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

Phase 1 - Study Phase Results

DRAFT REPORT

September 1, 2009

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Executive Summary

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1 Introduction

For the first time since its formation in 1999, the New York Independent System Operator (NYISO) is undertaking a process to analyze historic and future projected congestion on the New York Bulk Power System and the economics of relieving that congestion by adding transmission upgrades or by adding new electric resources to that system. This new economic planning process is entitled the Congestion Assessment and Resource Integration Study (CARIS). CARIS, which is described in detail in Section 2.1, builds off the NYISO existing Comprehensive Reliability Planning Process. Together with the Local Transmission Planning Process, (LTPP) these planning processes comprise the NYISO's Comprehensive System Planning Process (CSPP). Once the reliability planning phase of the CSPP is completed, the CARIS economic planning processes begin starting from a reliable system as described in the approved Comprehensive Reliability Plan. In essence, CARIS consists of two phases. In the first phase, the NYISO staff, in collaboration with its stakeholders and other interested parties, develops a ten year projection of congestion, identifies and ranks the most congested elements comprising the New York Bulk Power System, develops three studies of potential generic solutions to mitigate the identified congestion, performs a benefit/cost assessment of these solutions based on production cost savings, and provides additional information on other related congestion metrics. The results of this first phase are presented in a written report that is presented to the NYISO's Electric System Planning Working Group for review by stakeholders and all interested parties. The report is presented to the NYISO's Business Issues Committee for review within the NYISO's Governance process before being submitted to the NYISO Board of Directors for and approval.

This document is the first of its kind under CARIS. It presents the Phase 1 Study Results and serves the crucial function of providing objective factual information on the nature of congestion in New York that developers can use to decide whether to proceed with transmission upgrades or resource additions This report does not recommend specific transmission upgrades or resource additions. Developers can choose to invest and build projects on their own, based on the economics of those projects in the NYISO's markets. Developers may also propose transmission projects for cost recovery under the NYISO's tariff and proceed through the second phase of CARIS, which will be conducted by NYISO staff in 2010. For these projects, the NYISO will determine if they qualify as economic projects as defined by the NYISO tariff. Qualifying economic projects that elect to pursue cost recovery under the NYISO's CARIS provisions must be approved by at least 80 percent of the weighted vote of the LSEs that the NYISO identifies as beneficiaries of the transmission project. The New York Public Service Commission has jurisdiction to decide rate recovery of proposed economic non-transmission projects, such as generation and demand response, except for such projects that the New York Power Authority and Long Island Power authority propose for their own purposes. In sum, CARIS provides the data and the tools to help developers and policy makers decide whether and how to invest in projects to alleviate transmission congestion in New York.

This report presents the Phase 1 Study Results for the 2009 CARIS in the following manner. The Executive Summary sets forth the overall process and results of the three CARIS studies and scenarios and describes next steps. Chapter 1 introduces CARIS and provides a report roadmap. Chapter 2 describes how CARIS fits into the development of planning at the

NYISO over its first ten years of operation (2.1); explains the CARIS process in detail; (2.2), sets forth the stakeholder process for this first CARIS report (2.3); and describes the context of CARIS in relation to other planning process that are proceeding simultaneously in New York, in the northeastern United States and Canada, and in the Eastern Interconnection overall (2.4). Chapter 3 describes the models and sets forth the metrics CARIS uses to analyze the economic and other quantifiable benefits of relieving congestion in the New York Control Area (NYCA). Chapter 4 establishes the baseline system assumptions for the three CARIS studies and the methodology for analysis of system congestion, including: the impact of internal NYCA transactions and imports and exports; load and capacity forecasts; the transmission model; and the generation model. Chapter 5 provides the analysis and results of the three congestion studies, including: historic congestion; the selection of the most congested elements for the three studies and the results of those studies; describes generic transmission, generation and demand response solutions to the identified congestion; analyzes the benefit of alleviating the identified congestion compared to the costs of the generic solutions; and examines scenarios exploring the impact of variables such as alternative future load, fuel price and system resource retirements and additions. Chapter 6 describes the process for requesting additional studies. Chapter 7 summarizes the findings of the three CARIS studies and scenarios. Chapter 8 describes next steps in the project-specific phase of CARIS and sets forth a schedule for that process in 2010. Finally, the report provides a number of technical appendices, including a Glossary (Appendix A), the details of the CARIS process (Appendix B), detailed analysis data (Appendices C, D and E), a link to the CARIS Manual (Appendix F), and links to the 2009 Comprehensive Reliability Planning Process studies that CARIS is built upon (Appendix G).

2 Background

2.1 The Evolution of Planning at the NYISO

Since time of its formation in 1999, NYISO's has carried out two primary functions: (1) the operation of New York's bulk power system and (2) the administration of New York's competitive wholesale electricity markets. The restructuring of the electric industry from vertically-integrated transmission, generation and distribution companies operating on traditional cost of service regulation to wholesale markets was designed to incent private investment in generation, transmission and other resources and shift the risk of those investments away from ratepayers to investors operating in economically-efficient, transparent markets on a level playing field. Transmission planning, therefore, was restricted to conducting analyses for developers who sought to add transmission upgrades and additions under Section 19 and 32 of the NYISO's Open Access Transmission Tariff (OATT), which also allowed the New York Public Service Commission to request studies of transmission upgrades.

The NYISO, in collaboration with its stakeholders, developed a Comprehensive Reliability Planning Process (CRPP) in 2004 to identify the reliability needs of the bulk power system looking out ten years and seek market-based solutions to the indentified Reliability Needs. The CRPP is a long-range assessment of resource adequacy and transmission reliability over five-year and ten-year planning horizons. It includes the development of a Reliability Needs Assessment ("RNA") and a Comprehensive Reliability Plan ("CRP"). For each Reliability Need identified in the RNA, the NYISO seeks market-based solutions -- which may include generation, transmission, or demand response resources. At the same time the NYISO identifies the Responsible Transmission Owner(s) to plan and, if necessary, to implement a regulated backstop solution if no viable market-based solutions are developed in time to satisfy the Reliability Needs. Once it receives the market-based and regulated backstop solutions, the NYISO assesses these solutions and reports in the CRP whether the projects submitted will meet the identified Reliability Needs. The costs incurred by the Responsible Transmission Owners for the regulated backstop solutions are recoverable under the NYISO's tariff. The principal objective of the CRPP is to maintain reliability by incenting investment in new, market-based projects. The NYISO has now completed four annual cycles of CRPP. Most recently, the stakeholders developed and the Board of Directors approved the 2009 Comprehensive Reliability Plan that identifies no reliability needs through 2018 if system conditions do not change, and analyzed risks that could give rise to reliability needs before that time. The 2009 CRP forms the foundation for this first CARIS study..

In Order 890, FERC expanded the planning responsibilities of the NYISO and the New York TOs, setting forth nine principles that all planning processes are required to meet. In compliance, the NYISO and the TOs jointly filed in December 2007filed tariff changes creating a three-stage Comprehensive System Planning Process ("CSPP") over a two-year cycle. First, the New York Transmission Owners (TOs) conduct a Local Transmission Planning Process (LTPP) for each individual transmission system and provide the inputs and results to interested parties at the NYISO for review and comments. Second, the LTPP provides input into the CRPP, which remains largely unchanged from the process begun in 2005. Third, the NYISO conducts the CARIS first to study the benefits and costs of relieving congestion on the New York bulk power system to allow power to flow more freely from generators to customers over the grid, and second to facilitate solutions to that congestion from private developers or, in the event of supermajority approval of project beneficiaries, cost recovery of transmission solutions through the NYISO's tariff.

The joint NYISO/TO compliance filing was conditionally approved by FERC on October 18, 2008. The NYISO and the TOs have made three subsequent compliance filings, and final approval of the CSPP remains pending at FERC. Nevertheless, based on FERC's conditional approval and expectation that transmission planning proceeds forthwith, the NYISO and the TOs commenced its implementation of CARIS with interested parties based upon the 2009 CRP.

2.2 CARIS Process

Upon the approval and issuance of the CRP on May 19, 2009, the NYISO commenced an economic planning study process, known as CARIS.[1] The objectives of the CARIS economic planning process are to:

a. Project congestion on the New York State bulk power transmission facilities BPTFs over the ten-year planning period;
b. Identify, through the development of appropriate scenarios, factors that might mitigate or increase congestion;
c. Provide information to market participants and interested stakeholders regarding projects to reduce congestion;

[1] The CARIS is contained in Sections 11, 12, 13 and 15 of Attachment Y of the NYISO's Open Access Transmission Tariff.

d. Provide an opportunity for the development of transmission solutions to reduce the congestion;
e. Provide a process for the evaluation and approval of regulated economic transmission projects in order to obtain cost recovery under the NYISO Tariff; and
f. Coordinate the NYISO's congestion assessments and economic planning process with neighboring Control Areas.

The CARIS builds upon and aligns with the comprehensive reliability planning process and will assume a baseline reliable system for the ten-year study period in the 2009 CRP, which is 2009 to 2018. The diagram below presents a graphical depiction of the CARIS process.

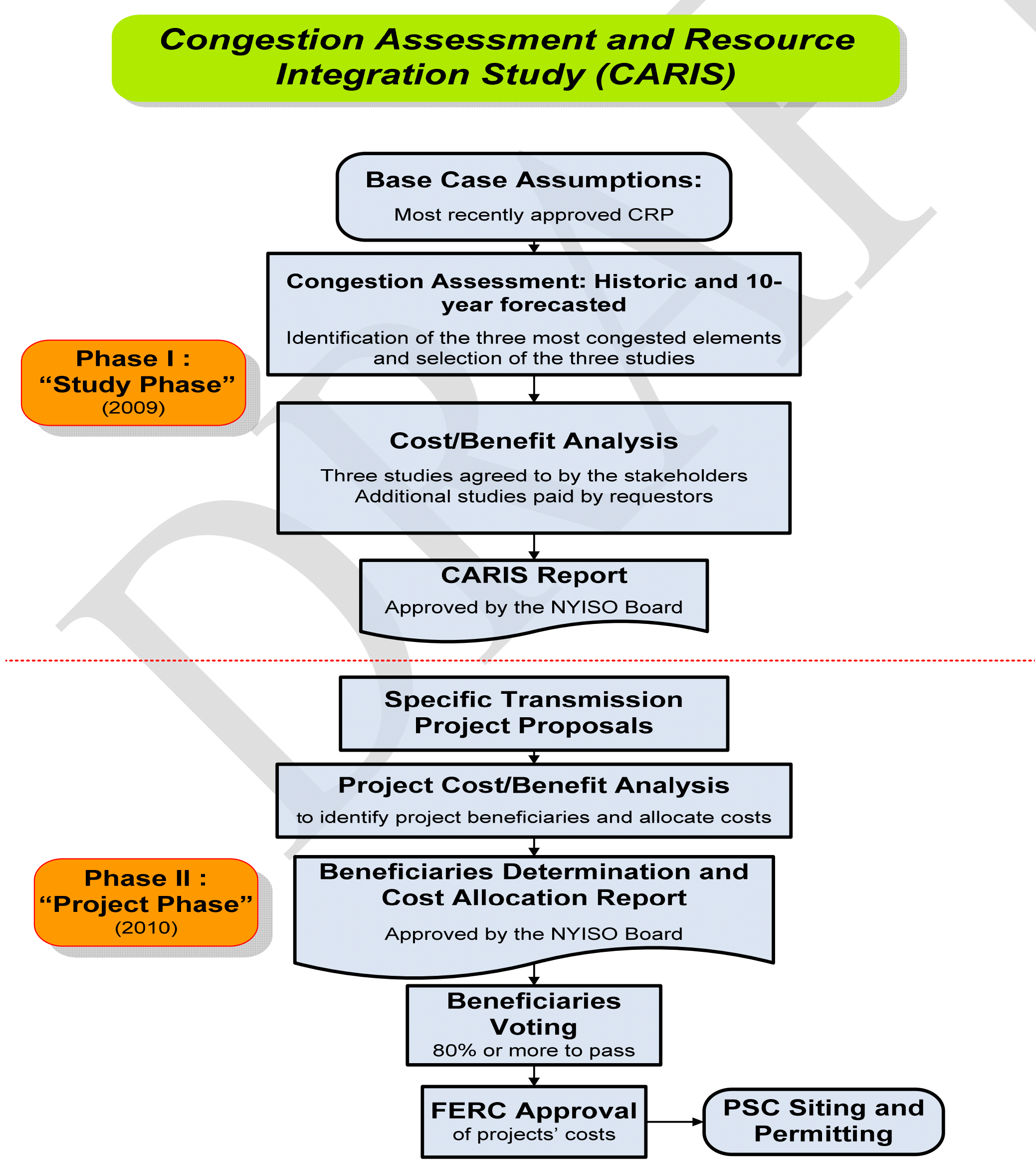

Figure 2-1-Overall CARIS process diagram

2.2.1 Phase 1 CARIS Study Process

The first phase of CARIS identifies three congestion studies developed with market participants' input. The three studies analyze congestion on the three most congested paths in the New York Bulk Power Transmission System. The studies provide historical analysis, as well as forward-looking estimates, of relevant cost metrics, including the primary metric of production cost savings of alleviating congestion on the New York State Bulk Power Transmission System over the ten-year study period. The CARIS report also performs scenario analysis based on stakeholder input, with consideration given to load forecast uncertainty, new resources, retirements, emissions changes, environmental and energy efficiency programs.

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 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 Manual for CARIS.

Each of the three studies NYISO conducts also contains a cost/benefit analysis of potential solutions. All resource types, including generation, transmission and demand response will be considered on a comparable basis as potential solutions to congestion. The solutions analyzed are not specific projects, but the addition of generic transmission, demand response and/or generation resources in key locations on the system to measure their effects on relieving transmission congestion. As more fully described in Section 3, the principal metric for measuring proposed solution benefits is the present value of ten years of production cost reductions across the New York Control Area that would result from each potential solution. The NYISO also reports data on additional metrics, including estimates of reductions in losses, location-based marginal prices for energy, installed capacity costs, ancillary services costs, emissions costs and payments for Transmission Congestion Contracts (TCCs). The CARIS report contains a discussion of its assumptions, inputs, methodology and analytical results. The Phase 1 report provides interested parties with a wide range of information to assist them in identifying and developing actual solutions to transmission congestion.

Upon completion of the analysis, the draft CARIS report is submitted to the Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) for review and comment. Following completion of that review, the draft CARIS report is send to the Business Issues Committee (BIC) and the Management Committee (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 his 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.

2.2.2 Phase 2 for Specific Projects

In the second phase of CARIS, conducted after the approval of this report, developers of potential transmission projects to alleviate congestion with an estimated capital cost in excess of $25M may seek regulated cost recovery through the NYISO's tariff. Such developers submit their projects to the NYISO for analysis of benefits and costs in accordance with beneficiaries pay cost allocation principles and methodologies. Projects are eligible for cost recovery if they would produce net savings based upon NYCA-wide product cost savings.

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 year from the proposed commercial operation of the project. Beneficiaries will be those Load Serving Entities (LSE) 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 Load Serving Entities' relative Location Based Marginal Price (LBMP) savings. Both production cost savings and LBMP load savings will be measured and compared on a net 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. The NYISO will also analyze and present additional information, 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 operating, other environmental effects, and integration of renewable resources. Although these data may influence how a benefitting LSE votes on a project, they will not be used for purposes of cost allocation.

