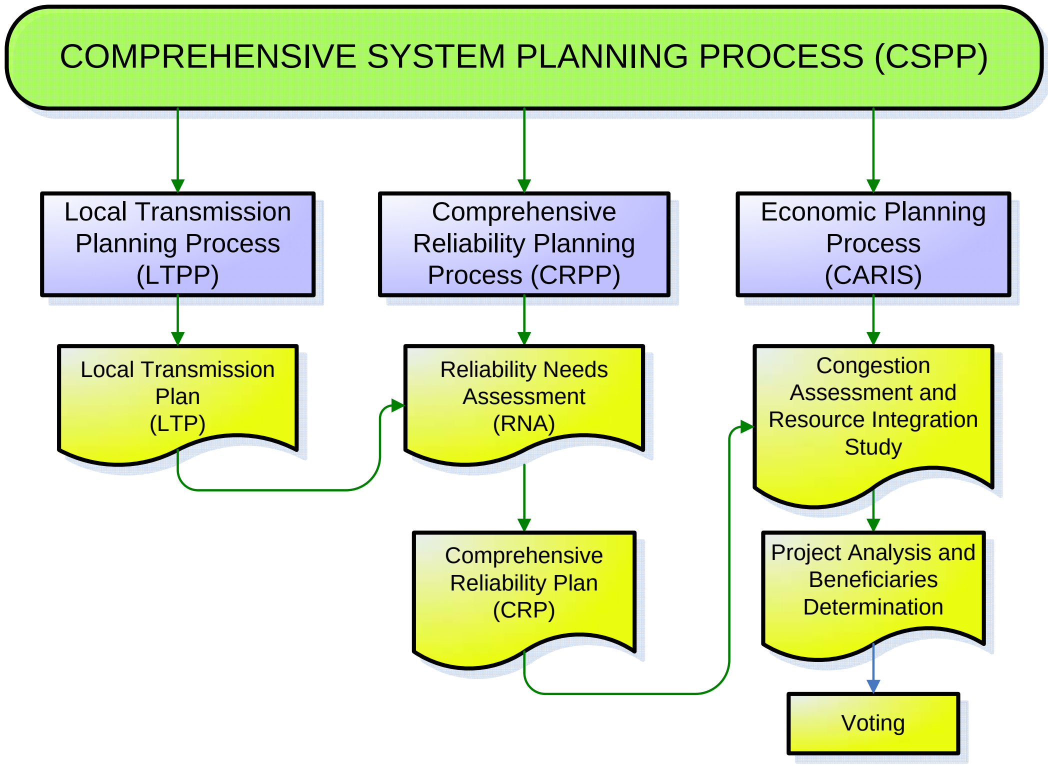

Figure 2-1: NYISO Comprehensive System Planning Process

2.2. CARIS Process

As directed by FERC Order 890, the NYISO collaborated with its stakeholders through multiple joint ESPWG and TPAS meetings, soliciting inputs and feedback, while developing CARIS procedures, study modeling and assumptions. Further, the procedures were reviewed with the BIC before implementing Phase 1 of CARIS.[1]

The objectives of the CARIS economic planning process are to:

a. Provide estimates of future congestion on the New York State bulk power transmission facilities over the ten-year CSPP planning horizon;

b. Identify, through the development of appropriate scenarios, factors that might mitigate or increase congestion;

c. Provide information to market participants, stakeholders and other interested parties on generic solutions to reduce congestion;

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

[1] The NYISO anticipates that any lessons learned from completion of the first CARIS study will be used to refine and improve the economic planning process.

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

The 2009 CARIS builds upon and aligns with the CRPP and assumes a baseline reliable system identified in the 2009 CRP for the ten-year study period from 2009 to 2018. Figure 2-2 below presents a graphical depiction of the CARIS process.

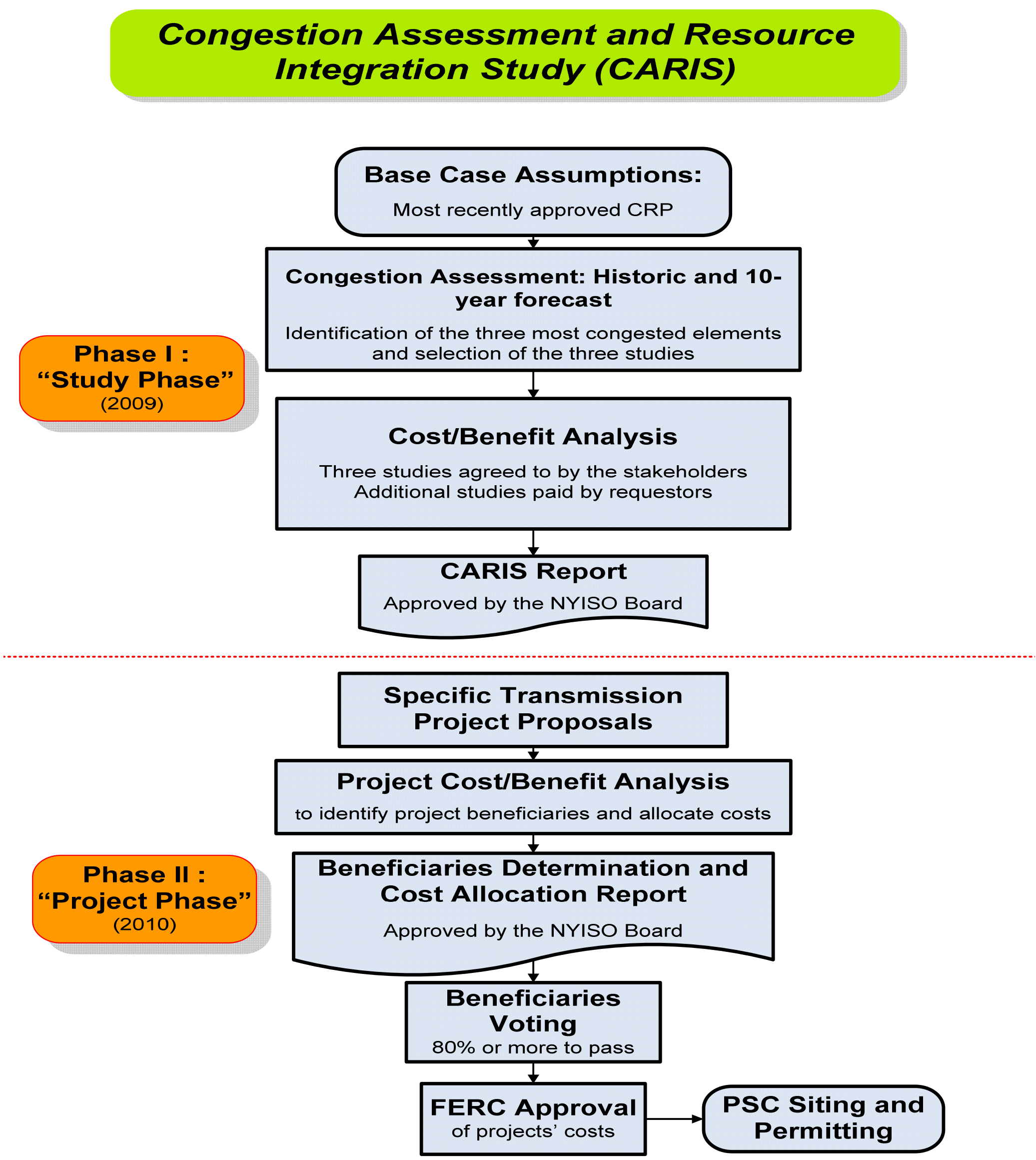

Figure 2-2: Overall CARIS Diagram

2.2.1. Phase 1 - Study Phase

In Phase 1 of the CARIS process, the NYISO, in collaboration with market participants, identifies the three most congested elements in the New York bulk power system, determines the three CARIS studies, applies the potential generic solutions to the congestion identified and conducts the benefit/cost analysis of the applied potential generic solutions. In addition, the NYISO also performs scenario analyses with consideration given to load forecast uncertainty, fuel forecast uncertainty, new resources, retirements, emissions changes, environmental proposals and energy efficiency programs.

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 five most congested elements, and through a relaxation process, develops potential groupings and ranks them based on the highest production cost savings resulting from the relaxation. The top three ranked groups become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts a benefit/cost analysis of potential generic solutions. All resource types, including generation, transmission and demand response are considered on a comparable basis as potential solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, demand response and/or generation resources placed in key locations on the system to measure their effects on relieving each of the three most congested elements. The principal metric for measuring proposed solution benefits for each generic solution is the change in NYCA wide production costs that would result from each potential solution, expressed as the present value over the ten-year planning horizon. The NYISO also reports data on additional metrics, including estimates of reductions in losses, changes in Locational Based Marginal Prices (LBMP) load 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 has been simplified to include congestion rent calculations only and is different from the TCC revenue metric contained in Phase 2. CARIS metrics are described in more detail in Section 3.

Upon completion of the Phase 1 analysis, the results of the analysis are presented to stakeholders in a written report. The report provides interested parties with a wide range of information, including a discussion of its assumptions, inputs, and methodology to assist them in identifying and developing actual solutions to transmission congestion. A draft CARIS report is first submitted to the ESPWG and the TPAS for review and comment. Following completion of that review, the draft CARIS report is sent to the BIC and the MC for discussion and action. Thereafter, the draft CARIS, with BIC and MC input, is forwarded to the NYISO Board for review and action. The draft CARIS is also provided to the Independent Market Advisor for review and consideration. The Board may approve the CARIS report as submitted or propose modifications on its own motion for further consideration. Upon approval by the Board, the NYISO issues the CARIS report and posts it on its website.

In addition to the three CARIS studies, stakeholders may also request additional studies of system congestion at their own expense. Requests may be made at any time, and studies will be conducted as the NYISO's resources allow. The NYISO posts all requests for studies on its website. The specific process for requesting, conducting and paying for additional studies is set forth in Section 1.1.2 of the Initial CARIS Manual.[2] Other information on additional studies, including the form to request additional studies, is posted on the NYISO website. No results of any additional studies are included in this report.

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[2] http://www.nyiso.com/public/webdocs/services/planning/initial_caris_manual_bic_approved/CARISmanual.pdf.

2.2.2. Phase 2 – Project Phase

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

Beneficiaries determined by the NYISO will be LSEs in load zones that economically benefit from the project, and cost allocation among them will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon LSEs' relative LBMP load savings. The aggregate LBMP load savings, for all zones that experience a reduction in LBMP, will be measured and compared on a net (reduced by TCC payments and bilateral contracts) present value basis with the project's revenue requirements over the first ten years of a project's life measured from its expected in-service date. LBMP load savings are calculated first on a zonal basis and are then allocated to each LSE in a zone according to the ratio of its load to all load in the zone - both expressed in MWh.

In addition to the NYCA-wide production cost 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 revenues and allocation of congestion rents to the TOs (for more detail on this metric see Section 3.3.2 of this report and the Initial CARIS Manual, Section 15.4b).

The NYISO will also analyze and present additional information by conducting scenario analyses, where appropriate, regarding future uncertainties, such as possible changes in load forecasts, fuel prices and environmental regulations, as well as other qualitative impacts, such as improved system operations, other environmental impacts, and integration of renewable resources. Although this data may assist and influence how a benefiting LSE votes on a project, they 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 benefit/cost analysis and beneficiary determination will be forwarded to the BIC and MC.[3] After the MC vote, 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 and posted on the NYISO's website, the project will be brought to the BIC meeting for a vote by the identified LSEs, utilizing the economic planning process voting procedure (see the Initial CARIS Manual, Appendix F), on whether the project is approved for cost allocation. The specific provisions for cost allocation are set forth in the Tariff which also calls for the NYISO to establish procedures to determine the specific list of voting entities for each proposed project. That procedure and procedures for conducting a vote for projects in Phase 2 of CARIS are under development at the ESPWG and are not the subject of this report. In order for a project to be approved for cost recovery, the Tariff states that "eighty (80) percent or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project." If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process does not relieve the developer of the responsibility to file with FERC for approval of the project costs and with the appropriate state authorities to obtain siting approval for the project.

2.3. 2009 CARIS Collaborative Process

As directed by FERC Order 890, the NYISO has encouraged all interested parties, including Market Participants, stakeholders, regulatory agencies and policy makers to participate in the CARIS process. As a result of this collaborative process, CARIS procedures and methodologies have been developed as set forth in the Initial CARIS Manual, Appendix F.

The NYISO began preparations to implement CARIS after it filed its joint December 2007 compliance filing with the TOs. Modeling tools and assumptions were discussed with stakeholders at ESPWG throughout 2008. During the final stages of the 2009 CRP process, the NYISO worked with the NYTOs and all interested parties at the ESPWG to establish the procedures for implementing CARIS as called for in the Tariff. To date, NYISO has drafted and obtained approval of the BIC for all of the procedures needed for completing the Phase 1 CARIS Report. These procedures are set forth in Appendix F of the Initial CARIS Manual.

The NYISO collaborated with its stakeholders through multiple joint ESPWG and TPAS meetings, soliciting inputs and feedback, while developing CARIS procedures, study modeling and assumptions. Further, the procedures were reviewed with the BIC before implementing Phase 1 of CARIS. [4] The ESPWG and TPAS completed their review of the CARIS report on ……date, and the NYISO staff forwarded the report to the Independent Market Advisor for his

[3] The NYISO benefit/cost analysis will be forwarded to the BIC and to the MC for discussion and action. The beneficiary determination will be provided to the BIC and the MC for review and comment, but not approval.
[4] The NYISO anticipates that any lessons learned from completion of the first CARIS study will be used to refine and improve the economic planning process.

comments. On ------ date, the BIC reviewed the CARIS report and recommended that the MC recommend that the NYISO Board of Directors approve the report. On ----- date, the MC reviewed the CARIS report and recommended that the Board approve it. Subsequent to MC approval, the NYISO forwarded the draft CARIS to the NYISO Board for review and approval.

It is important to point out that CARIS estimates of future congestion are forecasts and may be different than actual future congestion. The CARIS studies are based upon the 2009 CRP base case which was developed in mid 2008 and includes assumptions about the NYCA system and load growth which were reasonable during that time frame. The base case, however, does not include recent developments such as the load forecast reductions caused by the current economic downturn. Further, CARIS simulations are based upon a limited set of long term assumptions about the utilization of grid resources throughout the 10-year planning horizon which are subject to change. The costs used for the benefit/cost ratios developed for generic projects are representative of the average cost for a broad range of projects representative of the generic solution type and are intended for illustrative purposes within the CARIS Phase 1 only. For example, the CARIS studies do not assess reliability impacts associated with generic solutions and therefore the corresponding interconnection costs are not included in benefit/cost ratios for generic solutions.

2.4. Relationship of CARIS to other Planning Processes

Numerous electric system planning processes have taken root at the national, state, and local level simultaneous to the expansion of the NYISO's electric system planning functions. In the American Reinvestment and Recovery Act, Congress encouraged broader transmission system planning to upgrade aging facilities and expand transmission capability to move power between regions in the United States and Canada, such as for delivering renewable energy resources from resource rich areas to urban load centers. To implement this initiative, the US Department of Energy (DOE) has made funding available for interconnection-wide planning under a Funding Opportunity Announcement (FOA) issued on June 15, 2009. The NYISO is participating in the formation of the Eastern Interconnection Planning Collaborative (EIPC) to conduct transmission planning studies for the Eastern United States and Canada. On September 14, 2009, the EIPC applied to the DOE for a grant to fund this endeavor. (Placeholder for what will happen before we post the final report

Regionally, the NYISO continues to participate in the Northeast Coordinated System Planning Protocol (NCSPP). The NYISO, ISO New England (ISO-NE), Independent Electricity System Operator of Ontario (IESO), and PJM Interconnection LLC (PJM) executed the regional planning protocol in December 2004 to provide a vehicle to enhance coordination of planning in the northeastern United States, with the participation of Canadian planning authorities. The collaborative released a Northeast Coordinated System Plan (NCSP) in 2006 and in 2009 to address Reliability Needs among regions and seams issues among ISO and Regional Transmission Organization (RTO) markets. The 2009 NCSP is posted on the NYISO's website at http://www.nyiso.com/public/webdocs/services/planning/ipsac/NCSP03-27-09.pdf.

At the state level, the Governor of New York re-established a State Energy Planning Board (SEPB) by Executive Order in April 2008. The NYISO has actively participated in the

SEPB working group, filing comments, submitting white papers on timely topics, and conducting reliability modeling for a bulk power system assessment. The SEPB released a draft State Energy Plan (SEP) in August 2009, and the NYISO will submit further input during the 60-day public comment period. Pending the completion of the SEP in the fall of 2009, the NYSPSC has held Phase 3 of its Electric Resource Planning (ERP) proceeding in abeyance. The ERP proceeding will expand upon and implement SEPB policy initiatives, such as state support for renewable resources, demand response and energy efficiency.

With input from the NYISO, the NYTOs are conducting the New York State Transmission Assessment and Reliability Study (STARS). STARS is a joint study of the state's bulk power system over a 20-year planning horizon to help meet future electric needs, support the growth of renewable energy sources, and ensure the reliability of the power system. Its aim is to develop a thorough assessment of the transmission system and suggest long-range plans for coordinated infrastructure investment in the state's power system. Because the bulk power system is owned by separate entities, yet interconnected, the STARS will examine the types of investments, including smart grid applications, needed to meet the long-term needs of the entire control area to complement studies currently being performed by the New York Independent System Operator (NYISO).

Finally, at the municipal level, the City of New York created a City Energy Planning Board (CEPB) as part of Plan NYC. The CEPB is designed to provide a coordinated vision in providing for the future energy needs of New York City considering supply and demand while addressing cost, reliability and environmental impacts. The City has retained CRA International to conduct a Master Electrical Transmission Plan for the City, a long-term study of the City's energy needs and policy initiatives that will affect NYISO's planning processes. The New York City Economic Development Corporation released the results of this analysis in June 2009.

It is anticipated that specific projects which may result from any of the above initiatives will be analyzed under the NYISO's interconnection and planning processes, including CARIS, if funding under the NYISO Tariff is requested for an economic transmission 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. The details and assumptions in developing this database were discussed at various ESPWG meetings and are summarized in Appendix C. The database was used in two production cost simulation software tools: ABB's GridView and GE's Market Analysis and Portfolio Simulation (MAPS), which are widely accepted in the industry. For benchmarking purposes, both tools are being utilized, and appear to give comparable results. For the purposes of this report, Grid View results are presented. Moving,forward, the NYISO will maintain the common database for both tools.

For historic congestion analysis, the Portfolio Ownership and Bid Evaluation (PROBE) production cost simulation tool, developed by PowerGEM LCC, has been used in the last six years to perform the NYISO historic congestion analysis. PROBE utilizes the actual NYISO Day-Ahead Market (DAM) data to emulate the actual SCUC operation. Unlike in GridView and MAPS simulation, PROBE 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 values for the past events, it is nearly impossible to model them with certainty in projecting future transmission congestion. Therefore, it has been decided that these attributes are ignored in the ten-year forward looking CARIS analysis. For more detail on each simulation tool see Appendix D.

The methodology for conducting the CARIS was vetted with ESPWG and incorporated in the Initial CARIS Manual.

3.2. CARIS Metrics

One of the key metrics in the CARIS analysis is the transmission congestion in terms of demand dollar ($Demand) congestion. The demand dollar congestion values are calculated by multiplying zonal load with a transmission constraint's shadow price and zone's shift factor (SF) on that constraint. This definition is consistent with the definition that has been used for the reporting of historic congestion for the past six years.

In conducting Phase 1 of the CARIS process, the NYISO performed an assessment of historic and projected future congestion, identified the top three congested elements, and conducted benefit/cost analysis of each type of generic potential solution — transmission, generation and demand response/energy efficiency — to the identified congestion. The CARIS analysis reports various metrics that were developed with NYISO stakeholders at the ESPWG to measure the cost impacts of congestion and the benefits of its mitigation. The principal benefit metric for CARIS analysis is NYCA-wide production cost reduction that would result from each of nine generic potential solutions. Additional benefit metrics were analyzed as well and the results are presented in this report for information purposes only. All benefit metrics were determined by measuring the difference between the forecasted CARIS base case system value and a forecasted system value when each potential generic solution was added. The discount rate used for the present value analysis was the current weighted average cost of capital for the NYTOs.

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 reduction that would result from implementation of nine potential generic congestion mitigation solutions.

3.2.2. Additional Benefit Metrics[6]

The additional benefits, which are provided for information purposes only, include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services 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 methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Initial CARIS Manual.

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 and unhedged load payments. Total load payments include the LBMP payments (energy, congestion and losses) paid by electricity demand (forecasted load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area. Unhedged load payments represent total load payments minus the TCC payments.

Generator Payments – This metric measures the change in generation payments and includes the LBMP payments (energy, congestion, losses), and ancillary services payments made to electricity suppliers. Ancillary Services costs include payments for regulation services and operating reserves, including 10 minutes synchronous, 10 minutes non-synchronous and 30 minutes non-synchronous. Generator payments are calculated as the sum of the LBMP payments and ancillary services payments to generators and imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs – The measurement of this metric is highly dependent on the rules and procedures guiding the calculation of the installed reserve margin (IRM) and locational capacity requirement (LCR), both for the next capability period and future

[5] Section 11.3.d of the Tariff specifies that the principal benefit metric for the CARIS analysis.
[6] Section 11.3.d of the Tariff specifies the additional metrics. The additional metrics allow LSEs to consider other parameters when evaluating or comparing potential projects.

capability periods. Therefore, for the first CARIS cycle only, the NYISO will use the MW impact methodology.[7] For more detail on this metric see the Initial CARIS Manual.

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 a component of the production cost curve. 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 and for Phase 2 of the CARIS process:

- For Phase 1, the TCC payment metric measures the change in total congestion rents collected in the day-ahead market. Congestion rents are calculated as the product of the Congestion Component of the Day-Ahead LBMP in each Load Zone or Proxy Generator Bus and the withdrawals scheduled in each hour at that Load Zone or Proxy Generator Bus, minus the product of the Congestion Component of the Day-Ahead LBMP at each Generator Bus or Proxy Generator Bus and the injections scheduled in each hour at that Generator bus or Proxy Generator Bus, summed over all locations and hours.
- For Phase 2, the TCC payment metric referred to as TCC Revenues is used for the purposes of Phase 2 regulated economic transmission project cost allocation under Section 15.4 of the Tariff. The TCC revenue metric will measure net reductions in TCC Revenues and will reflect the forecasted impact of the project on TCC auction revenues and day-ahead residual congestion rents allocated to load in each zone, excluding the congestion rents that accrue to any incremental TCCs that may be made feasible as a result of this project. This impact will include forecasts of: 1) the total impact of that project on the Transmission Service Charge offset applicable to loads in each zone (which may vary for loads in a given zone that are in different Transmission Districts); 2) the total impact of that project on the NYPA Transmission Adjustment Charge offset applicable to loads in that zone; and 3) the total impact of that project on payments made to LSEs serving load in that zone that hold Grandfathered Rights or Grandfathered TCCs, to the extent that these have not been taken into account in the calculation of item 1 above. Calculations of net reductions in TCC revenues are detailed in the Initial CARIS Manual.

[7] For the future CARIS cycles, the NYISO will develop a methodology to reflect potential changes in ICAP costs separate from this temporary approach which is not meant to set precedence for the more fully developed ICAP cost methodology applicable to future CARIS cycles.

4. Baseline System Assumptions and Methodology

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. In accordance with the Tariff, the starting point in conducting CARIS analysis is the NYISO's most currently approved CRP. The 2009 CARIS analysis begins with the base case input assumptions provided in the 2009 CRP and aligns with the 10-year reliability planning horizon for the 2009 CRP.

4.1. Major System Assumptions

It is important to note that there are no substantive changes in base case input assumptions from the 2009 CRP except for those prescribed in section 1.1.3 of the Initial CARIS Manual.[8] This step resulted in no change in the system model from the 2009 CRP. Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis developed in collaboration with stakeholders. The key assumptions are presented below:

1. Power flow models - CARIS uses the same power flow base cases utilized in the 2009 CRP.

2. Load and capacity forecast was taken from the 2009 RNA/CRP. It represents the 2008 Gold Book econometric forecast adjusted for approximately 30% of the entire Energy Efficiency Portfolio Standard (EEPS) goals. The 2009 load forecast impacted by the recession was not used in the load model.

3. Transmission and constraint model utilizes a bulk power system representation comprising the entire Eastern Interconnection, including the United States and Canadian Provinces east of the Rocky Mountains, excluding Texas. The model uses the 2009 RNA/CRP transfer limits and system upgrades/additions. External transactions between NYCA and its neighboring control areas are modeled as the interchange flow between the load (export) and generator (import) proxy busses. Transmission outages were not modeled. Refer to Appendix D for details.

4. Production cost model utilizes the most economic security constrained dispatch of generation resources to serve the load subject to the constraints given in the model. To develop the production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed based on public domain information. The CO_2 emission cost forecast does not include Federal CO_2 policy. The model includes the planned maintenance generation outages, but not forced outages.

Notwithstanding the other major inputs listed in other sections that can have significant impact on the congestion projection, are the known events that have impacts on the simulation outcome, as summarized in Table 4-1.

[8] While the system topology and resource additions are the same as in the 2009 CRP, additional data inputs were needed for the CARIS studies since the CRP studies employed transmission and resource adequacy analyses while the CARIS uses production cost analysis requiring additional inputs

Table 4-1: Timeline of Major Events

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Caithness Installed	Empire Generator Installed	M29 Cable Installed		Susquehanna-Roseland Line Installed	SWCT Transmission Reinforcement Installed				New Power Flow Case
	Linden VFT Installed	Athens SPS Ends		West Central Interface Decreased from 1770 MW to 1425 MW		Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas	Estimated load and resource balances in neighboring areas
	Poletti Retired								
	New Power Flow								
	Increased Fuel Price								

Note: The contract between New Athens Generation Company and National Grid specifically calls for the removal of the Athens SPS at the end of 2010 unless a permanent physical reinforcement has been identified. There appears to be no intention to extend the operation of the current Athens SPS after 2010.

4.2. Load and Capacity Forecast

The load and capacity forecast used in the CARIS baseline system, provided in Table 4-2, was taken directly from the 2009 RNA/CRP. There were no changes made to the load forecast or the resource mix in the CARIS as compared to the 2009 CRP.

As reported in the CRP, the 2008 Gold Book forecasts for peak load and energy demand were modified to account for the impacts of programs such as the Energy Efficiency Portfolio Standard (EEPS) and Special Case Resources (SCRs) to reflect achievement of approximately 30% of the entire EEPS goal and increased SCR levels experienced in the market.[9]

[9] "SCR" values reflect projected August 2009 ICAP capability period values held constant over the ten-year Study Period.

Table 4-2: RNA Study Case Load and Resource Table with Updated TO Plans[10]

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Load										
NYCA	**34,059**	**34,269**	**34,462**	**34,586**	**34,725**	**34,905**	**35,029**	**35,258**	**35,430**	**35,658**
Zone J	12,127	12,257	12,361	12,452	12,537	12,627	12,683	12,787	12,879	12,980
Zone K	5,386	5,395	5,403	5,403	5,377	5,370	5,358	5,374	5,354	5,383
Resources										
NYCA										
"Capacity"	39,992	39,657	40,496	40,496	40,502	40,452	40,452	40,452	40,452	40,452
"SCR"	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084	2,084
Total	**42,077**	**41,741**	**42,580**	**42,580**	**42,586**	**42,536**	**42,536**	**42,536**	**42,536**	**42,536**
Res./Load Ratio	123.5%	121.8%	123.6%	123.1%	122.6%	121.9%	121.4%	120.6%	120.1%	119.3%
Zone J										
"Capacity"	10,097	9,206	9,206	9,206	9,206	9,206	9,206	9,206	9,206	9,206
"SCR"	622	622	622	622	622	622	622	622	622	622
Total	**10,719**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**	**9,828**
Res./Load Ratio	88.4%	80.2%	79.5%	78.9%	78.4%	77.83%	77.49%	76.86%	76.31%	75.71%
Zone K										
"Capacity"	5,938	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368	6,368
"SCR"	216	216	216	216	216	216	216	216	216	216
Total	**6,154**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**	**6,584**
Res./Load Ratio	114.3%	122.0%	121.9%	121.9%	122.4%	122.61%	122.88%	122.52%	122.98%	122.31%

4.3. Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation comprising 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 Texas. Figure 4-1 below illustrates the electric grid represented in the CARIS model comprising the Eastern Interconnection regions and Balancing Authorities. The CARIS model includes a full active representation for the NYCA, ISO-NE, IESO, and PJM (PJM Classic, Allegheny Power System (APS), American Electric Power System (AEP), Commonwealth Edison Company (CE), Duquesne Light Company (DLCO), Dayton Power and Light (DAY) and Virginia Power (VP)) for both the network model and the a production cost model. A proxy bus is used to model Hydro Quebec (HQ) to NYISO and ISO-NE. Transmission- only models are represented for Michigan Electric Coordinated Systems (MECS), First Energy Corporation (FE), Southwest Power Pool (SPP), MAR, Northern Indiana Public Service Company (NIPS), Ohio Valley Electric Corporation (OVEC), Tennessee Valley Authority (TVA), Florida Reliability Coordinating Council (FRCC), SERC Reliability Corporation (SERC), and equivalences for the Electric Reliability Council of Texas (ERCOT), and the WECC. For purposes of the CARIS report, the model is discussed in two parts: the NYCA system representation and the system representations for the external control areas.