The NYISO will calculate cost/benefit determination for particular projects and provide its cost/benefit analysis and beneficiary determination to the ESPWG for comment. Following that review, the NYISO cost/benefit analysis will be forward to the BIC and to the MC for discussion and action. After the MC vote, the costs/benefit determination will be forward to the Board of Directors for review and approval. The beneficiary determination is provided to the BIC and the MC for review and comment, but not approval. Thereafter the beneficiary determination is forwarded to the Board of Directors for review and approval.

After the project cost/benefit and beneficiary determinations are approved by the Board of Directors and posted on the NYISO's website, the project will be brought to the BIC for a vote on whether the project is approved for cost allocation. The specific provisions for cost allocation are set forth in the tariff, which 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.

2.3 2009 CARIS Collaborative Process

As a threshold matter, it is important to note that any interested party is encouraged to participate in the CARIS process. Such parties need not be Market Participants or stakeholders to fully engage in discussions on CARIS, and regulatory agencies and policy makers are welcome.

The NYISO began preparing 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. Additional staff and consulting resources were put in place in anticipation of the increased workload.

During the final stages of the 2009 CRP process, the NYISO worked with the TOs and all interested parties at the ESPWG to establish the procedures for implementing CARIS called for in the tariff. To date, NYISO has drafted and obtained approval of the BIC for all of the procedures for completing the Phase 1 CARIS Report. These procedures are set forth in the Initial Manual for CARIS that is posted under Planning on the NYISO website at the following link: http://www.nyiso.com/public/webdocs/services/planning/initial_caris_manual_bic_approved/CARISmanual.pdf. They include processes for: (i) selecting the three CARIS studies (Section 1.1.1); (ii) requesting and conducting additional studies (Section 1.1.2); (iii) including and scaling back Market-Based Solutions to obtain a baseline reliable system for the CARIS base case (Section 1.1.3); (iv) additional metrics for CARIS studies (Sect. 1.1.4); and establishing generic transmission, generation and demand response solutions for comparison with congestion relief benefits (Section 1.1.5). Work is underway to complete procedures for the project-specific phase of CARIS.

The NYISO began presenting its modeling assumptions, transmission models, baseline model and initial CARIS results in early 2009
http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf
. The NYISO presented a partial first draft of the CARIS report in August 2009. CARIS report drafts and scenario analyses were presented to joint meetings of ESPWG and TPAS on September 4 and 29, and October ___ 2009 (Subject to Confirmation). A complete draft of the CARIS report was presented to the BIC for review and action on October 21, 2009 (Subject to Confirmation). At the same time, the NYISO forwarded the draft CARIS report to David Patton of Potomac Economics as the NYISO's Independent Market Advisor and to the NYISO Board Members for their initial comments. After incorporating inputs from the interest parties at the ESPWG, TPAS, David Patton and the Board Members, the NYISO forwarded the draft CARIS report to the BIC for review and action. The BIC ??????_. Thereafter, the NYISO forwarded the CARIS report with the input of the BIC for review and action at the October 28, 2009 meeting of the MC (Subject to Confirmation). The MC ????. Subsequent to MC approval, the NYISO forwarded the draft CARIS to the Board of Directors for review and approval.

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. Implementing this initiative, the U.S. Department of Energy (DOE) has made funding available for interconnection-wide planning. The EIPC will take an interconnection-wide view of reliability and economic transmission expansion opportunities. 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. The EIPC will seek to avail itself of DOE grant funding for this endeavor. The NYISO has also sought to take advantage of DOE funding for Smart Grid projects by applying with the New York TOs for funding for reliability enhancements such as Phasor Measurement Units and capacitor installations.

Regionally, the NYISO continue to participate in the Northeast Coordinated System Planning Protocol (NCSPP). The NYISO, ISO New England and 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 release a Northeast Coordinated System Plan 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 the Plan's bulk power system assessment. The SEPB release a draft State Energy Plan in August 2009, and the NYISO will submit further input during the 60-day public comment period. Following the completion of State Energy Plan this fall, the Public Service Commission is expected to springboard off of the Plan by commencing Phase 3 of its Energy Resource Planning (ERP) proceeding. 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 New York TOs 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 state 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 as part of Plan NYC. The Board 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 long-term study of City energy needs and policy initiatives that will affect NYISO's planning processes.

3 CARIS Methodology

One of the first steps in developing the methodology for conducting CARIS was to choose a production cost simulation tool to forecast congestion. NYISO, in conjunction with the ESPWG, chose to use a long term commercially available software package rather than using the same tool as used for the historic congestion analysis.

There were two production cost simulation tools utilized in the CARIS process; GridView and MAPS. GridView was developed by ABB and MAPS was developed by General Electric Company. Both production cot simulation tools are widely accepted in the industry and both give comparable results. So it was decided by the NYISO and ESPWG to utilize both simulation tools for the first cycle of the CARIS process. The tool used for historic congestion analysis is PROBE, developed by PowerGEM LLC These production cost simulation tools are described below

3.1 Model Overview (GridView, MAPS, Probe)

Production cost simulation software is the primary analytical tool utilized in the CARIS process. Production-cost-simulation tools seek to minimize the cost of dispatching a static fleet of generation assets to serve a deterministic forecast of (typically hourly) loads.[2] In general terms Production cost simulations calculate the hourly production cost of supply resources under security constrained transmission network and area market conditions.

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To estimate the cost of transmission congestion, analysis tools and protocols were developed by the NYISO. The fundamental idea is to calculate what the day-ahead hourly clearing prices would be if there were **no** transmission constraints, using the same data and calculation approach as the NYISO Security Constrained Unit Commitment software (SCUC). The congestion cost then is the difference between the actual SCUC transmission constrained LMP's, loads, and bids, and the same calculation with all transmission constraints ignored. Annual cost is the sum of daily costs.

The reported numbers are the result of a simulation of the NYCA market using the hourly bids and network status actually used by NYISO to clear the day-ahead market. The simulation

[2] Kahn 1955

performs a security constrained unit commitment for the market "as it was", then removes all transmission constraints (other constraints such as desired net interchange (DNI), generator ramp rates and minimum run times are still enforced). Unit commitment and dispatch are then recalculated for this unconstrained scenario with no changes in bids from those actually submitted. The constrained and unconstrained results are compared to derive the cost of congestion. All calculations represent all market segments (e.g., fixed load, virtual load and generation, imports and exports), and actual hour-by-hour network status. The unconstrained scenario fixes the amount of virtual load and generation at their original MW levels.

PROBE, developed by PowerGEM LLC, is the day-ahead market simulation tool which was utilized by the NYISO as an analysis tool to develop the historic congestion. The results of PROBE were used in the benchmarking process of GridView and MAPS. PROBE is described below.

GridView

GridView, developed by ABB, is a powerful market simulation and analysis software designed to deal with the most challenging issues facing planners and decision-makers in the electric energy industry today. It simulates security constrained unit commitment and security constrained economic dispatch in a large-scale transmission network. The transmission network can be easily synchronized between power flow cases and the GridView model. In addition, the GridView contains detailed generator models with detailed transmission constraints. With database management tools, it is powerful yet user's friendly software tool for integrated engineering, reliability and economic analysis of electric power grid. It derives many of its advantages from its comprehensive modeling of the physical and financial aspects of the energy market, a user-friendly, Windows–based graphical user interface, and state-of-the-art programming for faster simulation speed. Important features of GridView are listed as followings:

- Detailed representation of the large scale transmission network
- Detailed transmission constraints of interfaces, contingency, and nomograms
- Detailed generation model for thermal, hydro, pumped storage, wind, solar, etc.
- Model of conditional constraints, thermal unit operational limits and ramping rates
- Co-optimization of energy and ancillary services
- Dynamic hydro model for hydro-thermal coordination
- Post contingency analysis for any given hour dispatch
- Monte Carlo simulation for modeling forced outages of generators and transmission lines, load and fuel price forecast, wind forecast, etc.

The simulation program mimics the operation of electricity markets by performing security constrained unit commitment and economic dispatch. The simulation is usually run sequentially in chronological order for a few days to several years, depending on the application. The typical outputs include:

- Transmission line utilization levels – hourly loading, loading factors
- Generator utilization – dispatch, production cost, revenues, hours on marginal
- Location market clearing prices for energy and ancillary services
- Transmission bottlenecks – hours of congestion, economic benefits of upgrades

Multi Area Production Simulation Software program (MAPS)

MAPS software, developed by General Electric Company, integrates highly detailed representations of a system's load, generation, and transmission into a single simulation. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation.

Generation system data capabilities of MAPS include multi-step cost curves, unit cycling capabilities, emission characteristics, and market bids by unit loading block. The generation units, along with chronological hourly load profiles, are assigned to individual buses on the system.

The transmission system is modeled in terms of individual transmission lines, interfaces (which are groupings of lines), phase-angle regulators (PARs), and HVDC lines. Limits can be specified for the flow on the lines and interfaces and the operation of the PARs. MAPS software models voltage and stability considerations through operating nomograms that define how these limits can change hourly as a function of loads, generation, and flows elsewhere on the system.

Hourly load profiles are adjusted to meet peak and energy forecasts input to the model on a monthly or annual basis. Information on hourly loads at each bus in the system is required for MAPS to accurately calculate electrical flows on the transmission system. This is specified by assigning one, or a combination of several hourly load profiles to each load bus. In addition to studying all of the hours in the year, MAPS can be used to study all the days in the year on a bi-hourly basis, or a typical week per month on an hourly or bi-hourly basis. With these modeling options, MAPS simulates the loads in chronological order and does not sort them into load duration curves.

Based on this detailed representation of the entire system, MAPS performs a security-constrained dispatch of the generation by monitoring transmission system flows under both normal and contingency conditions.

Because of its detailed representation of generation and transmission systems, MAPS can be used to study a number of issues related to the deregulated utility market:

- The attributes of different proposed market structures and the development of pricing algorithms.
- The possibility of one or more market participant exerting market power.
- The value of a generation portfolio operating in a deregulated market.
- The location of transmission bottlenecks and associated congestion costs as well as transmission congestion contract (TCC) valuation.
- The impact on total system emissions that result from the addition of new generation.

PROBE (PoRtfolio Ownership and Bid Evaluation)

PROBE, developed by PowerGEM LLC, is a day-ahead market simulation software product that provides a simple and efficient study and decision support tool for LMP-based electricity markets. PROBE has unique abilities to simulate the day-ahead and real time LMP-based market clearance, utilizing a full transmission model and conventional N-1 contingency analysis.

In contrast to other Planning-type software products, PROBE is designed to reproduce the day-ahead market clearing calculation as closely as possible. To accomplish this, PROBE is customized to model each ISO's market rules, including rules regarding co-optimization of energy and ancillary services, mitigation, marginal losses, and other custom market rules. PROBE uses actual submitted generator parameters and bids for each market day, including energy, start-up, and ancillary services bids for generators, import/export bids, virtual bids, and fixed and price-capped demand bids. This modeling, along with the use of each day's network model, ensures relevance to the actual day-ahead market.

PROBE provides fast simulation using an LP-based Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC) engine. PROBE has capabilities to perform batch-mode simulation of consecutive days to provide longer-term studies on a monthly, quarterly, or yearly basis. PROBE's reporting capabilities combine market clearing data with TCC and financial information to get a comprehensive picture of market performance.

The key aspects of PROBE are:

- Modeling and results closely aligned with actual day-ahead markets due to extensive customization for various ISOs
- Use of actual market participant bids and generator parameters to ensure good results
- Ability to run Simulator through batch mode to perform studies over longer time periods
- Very fast simulation capabilities with SCUC and SCED; extensive simulator calculations
- Flexibility for a wide range of studies; used across many departments
- Simple data storage methodology

3.2 Modeling Validation

3.2.1 Database Verification

To help ensure that the CARIS analyses produced accurate results, the NYISO conducted a two-stage data and modeling verification process. This involved a review of all input data and many of the program parameters on two separate occasions, prior to the development of the base case analyses. The verification process was conducted by NYISO System and Resource Planning staff under the direction of a team leader who was not directly involved with the CARIS analysis.

The following topics were examined as part of data verification:

- forecasts of hourly load data for NYISO zones and external areas;
- hourly import and export schedules;

- transmission system losses;
- transmission interface transfer limits, contingencies & nomograms;
- generator incremental heat rates and emissions rates;
- modeling of combined cycle units;
- fuel price forecasts;
- modeling of pumped storage & hydro units; and
- geographical location of generators by size and type.

The verification process involved a direct comparison of data contained in the Gridview and MAPS models with the primary data sources from which those inputs were derived. Where modeling choices were made, as in the case of incremental heat rates and combined cycle units, the modeling method was compared to the desired approach.

In several cases, discrepancies were noted by the data verification team. A log of discrepancies was kept and after the first stage of data verification, the log was presented for review and discussion with the CARIS team. The CARIS team was then directed to remedy the discrepancies in data or modeling choices made. These changes were accomplished before the development of the base case scenarios.

Once the base case scenarios were developed, reviewed, and confirmed, the Gridview and MAPS input files used to generate those results were saved as reference cases from which all future scenarios were developed. This was done to ensure that all subsequent scenarios were all performed from the same set of standard conditions.

After the development of the base case scenarios, a second stage of data verification was performed, similar to the first. This was to confirm that no significant elements of the data inputs or modeling assumptions had been made subsequent to the development of the base case analyses.

3.2.2 Model Verification/Backcast

The objective of the back casting process was to see how the simulations using CARIS Database compared against past quarters so that we can feel confident about results coming out of our model.

- **Analysis** – We looked at transmission outages in 2009 and impact of those outages on major interfaces like Central East. We reduced the Central East limit to capture the impact of transmission outages and ran the simulation with Central East limit at 2400 and Ravenswood ST out of service for the 4 months.

The CARIS data base model simulations were benchmarked against 2009 First four months of publically available generation data EIA F923 and 2009 NYISO congestion numbers.

<u>Generation Comparison</u>

We looked at actual generation available from publically available sources of data. The table below summarizes the comparison of results of CARIS database to 2009 Jan- April. When we compare the NYC generation to actual generation the results are within 5 % of each other.

Jan - April 2009 Actual (1)						
Facility Name	FO2	RFO	KER	NG	WO	Grand Total
Arthur Kill Generating Station		0	0	215,920		215,920
Astoria Energy	28,380			982,634		1,011,014
Astoria Gas Turbines			4,387	7,748		12,135
Astoria Generating Station		136,792		330,972		467,764
Brooklyn Navy Yard Cogeneration	2,635			568,240		570,875
Charles Poletti		76,693		413,334		490,027
East River	0	39,563		775,794		815,357
Gowanus Gas Turbines Generating	4,435	0	0	955		5,390
Linden Cogen Plant	2,578			1,659,797	67,491	1,729,866
Narrows Gas Turbines Generating	16,701		0	7,469		24,170
Poletti 500MW CC	0		19,919	791,248		811,167
Ravenswood	0	39,757	11,041	735,385		786,183
	54,729	292,806	35,347	6,489,495	67,491	6,939,868
Jan - April 2009 Projected						
Plant Name	FO2	FO6	KER	NG		Grand Total
Arthur Kill Generating Station				432,487		432,487
Astoria Energy				952,019		952,019
Astoria Gas Turbines	677		0	16,751		17,428
Astoria Generating Station		0		1,800,823		1,800,823
Brooklyn Navy Yard Cogeneration				130,950		130,950
Charles Poletti		0		490,159		490,159
East River		0		155,027		155,027
Gowanus Gas Turbines Generating	6,432			189,780		196,212
Linden Cogen Plant				1,081,142		1,081,142
Narrows Gas Turbines Generating			0	96,700		96,700
Poletti 500MW CC				857,085		857,085
Ravenswood		0	0	1,192,269		1,192,269
Grand Total	7,109	0	0	7,395,193	0	7,402,302
(1) Source: EIA						

Congestion Comparison

The table below summaries
Compare 2009 Q1 Projection versus Probe results

	Probe	CARIS (CE 2400)
2009 Q1	194 MIL $	117 MIL $

- CARIS base case modeling results are reasonably close with PROBE once adjusted for CE limit
- CARIS base case modeling results would be further aligned with PROBE if all Transmission outages are considered (e.g. Laden-Buch and Buch-Millwood throughout March)

- Summary

- General overall agreement on total production and fuel mix (6% higher generation level supported by forecasts in fuel and load, Rav 3 active in model during back cast period, and Linden EIA reporting)
- Some specific plants show generation shifts (Sensitivity case better aligns unit generation levels except Linden due EIA reporting; unit results further aligned with Rav 3 out)
- Congestion will align better when we capture all transmission outages.