[10]New York Control Area (NYCA) "Capacity" values include resources internal to New York, additions, reratings, retirements, purchases and sales, and UDRs [WHAT DOES THIS MEAN – DEFINE] with firm capacity. Zone K "Capacity" values include UDRs with firm capacity. Wind generation values include full nameplate capacity.

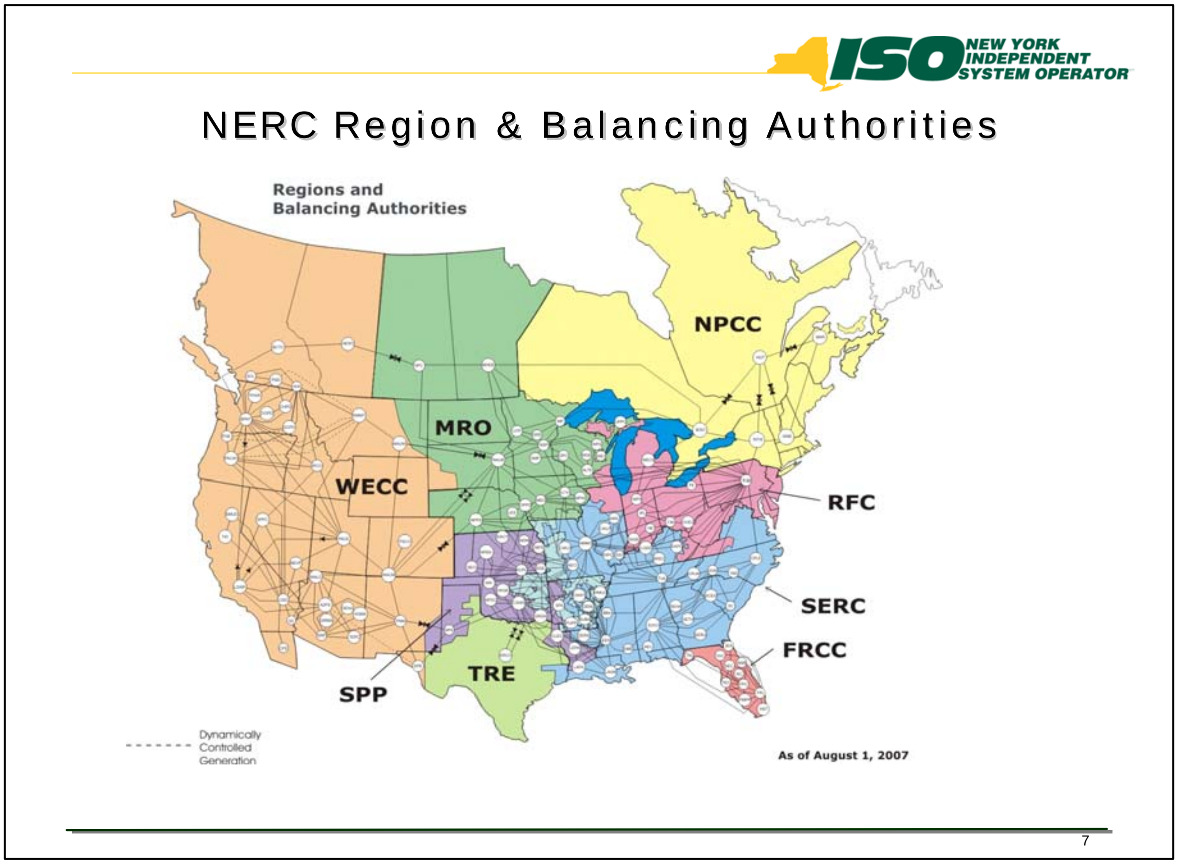

Figure 4-1: All Areas Modeled in CARIS (Excluding WECC & TRE)

4.3.1. New York Control Area Transfer Limits

In the resource adequacy analysis for the 2009 RNA, interface transfer limits were assumed to be constant from the end of the first five years throughout the second five-year period. The assumed interface transfer limits were confirmed during the CRP evaluation of the baseline system. For the resource adequacy analysis of the RNA/CRP, emergency criteria transfer limits are employed in the GE-MARS software model, while the transfer limits for the CARIS study are based upon normal criteria transfer limits. For voltage and stability based limits, the normal and emergency limits are assumed to be the same. The normal voltage transfer limits for critical NYCA transmission interfaces in the CARIS were taken from the RNA and the CRP with some exceptions as indicated in Table 4-3 below.

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

	2009 CARIS Study				
Interface	2009	2010	2011	2012	2013
WEST CENTRAL-Open	1770	1770	1770	1770	1425
CENTRAL EAST	2600	2600	2600	2600	2600
CONED – LILCO	2166	2166	2166	2166	2166
UPNY-ConEd	5000	5000	5000	5000	5000
Dunwoodie (I) to NYCity (J)	4000	4075	4400	4400	4400
Dunwoodie (I) to Long Island (J)	1217	1265	1265	1265	1265
Spr/Dunwoodie South	5315	5290	5365	5365	5365

Note: Central East and UPNY-ConEd were modeled differently than the RNA/CRP values[11]

4.4. Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using the Power Technologies Inc. Power System Simulator for Engineering (PSS/E) MUST software application which uses the transmission planning set of design criteria contingencies. Instead, CARIS uses the most limiting monitored line and contingency sets which MUST identified as the most limiting constraint to the NYCA cross-state transmission interfaces to determine thermal transfer limits as the load and generation is varied throughout the annual simulations. The resulting monitored lines and contingency sets used in the CARIS do not include lines which have less than a five 5 percent impact on the NYCA cross-state transmission interfaces, or the lines that only impact local 115-138 kV transmission or sub-transmission constraints.

[11] Central East was not modeled explicitly in the RNA/CRP but was modeled with the Fraser - Gilboa circuit. UPNY/ConEd was modeled with a nomogram in the RNA/CRP whereby two 300 MW reductions from 5300 MW were applied depending upon the generation availability and load in SENY. This was simplified to one value of 5000 MW for CARIS.

Fuel Forecasts

4.4.1. CARIS Base Annual Forecast

The starting point for preparing the fuel price forecasts for CARIS is the US Energy Information Administration's (EIA)[12] current national long-term forecast of delivered fuel-prices that 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, is used to inflate the *real* values to *nominal* values.

4.4.2. New York Fuel Forecast

In developing the New York's fuel forecast, adjustments were made to the EIA's fuel forecast to reflect bases for fuel prices in New York. A key source 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 information collected through Form EIA-423 (2000-2007) and EIA-923 (2008 onwards).[13] The base annual forecast series are then subjected to an adjustment to reflect the New York 'basis' relative to the national prices as follows:

Natural Gas (Figures 4-2 and 4-3):

A historical analysis of EIA's national AEO forecasts of delivered fuel-prices suggests that they are around 5% higher than Henry Hub prices. Any basis for New York, then, is assessed against 105% of Henry Hub price forecasts. The natural gas price for zones I through K is the Transco Zone 6 (NY) and the proxy for the remainder of NYISO zones is the Tetco-M3 trading price. Analysis of historical prices reveals that, relative to 105% of Henry Hub prices, on average, the basis for Transco Zone 6 (NY) is around 13% and for Tetco-M3 it is 5.5%. (The 7.5 percentage-point differential is consistent with the sum of historical difference between the two prices and the applicable taxes in the New York City area.)

Fuel Oils (Figures 4-2 and 4-3):

Based on reports drawn from EIA-423 for the years 2002-2007, prices of both distillate and residual oils are about 15% cheaper in New York as compared to the US average price. Since the overwhelming bulk of oil-based generation is situated in Zones J and K, the basis for the Downstate zones is -15%. To allow for additional transportation charges, the basis for the Upstate zones is -10%.

Coal (Figures 4-2 and 4-3):

[12] www.eia.doe.gov

[13] 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

The data for Bituminous Coal in EIA-423 was used to calculate a common basis for all NYISO zones. Prices in New York are, on average, 15% higher than in the United States as a whole.

<u>Uranium (Figures 4-2 and 4-3):</u>

It is assumed that the same fuel price applies to all nuclear generators in the United States.

4.4.3. Seasonality and Volatility

All average monthly fuel prices, with the exception of 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 methods.[14] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

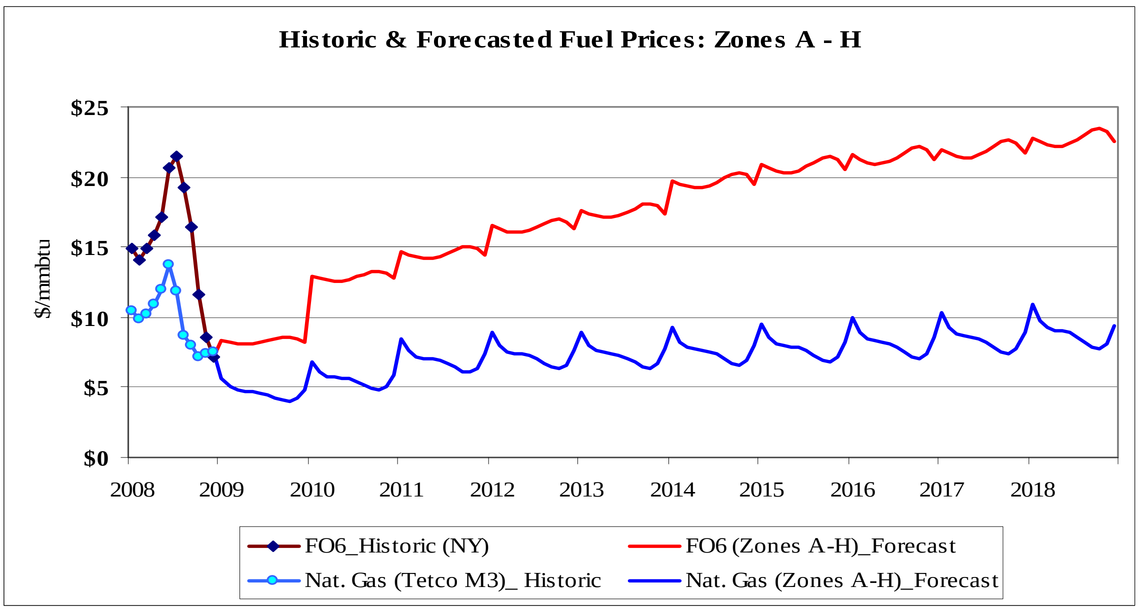

Figure 4-2: Historic and forecasted fuel prices for Zones A-H

[14] This is a two-step process: First, using multi-year time-series, deviations around a time-varying trend (e.g. a centered 12-month moving average or a Hodrick-Prescott Filtered trend) were calculated; second, a 4-degree polynomial trend was fitted to the estimated seasonal factors.

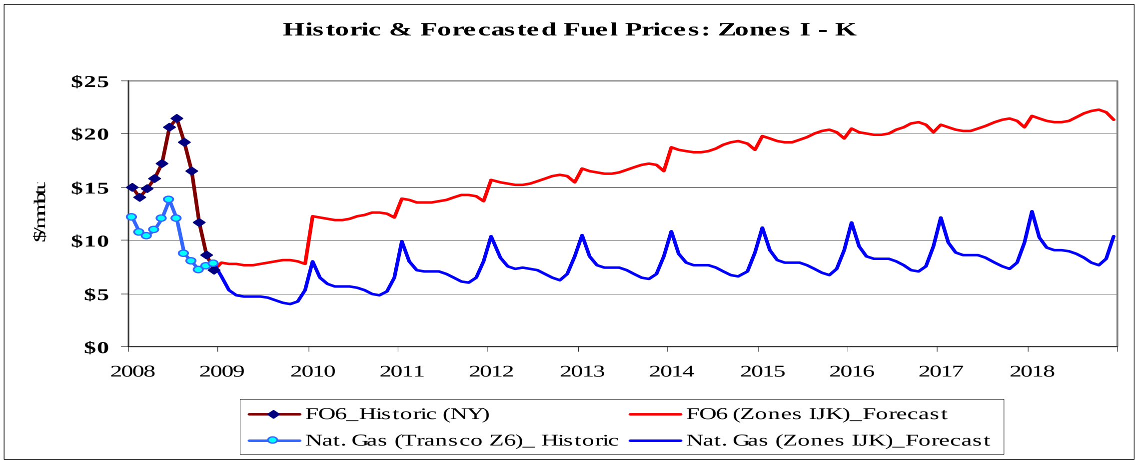

Figure 4-3: Historic and forecasted fuel prices for Zones I-K

The seasonalized time-series represents the forecasted trend of average monthly prices (i.e., a trend). However, in order to facilitate simulation studies to explore scenarios with higher/lower prices, the NYISO developed volatility-factors to capture typical intra-month variability of prices. These factors were the typical monthly standard deviation of daily prices, based on historical data. For natural gas and fuel oils, this monthly volatility factor equals the average standard deviation of daily prices. In the case of coal, only monthly average prices are available; therefore, the corresponding factor is the standard deviation of average monthly prices. This approximation is reasonable because coal prices exhibit relatively muted volatility, as compared to natural gas, and fuel oils.

4.4.4. External Areas Fuel Forecast

The fuel forecasts for the three external areas, ISO-NE, PJM, and IESO, were also developed. The starting point was the base-line annual forecasts of each fuel for New York.[15] The annual averages and the seasonal factors for each external control area were estimated as follows: For ISO-NE and PJM, information obtained from EIA Form 423 (EIA-423) was used to calculate the basis relative to figures for New York, and for IESO the basis was based on data from a recent publication.[16]

Tables 4-5, 4-6, 4-7 and 4-8 below outline the assumptions that went into the fuel-price forecasts for each external control area.

[15] These forecasts were, in turn, based on EIA's current national long-term forecast of delivered fuel-prices.
[16] Ontario Wholesale Electricity Market Price Forecast For the Period May 1, 2008 through October 31, 2009, Presented to Ontario Energy Board, April 11, 2008 by Navigant Consulting Inc., Toronto, Ontario.

Table 4-4: ISO-New England Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones I – K	Same as the factor for Zones I – K
FO2	120% of the price for New York	Same as the factor for New York
FO6	115% of the price for New York	Same as the factor for New York
Coal	125% of the price for New York	Same as the factor for New York

Table 4-5: PJM-East Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones A – H	90% of the factor for Zones A – H in Jan.; 95% in Feb., and 100% for other months
FO2	125% of the price for Zones A – H	Same as the factor for New York
FO6	113% of the price for Zones A – H	Same as the factor for New York
Coal	97% of the price for Zones A – H	Same as the factor for New York

Table 4-6: PJM-West Assumptions

	Annual Average	Monthly Factor
Natural Gas	Same as the price for Zones A – H	88% of the factor for Zones A – H
FO2	125% of the price for Zones A – H	Same as the factor for New York
FO6	113% of the price for Zones A – H	Same as the factor for New York
Coal	82% of the price for Zones A – H	Same as the factor for New York

Table 4-7: IESO Assumptions

	Annual Average	Monthly Factor
Natural Gas	84% of the price for Zones A – H; rest of the months the same as the price for Zones A – H	90% of the factor for Zones A – H
FO2	Same as the EIA national forecast	Same as the factor for New York
FO6	Same as the EIA national forecast	Same as the factor for New York
Coal	120% of the price for New York	Same as the factor for New York

4.5. Emission Cost Forecast

The costs of emission allowances are an increasing portion of generators' production costs. Currently all NYCA fossil fueled generators greater than 25 MW and most generators in surrounding states are required to hold allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2. There are exchanges for trading allowances and futures contracts for allowances. The Chicago Climate Futures Exchange (CCFE) offers standardized and cleared futures and options contracts on emission allowances and other environmental products. The emission allowance price forecasts were created by using future contract values on May 15, 2009. Extrapolations were made for years where futures contracts were not traded. The simulations were based on the assumption that all fossil generators are required to have emission allowances equal to their respective emissions.

Emission costs are the product of emission rate and emission allowance costs. Annual emission rates were used in the simulations. The annual emission rates in terms of #/mmBTU are available from the EPA's Clean Air Markets Division (CAMD). Since the emission rate determined above is an average emission rate, the same rate was used across the operating range.

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

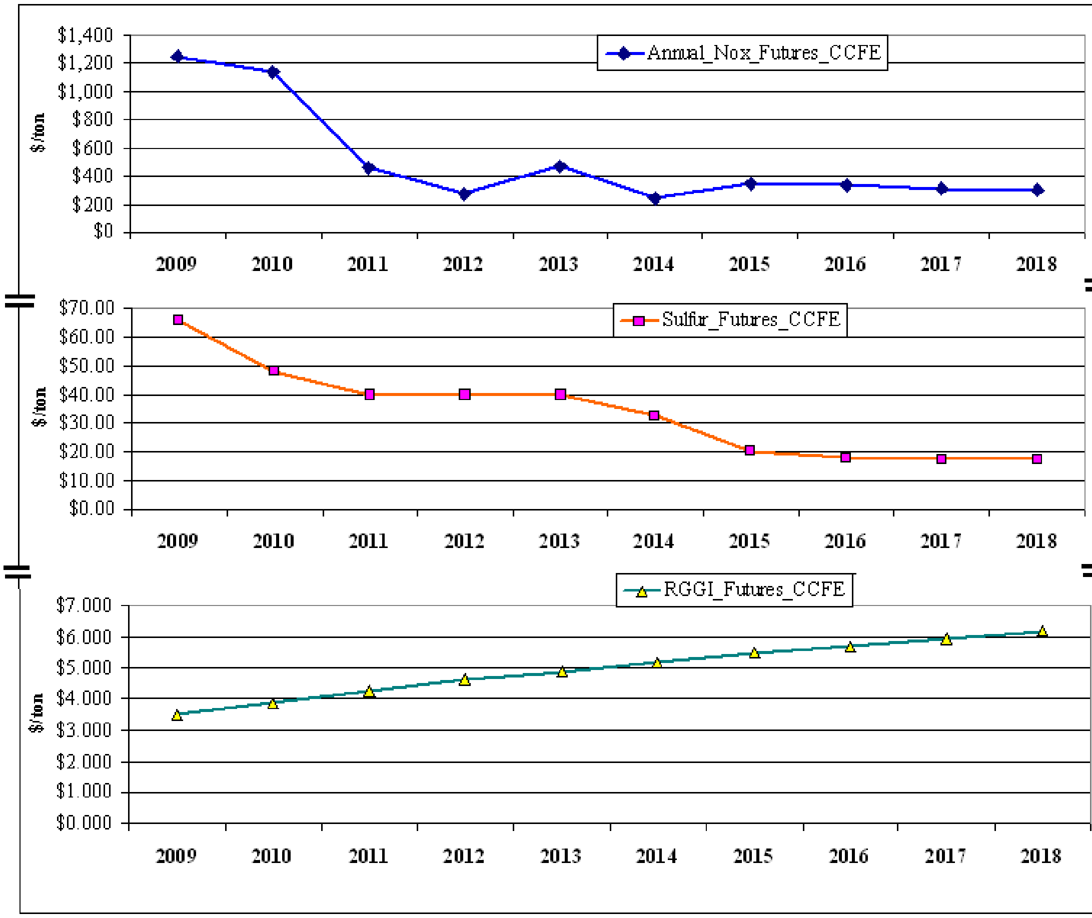

Figure 4-4: Emission Allowance Forecast

With respect to the carbon emission futures under the Regional Greenhouse Gas Initiative (RGGI), the data from the CCFE was available only through 2012. The implied trend was extrapolated to cover the 2013-2018 period.

4.6. Potential Generic Solutions

Generic solutions are evaluated by NYISO for each identified congested element or grouping utilizing each resource type – generation, transmission, and demand response – as required in Section 11.3 of the Tariff. The development of the generic solutions representative costs are accomplished by consultants experienced with NYISO's market and systems and with stakeholder input.[17]. This methodology was based on utilizing typical MW block size generic solutions, a standard set of assumptions, and an order of magnitude costs for each resource type.

[17] NERA/Sargent & Landy, Quanta Services, and Brattle Group were retained to provide the initial cost assessment for the generation, transmission and demand response solutions.

It should be noted that the estimates included in the Potential Generic Solution Cost Matrix should not be utilized for purposes outside of the CARIS process. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic order of magnitude solution estimates.

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
- Blocks sizes are in comparable proportions between the resource types

The block sizes selected for each resource type are presented in Table 4-9 through Table 4-11.

Table 4-8: Transmission Block Sizes

Location	Line System Voltage (kV)	Block Ampacity (Amp)	Block Capacity (MVA)
Zone A-J	345	1673	1000
Zone K	138	2092	500

Note: 138 kV was selected for Zone K due to the limited number of 345 kV substations located within this Zone. The block capacity was reduced accordingly to be reflective of the typical line size for this voltage class.

Table 4-9: Generation Block Sizes

Plant Location	Plant Block Size Capacity (MW)
Zone A-K	250

Table 4-10: Demand Response Block Sizes

Location	Demand Response Block Size (MW)	Portfolio Type
Zone A-K	100	Energy Efficiency
Zone A-K	100	Demand Response

4.6.2. Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types is very dependent on many different parameters and site specific situations. A detailed list of assumptions utilized for each resource is included in the Potential Generic Solution Cost Matrix, in Appendix C.

The following guidelines and assumptions are used to select the potential generic solution and determine their cost:

<u>Transmission Resource</u>

- 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.
- The cost of the Transmission solution would be affected by the following:
    1. type of construction (typical conventional overhead or underground)
    2. voltage and ampacity capability
    3. substation interconnection
    4. rights of way
    5. permitting
    6. system upgrade facilities
    7. order of magnitude cost estimate

<u>Generation Resource</u>

- The generic generation solution consists 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 is selected.
- The cost of the Generation solution would be affected by the following:
    1. type of plant
    2. length, type, voltage and ampacity of generator lead
    3. substation interconnection
    4. length of gas line
    5. rights of way
    6. permitting
    7. system upgrade facilities
    8. order of magnitude cost estimate

Demand Response

- The generic demand response solution is modeled as a reduction in load within the zone where the most downstream grouped congested element is terminated.
- The on-peak demand is assumed to be concentrated in the top 60-100 highest load hours.
- The demand response installed in a zone is limited to less than 10% of the peak zonal load. If the "block" demand response exceeds 10% of the peak zonal load, it is prorated based on peak load between the selected zone and the next downstream zone.
- The cost of the Demand Response solution would be affected by the following:
    1. zonal locations
    2. energy efficiency (available 8760 hours/year)/ demand response
    3. utility demand side management filings
    4. order of magnitude cost estimate

4.6.3. Order of Magnitude Unit Pricing

Order of magnitude unit pricing cost estimates were developed based on the block sizes and assumptions for each resource type. The NYISO utilized engineering consultants to develop order of magnitude cost estimates based on their experience in the industry and similar existing projects or programs currently being considered within New York. The order of magnitude cost estimates took into account the cost differences between geographical areas within New York. Three sets of costs were developed that are reflective of the differences in labor, land and permitting costs between Upstate, Downstate and Long Island. The order of magnitude unit pricing for the following elements, listed in Table 4-11, were developed for the three resource types[18] and for each geographical area.

Table 4-11: Order of Magnitude Unit Pricing Elements

Transmission	Generation	Demand Response
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	

All costs were reviewed by the Transmission Owners and stakeholders through the stakeholder process. As part of this process, ranges for the cost for each element were developed in order to address the wide variability that can occur in a project due to such items as permitting, right of way constraints, and existing system conditions. The resulting order of magnitude unit pricing levels are included in the Potential Generic Solution Cost Matrix in Appendix C.

4.6.4. Application of Order of Magnitude Cost Estimates

Upon selection of the three congestion areas to be studied and their potential solutions, the order of magnitude unit pricing element are utilized to develop order of magnitude generic solution costs for inclusion in the benefit to cost ratio analysis. If the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs included in the matrix. These complexities may include but are not limited to right of way restrictions, terrain and/or permitting difficulties.

[18] For this CARIS cycle Demand Resource costs considered potential market value and not actual costs to build or implement DSM. In the next CARIS cycle the actual cost estimates will be considered for Demand Response solutions.

5. 2009 CARIS Analyses – Study Phase

This section presents the results of Phase 1, the Study Phase, of the CARIS process. Specific economic projects are not considered in this phase. They will be subsequently studied in Phase 2, the Project Phase, of the CARIS process. The results are presented below and described in more detail in Appendix E. The process steps include:1) congestion assessment; 2) ranking of congested elements; 3) selection of three studies; 4) potential generic solutions application; 5) benefit/cost analysis; and 6) scenario analysis.

The Study Phase of the CARIS process begins with the development of a ten-year projection of future congestion costs resulting from NYCA system facilities. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. Based on this ranking, the top five congested elements are identified, and a grouping process is implemented to develop the three studies comprising CARIS. Potential solutions to these most congested groupings are then assessed, and the benefit/cost ratios are presented based on generic solution costs and forecasted production cost savings. Scenario analyses are also conducted to determine the impact of uncertainties on the projection of congestion.

5.1. Congestion Assessment

Congestion assessment is performed both from a historical and future perspective and is done separately. The results are presented in the following two sections of this chapter..

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements is taken into consideration. The concept of positive versus negative congestion is based on how the congestion relates to the reference point. New York uses the Marcy bus as its reference point. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and this means that more expensive generators, most often downstate, are required to serve load at such location, compared to the load at Marcy due to system constraints. Any location with LBMP below reference LBMP has negative congestion. This typically happens due to transmission constraints in generator pockets when lower cost generation cannot be delivered in full to the New York grid, or when all available relatively inexpensive imports cannot be fully delivered.

5.1.1. Historic Congestion

Historic congestion assessment has been conducted at the NYISO for the last six years 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 (BPCG) 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. The NYISO uses PROBE production cost simulation tool to generate historical results, which, unlike the CARIS forecasted results, include, among others, the impact of virtual bidding and actual transmission outages on congestion. This is explained in more detail further in the text and in Appendix D.

Table 5-1 below summarizes the impact of historic congestion on BPC, unhedged congestion payments, generator payments, and load payments over the past six years, including zones both internal and external to NYCA. The results represent the change in metrics' values between a constrained system and a system in which all constraints are relieved. When all the constraints were relieved, BPC and congestion payments resulted in positive savings, while generator payments and load payments resulted in negative savings for the majority of studied historic years. More information on historic congestion metrics and how they are calculated is included in Appendix E.

Table 5-1: PROBE NYCA System Congestion Impact - Mitigated Bids ($ in Millions), 2003-2008

Total NYCA Congestion Impact - Mitigated Bids ($ Millions), 2003 - 2008

Year	**BPC ($mil.) (mitigated)**	**Unhedged Congestion Payments* ($ mil.)**	**Generator Payments ($ mil.)**	**Unhedged Load Payments* ($mil.)**
2003	85	293	-136	-136
2004	72	316	-181	-181
2005	113	685	-71	-71
2006	118	921	59	59
2007	130	806	-107	-107
2008	243	1,525	-417	-417

* The values do not include TCC hedge.

Figure 5-1 below illustrates a cumulative effect of bid production costs savings over the past six years.

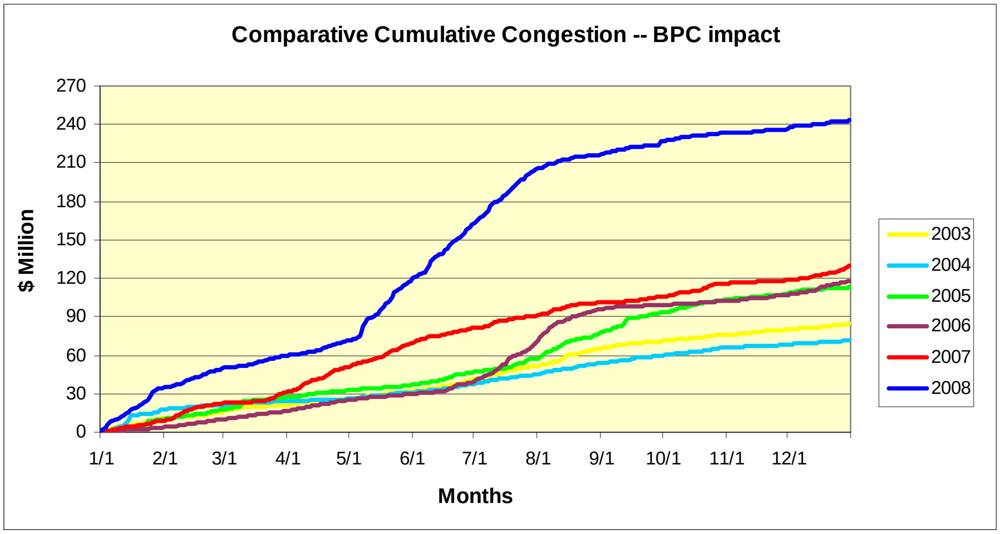

Figure 5-1: PROBE Cumulative BPC Impact

Historic congestion values by zone are presented in Table 5-2 indicating the highest congestion in New York City and Long Island. Total NYCA congestion (TCC hedge is included) in 2008 nearly doubled in comparison to 2007, mostly due to high fuel prices in 2008.