3.3 CARIS Metrics

In conducting the CARIS Study Phase, the NYISO performs an assessment of historic and projected future congestion identifies the top three congested elements, and conducts benefit/cost analysis of each type of generic potential solution – transmission, generation and demand response/energy efficiency -- to the congestion identified congested elements. This analysis applies benefit/cost metrics that were developed with NYISO stakeholders at the ESPWG. The principal benefit metric for the CARIS analysis is NYCA-wide production cost reduction that would result from each generic potential solution. Additional benefit metrics were analyzed and are presented as additional , for information only. These , shall 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 additional benefit metrics will be determined by measuring the difference between the CARIS base case system value and a system value when the potential generic solution is added. The discount rate to be used for the present value analysis shall be the current weighted average cost of capital for the NY Transmission owners. The definitions of the additional metrics are located in Appendix B1 and summarized below.

3.3.1 Principal Benefit Metric

Section 11.3.d of Attachment Y of the OATT provides that the principal benefit metric for the CARIS analysis will be expressed as the present value of the NYCA wide production cost reduction that would result from each potential solution.

3.3.2 Additional Benefit Metrics

Also taken from Section 11.3.d, the additional benefits, which are expressed for information only include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. 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.

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 includes 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. Thus, 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 IRM and LCR, both for the next capability period and future capability periods. Therefore, only for the first CARIS cycle, the NYISO will use the MW impact methodology described below. For the future CARIS cycles, the NYISO will develop a methodology to reflect potential changes in ICAP costs separate from this temporary approach set forth below. The temporary approach is not meant to set precedence for the more fully developed ICAP cost methodology applicable to future CARIS cycles.

The MW impact methodology:

1. Determine the base system LOLE for the horizon year (e.g. 2018 LOLE 0.02).

2. Add a potential generic solution to congestion identified.

3. Calculate the LOLE for the system with the potential generic solution added.

4. If the LOLE is lower that the base system, reduce generation in all NYCA zones proportionally regardless of type of generic solution until the base system LOLE is reached. The amount of reduced generation is reported as the NYCA MW impact.

Ancillary Services Costs - This metric measures the change in Ancillary Services costs, which include payments for Regulation Services and Operating Reserves, including 10 Minute Synchronous, 10 Minute Non-synchronous and 30 Minute Non-synchronous.

Emission Costs - This metric measures the change in the total cost of emission allowances for CO_2, NOx, and SO_2, emissions on a zonal basis. Total emission costs are a cost component of also the production cost curve that combines forecasted total emissions and forecasted allowance prices for the NYCA.

TCC Payments -

The TCC Payment metric set forth below will be used, pending FERC's approval of NYISO's May 19, 2009 FERC filing for purposes of Phase 1 of the CARIS process and will not be used in the Projects Phase for regulated economic transmission project cost allocation under Section 15.4. The TCC payment metric will measure the change in total congestion rents collected in the day-ahead market. Congestion rents shall be 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.

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 Attachment Y of the NYISO OATT the starting point for CARIS is the NYISO's current CRP. This 2009 CARIS begins with the Base Case input assumptions provided in the 2009 CRP. No changes have been made in these Base Case assumptions. The CARIS process aligns with the NYISO's 10-year reliability planning horizon for the 2009 CRP. The OATT requires that the CARIS process assume that the NYCA bulk power system meets the applicable reliability criteria for the entire ten-year planning horizon studied in the CRP. The 2009 CRP concluded that there were no reliability needs through 2018.

It is important to note that there are **no** changes in Base Case input assumptions from the 2009 CRP except for those prescribed in section 1.1.3 of the CARIS procedure manual; *Inclusion of Market-Based Solutions (MBS) and Reliability Backstop Solutions (RBS) in CARIS Base Case; Scaling Back MBS. This step resulted in no change in the system model.*

Appendix C lists all of the input data and the rationale for each. Below are descriptions of key data sources and assumptions. The data was developed based on the OATT and in collaboration with stakeholders. The study system and assumptions are based on the 2009 RNA/CRP

4.1 Power Flow Data Used in the CARIS Model

CARIS uses the network topology, system impedance and transmission line ratings that were developed from the 2009 CRP power flows. A brief summary of the power flow cases developed in the CRP from the 2008 FERC 715 filing base cases:

- Summer 2009 Peak Load
- Summer 2013 Peak Load
- Winter 2013/2014 Peak Load
- Summer 2018 Peak Load

For the intermediate years between 2010 to 2017, the power flow cases were based on data provided in the FERC 715 2013 Summer Peak Load case. PJM system changes modeled in PJM's 2012 RTEP Study and NYISO system changes described in the 2009 CRP Study required changes such as additional generators and transmission lines to these power flow cases to capture the sequencing of these additional resources. The FERC 715 2018 Summer Peak Load case and NYISO system changes described in the 2009 CRP Study were used to develop the 2018 power flow case. The winter transmission line ratings from the FERC 715 Winter 2013/2014 Peak Load case was used for all years assessed in the CARIS.

4.2 Load and Capacity Forecast

The load and capacity forecast used in the CARIS baseline system, provided in Table 4-1, was taken directly from the 2009 RNA. There were no changes made to the load forecast or the resource mix in the transition from the CRP to the CARIS.

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 EEPS and SCRs to reflect achievement of approximately 30% of the entire EEPS goal and increased SCR levels experienced in the market.

Table 4.1: RNA Study Case Load and Resource Table with Updated TO Plans[3]

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 CARIS Model

The CARIS analysis models the bulk power system throughout the entire Eastern Interconnection, which is defined roughly as the as the electric network in the US states and Canadian Provinces west of the Rocky Mountains, excluding Texas. A detailed representation of this network, with equivalents for the WECC and Texas is developed in the NERC Multi-area Modeling Working Group (MMWG) process. Figure 4-1 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 NYCA, ISONE, IESO, and PJM

[3] New York Control Area (NYCA) "Capacity" values include resources internal to New York, Additions, Reratings, Retirements, Purchases and Sales, and UDRs with firm capacity. Zone K "Capacity" values include UDRs with firm capacity. Wind generation values include full nameplate capacity.

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

(PJM Classic, AP, AEP, CE, DLCO, DAY and VP)) for both the network model and a production cost model. A proxy bus is used to model HQ to NYISO & ISONE. Transmission only models are represented for MECS, FE, SPP, MAR, NIPS, OVEC, TVA, FRCC, SERC, and equivalences for ERCOT, and 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.

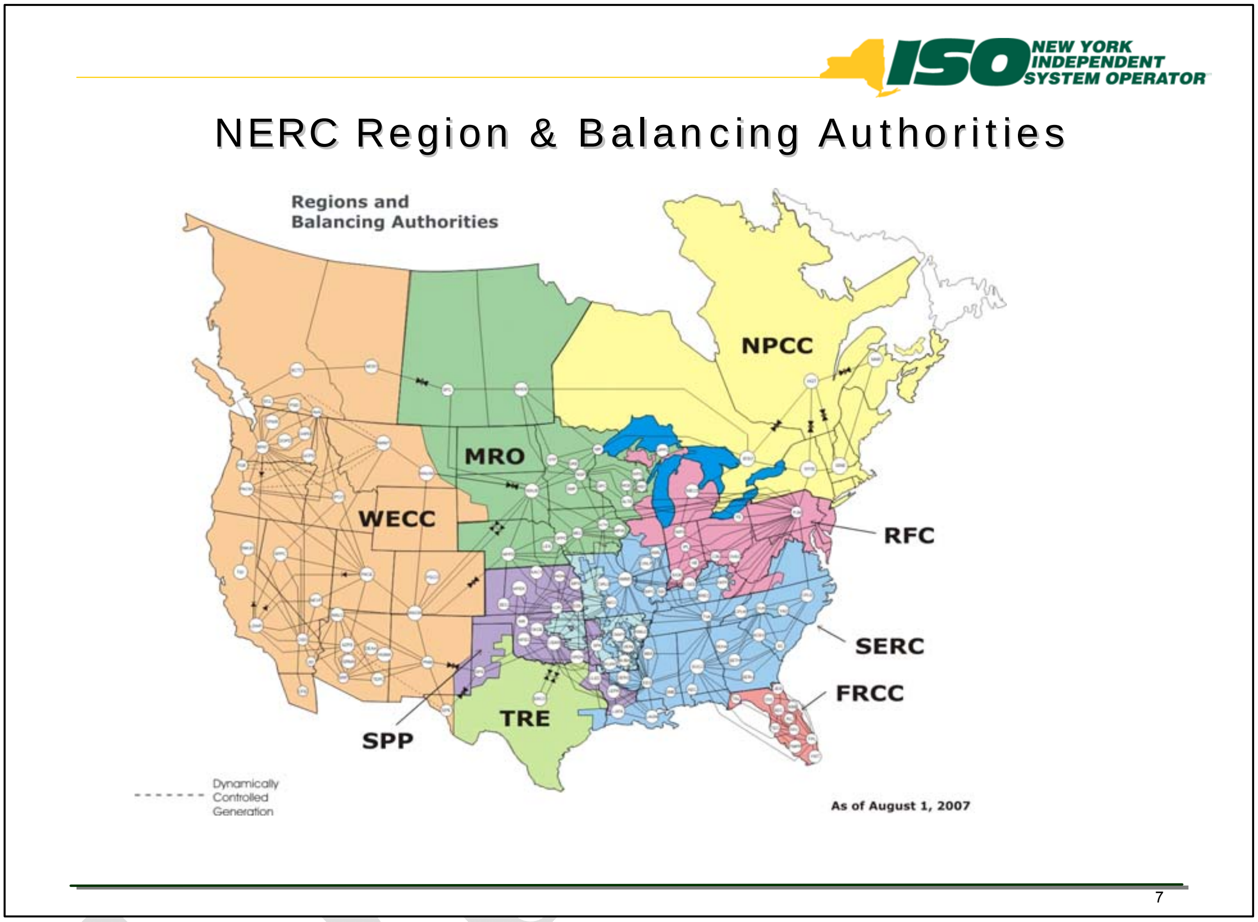

Figure 4-1: Represented Area Modeled in CARIS

4.3.1 New York Control Area Model

Figure 4-2 below displays the bulk power system for NYCA, which is generally facilities 230 kV and above, but does include certain 138 kV facilities and a very small number of 115 kV facilities. The balance of the facilities 138 kV and lower are considered non-bulk or sub-transmission facilities. The figure also displays key transmission interfaces for New York.

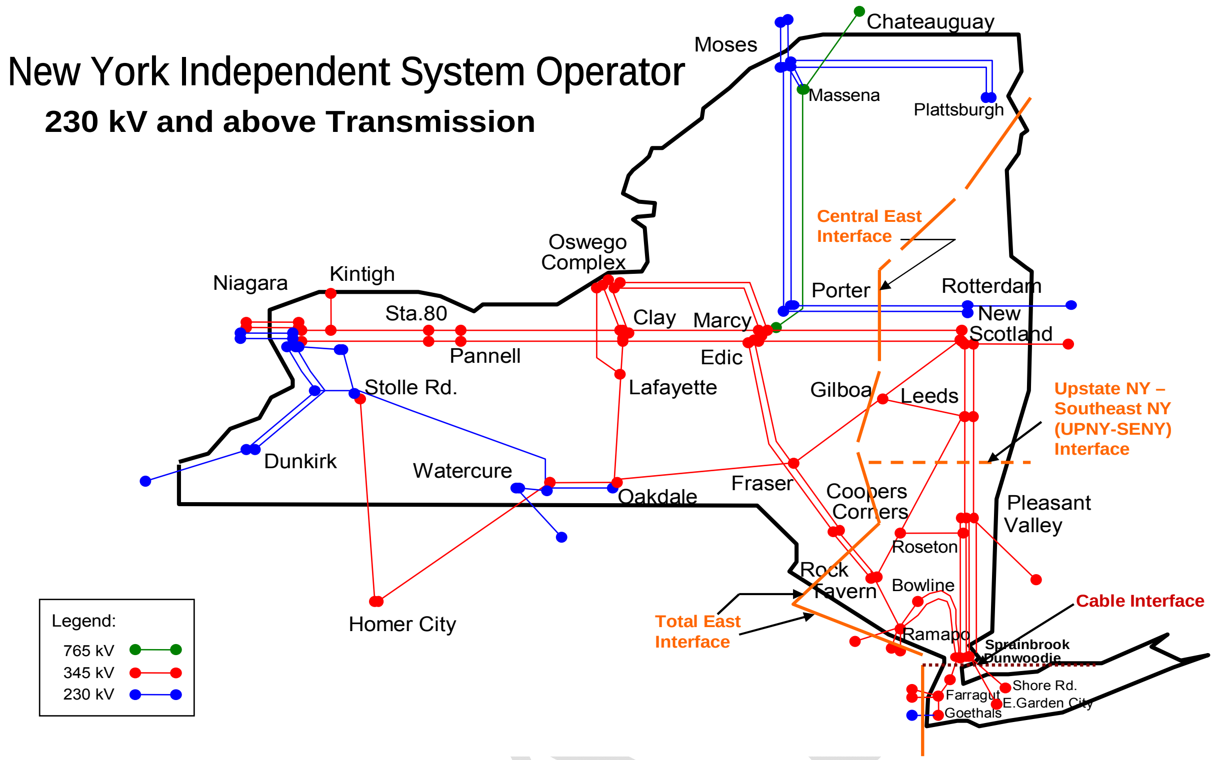

Figure 4-2: NYISO 230 kV and above Transmission Map

4.3.2 New York Control Area Upgrades

The highlights of year on year model changes are as follows:

a. Caithness Long Island – new 320MW, Combined Cycle, LIPA, Suffolk, NY, Commercial Operation - 4/2009;
b. BesiCorp – new 660MW, Combined Cycle, National Grid, Rensselear, NY, proposed Commercial Operation 2/2010;
c. Polleti - 890.7MW, retirement expected 2/2010;
d. M29 – 345kV transmission line from an existing station in Yonkers NY to a new substation in NYC, expected in-service date 2011

4.3.3 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 MARS 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 are indicated in Table 4-1 below.

Table 4-1 - Transmission System Base Case Normal Voltage Transfer Limits for Key Interfaces in MW

Interface	2009 CARIS Study				
	2009	**2010**	**2011**	**2012**	**2013**
WEST CENTRAL-OP	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	4000	4400	4400	4400
Dunwoodie (I) to Long Island	1217	1265	1265	1265	1265
Spr/Dunwoodie So.-OP	5315	5290	5365	5365	5365

Normal thermal interface transfer limits for the CARIS study are not directly utilized as the monitored element and contingencies, which set the limit, are employed. The CARIS constraint data consist of approximately 2000 monitored bulk power transmission elements, contingencies, and nomograms to model the transmission constraints limiting the economic dispatch of the system.