Table 5-2: Historic Congestion by Zone 2004-2008

Historic Congestion $Demand Payment ($ in Millions)

Zone	2004.0	2005.0	2006.0	2007.0	2008.0
West	-0.7	-4.9	0.9	-14.1	-25.2
Genessee	0.5	-1.3	1.6	-14.0	-9.4
Central	0.5	-1.2	3.5	9.4	18.4
North	0.0	-1.1	-0.2	-0.3	-1.8
Mohawk Valley	0.1	-0.3	2.1	4.6	9.8
Capital	7.5	19.3	27.2	73.8	143.4
Hudson Valley	4.9	19.9	54.4	86.9	175.5
Millwood	2.7	11.8	26.7	30.8	78.0
Dunwoodie	4.4	23.6	44.1	56.1	124.4
NYCity	581.8	808.7	672.9	700.0	1402.7
Long Island	229.5	508.0	708.2	517.9	624.4
NYCA Total	**831.2**	**1,382.3**	**1,541.5**	**1,451.1**	**2,540.3**

Historic Congestion Source: PROBE DAM quarterly reports
DAM data include Virtual bidding and Transmission planned outages

Table 5-3 below lists historic congestion values for top constraints from 2004 to 2008. Based on the positive congestion values, the top three congested constraints are Central East, Leeds-Pleasant-Valley, and Dunwoodie Shore Road.

Table 5-3: Historic Congestion by Constraint ($ in Millions) 2004-2008

Constraint	2004	2005	2006	2007	2008	Total
CENTRAL EAST - VC	52	102	187	571	1,199	2,112
PLSNTVLY 345 LEEDS 345 1	27	182	452	435	667	1,763
DUNWODIE 345 SHORE_RD 345 1	152	348	492	260	187	1,439
MOTTHAVN 345 RAINEY 345 2	0	0	0	43	272	315
RAINEY 138 VERNON 138 1	5	84	21	19	81	210
WEST CENTRAL	(0)	(0)	(2)	(51)	(55)	(108)
E179THST 138 HELLTP_W 138 1	(9)	(18)	(10)	(12)	(34)	(83)

* Ranking is based on absolute values.

5.1.2. Projected Congestion

A projection of future congestion is reported as demand dollar ($Demand) congestion. Congestion forecasts resulting from the simulation are highly dependent upon many long-term assumptions. The CARIS model utilizes input assumptions listed in Appendix C.

When comparing historical congestion values to projected congestion values, one must bear in mind that there are significant differences in assumptions used by the PROBE and CARIS tools. The CARIS tools 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 payments (BPCG); and f) co-optimization with ancillary services. Another factor when comparing historic and future congestion values is the fuel prices. Projected fuel prices for 2009 are much lower that 2008 fuel prices.

The relative values of congestion shown in Table 5-4 indicate that the majority of the projected congestion is in the downstate zones.

Table 5-4: Projection of Future Congestion 2009-2018 (nominal $ in Millions)

Area	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016	2,017	2,018
West	(5)	(13)	(12)	(14)	(34)	(33)	(36)	(41)	(45)	(57)
Genessee	(3)	(3)	(3)	(4)	(23)	(21)	(22)	(25)	(29)	(37)
Central	1	1	1	1	(0)	(0)	(2)	(2)	(1)	1
North	0	1	1	1	0	0	0	1	1	1
Mohawk Valley	1	1	2	2	1	1	1	2	2	2
Capital	5	15	14	18	13	13	15	19	23	23
Hudson Valley	8	20	35	38	33	33	35	39	43	50
Millwood	3	6	11	12	11	10	11	12	13	15
Dunwoodie	6	14	26	28	24	24	26	28	30	36
NYCity	87	209	271	300	278	292	326	375	410	426
Long Island	27	69	98	106	93	91	97	106	116	132
NYISO Total	**130**	**319**	**443**	**488**	**397**	**410**	**452**	**514**	**563**	**593**

Table 5-5 lists the future top most congested elements: Leeds-Pleasant Valley, Central East, West Central, Astoria West, Mott Haven-Rainy and Dunwoodie Shore Road.

Table 5-5: Projection of Future Congestion 2009-2018 (nominal $ in Millions)

Constraints	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
LEEDS-PLEASANT VALLEY 345 KV	35.12	68.87	229.8	245.05	219.98	217.07	214.79	227.77	235.75	292.82	1,987.01
CENTRAL EAST	26.84	92.59	79.9	102.69	66.98	62.32	74.66	97.01	125.63	117.9	846.51
MOTT HAVEN-RAINEY 345 KV	1.44	15.38	2.01	3.52	5.51	7.96	9.72	12.88	15	23.52	96.94
DUNWOODIE-SHORRD 345	4.26	15.69	7.57	7.23	6.73	6.31	6.44	7	8.12	8.5	77.86
WEST CENTRAL-OP	-0.02	-2.85	-3.3	-4.51	-52.62	-48.09	-46	-54.48	-63.6	-86.5	-361.97
ASTORIAW138-HG5 138	-2.45	-9.26	-12.01	-10.51	-11.29	-12.45	-13.2	-14.71	-14.52	-16.93	-114.89

Note: Allowance for diminishing congestion in the future years in the approved ranking procedure directs the selection of West Central as the third ranked element.

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 identified constraint. The fifteen years of statistics are analyzed to identify recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system. Ranking of the identified constraints is initialy based on the highest present value of congestion over the fifteen years of the study.

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. Dunwoodie-Shore Road and Mott Haven-Rainey’s historic congestion diminishes in the future with the addition of the Caithness plant and the planned installation of the M29 Cable. Dunwoodie-Shore Road congestion declined substantially in 2007 when Neptune cable came into service. The top five 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 Congestion Over the Fifteen Years Aggregate

Element	Present Value of Congestion in $ mm		
	Historic	Future	Aggregate
LEEDS-PLEASANT VALLEY 345 KV	$ 2,063	$ 1,307	$ 3,370
CENTRAL EAST	$ 2,442	$ 567	$ 3,009
WEST CENTRAL-OP	$ (120)	$ (230)	$ (350)
DUNWOODIE-SHORE ROAD 345 KV	$ 1,770	$ 59	$ 1,829
MOTT HAVEN-RAINEY 345 KV Q12	$ 341	$ 66	$ 407
ASTORIA W 138-HELLGATE5_138	$ 50	$ (78)	$ (28)

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 2007 through August 2009, and projected number of congested hours, from 2009 through 2018. Based on the projected values, the most congested constraint in terms of frequency is Dunwoodie-Shore Road, followed Athens Pleasant Valley, West Central, Central East, and Mott Haven Rainey respectively.

Table 5-7: Number of Congested Hours by Constraint

# of Congested Hours	Actual			CARIS Base Case Projected									
Constraint	2007	2008	2009	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CENTRAL EAST	3,189	5,182	3,351	1,001	1,643	1,392	1,527	1,099	1,020	1,115	1,188	1,326	1,249
ATHENS_PLTVLLEY	1,494	1,013	661	681	860	2,289	2,381	2,154	2,148	2,087	2,123	2,017	2,094
NY MTHAVN-RAINY	1,354	671	1,184	536	1,333	483	652	789	883	925	1,019	1,193	1,562
DUNWOODIE_SHORRD	245	25	1,064	2,797	3,484	2,527	2,366	2,224	2,171	2,014	2,048	2,074	2,129
WEST CENTRAL-OP	1,943	2,120	278	5	277	318	403	2,618	2,366	2,160	2,257	2,356	2,745

5.3. Selection of Three Studies

Selection of the three CARIS studies is a two-step process in which the top five 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 five ranked constraints is utilized to determine the three studies.

In the first step, the five congested elements with the highest present value ranking are utilized for further assessment under the CARIS process, as explained in the previous step 5.2. In the second step, this assessment is accomplished in multiple iterations to include additional elements that appear as limiting when each of the top five congested elements are relaxed. The assessed element groupings are then ranked based upon the highest change in production cost. The three ranked groupings with the largest change in production cost are selected as the three CARIS studies. The three CARIS studies, as shown in Table 5-8: include Leeds - Pleasant Valley, Central East, and West Central. The detailed discussion on the ranking process is presented in Appendix E.

Table 5-8: Top Three CARIS Studies (nominal $ in Millions)

Constraints	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
LEEDS-PLEASANT VALLEY 345 KV	35.12	68.87	229.8	245.05	219.98	217.07	214.79	227.77	235.75	292.82	1,987.01
CENTRAL EAST	26.84	92.59	79.9	102.69	66.98	62.32	74.66	97.01	125.63	117.9	846.51
WEST CENTRAL-OP	-0.02	-2.85	-3.3	-4.51	-52.62	-48.09	-46	-54.48	-63.6	-86.5	-361.97

The location of the top three congested groupings, along with their base present value congestion payment, is presented in Figure 5-2.

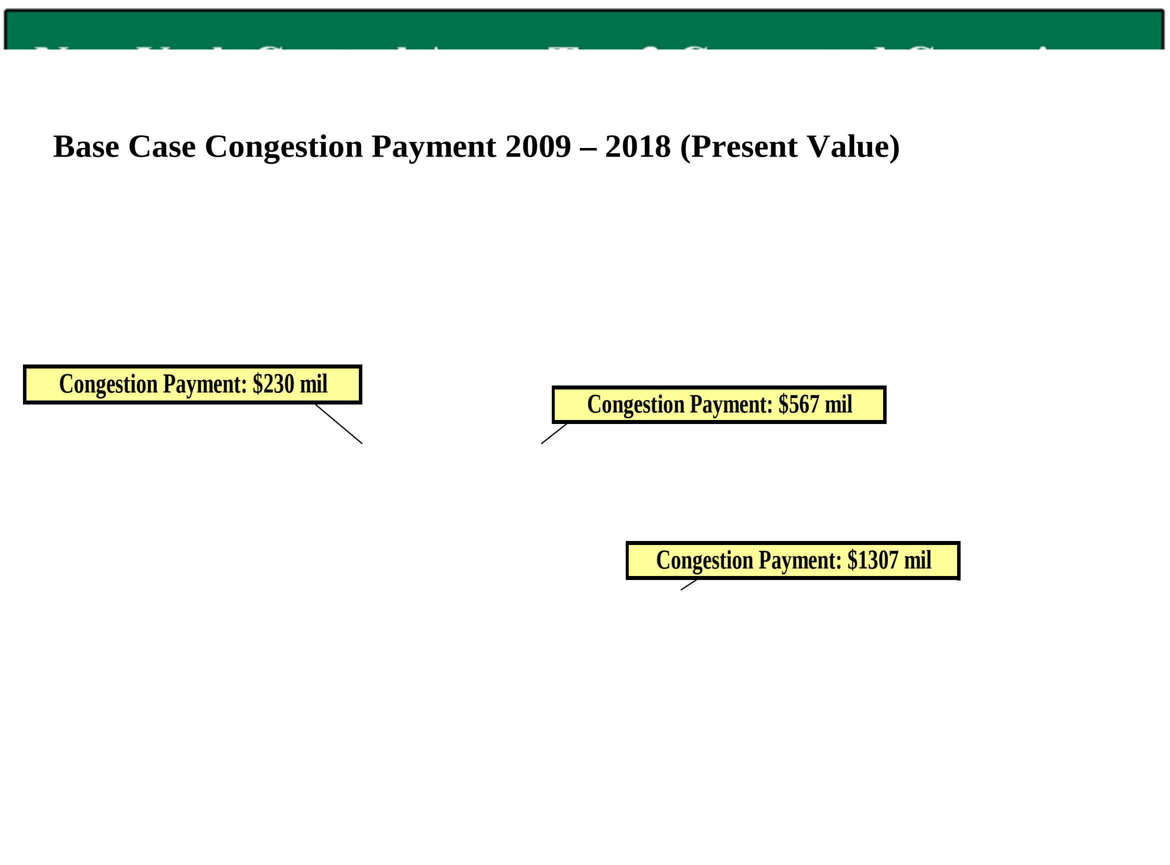

Figure 5-2: Base Case Congestion Payment of the Top 3 Congested Groupings

5.4. Potential Generic Solutions

The congestion of each of the three groupings being studied is mitigated by individually applying one of the generic resource types; transmission, generation 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. 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 proposed.
- Generic solutions are not assessed for impacts on system reliability.

In order to mitigate the congestion identified on the three groupings that comprise the three CARIS studies, all three types of potential generic solutions – transmission, generation, demand response - were applied to each congested groupings consistent with the methodology explained in Section 4 of this report. The results of the three potential generic solutions are to provide indicative information to interested parties. The following potential generic solutions were applied for each study:

Study #1 – Leeds - Pleasant Valley

The following generic solutions were applied for Leeds-Pleasant Valley Study:

- Transmission: A new 345 kV line from Leeds to Pleasant Valley- 39 Miles. The new line relieves the Pleasant Valley Leeds thermal limit and increases the UPNY-SENY voltage limit by approximately 1000 MW and Central East voltage limit by 50 MW.
- Generation: Install a new 500 MW Plant at Pleasant Valley
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

Table 5-9 shows the NYCA production cost savings from 2009 to 2018 for Leeds-Pleasant Valley study after potential generic solutions were applied.

Table 5-9: Leeds - Pleasant Valley: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Transmission	4.8	5.3	14.0	13.9	12.6	10.4	9.6	10.9	11.0	12.4
Generation-500	29.9	36.4	40.5	37.2	33.4	34.2	33.3	33.8	35.3	31.8
Demand Response	24.1	28.9	27.6	25.2	24.2	24.2	24.6	23.9	22.9	20.9

The new Leeds-Pleasant Valley 345 kV transmission solution relieves the congestion across existing Leeds-Pleasant Valley transmission lines and the UPNY SENY transmission interface. The total ten-year production cost savings of $162 million are dependent upon the spread between upstate and downstate fuel costs. Relieving the congestion on the Leeds-Pleasant Valley lines increases the congestion on the other two study groups: Central East and West Central.

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, 90 Miles. The new line relieves the Central East thermal limit and increases the Central East voltage limit by 500 MW.
- Generation: A new 500 MW Plant at New Scotland
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone F (200 MW is less than 10% of Zone F's peak load)

Table 5-10 shows the NYCA production cost savings from 2009 to 2018 for Central East study after potential generic solutions were applied.

Table 5-10: Central East: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission	1.8	6.1	2.8	2.0	2.5	1.4	2.7	2.6	2.9	1.7
Generation	21.0	25.2	25.7	18.8	17.5	23.8	23.0	21.6	24.9	22.4
Demand Response	22.0	26.6	26.2	19.1	22.0	21.4	20.9	21.4	19.4	16.9

The addition of the Edic-New Scotland relieves the Central East congestion but does not have significant impact on production cost because of the Leeds-Pleasant Valley congestion which bottles generation in upstate New York.

Study #3 - West Central

The following generic solutions were applied for the West Central study and the results are shown in Table 5-11:

- Transmission: A new 345 kV line from Niagara to Pannell to Clay- 149 Miles.

  The West Central transmission constraint is due to the West Central voltage limit for the loss of Ginna generator. Initial voltage analysis was performed with the addition of a Pannell Rd-Clay 345 kV transmission line but the transmission line did not result in any improvement in the voltage performance. Recognizing the voltage performance may be more a function of local system problems and that West Central is tightly coupled with the Dysinger East transmission interface, a new circuit from Niagara to Clay was inserted and the voltage limit improved by over 500 MW. This was chosen to stay within the procedures for the development of generic solutions, although it is recognized that other non-bulk power system solutions may exist as well.

- Generation: Install a new 500 MW Plant at Clay
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone C (200 MW is less than 10% of Zone C's peak load)

Table 5-11 shows the NYCA production cost savings from 2009 to 2018 for West Central study after potential generic solutions were applied.

Table 5-11: West Central: NYCA Production Cost Savings (Present Value $ in Millions)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Transmission	8.0	7.9	8.1	7.7	11.4	10.0	11.2	11.2	8.3	8.2
Generation-500	9.5	12.5	16.1	13.4	12.6	15.5	16.7	16.0	20.0	19.0
Demand Response	19.6	25.1	25.1	18.4	21.5	22.3	21.7	22.7	20.2	20.1

The addition of Niagara-Rochester–Pannell-Clay 345 kV transmission line relieves the West central congestion. The production cost savings increase with time as the fuel prices increase and there is sufficient generation in Ontario and West New York to transfer to the rest of New York.

The summation of production cost savings, from 2009 to 2018, of the three generic solutions for each congestion grouping, is shown in Figure 5-3. The greatest production cost savings for each congestion grouping has resulted from the generic generation solutions. It is worth noting that the energy efficiency generic solutions resulted in the second highest production cost savings for each grouping.

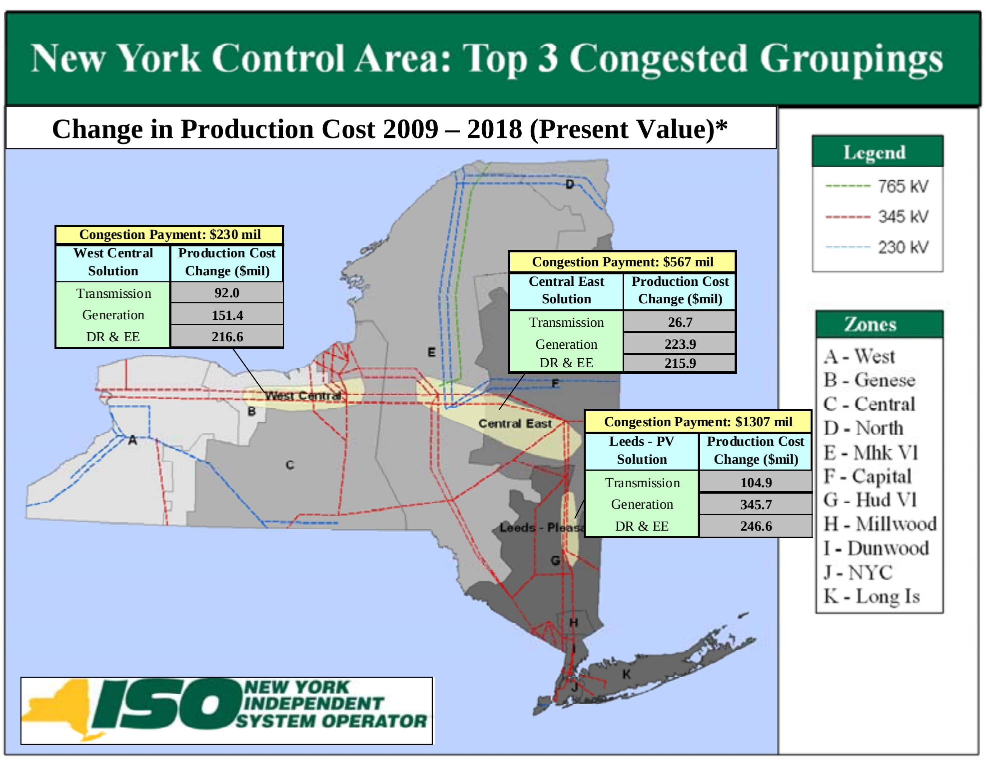

Figure 5-3: Production Cost Savings 2009-2018

5.5. Benefit/Cost Analysis

The NYISO conducted benefit/cost analysis for each of the three studies comprising the CARIS: Central East, Leeds - Pleasant Valley, and West Central.

5.5.1. Cost Analysis

Table 5-12 includes the total order of magnitude cost estimate for each potential generic solution based on the unit pricing included in Appendix C. The detailed cost breakdown for each solution is included in Appendix E.

Table 5-12: Potential Generic Solution Costs for Each Study Table

Potential Generic Solution Cost Summary ($M)

Congested Groups	**Central East**	**Leads - Pleasant Valley**	**West Central**
Transmission			
Substation Terminals	Edic to New Scotalnd	Leeds to Pleasant Valley	Niagara to Pannell to Clay
Miles	90	39	149
High	$477	$222	$790
Mid	$333	$155	$552
Low	$189	$87	$313

Generation			
Substation Terminal	New Scotland	Pleasant Valley	Clay
# of 250MW Blocks	2	2	2
High	$831	$911	$831
Mid	$681	$751	$681
Low	$531	$591	$531

Demand Response			
Zone	F	G	C
# of Blocks	1	1	1
High	$580	$580	$580
Mid	$390	$390	$390
Low	$190	$190	$190

5.5.2. Primary Metric Results

The primary metric used to conduct benefit/cost analysis for the three CARIS studies is the change in NYCA-wide production costs. Identified congestion on each of the three congested groupings was mitigated by applying three potential generic solutions, including transmission, generation, and demand response. As Table 5-13 below indicates that the highest savings in production costs would be achieved if Leeds - Pleasant Valley constraint is mitigated. By adding a new 500 MW generation, the production cost would be reduced by $345.7 million from 2009-2018. Further investigation revealed that the most efficient generation placed at the New Scotland 345 kV substation has increased the congestion over the Leeds-Pleasant Valley interface, thus most of the efficient energy produced by the generic generator flows into the ISO-NE area.

Table 5-13: NYCA Production Cost Generic Solutions Savings 2009-2018 (Present Value - $ in Millions)

	Central East	**Leeds to Pleasant Valley**	**West Central**
Transmission	**26.7**	**104.9**	**92.0**
Generation	**223.9**	**345.7**	**151.4**
Demand Response & EE	**215.9**	**246.6**	**216.6**

5.5.3. Benefit/Cost Ratios

Disclaimer associated with benefit to cost ratios

These benefit/cost ratios are used to give a relative indication of the project's economic merit. The costs used are overnight costs and were not translated in an annual revenue requirement. The annual revenue requirements are highly dependent on the assumed life of the project and many factors associated with the specific location and developer. For a specific project, the benefits would be dramatically different than those based on production cost savings: these could include generator payments as well as capacity payments.

Figure 5-4 shows the B/C ratios when a carrying charge of 16% is applied for illustrative purposes.

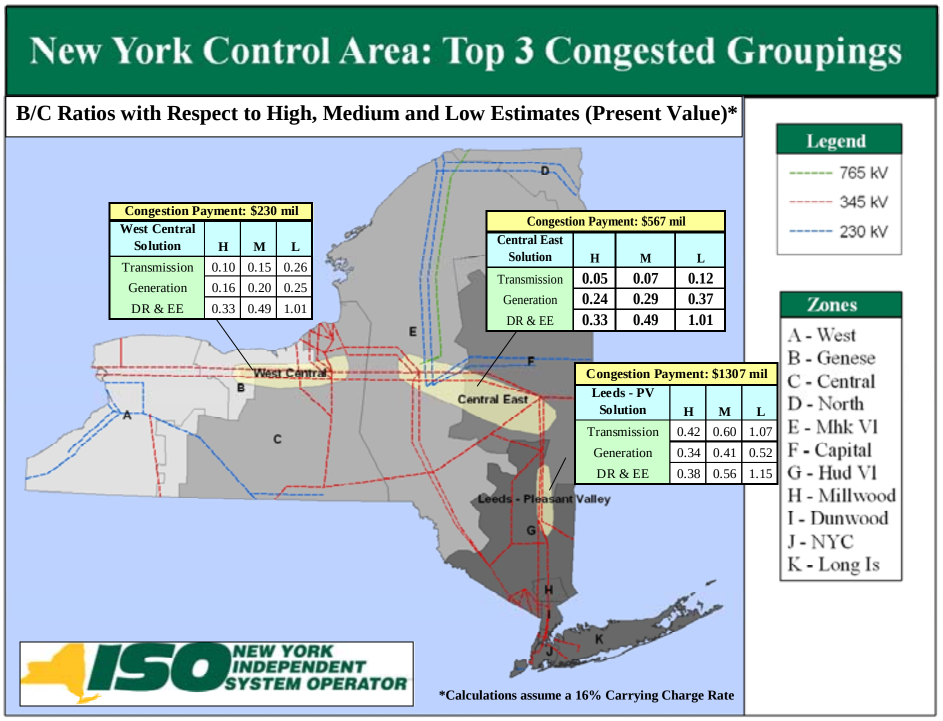

Figure 5-4: B/C Ratio (High, Medium, and Low Cost Estimate Ranges)

Plotted in Figures 5-5, 5-6 and 5-7 are the 10 year cumulative benefits from 2008 to 2018 for each of the three generic solutions. The Benefit-Cost ratios displayed are based on the cumulative present value of the benefits and an assumed 16% project carrying cost charge. The ratios of the cumulative benefits to an overnight cost, plus a 16% adder for a project carrying cost ("the total cost"), are also shown in the figures. For example, looking at the cumulative graph of the Central East generic generation solution in Figure 5-5, by 2018, 41% of the total cost would be recovered by production cost savings. There are additional benefits continuing beyond the ten-year planning horizon that are not included here.

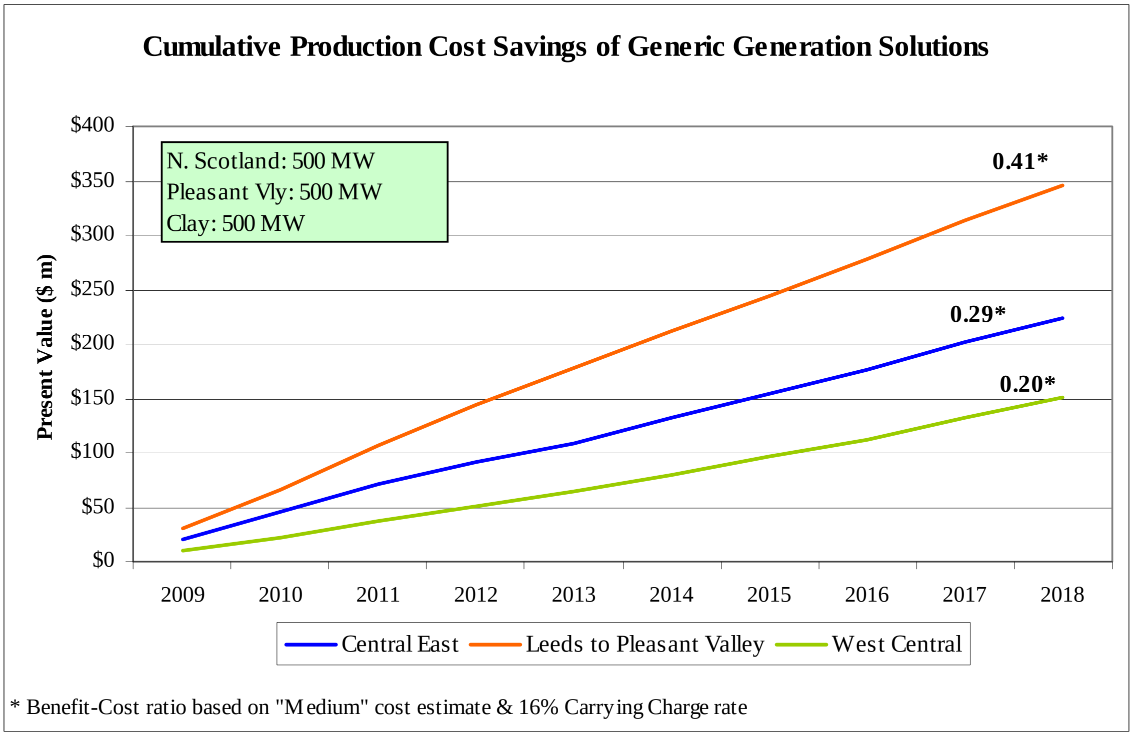

Figure 5-5: Cumulative Benefits of Generic Generation Solutions of Each Study (Present Value $ in Millions)