The CARIS thermal transfer limit data was initially developed by performing thermal transfer analysis using the PSS/E MUST application using the transmission planning set of normal criteria contingencies. MUST identifies the most limiting monitored line and contingency sets which has the most impact on NYCA Cross-State transmission interfaces. The planning models utilize a set of monitored lines and contingencies and were then compared with monitored lines and contingency sets used in the NYISO SCUC analysis. The resulting monitored lines and contingency sets used in the CARIS does not include lines which have less than a 5% impact on the NYCA Cross-State transmission interfaces or only impact local 115-138 kV transmission or subtransmission constraints. Table 4-2 lists the monitored lines and contingency set typically limiting the NYCA Cross-State transmission interfaces.

Table 4-2 - Transmission System Base Case Normal Thermal Transfer Limiting Element and Contingencies for Cross-State Transmission Interfaces

Limiting Element	Rating		Limiting Contingency	
Niagara – Rochester (NR2) 345kV	@LTE	1501 MW	L/O	AES/Somerset – Rochester (SR-1) 345kV
Stolle Rd – Meyer (67) 230kV	@NOR	430 MW	L/O	Pre-Contingency loading
Leeds – Pleasant Valley (92) 345kV	@LTE	1538 MW	L/O	Athens – Pleasant Valley (91) 345kV
Mott Haven - Rainey 345kV (Q11)	@SCUC	765 MW	L/O	Mott Haven - Rainey 345 kV (Q12)

Dunwoodie – Shore Rd. (Y50) 345kV	@NOR	653 MW*	L/O	Pre-contingency Loading
Fraser – Coopers Corners (33) 345kV	@LTE	1404 MW	L/O	Double-circuit Tower 31&41 Marcy – Coopers Corners (UCC2-41) 345kV Porter – Rotterdam (31) 230kV
Fraser – Coopers Corners (33) 345kV	@NOR	1207 MW		Pre-Contingency Loading

4.3.4 External Areas

The external areas immediately adjacent to directly around the NYCA are also modeled at full representation. These, except for Hydro Quebec. Those areas include ISONE, IESO, PJM (PJM Classic, AP, AEP, CE, DLCO, DAY and VP). Since HQ is asynchronously tied to the bulk system, proxy buses from HQ to NYISO and HQ to ISONE are modeled. External areas surrounding the above areas only model the transmission system to capture the impact of loopflows.

Table 4-3 illustrates the external transmission limits used in the CARIS Study.

Table 4-3 - External Area Transmission Transfer Limits

Area	Interface	2009	2010	2011	2012	2013	2014
IESO	IMO EXPORT	2500	2500	2500	2500	2500	2500
IESO	IMO-MISO	1	1	1	1	1	1
IESO	IMO-NYISO	2000	2000	2000	2000	2000	2000
ISONE	Boston	4900	4900	4900	4900	4900	4900
ISONE	Connecticut-Export	2200	2200	2200	2200	2200	3600
ISONE	East-West (NE-NY)	2100	2100	2100	2100	2100	2100
ISONE	ISO-NE EXPORT	4000	4000	4000	4000	4000	4000
ISONE	ISONE-NYISO	1400	1400	1400	1400	1400	1400
ISONE	LI – ISONE	450	450	450	450	450	450
ISONE	ME – NH	1400	1400	1400	1400	1400	1500
ISONE	NB – NEPOOL	500	500	500	500	500	500
ISONE	North – South	2700	2700	2700	2700	2700	2700
ISONE	Norwalk-Stamford	1300	1300	1300	1300	1300	1300
ISONE	Orrington South	1050	1050	1050	1050	1050	1050
ISONE	SEMA	1450	1450	1450	1450	1450	1450
ISONE	SEMA/RI	2200	2200	2200	2200	2200	2200
ISONE	South West CT	2350	2350	2350	2350	2350	3650
ISONE	Surowiec South	1150	1150	1150	1150	1150	1150
NYISO	NYISO-HQ	1050	1050	1050	1050	1050	1050
NYISO	NYISO-IESO	2500	2500	2500	2500	2500	2500
NYISO	NYISO-PJM	2500	2500	2500	2500	2500	2500
PJM	APSOUTH	3250	3250	3250	3250	3250	3250
PJM	Central Interface	5200	5200	5200	5200	5200	5200

PJM	Eastern Interface	7000	7000	7000	7000	7000	7000
PJM	PJM East – NYISO	2500	2500	2500	2500	2500	2500
PJM	PJM EXPORT	6000	6000	6000	6000	6000	6000
PJM	PJM West – NYISO	2000	2000	2000	2000	2000	2000
PJM	PJM_Extension Export	1500	1500	1500	1500	1500	1500
PJM	PJM_HomerCty	531	531	531	531	531	531
PJM	PJM-VAP	500	500	500	500	500	500
PJM	Western Interface	6250	6250	6250	6250	6250	6250

4.3.5 External Area Model Upgrades

There are two major transmission additions that were added to the base cases. The first was the TrAIL Line (which is located in PJM and is scheduled to go commercial in 2010; and the second is the Susquehanna-Roseland 500kV addition which is located in PJM and is scheduled to go commercial in 2013.

4.3.6 Loop Flows

The phenomenon of loop flow has been widely studied and its impact on transmission line loading is well documented and understood.

Neighboring transmission systems are usually tightly connected together, and this can cause loop flow, or unscheduled flows occurring on a neighboring system. These unscheduled flows can have a component resulting when one system is transferring power across its own system and a second component resulting from transactions between systems.

A second component of loop flow is caused by electric transactions that are scheduled from one specific location to another without regard to the actual flow of energy. Loop flow results from the effect of those unscheduled flows.

The first type of loop flow was captured in the CARIS databases simply by expanding the simulations to include the hourly dispatch of generation and load in the NYISO and its neighboring control areas RFC, ISONE, Ontario Hydro and Hydro Quebec (HQ modeled as Proxy bus). Expanding the simulation to include the NYISO neighboring markets allows for more accurate flow calculations on NYISO transmission lines by taking into account the impact of the neighboring systems' load and generation on NYISO transmission lines. This approach is also consistent with the NYISO's DAM (SCUC) methodology.

The second component of loop flow, which is caused by unscheduled flows, was modeled in the CARIS databases by setting nomograms to certain levels on the Lake Erie clockwise/counterclockwise flows.

4.3.7 Hurdle Rates and Interchange Models

Hurdle rates set the conditions in which economy interchange can be transacted between neighboring market/control areas. It represents a minimum savings level that needs to be achieved before energy will flow areas across the interchange. Hurdle rates often serve two purposes. First, they are sometimes used when a base case is being prepared to help calibrate the production-cost simulation so that it replicates a historical pattern of generation dispatch. Second, they may be used to find a different (and usually lower-cost) combination of generation resources to meet loads aggregated from the base case.

Two hurdle rates are used in the CARIS base case, one for the commitment and a separate one for the dispatch. The commitment hurdle rate sets the level that a unit commitment change will be made and dispatch hurdle rate sets a level that will allow economic dispatch to be changed to allow scheduled energy to flow between market areas. Hurdle rates are held constant throughout the future year simulations.

Hurdle Rates on several closed and open interfaces were used to model regional power imports, exports and wheel through transactions, Table 4-4. These hurdle rates are acceptable practice in conducting multi-pool production cost simulations and they are used to represent several phenomena such as complex market pricing at the boundary busses, cost mark-ups and market inefficiency. The Hurdle Rates values in the CARIS databases are also consistent with previous NYISO and consultant studies. In addition, the annual NYISO imports are consistent with historic import levels.

Table 4-4 - Hurdle Rates utilized in the CARIS simulations

Interface	**Unit Commitment - $/MWH**		**Economic Dispatch - $/MWH**	
	Imports	**Exports**	**Imports**	**Exports**
NYISO AC	1000	1000	6	6
ISONE AC	1000	1000	8	3
PJM AC	1000	1000	8	8
Ontario Hydro	1000	1000	6	6
Lake Erie Loop Flow	1000	1000		
…				

While no firm power transactions were specifically modeled, the NYISO DC tie-lines (Neptune and CSC) were excluded from the interfaces and therefore flows on those facilities were not subject to hurdle rates. It should be noted that the flow on the CSC line was allowed to reverse direction (i.e. flow toward ISONE) but the Neptune flows was restricted to 660 MW into Long Island and reverse flow toward PJM was not allowed to occur in the simulation. Exclusion of the DC tie-lines from the interfaces was necessary to capture their historic scheduled flows (*e.g.*, 90% loading factor on Neptune) and thus how they are expected to be operated in the future.

4.4 Production Cost Model

Production costing models require input data to develop cost curves for the resources that the model will commit and dispatch to serve the load subject to the constraints given the model. This section will discuss how the "production cost data" for these resources were identified and quantified. The model simulations are driven by incremental cost of production of generators. The incremental cost of generation is product of the incremental heat rate times the sum of fuel cost, emissions cost, and variable operation and maintenance expenses. Section 4.4.1 reviews how heat rate information was developed for the NYCA generation fleet. Section 4.4.2 reviews the development of emission allowance forecasts. Section 4.4.3 reviews the development of the fuel forecast.

4.4.1 Heat Rates

Fuel costs represent the largest incremental expense for fossil fueled generating units. Fuel costs are the product of fuel prices and incremental heat rates. Thus it is critically important to the quality of the results of CARIS that individual generating unit heat rates used in the simulations be an accurate representation of reality. Individual unit heat rates are important competitive information and thus are not widely available from generator owners. Both of the simulation models have databases that represent the model providers' best estimates of heat rates. When the heat rates from the two models were compared it was apparent that significant differences existed.

In order to gain additional insight as to which, if either, dataset was an accurate representation of actual unit performance, publicly available information reporting heat input was matched with net generator production from NYISO market data to calculate hourly heat rates for 2008. One vendor has substituted a dataset for which the NYISO did not have a direct license agreement thus removing that data set from further consideration. Unit heat input data is available from the USEPA's Clean Air Market Data. This data set was then used to calculate unit heat rates and incremental heat rates across each units operating range through the use of regression analysis techniques. First, second, and third order polynomials developed. Generally, third order polynomials resulted in the best fit. A small number of data points were eliminated for a few units to improve curve fit. The eliminated data could be the result of errors in reporting or represent limited operation within a specific hour. These calculated heat rates were then compared to the remaining simulation model data for each fossil fueled unit in NYCA and one heat rate curve was selected for each unit.

Consideration was given to using this approach across all of the units in the simulation, however, the relative smaller impact of heat rate inaccuracies for non-NYCA units and the shear magnitude of the effort to correct heat rates for all units in the simulation lead to the conclusion that vendor supplied heat rate information should be used for all non-NYCA units.

Both simulation models employ power points which are points in the units operating range where specific data such as heat rate is tied to the power point. In general there are minimum and maximum points where the unit can be simulated to operate on a sustained basis. There may also be additional intermediary points. Each of these points was tied to a point on the heat rate curve and the incremental heat rate was determined.

A review of the actual operating performance of NYCA units revealed that the vendor supplied data sets did not accurately capture the point of minimum operation for units that have emission control systems that are sensitive to flue gas exit temperatures for the control of NOx emissions.

The minimum operating points for units with these permit conditions were increased to reflect these operating limits.

Heat Rates of marginal units are increasing from Zone A through Zone E and the implied heat rates, Figure 4-3, display the expected seasonal patterns with Summer months being the highest. The relative magnitudes are consistent with the differences in the generation fuel-mixes. Heat rates of Marginal units are highest for Millwood, Hudson Valley, NYC and Long Island.

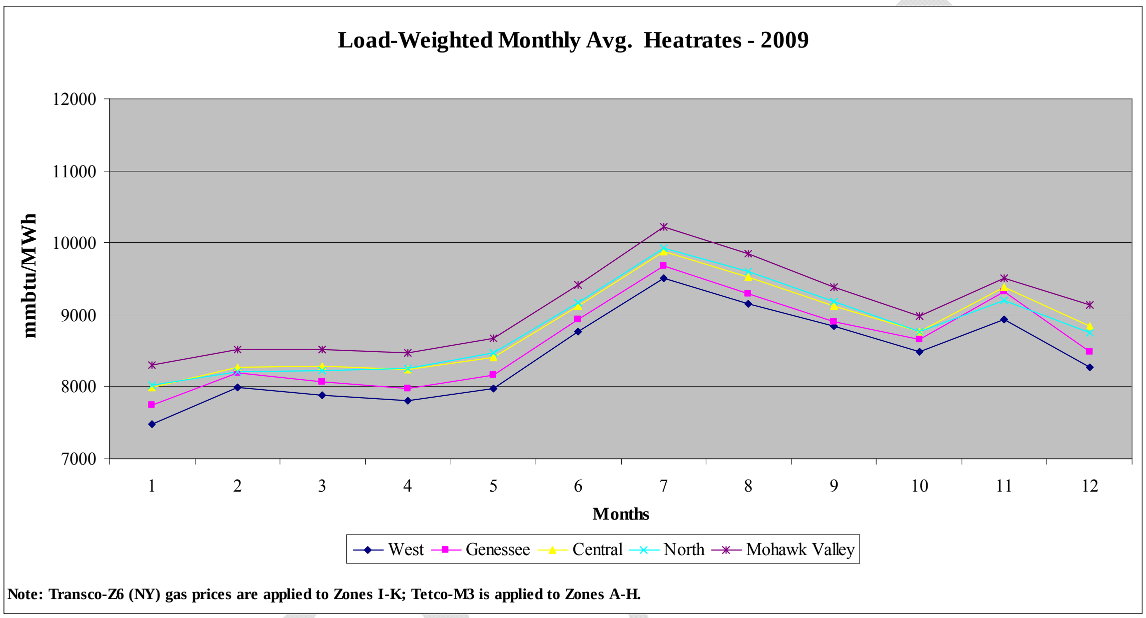

Figure 4-3 - Load-weighted monthly average heat rates for upstate NY

In all zones,

Figure 4-4, the implied heat rates display the expected seasonal patterns. With respect to zones G and J, the difference in assumed gas prices explains the parity during non-winter months and the divergence during the winter.

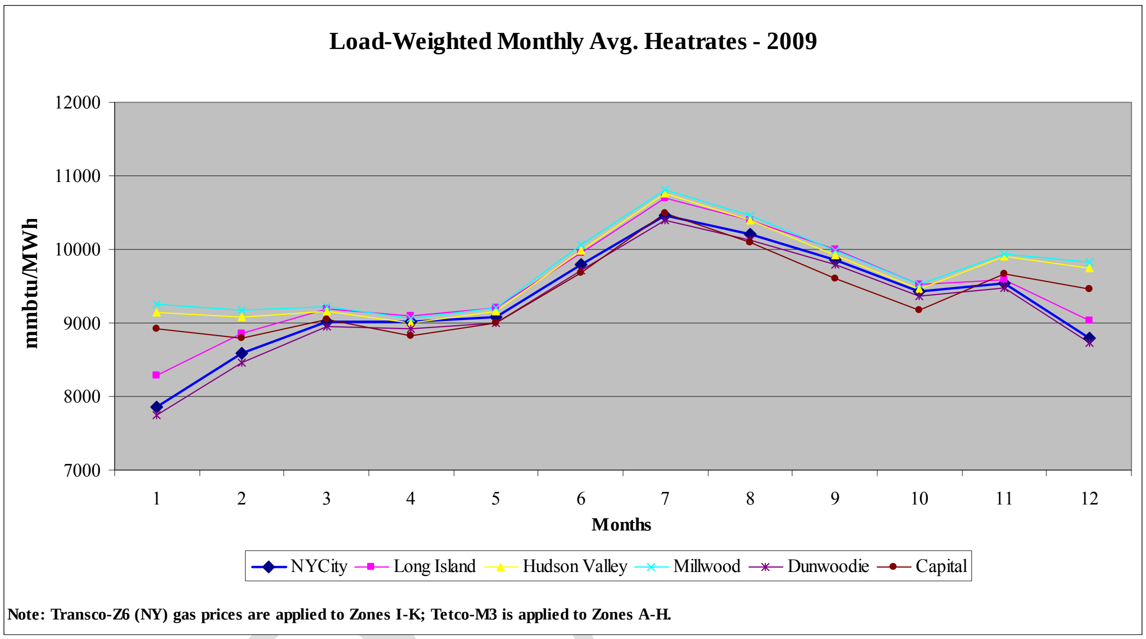

Figure 4-4 - Load-weighted monthly average heat rates for downstate NY

4.4.2 Emission Cost Forecast

The costs of emission allowances are an increasing proportion of 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 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 USEPA CAMD. Since the emission rate determined above is an average emission rate, the same rate was used across the operating range.