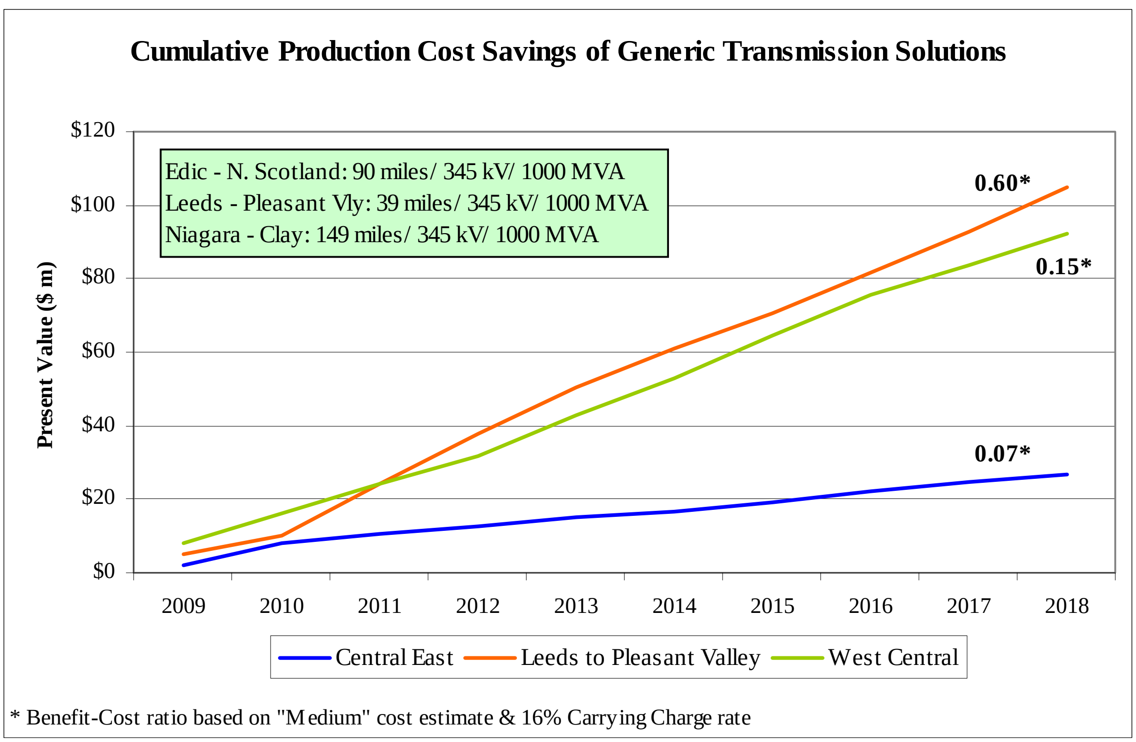

Figure 5-6: Cumulative Benefits of Generic Transmission Solutions of Each Study (Present Value $ in Millions)

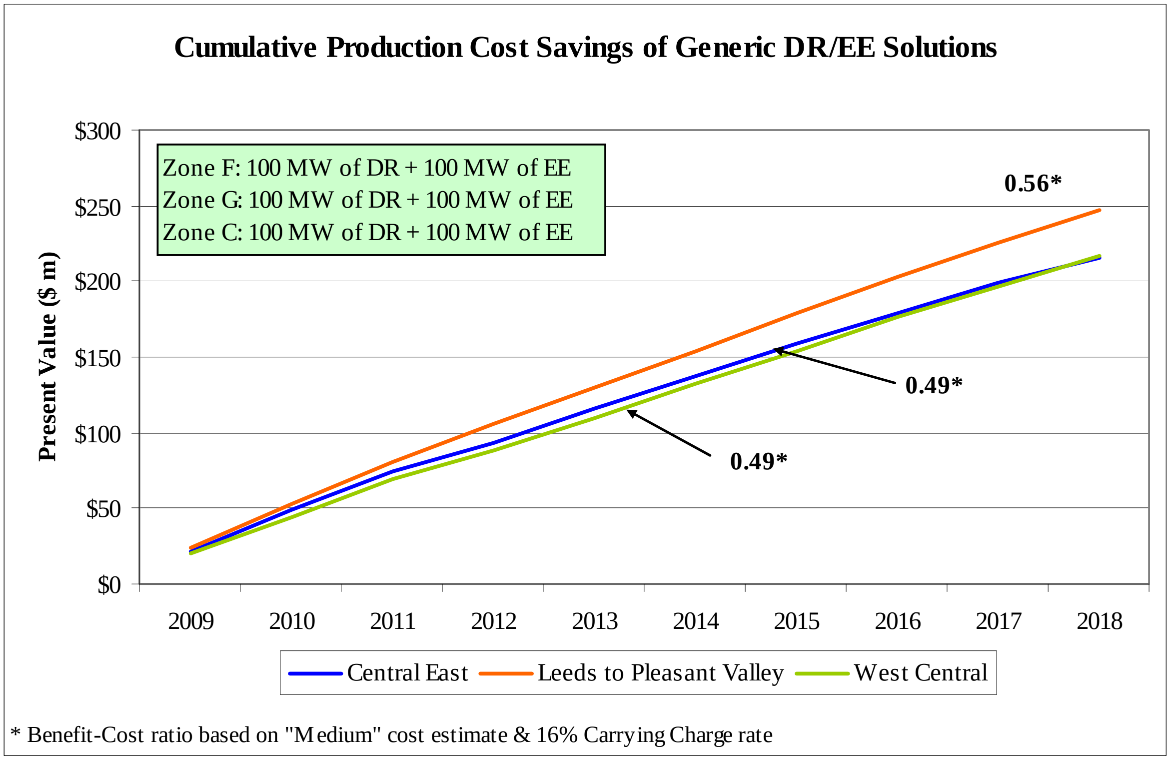

Figure 5-7: Cumulative Benefits of Generic Demand Response/Energy Efficiency Solutions of Each Study (Present Value $ in Millions)

5.5.4. Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Table 5-14 and Table 5-15 to show the change in: generator payments; LBMP-based load payments; TCC payments (congestion rents); marginal load payment losses; emission costs/tons; and ICAP MW impact after the potential generic solutions are applied. The values represent the difference between the applied potential generic solutions' values and the base case values for all the metrics except for the ICAP metric. Negative values imply a reduction in costs/tons. The ICAP numbers represent the amount of capacity that can be removed across NYCA and still meet the base LOLE requirement after the potential generic solutions are applied.

Table 5-14: Change in Generator Payments, Load Payments, TCC Payments, Losses and ICAP

Study	Solution	Generator Payments ($ m)	Load Payments ($ m)	Congestion Rents* ($ m)	Losses ($ m)	ICAP (MW)
	Transmission					
Central East	Edic - New Scotland	67	86	94	-798	0
Leeds - Pleasant Valley	Leeds - Pleasant Valley	306	-76	-738	-279	250
West Central	Niagara - Clay	-519	-358	176	76	0
	Generation					
Central East	New Scotland	-257	-479	276	101	255
Leeds - Pleasant Valley	Pleasant Valley	-52	-784	-326	-14	595
West Central	Clay	-389	-457	310	250	220
	Dd Response & Energy Eff.					
Central East	Zone F	-343	-442	21	-31	70
Leeds - Pleasant Valley	Zone G	-347	-478	-36	-73	225
West Central	Zone C	-352	-480	44	8	70

* Congestion Rents are calculated as Shadow Price times Flow across all constraints in the system.

Table 5-15: Change in CO_2, SO_2 and NO_X Emissions

		Emissions					
Study	Solution	CO2		SO2		NOx	
		'000s Tons	Cost ($m)	Tons	Cost ($m)	Tons	Cost ($m)
	Transmission						
Central East	Edic - New Scotland	77	0.4	178	3.0	203	0.1
Leeds - Pleasant Valley	Leeds - Pleasant Valley	-1,558	-8.0	-1,908	-0.1	-1,960	-0.7
West Central	Niagara - Clay	-1,255	-6.7	31	0.0	-396	0.0
	Generation						
Central East	New Scotland	-2,229	-11.1	-9,375	-0.4	-5,266	-3.1
Leeds - Pleasant Valley	Pleasant Valley	361	2.2	-9,693	-0.4	-7,413	-3.9
West Central	Clay	999	5.4	-6,445	-0.3	-4,758	-2.7
	Dd Response & Energy Eff.						
Central East	Zone F	-1,565	-7.7	-1,370	0.0	-959	-0.5
Leeds - Pleasant Valley	Zone G	-1,942	-9.5	-1,715	-0.1	-1,333	-0.7
West Central	Zone C	-1,535	-7.5	-1,324	0.0	-992	-0.6

Figures 5-8 and 5-9 below depict the projected base case LBMP in 2009 and 2018 respectively. The average LBMP in 2009 is $45, ranging from $41 in West zone to $48 in NYC and Long Island zones. In 2018, an average projected LBMP is $76, ranging from $64 in West zone to $84 in NYC and Long Island zones.

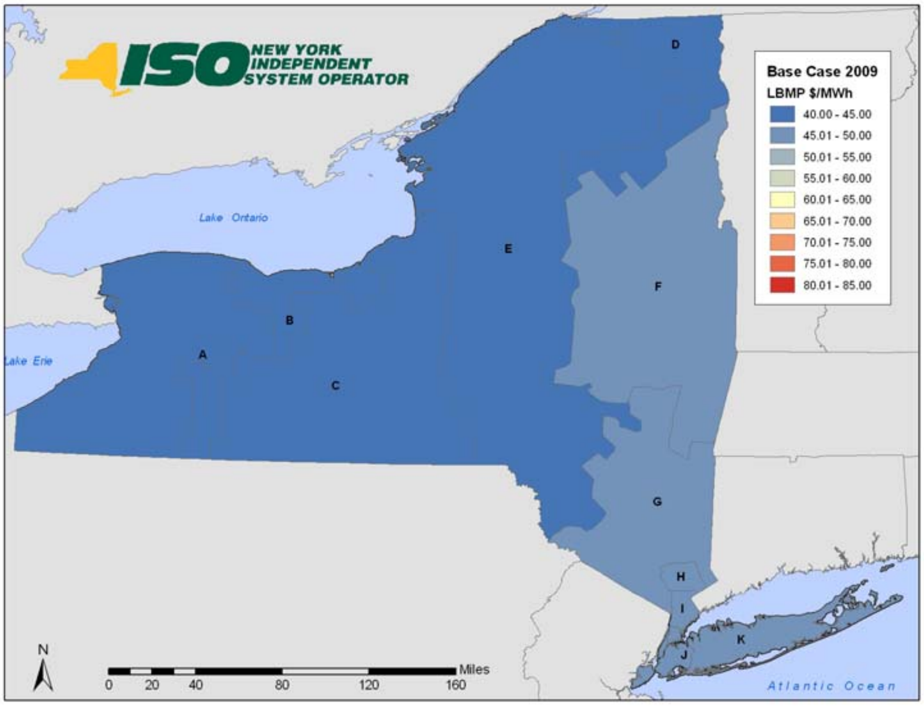

Figure 5-8: 2009 Base Case LBMP/MWh

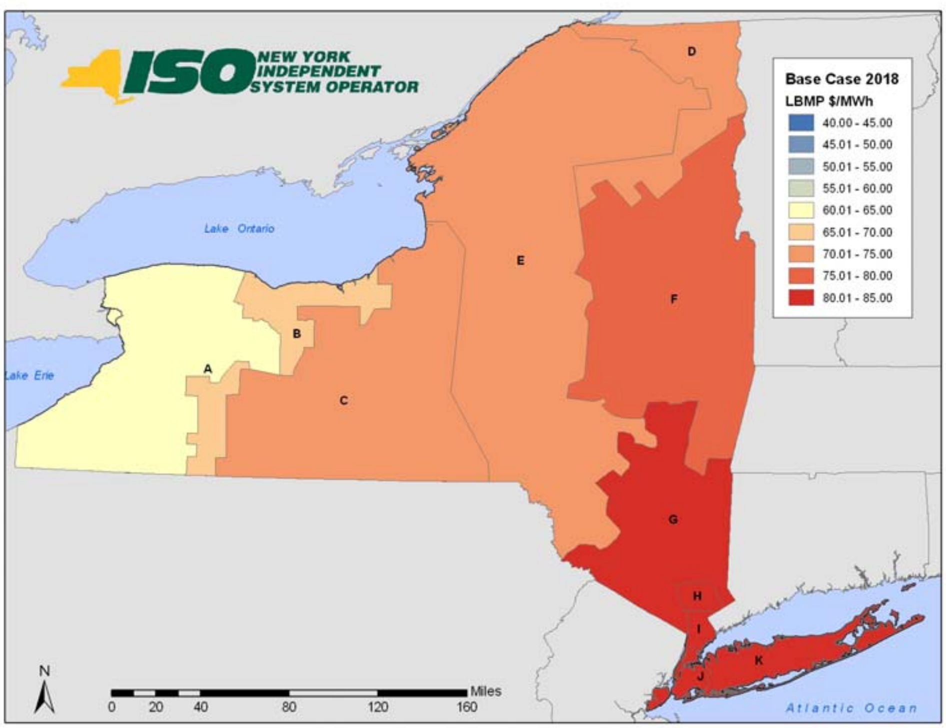

Figure 5-9: 2018 Base Case LBMP/MWh

5.6. Scenario and Sensitivity Analysis

Scenario/sensitivity analysis is performed to explore the impact of uncertainties associated with significant drivers or variables to the base case. Since this is an economic study and not a reliability analysis these scenarios should particularly explore factors that impact the magnitude of congestion across constrained elements. Therefore, the assumptions modeled within these scenarios may not necessarily apply the same criteria as a reliability planning approach.

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario and sensitivity analyses are methods of identifying the relative impact of pertinent variables on the cost of congestion. The CARIS Scenario studies were presented to ESPWG and modified based upon the input received and the availability of NYISO resources. The focus of these studies was to examine the impact of proposed State policies, fuel price and load forecast uncertainties, costs of emissions, and impacts of various new resources. The objective of the scenario study is to determine change in the costs of congestion on the top three congested paths within in NYCA, resulting from assumptions that differ from the base case. The simulations were conducted for the mid period year 2013, and 2018.

5.6.1. Variables for Consideration

Load Growth

The impact of a higher forecast of load growth was evaluated by using the high load forecast prepared for the 2009 RNA... The impact of a low load growth forecast utilized the full "15 X 15" forecast from the 2009 RNA. The updated load forecasts for the 2009 RNA was developed from the 2008 Load and Capacity Data "Gold Book".

Fuel Price Uncertainty

The impact of a higher and lower fuel price forecast was also evaluated. The fuel forecasts utilized in CARIS employed historical price volatility to build a statistical profile around the expected prices that were used in the base case. The high fuel price forecast is one standard deviation above the expected price and the low fuel price forecast is on standard deviation below the expected price. The updated fuel price forecast used the same methodology as the base fuel price forecast applied to slightly more current market data.

New Resources

New resources usually impact the cost of congestion and can raise or lower it. New resources can come from the market, the planning process, government initiatives, as well as other sources. New York State is currently proposing an expanded Renewable Portfolio Standard. This proposal will require New York to obtain 30% of its electricity from certain types of new renewable resources by 2015. The study assumed that incremental renewable energy requirements of this proposed standard would be satisfied through the use of wind energy. The contemporaneous work of the NYISO on its wind study provided the location, project size, and production profiles examined in this study. In 2013, 5,100 GWH of additional renewable energy will be required. The requirement rises to 7,100 GWH in 2015 and is then capped.

The NYISO update scenario also includes the build out at the Astoria Energy facility to the limit of its existing Interconnection Agreement. Some additional wind generation facilities have been added since the work done for the 2009 RNA. These include Wethersfield, High Sheldon, and Canandaigua.