Figure 4-5 shows the Emission Allowance Forecast by year in $/Ton.

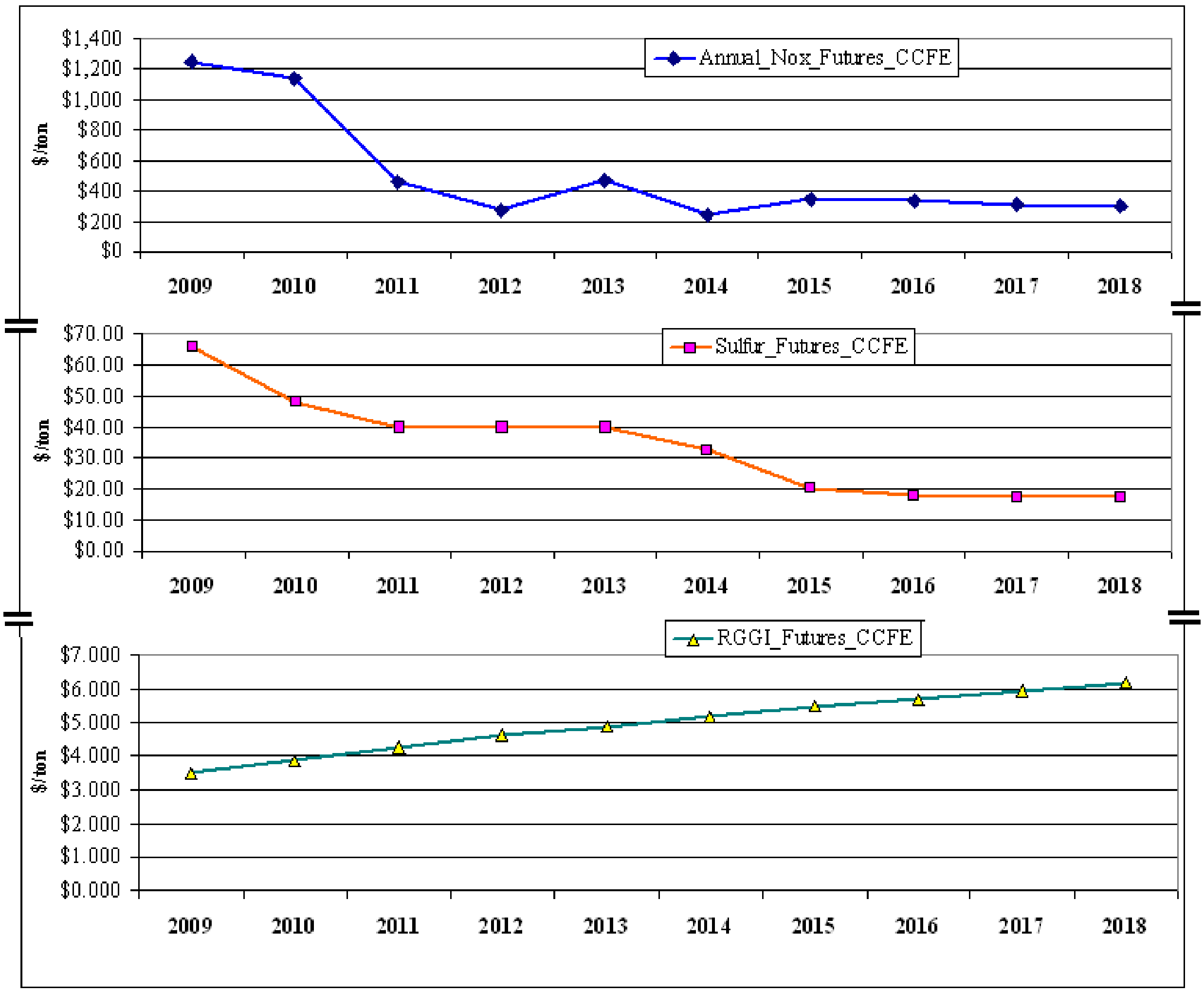

Figure 4-5 - Emission Allowance Forecast

4.4.3 Fuel Forecasts

Base Annual Forecast

The starting-point for preparing the fuel-price forecasts for CARIS is EIA's (Energy Information Administration – www.eia.doe.gov) 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; e.g. 2007. 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. This shall serve as the base annual forecast series.

Adjustments to reflect Bases for 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).[4] 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 (Figure 4-6 & Figure 4-7):

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 (Figure 4-6 & Figure 4-7):

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 U.S. 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 (Figure 4-6 & Figure 4-7):

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 the U.S. as a whole.

Uranium (Figure 4-6 & Figure 4-7):

It is assumed that the same price applies to all nuclear generators in the U.S.

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

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[4] 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

[5] 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.

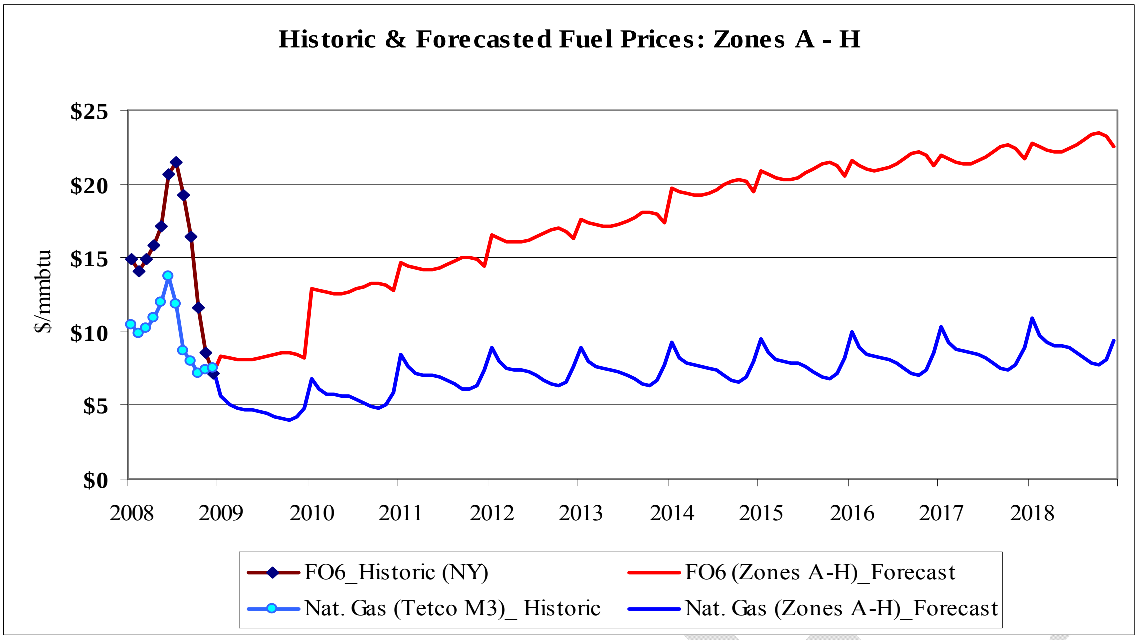

Figure 4-6 - Historic and forecasted fuel prices for Zones A-H

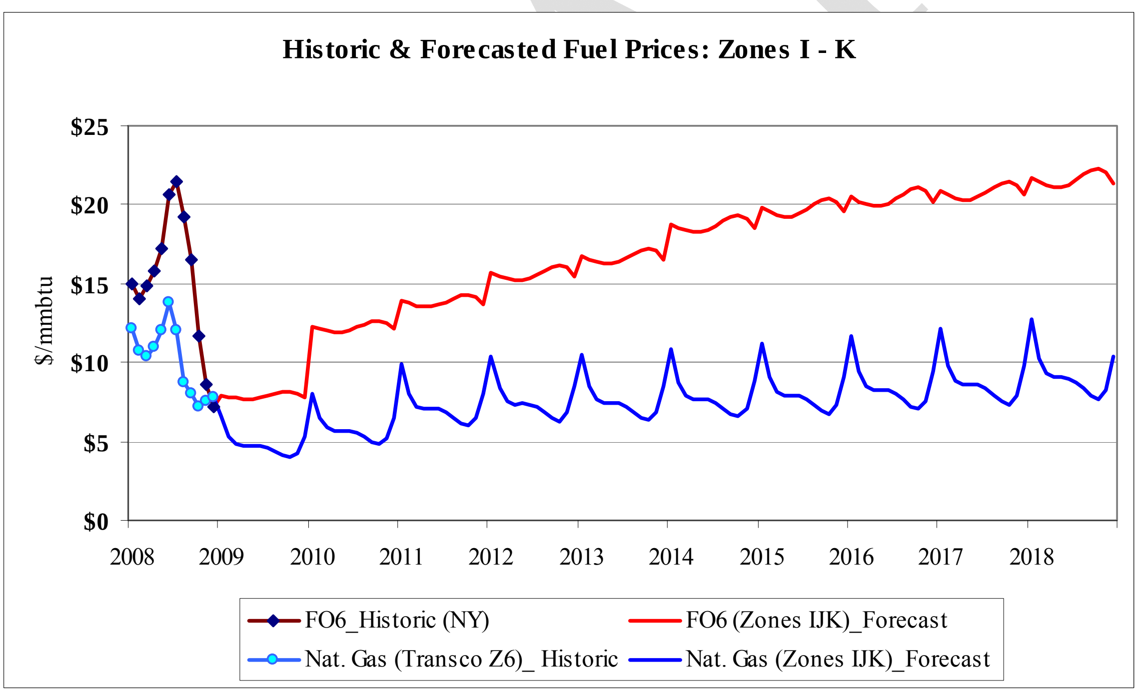

Figure 4-7 - Historic and forecasted fuel prices for Zones I-K

The seasonalized time-series represent 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, NYISO developed volatility-factors to capture typical intra-month variability of prices. 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)

The forecasts for the three external areas, *Figure 4-8* **and** Figure 4-9 **were developed as follows:**

This procedure outlines the process of developing monthly fuel-price forecasts for three adjacent control areas – ISO-NE, PJM, and IESO.

The starting point was the base-line annual forecasts of each fuel for New York[6]. 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.[7]

Table 4-5, Table 4-6, Table 4-7, & Table 4-8 below outline the assumptions behind fuel-price forecasts for each external control area.

Table 4-5 - 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 4-6 - 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 4-7 - 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

[6] These forecasts were, in turn, based on EIA's current national long-term forecast of delivered fuel-prices.
[7] 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.

Coal	82% of the price for Zones A – H	Same as the factor for New York

Table 4-8 - 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

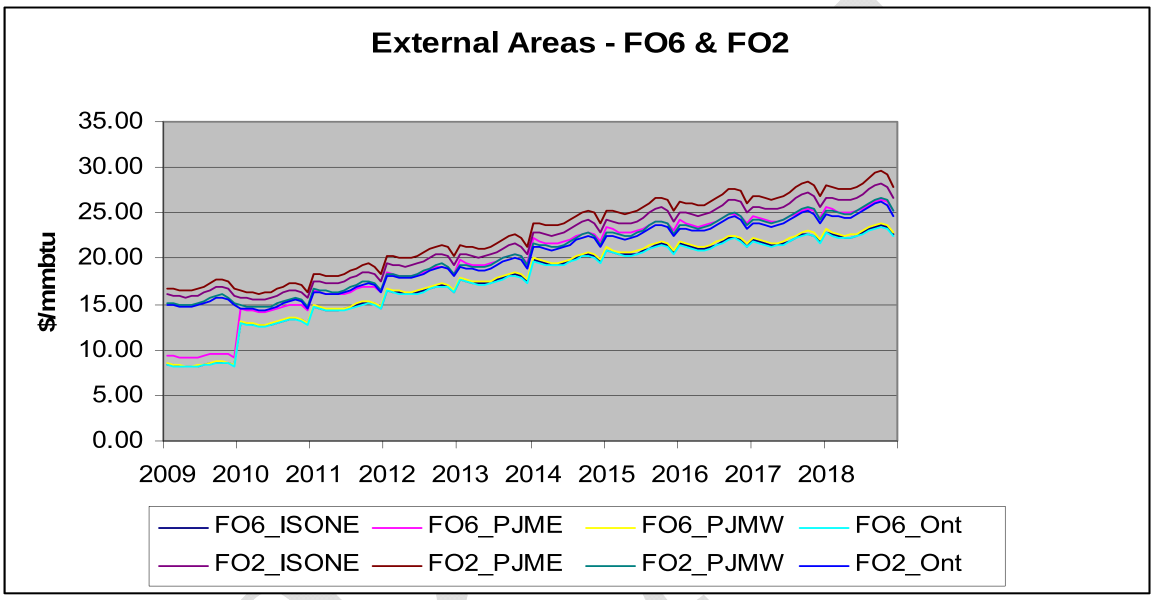

Figure 4-8 - Forecasted oil fuel prices for ISONE, PJM, & Ontario

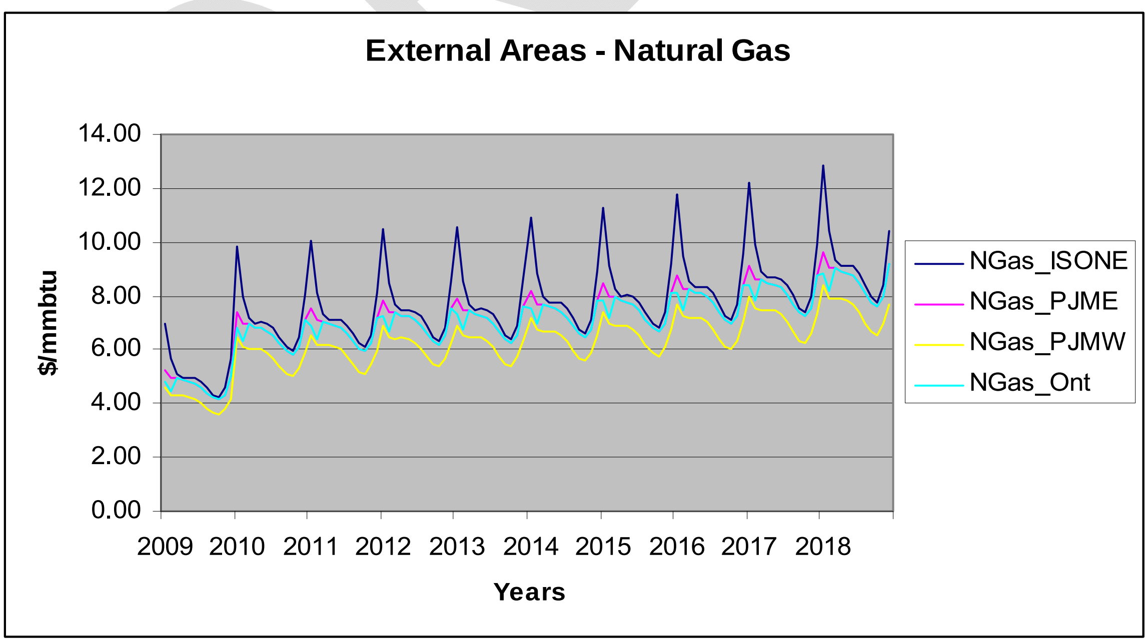

Figure 4-9 - Forecasted natural gas prices for ISONE, PJM, & Ontario

4.4.4 Fuel Switching

Fuel switching capability is widespread within NYCA. 37% of the 2009 NYCA generating capacity, 14,470 MW, has the ability to burn either oil or gas. There are two reasons that generating facilities would exercise the capability to burn oil: the first reason is that oil would be the economic choice, the second would be satisfy reliability rules. Historically significant quantities of oil have been used. (Wes will provide a table)