New resources can have a significant impact on the cost of congestion in New York. Scenarios were constructed to examine the impacts on the cost of congestion when additions are located at or near a border location or in congested areas. One scenario examined the impact of connecting a 500 MW natural gas combined cycle plant to the 345 kV system at the position currently occupied by the Poletti Station. Two other analyses were conducted for a similar facility located on Staten Island, the southern end of the NYCA system and for Massena at the NYCA's northern boarder, respectively. The dispatch cost for these facilities was set at 95% of its running cost to simulate the effects of the new, economically attractive source of energy.

Environmental Mandates and Retirements

The 2009 RNA examined the potential impact of several developing environmental regulations. The first was the implementation of the Regional Greenhouse Gas Initiative, (RGGI) which limits the total CO2 emissions from power plants across a ten state region. The 2009 RNA scenario analysis concluded that under some combinations of fuel prices and CO2 Allowance prices that some coal fired power plants would be more likely to retire. The CARIS analysis continues to treat coal fired power plants with capacity factors below 50% as likely candidates for retirement. In the State Policy Case this retirement criteria was applied.

New York State is in the process of revising NOx emission regulations for fossil fired power plants. The 2009 RNA examined the impact of these regulations on reliability. The State Policy Case uses the same capacity limitations on the High Emitting Combustion Turbines.

Emission Costs

Emissions of SO2, NOx, and CO2, all 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 proprietary forecasts and market prices from the Chicago Climate Futures Exchange. To examine the sensitivity of congestion costs to variations in the prices of these allowances, the forecast prices of SO2 and NOx were doubled. The price of CO2 allowances was established at $25/ton in 2013 and forecasted to escalate at CPI plus 5% as prescribed HR 2454 and the Kerry-Boxer Senate proposal.

Energy Efficiency

Energy efficiency and demand response act to reduce the cost of congestion when they are installed downstream of a transmission constraint. EE and DR reduce congestion by reducing peak load and altering the load profile. EE and DR are examined as generic solutions in the studies of each of the three congested interfaces. EE and DR act to alter the load forecast and have been factored into the base case. The working assumption for the base case was that the identified funding will achieve approximately one third of the load reduction necessary to achieve the "15 x15" goal. A low load forecast has been developed to examine the impact of the "15 x 15" goal on the cost of congestion.

5.6.2. Scenarios

Table 5-16 summarizes the scenarios studied in the CARIS Phase 1 report. More specific description on each scenario is presented as follows.

Case #1 – State Policy

The purpose of this case is to examine the aggregated impact of new and likely to emerge State and Federal policies on the cost of congestion. In his January 7, 2009 State of the State Address, Governor Paterson announced a "45 x 15" initiative that sets targets for the State to meet 45 percent of its electricity needs through improved energy efficiency and renewable energy by 2015. The Draft State Energy Plan released on August 10, 2009 provides that the energy efficiency portion of that Governor's initiative is 15 of the total 45 percent. (This is also known as the "15 x 15" Energy Efficiency Portfolio Standard recently implemented by the Public Service Commission's June 23, 2008 "Order Establishing Energy Efficiency Portfolio Standard and Approving Programs" (Case 07-M-0548).) While the Public Service Commission has yet to directly address the renewable portion of the "45 x 15" initiative, this scenario assumes that the State's current Renewable Portfolio Standard (RPS) (Case 03-E-0188) will be expanded to meet 30 percent of the retail electricity use with renewable energy generation by 2015.

This case uses the low load growth forecast which is the equivalent of the full 15 x 15 from the 2009 RNA. Fuel prices will be the same as the base case. New wind resources beyond those in the 2009 RNA will be added with a simulated additional 5,100 GWh annually in 2013. These new wind resources selected based on their respective positions in the Interconnection Queue. Similarly, 7,100 GWh annually beyond the 2009 RNA will be simulated for 2017. To simulate the effects of unit retirements, the model will be run in an iterative manner to identify coal fired generators which experience a drop in production to levels below a 50% capacity factor. These units will be removed and the models rerun. SO2 and NOx allowance prices will be doubled from the base case to simulate continuing evolution of the reductions required through the CAIR program on Ozone SIP calls. CO2 prices will start at $25/ton in 2013 and increase consistent with the prescribed requirements of the proposed legislation. The impact of OTC NOxRACT limitations will be simulated through the use of capacity limits on High Emitting Combustion Turbines as examined in the 2009 RNA.

Case #2 - NYISO Update

This case will examine the impact of updated load and fuel price forecasts as well as the addition of several units that now would meet the criteria for consideration in the RNA. All other variables are the same as in the base case.

Case #3 - High Growth

This scenario will examine the impact on the cost of congest that results from a higher load growth forecast. To the extent that additional generation is required to maintain an acceptable LOLE, then peaker units will be added at existing facilities to meet the requirement. All other inputs are as they are in the base case.

Case #4 - High Fuel Price

This case will examine the impact of higher fuel prices on the cost of congestion. All other inputs are as they are in the base case.

Case #5 - High Growth and High Fuel Price

This scenario will examine the impact of the combined changes from Cases #4 and #5. All other inputs are as they are in the base case.

Case #6 - Low Fuel Price

This case will examine the impact of lower fuel prices on the cost of congestion. All other inputs are as they are in the base case.

Case #7 - New Resources on the HQ Interface

This analysis will include two new generic 500 MW combined cycle plants that inject energy at Massena. The plants will dispatch at 95% of running cost to simulate the maximum impact on congestion. The transmission system, together with other inputs is as it is in the base case.

Case # 8 - Modified Policy

This case will be designed to similar to Case # 1, however, the low load growth, and low fuel prices will be utilized. All other inputs remain the same as in the base case.

Case #9 - New Astoria Generator on 345 kV

This scenario examined the impact on the cost of congestion of locating a new generic 500 MW natural gas combined cycle plant connected to the 345 kV system at the position currently occupied by the Poletti Station. The plant will dispatch at 95% of running cost to simulate the maximum impact on congestion. All other inputs are as they are in the base case.

Case # 10 - New Staten Island Generator

This scenario examined the impact on the cost of congestion of locating a new generic 500 MW natural gas combined cycle plant connected to the 345 kV system at Goethals. The plant will dispatch at 95% of running cost to simulate the maximum impact on congestion. All other inputs are as they are in the base case.

Table 5-16: Scenario Matrix

Variables → / Scenarios ↓	Load Forecast Uncertainty	Fuel Price Uncertainty	New Resources	Retirements	Emissions Data & Cost of Allowances	Environmental Mandates	Energy Efficiency Mandates
State Policy Case # 1	Low Load Growth	Base case	NYS RPS	Coal with less than 50% capacity factor	Double NOx&SO2 prices, CO2@ $25/ton	NOxRACT Capacity Limits on OTC HECTs	High DR/EE Full 15x15
NYISO Update Case #2	2009 Goldbook	New Fuel Price Forecast	Add 2009 RNA Update Plants	None	Base case	Base case	Base case
High Growth Case #3	High Load Growth	Base case	New Peakers to Maintain LOLE < 0.1	None	Base case	Base case	None
High Fuel Price Case #4	Base case	High Fuel Prices	None	None	Base case	Base case	Base case
High Growth and High Fuel Price Case #5	High Load Growth	High Fuel Prices	New Peakers to Maintain LOLE < 0.1	None	Base case	Base case	Base case
Low Fuel Price Case #6	Base case	Low Fuel Prices	None	None	Base case	Base case	Base case
New HQ Resource on the Border Case #7	Base case	Base case	500 MW CC @ Chateguay and 500 MW CC @ St. Lawrence Both Dispatch @ 95% of Cost	None	Base case	Base case	Base case
Modified State Policy Case # 8	Low Load Growth	Low Fuel Prices	NYS RPS	Coal with less than 50% capacity factor	Double NOx&SO2 prices, CO2@ $25/ton	NOxRACT Capacity Limits on OTC HECTs	High DR/EE Full 15x15
New Astoria Generator @ 345 kV Case #9	Base case	Base case	Generic 500 MW Generator @ Poletti Bus 345kv	None	Base case	Base case	Base case
New Staten Island Generator @ 345 kV Case #10	Base case	Base case	Generic 500 MW Generator @ Goethals	None	Base case	Base case	Base case

Table 5-17 represents the impact of each scenario on congestion and reports the change in congestion values between the scenario's congestion values and the base case congestion values. Negative numbers represent a reduction in congestion..

Table 5-17: Comparison of Base Case and Scenario Cases

	Change in Congestion - $ m					
	Central East		**Leeds - Plsnt. Valley**		**West Central**	
Scenario	2013	2018	2013	2018	2013	2018
1 – State Policy	21	149	(81)	(59)	(51)	(83)
2 - NYISO Update	151	177	94	29	(19)	(9)
3 - High Growth	(11)	(38)	18	49	3	9
4 - High Fuel Price	87	85	177	188	66	66
5 - High Growth and High Fuel Price	65	27	201	254	75	81
6 - Low Fuel Price	(5)	(26)	68	86	10	9
7 - New Resources on the HQ Interface	164	196	77	197	(28)	(36)
8 - Modified Policy	1	149	(38)	(59)	(50)	(83)
9 - New Astoria Generator on 345 kV	(2)	(4)	(46)	(50)	(2)	(2)
10 - New Staten Island Generator	(3)	(5)	(6)	(8)	(2)	(1)
Change is calculated as Solution minus Base						

6. 2009 CARIS Conclusions – Study Phase

To be added at a later date.

7. Next Steps

7.1. Phase 2 – Specific Transmission Project Phase

Upon the approval of the Phase 1 study results by the NYISO Board, the NYISO staff will start conducting Phase 2 - the Project Phase - of the CARIS process. Phase 2 deals with the specific project proposals seeking cost recovery submitted by the developers to mitigate congestion identified in Phase 1. Regulated economic transmission project proposals and accelerated regulated backstop solutions[19] to the congestion identified in Phase 1 will be considered by the NYISO in Phase 2. Nevertheless, any interested party can request an additional study of congestion on the NYCA bulk power system at any time. 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 if the NYISO is provided cost information by the study requestor.

Transmission projects seeking cost recovery will be further assessed by NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff[20]. To qualify, the total capital cost of the project must exceed $25 million, the benefits must exceed their cost measured over the first ten years from the proposed commercial operation date, and a super-majority (>.80%) of the weighted vote cast must be in favor of the project. Additional details on Phase 2 process can be found in Appendix F and Initial CARIS Manual.

7.2. Project Phase Schedule

Phase 2 of the CARIS process will start after the NYISO Board's approval of the Phase 1 study results, which is anticipated to occur in the beginning of 2010. Throughout the 2010, NYISO staff will be evaluating submitted regulated economic transmission proposals for benefit/cost analysis, and if a developer seeks cost recovery, determining beneficiaries. The results of these analyses will provide a basis for beneficiary voting on each proposed transmission project. Upon the completion of the 2011 CRP, the next CARIS cycle will start.

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[19] Regulated backstop solutions will qualify for the cost allocation and cost recovery only if the implementation of such regulated backstop solutions is accelerated solely to reduce congestion in earlier years of the study period.

[20] Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated return and therefore are not obligated to follow the requirements of Phase 2. The cost of a market-based project shall be the responsibility of the developer.

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 landmark 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 US 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)	An annual 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 annual process that evaluates resource adequacy and transmission system security of the state's bulk electricity grid over a 10-year period and evaluates solutions to meet those needs. The CRPP consists of two studies: the RNA, which identifies potential problems, and the

TERM	DEFINITION
	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	Transmission paths that are constrained, which may limit power transactions because of insufficient capability.
Congestion Rent	The opportunity costs of transmission Constraints on the NYS 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 by15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.

TERM	DEFINITION
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]
Grid View Software	An analytic tool for market simulation and asset performance evaluations.
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.

TERM	DEFINITION
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 Advisor	Person, persons or 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)	Zone K and Zone J
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.
MAPS Software	An analytic tool for market simulation and asset performance evaluations.
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

TERM	DEFINITION
	purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO's 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 10,775-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 Energy Planning Board (SEPB)	Established by New York's governor in April 2008 to create a state energy plan (SEP) that examines and lays out goals addressing all aspects of New York's energy use and conservation.
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	A graphical calculating device - a two-dimensional diagram designed to allow the approximate graphical computation of a function: it uses a coordinate system other than Cartesian coordinates. Like a slide rule, it is a graphical analog computation device; and, like the slide rule, its accuracy is limited by the precision with which physical markings can be drawn, reproduced, viewed, and aligned. Most nomograms are used in applications where an approximate answer is appropriate and useful. Otherwise, the nomogram may be used to check an answer obtained from an exact calculation method. [FROM WIKIPEDIA]
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.
NYISO Governance Process	A shared governance process by which representatives from stakeholder groups discuss debate and vote on issues directly affecting the NYISO's operations, reliability and markets. The three committees – Management, Operating and Business Issues – are supported by several subcommittees, which are made up of individuals from five major sectors of the marketplace: Transmission Owners, Generation Owners, Other Suppliers, End-Use Consumers, and Public Power and Environmental Parties.
Operating Reserves	Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. [SERVICES TARIFF TERM]
Phase Angle Regulator	Device that controls the flow of electric power in order to increase the

TERM	DEFINITION
(PAR)	efficiency of the transmission system.
Plan NYC	New York City goal, announced by Mayor Michael R. Bloomberg in 2007, of reducing its citywide carbon emissions by 30% below 2005 levels by 2030.
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.
Regional Transmission Operator (RTO)	An organization that is responsible for moving electricity over large interstate areas. They schedule the use of transmission lines; manage the interconnection of new generation and monitor the markets
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)	An annual report that evaluates resource adequacy and transmission system security over a 10-year planning horizon, and identifies future needs of the New York electric grid. It is the first step in the NYISO's CRPP.
Responsible Transmission Owner (Responsible TO)	The Transmission Owner or TOs designated by the NYISO, pursuant to the NYISO Planning Process, to prepare a proposal for a regulated solution to a Reliability Need or to proceed with a regulated solution to a Reliability Need. The Responsible TO will normally be the Transmission Owner in whose Transmission District the NYISO identifies a Reliability Need.
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.
Smart Grid	A combination of transmission/distribution and communications technologies that enables the routing of power in optimal ways to respond to a wide range of conditions
Special Case Resource	A NYISO Demand Response program designed to reduce power usage by

TERM	DEFINITION
(SCR)	businesses and large power users qualified to participate in the NYISO's ICAP market. Companies that sign up as SCRs are paid in advance for agreeing to cut power 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 Line Losses	Power consumed by the delivery system from electric current overcoming the resistance of the wires, transformers and other components of the power system that result in power being converted into heat.
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.
Wheels Through	Transmission Service, originating in another Control Area that is wheeled through the NYCA to another Control Area. [SERVICES TARIFF TERM]
Working Groups	Groups comprised of NYISO stakeholders, convened to address transmission system and market issues under the NYISO governance system.