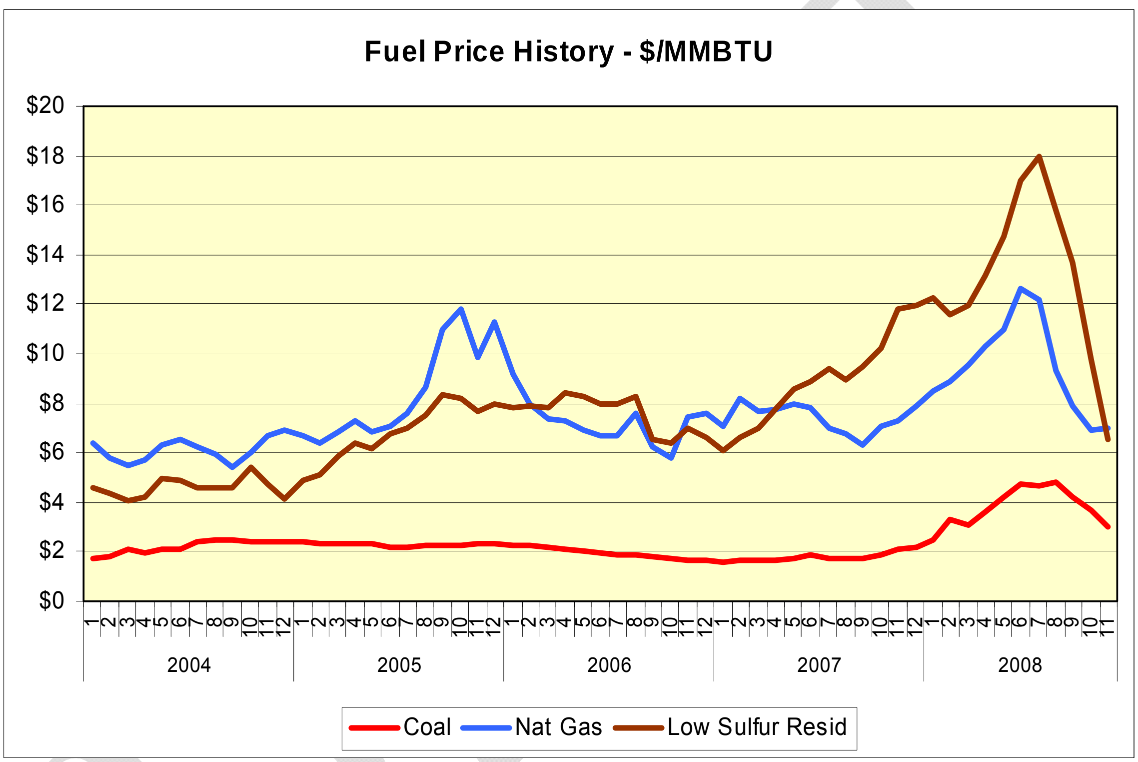

Figure 4-10 - Historical fuel prices of coal, natural gas, and low sulfur coal

Both simulation models can select the economic fuel based on monthly production costs for units with duel fuel capability. For the planning horizon, the fuel price forecast does not show that low sulfur residual fuel oil will be an economic choice on a monthly basis.

The New York Reliability Council has established rules for the reliable operation of the New York Bulk Power System. Two of those rules guard against the loss of electric load because of the loss of gas supply. Rule I-R3 states "The New York State Bulk Power System shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone. Rule I-R5 similarly states, The New York State Bulk Power System shall be operated so that the loss of a single gas facility will not result in the uncontrolled loss of electricity within the Long Island zone. To satisfy these criteria, annual studies are performed that update the configurations of the electricity and gas systems and simulate the loss of a various gas supply facilities. The loss of these gas facilities leads to the loss of some generating units. This deficiency must be made up though the increased use of imports and oil burning capacity. The timeframes are on the order of seconds. In order to increase the amount of oil being consume, some older steam units burning minimum amounts of oil so oil burn can be increased almost instantly. Some new combined cycle units in these zones have the ability to "switch on the fly" with limited loss of output that can be quickly recovered. As the fleet in these zones has seen a shift to increased use of combined cycle units with switch on the fly capability the amount of oil used in steam units to satisfy minimum oil burn criteria has decreased. In order to simulate the use of oil in steam units to satisfy these reliability criteria, Ravenswood #3 and Northport #4 were forced to use oil up to their minimum. For operation at higher load levels the models then simulate these units as duel fuel units that selected the economic fuel.

4.4.5 Generation Maintenance

Planned maintenance outages duration was developed based upon historic 2007 and 2008 maintenance schedules -- FERC FORM 714 2007-2008. The planned outage schedules were initially specified by the program and manually modified so that the total capacity outage for each month and zone is consistent with historic levels.

The unforced outage duration was based upon the data specified in the 2009 CRP. The unforced outage duration was then added to the planned outage schedule was modified to include the unforced outage duration.

4.5 Generic Solution Cost Matrix

4.5.1 Methodology

A generic solution was evaluated by NYISO staff for each identified congested element or grouping utilizing each resource type (generation, transmission, and demand response) as required in Section 11.3c of Attachment Y of the OATT. The development of the generic solutions and its representative cost were accomplished by using a cost matrix methodology. 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. The block sizes, assumptions and cost estimates were vetted through the stakeholder process at the ESPWG.

4.5.2 Resource Block Sizes

Typical resource block sizes were 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 as follows:

Table 4-9 - 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

Table 4-10 - Generation Block Sizes

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

Table 4-11 - Demand Response Block Sizes

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

4.5.3 Assumptions

Developing cost estimates for these resource types are very dependent on many different parameters and site specific situations. Therefore, a set of assumptions that address the following items were developed for each resource type:

Transmission Resource

1. type of construction (i.e. 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

Generation Resource

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

1. zonal locations
2. energy efficiency/ demand response
3. utility demand side management filings
4. order of magnitude cost estimate

A detailed list of assumptions utilized for each resource is included in the Potential Generic Solution Cost Matrix included in Appendix C.

4.5.4 Order 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 NY. The order of magnitude cost estimates took into account the cost differences between geographical areas within NY. 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 were developed for the three resource types and for each geographical area:

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 Market Participants 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 are included in the Potential Generic Solution Cost Matrix in Appendix C. It should be noted that the Demand Response resource type costs were based on New York utility filings for their Demand Side Management programs. The NYISO will consider utilizing a customer installed cost approach in future CARIS analysis

4.5.5 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 cost estimates will be utilized to develop order of magnitude generic solution costs for inclusion in the benefit to cost ratio analysis. If upon a cursory review of 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.

4.5.6 Disclaimers

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

5 2009 CARIS Analyses – Study Phase

The results in this chapter is preliminary and results are subject to change

5.1 Congestion Assessment

This section presents the results of the first, or study phase, of the CARIS process. Details of this process are presented in Appendix X.X. The results of the process steps in Phase 1 are presented below. The study phase begins with the development of a ten year projection of future congestion costs impacting the NYCA system. 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 three 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 assessed and benefit cost ratios based on project costs and production cost savings as well as additional metrics to identify other potential cost savings associated with additional metrics. Scenario analysis is conducted to determine the impact of uncertainties on the projection of congestion and development of the metrics that may increase or decrease the calculation of benefits.

5.1.1 Historic Congestion

Historic congestion assessment, Table 5-1, has been ongoing at the NYISO for six years. Metrics and procedures were developed with the ESPWG and approved by the NYISO Operating Committee. The results of the assessment are posted on the NYISO website quarterly.

Table 5-1 - Historic Congestion Assessment

YEAR	CARIS Metrics - DAM bid based(1) million$				NYCA Actual GWh		
	Load Payment	Generator Payment	Production Cost(2)	Congestion	Demand	Generation	Interchange
2004	10,059	8,615	N/A	831	160,211	147,171	13,040
2005	15,314	13,153	N/A	1,382	167,208	153,265	13,943

2006	11,969	10,241	N/A	1,541	162,237	148,359	13,878
2007	12,831	10,840	N/A	1,451	167,341	150,407	16,934
2008	15,485	12,178	N/A	2,540	165,613	144,619	20,994

(1) Source: Annual Congestion Report

(2) Market Reports reports Bid Production Cost values, which are negative numbers caused by a high number of negative market bids (Nuclear Units and other Bilaterals)

Where should we discuss differences in the levels of congestion caused by outages/virtuals/etc?

5.1.2 Projected Congestion

A projection of future congestion, Table 5-2, is developed from analysis conducted with a production cost model that employs security-constrained unit commitment and economic dispatch and utilizes the CARIS base case developed as part of the CARIS process implemented with full ESPWG participation.

Congestion associated with the constraints modeled is defined as $demand congestion that has been used for the reporting of the historic congestion for the past six years. This differs from the classical "congestion rent" definition.

Table 5-2 - Projection of Future Congestion 2009-2018

YEAR	**CARIS Metrics - DAM bid based(1) million$**				**NYCA Actual GWh**		
	Load Payment	**Generator Payment**	**Production Cost(2)**	**Congestion**	**Demand**	**Generation**	**Interchange**
	PROJECTED				**PROJECTED**		
2009	7,409	6,772	4,206	118	168,128	158,034	10,094
2010	9,817	8,714	5,159	119	169,747	155,017	14,730
2011	10,046	8,894	5,309	128	170,954	155,679	15,274
2012	10,520	9,269	5,578	140	171,927	155,939	15,988
2013	10,760	9,471	5,739	94	173,156	156,723	16,433
2014	11,343	10,000	6,074	99	174,800	158,246	16,553
2015	11,786	10,333	6,361	113	176,177	158,513	17,664
2016	12,369	10,779	6,678	134	178,250	159,559	18,691
2017	12,910	11,222	7,041	154	179,283	160,061	19,222
2018	13,618	11,638	7,190	186	180,427	158,571	21,856

(1) Source: Annual Congestion Report

(2) Market Reports reports Bid Production Cost values, which are negative numbers caused by a high number of negative market bids (Nuclear Units and other Bilaterals)

5.1.3 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 based on the highest Present Value of congestion over the fifteen years in the first year of the study, or 2009.

NOTE: Need to get a consistent way to reference these "rows" Are they monitored elements/contingency pairs, congested elements, or constraints? Constraints are the broadest description.

Insert fifteen year table and discussion of the ranking results.

****ADD WORDS TO EXPLAIN NEGATIVE CONGESTION FROM PROJECTED PERSPECTIVE****

5.2 Selection of Three Studies

From the table and ranking results discussed in section 5.1.3, the top three ranked constraints are identified as primary for further assessment to identify potential for grouping of these primaries with other constraints that would comprise the three studies.

The three congested elements with the highest present value ranking shall be utilized for further assessment under the CARIS process for that cycle. This assessment will be accomplished in multiple iterations to include additional elements that appear as limiting when each of the top three congested elements are relaxed. The assessed element groupings will then be ranked based upon change in production cost. The three ranked groupings with the largest change in production cost will then be selected as the three CARIS studies.

- In order to identify additional elements that may have a significant impact on congestion, each primary element being studied will be relieved independently of each other for a mid and horizon year (2013 and 2017) Table 5-3
- The primary element's constraint is relieved by replacing its limit with 9999.
- The resultant new list of top congested elements from the two year analysis will be reviewed to determine if any additional elements that are electrically adjacent to the primary element have become congested. A congested element will be considered electrically adjacent if it is connected within one bus away from the primary element's bus.
- If a new electrically adjacent element is revealed in the top five most congested element listing, a grouped analysis will be completed which relieves both the primary and the new adjacent element.

If multiple additional electrically adjacent elements are revealed in the top five most congested elements listing, then a grouped analysis will be performed on each independently. The grouping with the highest improvement in production cost savings will be selected as the study grouping.

Table 5-3 - Congestion Results when the Top Three Congested Elements are Relaxed

	2013				2017			
Congested Contraint	**Base**	**Central East Relaxed**	**Leeds-PV Relaxed**	**Dunwoodie-Shore Rd. Relaxed**	**Base**	**Central East Relaxed**	**Leeds-PV Relaxed**	**Dunwoodie-Shore Rd. Relaxed**
CENTRAL EAST	35.14	0.00	38.76	34.11	86.47	0.00	91.49	92.32
ATHENS_PLTVLLEY_345_ PLTVLLEY_LEEDS 3_2	38.52	39.52	0.00	39.35	44.15	47.27	0.00	46.97
HMPHRBR_DVNPT_345_ DUNWODIE_SHORE RD_1	12.59	12.32	13.50	0.00	11.69	11.18	12.71	0.00
DUNWOODIE_SHORRD_345_ DUNWODIE_ SHORE RD_1	17.38	17.37	19.01	0.00	14.76	15.04	16.40	0.00
LIPA Cable	5.08	5.16	5.66	4.41	4.78	4.93	5.33	4.01
NYCLP Greenwood	1.43	1.46	1.96	1.36	2.19	2.26	2.59	2.07
Ontario North-NYISO	(7.83)	(7.94)	(8.03)	(7.78)	(7.89)	(8.29)	(8.13)	(7.87)
PJM_LINDEN GOETHALS	(9.62)	(9.64)	(9.96)	(9.54)	(9.77)	(9.68)	(9.83)	(9.68)
WEST CENTRAL-OP	(24.85)	(30.11)	(28.10)	(25.25)	(34.13)	(41.91)	(36.25)	(32.63)
Dunwoodie (I) to Long Island (K)				27.72				24.57
NYCA Total	**94.00**	**53.12**	**52.45**	**90.91**	**154.00**	**59.87**	**109.21**	**160.09**

No additional electrically adjacent congested elements were found for Central East or Leeds- PV. Upon relieving the Dunwoodie to Shore Rd. line, the Dunwoodie to Long Island Interface became congested. Therefore, this interface with be grouped with the Dunwoodie-Shore Rd. line for determining a potential solution.

5.3 Potential Generic Solutions

5.3.1 Methodology

The congestion of each grouped elements being studied will be relieved by individually applying one of the resource types. The resource type will be applied based on the rating and size of the "blocks" determined in the Generic Solutions Cost Matrix included in Appendix **. The following guidelines will be used in order to select how the resource type "block" will be integrated into the system:

Transmission:

- The generic transmission solution will consist of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line will terminate 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 will be selected.

Generation:

- The generic generation solution will consist of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution will terminate 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, then the substation that has the highest relative shift factor will be selected.

Demand Response:

- The generic demand response solution will be modeled as a reduction in load within the zone that the most downstream grouped congested element being studied 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 will be limited to less than 10% of the peak zonal load. If the "block" demand response exceeds 10% of the peak zonal load, then it will be prorated based on peak load between the selected zone and the next downstream zone.

5.3.1.1 Modeling Modifications

Upon selection of the potential solutions for each resource type for each grouped elements studied, the potential solutions will be individually modeled in the base case in order to determine its impact on the grouped element's congestion. It will be assumed that the generic potential solution will be installed in the first study year. This will allow for the calculation of the full 10 year production cost and additional metrics resulting from the potential solution.

The base case transfer limits for the appropriate interfaces will be recalculated for the mid-year and horizon year with all facilities in-service.

Initially one single "block" size for each resource type will be modeled. If a majority of the congestion of the grouped elements being studied is not relieved, then an additional block will be installed. However, if adding the additional block will result in reducing the benefit to cost ratio, then it will not be included.

The costs of the generic solution's potential system impact on reliability are included in the System Upgrade Facilities generic cost estimate ranges. Therefore, the potential solutions impact on reliability is not investigated.

5.3.1.2 Disclaimers

- 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.

5.3.2 Grouped Congested Elements Potential Solutions

5.3.2.1 Central East Interface

In order to determine the upstream and downstream locations needed to develop the potential solutions for relieving the congestion on the Central East Interface, the elements that make up this interface as shown in Table 5-4 below were examined.

Table 5-4 - Elements which Comprise the Central East Interface

Interface	From Bus Number	From Bus Name	From Bus Voltage (KV)	To Bus Number	To Bus Name	To Bus Voltage (kV)
CENTRAL EAST	100511	GRAND IS	115	147852	PLAT T#3	115
CENTRAL EAST	130797	E.SPR115	115	137886	INGHAM-E	115
CENTRAL EAST	137200	EDIC	345	137452	N.SCOT77	345
CENTRAL EAST	137210	PORTER 2	230	137730	ROTRDM.2	230
CENTRAL EAST	137210	PORTER 2	230	137730	ROTRDM.2	230
CENTRAL EAST	137228	INGMS-CD	115	137886	INGHAM-E	115
CENTRAL EAST	137228	INGMS-CD	115	137302	INGHAMS	46
CENTRAL EAST	137453	N.SCOT99	345	147833	MARCY T1	345

This interface includes two lines which meets the guideline of tying into an existing 345kV substation for Zones A-G. These lines are Edic to New Scotland and Marcy to New Scotland. It has been determined that the physical distance between Edic to New Scotland is less than Marcy to Scotland. Therefore, the initial potential generic solutions for relieving the Central East Interface for each resource types are as follows:

- Transmission: A new 345 kV line from Edic to New Scotland, 90 Miles
- Generation: Install a new 250 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)

The transmission generic solution reduced the congestion on the Central East interface in 2013 from $35.1 M to $7.5 M or 79% and in 2017 from $86.5 M to $29.1M or 66%. Since the majority of the congestion is relieved, no additional block will be added for this solution.

The generation generic solution reduced the congestion of the Central East Interface in 2013 from $35.1 M to $21.9 M or 38% and in 2017 from $86.5M to $xxxM. Since the majority of the congestion was not relieved, a second 250MW block of generation is installed. Adding a second block resulted in the congestion being reduced to $15.2 M or 57% in 2013 and to $50.7 M or 41% in 2017.

The demand response solution reduced the congestion of the Central East Interface in 2013 from $35.1 M to $ 33.3 M or 5.1% and from $86.5 to $82 M or 5.2%. Since a majority of the congestion is not relieved, additional blocks of demand response is required.
Need to add results for additional blocks as necessary

The recommended generic solution and block sizes for each resource type based on the amount of relieved congestion are as follows:

- Transmission: A new 345 kV line from Edic to New Scotland, 90 Miles

- Generation: Install a new 500 MW Plant at New Scotland

- Demand Response: Install XX MW Demand Response and XX MW Energy Efficiency in Zone F (200 MW is less than 10% of Zone F's peak load)

Still need to determine block sizes for demand response

5.3.2.2 Leeds - Pleasant Valley

Since the Leeds - Pleasant Valley line terminates at substations that meet the guidelines, the initial potential generic solution for relieving the Leeds to Pleasant Valley congestion for each resource types are as follows:

- Transmission : A new 345kV line from Leeds to Pleasant Valley- 39 Miles

- Generation: Install a new 250 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)

The transmission generic solution reduced the congestion on the Leeds to Pleasant Valley Lines in 2013 from $38.5 M to $0 M. Since all of the congested is relieved, no additional block will be added for this solution.

The generation generic solution reduced the congestion of the Leeds to Pleasant Valley lines in 2013 from $38.5 M to $26.2 M or 32% and in 2017 from $44.2 M to $xxM. Since the majority of the congestion was not relieved, a second 250MW block of generation is installed. Adding a second block resulted in the congestion being reduced to $18.5 M or 52% in 2013 and to $20.5 M or 54% in 2017.

The demand response solution reduced the congestion of the Leeds-Pleasant Valley lines in 2013 from $38.5 M to $36.6 M or 4.9% and in 2017 from $44.2M to $42.5 M or 3.9%. Since a majority of the congestion is not relieved, additional blocks of demand response are required.
Need to add results of installing additional blocks.

The recommended generic solution and block sizes for each resource type based on the amount of relieved congestion are as follows:

- Transmission : A new 345kV line from Leeds to Pleasant Valley- 39 Miles

- Generation: Install a new 500 MW Plant at Pleasant Valley

- Demand Response: Install xx MW Demand Response and xx MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

Still need to determine block sizes for demand response

5.3.2.3 Dunwoodie - Long Island Interface

Since the Dunwoodie-Shore Rd line terminates at substations that meet the guidelines, the initial potential generic solution for relieving the Dunwoodie to Shore Rd line congestion for each resource types are as follows:

- Transmission: A new 345kV line from Dunwoodie to Shore Rd.- 19 Miles

- Generation: Install a new 250 MW Plant at Shore Rd. 345kV

- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone K (200 MW is less than 10% of Zone K's peak load)

The transmission generic solution reduced the congestion on the Dunwoodie to Long Island interface in 2013 from $30.9 MW to $0 M Since all of the congested in relieved, no additional block will be added for this solution.

The generation generic solution reduced the congestion of the Dunwoodie- Long Island interface in 2013 from $30.9 M to $15.3 M or 50.5%. Since the majority of the congestion was relieved, a second 250MW block of generation is not installed.

The demand response solution reduced the congestion of the Dunwoodie-Long Island interface in 2013 from $30 M to $25.6 M or 15% and in 2017 $26.5 M to $22.7M or 14%. Since a majority of the congestion is not relieved, additional blocks of demand response are required.
Need to added results of installing additional blocks.

*** Need discussion regarding tying into 138kV at Shore Rd. Need discussion of the results from tying into 138kV at Shore Rd.***

5.4 Benefit/Cost Analysis

5.4.1 Primary Metric Results

5.4.2 Additional Metrics Results

Additional Metrics, which are provided for information purposes in Phase I, include the change in LBMP-based load payments ($), generator payments ($), congestion payments ($), congestion rent value ($), CO2, NOx and SO2 emission (tons) and losses (not sure if this metric is $ or MW).

5.5 Scenario Analysis (consider a separate section)

6 2009 CARIS Findings – Study Phase

6.1 Base case Findings

6.2 Scenario Findings

7 Next Steps

7.1 Phase 2 - Project Phase

7.2 Project Phase Schedule

Appendix A – Glossary

1. Congestion Rent

The hourly congestion rent for a constrained facility is defined as the active power flow (MW) on the constrained facility multiplied by its shadow price. Shadow price is defined as the incremental production cost saving if the constrained element flow limit is increased by 1MW. Shadow prices on constrained elements are non-zero during hours of congestion (or constrained element MW flow is equal to constrained element limit).

Congested rent value by constraint = sum of all hours (constrained element MW x Shadow Price $/MW)

Total congestion rent = Sum of all constraints congestion rent

Constrained facilities are then listed in descending order based on their congestion rent values in order to show highly congested locations on the NYCA system. Other information such as number of congested hours will be provided.

2. Demand$_Congestion

Demand$_Congestion is the congestion cost component paid by NYCA load. It is defined as the shadow price of each constrained elements multiplied by the load affected and calculated as follows:

Demand$_Congestion by constraint = For all areas (For all hours (ShadowPrice x AreaGSF x AreaLoad))

Total Demand$_Congestion = Sum of all constraints' Demand$_Congestion

Constrained facilities are then listed in descending order based on their Demand$_Congestion values in order to show highly congested locations on the NYCA system. Demand$_Congestion values by zone can also be reported.

3. Generator Payment

Generator Payment is also referred to as Generator Revenues. It is a zonal LBM based revenues or payment to generators located in a zone. The hourly revenue or payment to each generator is the determined as the hourly generator MW dispatch multiplied by the generator's LMP or spot price. The annual generator payment is then the sum of all 8760 hourly generator payments.

Annual generator LBMP payment = sum of all hours (generator LMP x generator MW dispatch)

Zonal generator payment = sum of generator payment located in a zone

Generator Payment benefits or saving of a proposed project is then the change in the NYCA Generator Payment for the "with" and "without" project cases. Total Generator payment benefits are also calculated on a zonal basis.

4. Load Payment Metric

Load Payment or LBMP payment is the total energy cost to consumers. It is a zonal LBMP based consumer payment. Hourly load-weighted average LMP price for each zone is calculated and multiplied with the zonal load to determine the hourly zonal load payment. The annual load payment is then the sum of all 8760 hourly load payments.

Annual Zonal LBMP payment = sum of all hours (zonal LBMP x zonal load)

Zonal LBMP = zonal average load-weighted LMP

Load Payment benefit or saving of a proposed project is then the change in the NYCA Load Payment for the "with" and "without" project cases. Total Load Payment benefits are also calculated on a zonal basis.

5. NYCA Production Cost and Production Cost Benefit Metrics

NYCA production cost is the total generation cost of producing power to serve load. The total cost includes the following components:

1. Fuel cost (fuel consumption MBtu multiplied by fuel cost $ /MBtu)
2. Variable O&M cost (VOM adder $/MWh)
3. Emission cost (emission allowance price multiplied by total allowance)
4. Start-up Costs (number of starts multiplied by start-up cost)
5. NYCA Imports or Exports evaluated at the LMP values. (Needs further clarifications)

Production cost benefit or saving of a proposed project is then the change in the NYCA production cost for the "with" and "without" project cases. Total Production Costs benefits are also calculated on a zonal basis.

Appendix B –Congestion Assessment and Resource Integration Study (CARIS) Process

B.1. Phase 1 – Study Phase

The purpose of Phase 1 or the Study Phase, Figure B - 1 is to gather, organize, and develop information related to congestion as it impacts the NYCA for stakeholders. More specifically:

a. Post historic congestion and identify significant causes of historic congestion;
b. Project congestion on the New York State BPTFs over the ten-year planning period;
c. Identify the most congested elements or contingency pairs of elements;
d. Identify, through the development of appropriate scenarios, factors that might mitigate or increase congestion;
e. Provide information regarding generic projects to reduce congestion;

The study phase starts with the gathering of historic and the projection of future congestion information. That information is used to identify significant and reoccurring congestion. The historic congestion information is a compilation of the last six years of congestion data which is posted quarterly and the projected congestion is simulated from security-constrained unit commitment and economic dispatch software and posted once per CARIS cycle. A CARIS cycle is two years.

Based upon the combination of historic and projected congestion metrics each congested element or contingency pairs of elements are ranked by the following formula developed in conjunction with the ESPWG:

Present Value in Year 1 = [(Sum of the Future Value of Congestion from the Prior 5 Historic 12-Month Periods) + (Sum of the Present Value of Congestion from the Future 10 years)]

The rankings are posted for stakeholder review. The rankings are finalized after the stakeholder review and from this final ranking the top three congested elements/contingency pairs of elements are selected and posted for study. Additional information can be found in CARIS Procedure X – Criteria for the Selection of CARIS Studies, Appendix F.

During this process a request for additional studies from stakeholders is posted by the NYISO. These studies are in addition to the three identified studies noted above. Any stakeholder is eligible to request an additional study. All requests will be posted on the NYISO website. Additional details can be found in CARIS Procedure X – Process for Additional Studies, Appendix F.

Once the three studies are selected, benefit/cost analysis is performed. To perform the benefit analysis assumptions for the baseline system are developed in conjunction with the ESPWG. Based on Attachment Y of the Tariff, the baseline system for the CARIS simulations assumes a reliable system throughout the Study Period, based upon the solutions identified in the most recently completed and approved CRP. The baseline system for the CARIS incorporates sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered in prior or current CRPs. If more market based solutions have been proposed than the minimum needed to meet the identified Reliability Needs, the NYISO, in conjunction with the ESPWG, has developed methodologies to scale back market-based solutions to the minimum needed to meet the identified Reliability Needs. Regulated backstop solutions that have been proposed but not triggered in the most recent CRP shall also be used if there are insufficient market-based solutions for the ten-year study period. Additional information can be found in CARIS Procedure X – Procedure for inclusion of Market Based Solutions & Regulated Backstop Solutions in CARIS Base Case, and Procedure to Scale Back Market Based Solutions, Appendix F.

In conducting the CARIS, the NYISO conducts benefit/cost analysis of each potential generic solution to the congestion identified. One potential generic solution is determined by NYISO for each resource type (generation, transmission, and demand response) for each of the three congestion studies. During each cycle, NYISO will develop with ESPWG specific project criteria for each resource type (generation, transmission, and demand) including block size and construction assumptions. Following the identification of the three studies, each resource type shall be applied in year one of the planning horizon, in sufficient quantities of generic block sizes associated with each resource type and specific locations to alleviate a substantial and comparable portion of the identified congestion over the planning horizon. Additional details can be found in CARIS Procedure X – Potential generic Solutions, Appendix F.

The principal benefit metric for the CARIS analysis will be expressed as the present value of the NYCA wide production cost reduction that would result from each potential solution. Additional benefit metrics calculated include estimates of reduction in losses, LBMP load costs, generator payments, ICAP costs, Ancillary Services costs, emission costs, and TCC payments. Additional details can be found in CARIS Procedure X – Additional Benefit Metrics for CARIS Studies Methodology and Models to Develop and Implement Additional Metrics, Appendix F.

The costs of potential generic solutions utilized in the benefit/cost analysis are order of magnitude estimates developed for each resource type. The costs will be developed for relevant geographic locations during each CARIS cycle. The order of magnitude costs will be provided to the ESPWG for their review and acceptance during each CARIS cycle as part of the Assumption Matrix approval process. If upon a cursory review of the location for the potential solution identifies unusual complexities, a contingency factor will be applied to the costs.

To add additional information to the benefit/cost analysis, scenario analysis is performed. The scenarios are developed in conjunction with the ESPWG. Variables for consideration in the development of these scenarios include but are not limited to: load forecast uncertainty, fuel price uncertainty, new resources, retirements, emission data, the cost of allowances and potential requirements imposed by proposed environmental and energy efficiency mandates, as well as overall NYISO resource requirements.

The NYISO will prepare a draft of the Study Phase of the CARIS which includes a discussion of assumptions, inputs, methodology, and results of the analyses. The draft of the Study Phase of the CARIS shall be submitted to both TPAS and the ESPWG for review and comment. Following completion of that review, the draft of the Study Phase of the CARIS shall be sent to the Business Issues Committee and the Management Committee for discussion and action. Following the Management Committee vote, the draft of the Study Phase of the CARIS, with Business Issues Committee and Management Committee input, will be forwarded to the NYISO Board for review and action. Concurrently, the draft of the Study Phase of the CARIS will be provided to the Independent Market Monitor for his review and consideration. Upon approval by the Board, the NYISO shall issue the Study Phase of the CARIS to the marketplace by posting it on its website.

In order to provide ample exposure for the market place to understand the content of the Study Phase of the CARIS, the NYISO will provide various opportunities for Market Participants and other potentially interested parties to discuss final CARIS. Such opportunities may include presentations at various NYISO Market Participant committees, focused discussions with various industry sectors, and /or presentations in public venues.

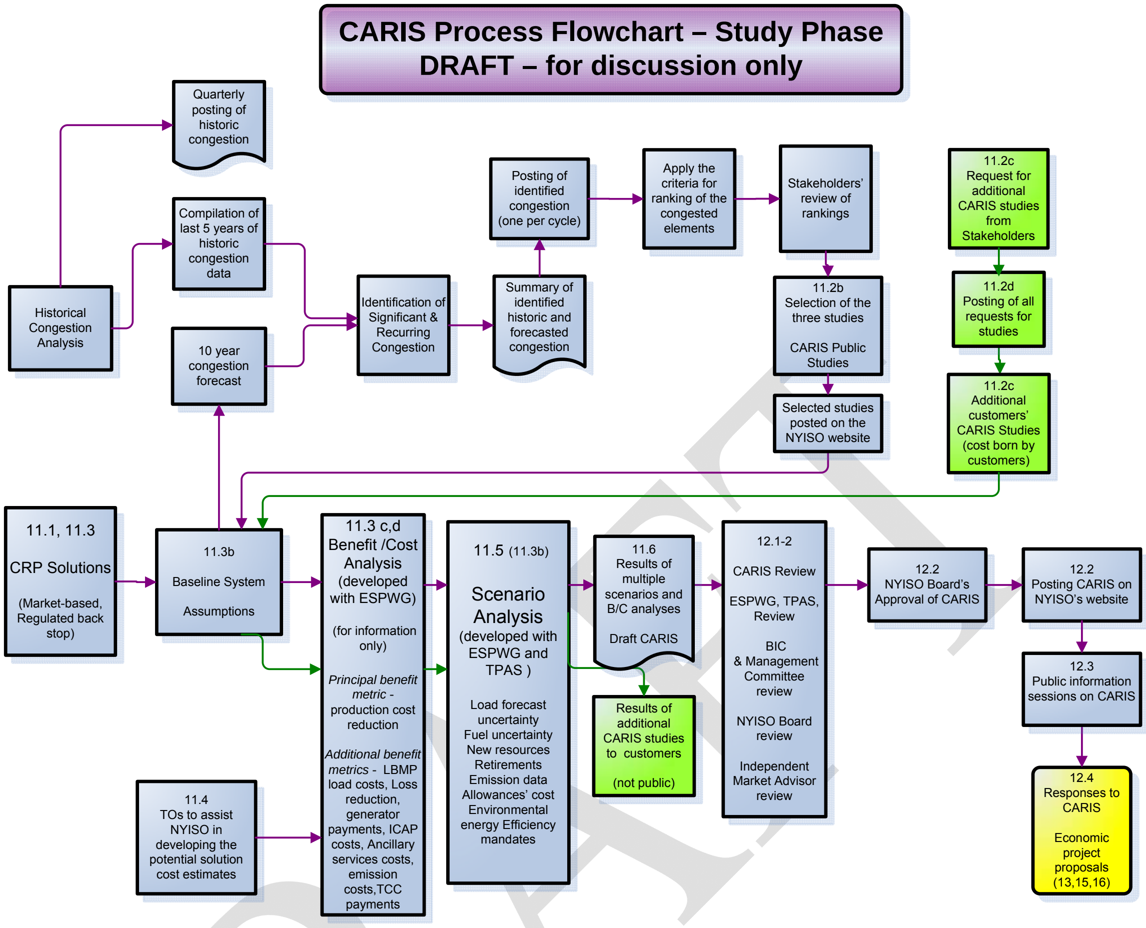

Figure B - 1 – Phase 1 or Study Phase of the CARIS Process

B.1.1. Phase 1 – Procedures

Summary of the procedures associated with Phase 1 – Study Phase include the following:

a. Criteria for Selection of CARIS Studies (Attachment Y: Section 11.2.b)

The congestion metric that is used to select the three CARIS studies is the change in total bid/forecasted production costs in accordance with Appendix A to Attachment Y of the NYISO OATT. Congestion will be identified from the list of most congested monitored element/contingency pairs.

This procedure will utilize an unweighted present value cost of congestion for the most congested elements considering both historic (5 years) and 10-year forecasted data. The three congested elements with the highest present value ranking shall be utilized for further assessment under the CARIS process for that cycle. This assessment will be accomplished in multiple iterations to include additional elements that appear as limiting when each of the top three constrained elements are unconstrained. The assessed element groupings will then be ranked based upon change in bid production cost. The three ranked groupings with the largest change in bid production cost will then be selected as the three CARIS studies.

b. Process for Additional Studies (Attachment Y: Section 11.2.c)

Any NYISO Market Participant or other stakeholder (requestor) is eligible to request such congestion and/or resource integration studies. Requests will be accepted throughout the CARIS cycle. The requestor is responsible for all reasonable actual costs incurred by the NYISO for the additional study(-ies). The NYISO will post the requests for additional studies on its Website. The postings shall include a general description of the study requests, the date of receipt, and the identity of the requestor. There is a provision to allow combination/cost sharing of identical/similar or overlapping study requests from different parties if the parties agree.

The results of these additional studies will NOT be posted on the NYISO website or otherwise released by the NYISO to parties other than the requestor—except with the express written permission of the requestor. If a requestor should seek regulated cost recovery under the NYISO Tariff based upon the results of such studies, the studies would be posted on the NYISO website at that time.

c. Procedure for inclusion of market-based & regulated backstop solutions in CARIS base case and Procedure to scale back market-based solutions (ATTACHMENT Y: SECTION 11.3.b)

CARIS will assume a reliable system based upon the solutions identified in the most recently completed and approved CRP. The baseline system for the CARIS shall first incorporate sufficient viable market-based solutions to meet the identified Reliability Needs as well as any regulated backstop solutions triggered (and not subsequently halted) in prior or current CRPs. If a TO, or an other developer, is proceeding with an alternative regulated solution that has been approved by the PSC and not subsequently halted, then such project shall be included in the CARIS base case. Resources modeled in the CARIS base case will not be evaluated as potential economic solutions.

If more market-based solutions were proposed than needed to meet the Reliability Needs, the market-based solutions will be scaled back to the minimum needed to meet the identified Reliability Needs (statewide LOLE of 0.1) by using the following methodology:

- *All MBS will be sorted by size from largest to smallest regardless of resource type and scaled back sequentially until both the LCR and statewide LOLE requirement are met.*

d. Procedure for additional benefit metrics for CARIS studies, methodology and models to develop and implement additional metrics - 11.3.d.

In addition to the principal benefit metric (NYCA-wide production costs) for CARIS studies, the NYISO will also use the additional benefit metrics in conducting the CARIS study. The additional metrics will estimate the benefits of the potential solutions to the congestion identified and will be used for information purposes only Additional metrics include:

a. LBMP load costs
b. Generator payments
c. Reduction in losses
d. TCC payments
e. Emission metric
f. ICAP costs

e. Draft procedure for determination of potential generic solutions - 11.4.
One potential generic solution (Phase 1) will be determined by NYISO for each resource type (generation, transmission, and demand response) using a cost matrix methodology. The cost matrix methodology will be based upon a typical block size generic solution and a list of construction assumptions for each resource type.

The NYSIO will provide recommended order of magnitude costs for each resource type. The costs will be developed for relevant geographic locations during each CARIS cycle. The cost matrix will be provided to the ESPWG for their review and acceptance during each CARIS cycle as part of the Assumption Matrix approval process.

Each potential generic solution, for each of the three studies, will be applied to alleviate identified congestion starting in year one of the ten-year planning horizon.

B.2. Phase 2 – Projects Phase

The results of the Phase 1- Study Phase will provide information to stakeholders who are interested in proposing an actual project to address specific congestion identified in the CARIS Study Phase report. Any interested developer can propose any type of project, such as a generator or demand response, to specific congestion identified in the Study Phase. However, Phase 2 – Specific Project Phase applies only to regulated economic transmission project responses to specific congestion issues and regulated backstop solutions when the implementation of the regulated backstop solution is accelerated solely to reduce congestion in earlier years of the study period.

Market-based responses to congestion identified in the Study Phase 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 of the market based proposal.

To be eligible for cost recovery in Phase 2, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project, the total capital cost of the project must exceed $25 million, and a super-majority of the beneficiaries must vote in favor of the project.

Phase 2, Figure B - 2 starts with the NYISO evaluating proposed project to determine if the proposed project is an economic transmission project. If the proposed project is an economic transmission project, the NYISO will perform a ten year B/C analysis from the proposed in-service date, which is paid for by the developer. The benefit metric will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date of the project. The estimated cost of each economic transmission project will be supplied by the developer and the cost metric will be the present value of the annual total revenue requirement for the project, reasonably allocated over the first ten years from the proposed commercial operation date of the project.

As stated above, if the proposed economic transmission project has a B/C >1 over the first ten years from the proposed commercial operation date of the project and the total capital cost of the proposed project is greater than $25 million, then the proposed project will be eligible to proceed to the next steps.

In addition to the metrics used in the B/C analysis, for informational purposes only, the NYISO will also calculate the present value and annual total revenue requirement for the project over a 30 year period commencing with the proposed commercial operation date of the project. Also, the NYISO will work with the ESPWG to consider the development of additional metrics for informational purposes only. These additional metrics shall include those that measure reductions in LBMP load costs, changes to generator payments, ICAP costs, Ancillary Service costs, emissions costs, losses and TCC payments. Consideration of these additional metrics will take into account the overall resource commitments of the NYISO.

In addition to the B/C analysis, the NYISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, which shed additional light on the cost and benefit of a proposed project.

Additional details can be found in CARIS Procedure X – NYISO cost allocation procedures for regulated economic transmission projects, Appendix F.

The results of the B/C analysis, additional metrics and the scenario analysis, along with the determination of the beneficiaries, will be documented and submitted to the ESPWG for review and comment. Following completion of that review, the NYISO's analysis shall be forwarded to the Business Issues Committee and Management Committee for discussion and action. Following the Management Committee vote, the NYISO's project B/C analysis and beneficiary determination will be forwarded, with the input of the Business Issues Committee and Management Committee, to the NYISO Board for review and action. Upon final approval of the Board, project B/C analysis and beneficiary designations shall be posted by the NYISO on its website.

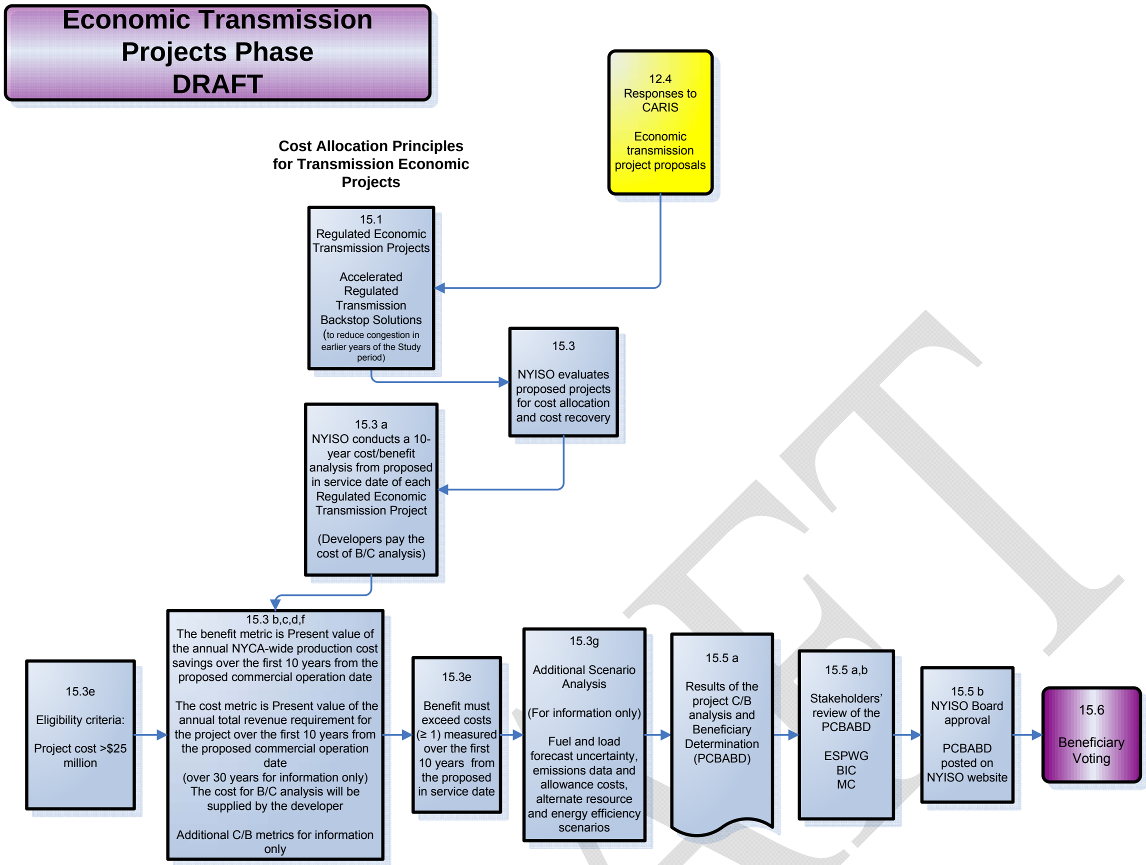

Figure B - 2 – Phase 2 – Project Phase of the CARIS process

B.2.1. Phase 2 – Procedures

a. NYISO cost allocation procedures for regulated economic transmission projects (Attachment Y, Sections 15.3 & 15.4)

To be eligible for cost allocation and recovery, the benefit of the proposed project must exceed its cost measured over the first ten years from the proposed commercial operation date for the project. The benefit metric for eligibility under the NYISO's cost/benefit analysis will be expressed as the present value of the annual NYCA-wide production cost savings that would result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project.

The cost for the NYISO's benefit/cost analysis will be supplied by the developer of the project, and the cost metric for eligibility will be expressed as the present value of the annual total revenue requirement for the project, reasonably allocated over the first ten years from the proposed commercial operation date for the project.

The beneficiaries will be those load zones who experience net benefits measured over the first ten years from the proposed commercial operation date for the project. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project.

b. Draft Procedure for Project Cost Overruns – 15.4.c.

This procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process to allocate the risk of increases in project costs after benefit/cost analysis is completed. The developers will provide a risk profile with their project proposals. The risk profile will address the following items:

- *The stage of project development and the level of accuracy of the project cost estimate.*
- *Required cost overruns sharing if any between the Developer and the LSEs benefiting from the project.*
- *Required project cost increase sharing if any due to a force majeure between the Developer and the LSEs benefiting from the project.*
- *Identification of conditions if any for canceling the project by the Developer including terms and conditions for allocating sunk costs and lost benefits.*

The developers will provide quarterly project status reports to the benefiting LSEs and the NYISO which will include any changes to the project schedule or costs.

B.3. Voting, Cost Allocation, and Cost Recovery

The CARIS process requires the determination of beneficiaries for voting and cost allocation, Figure B - 3. The cost of a regulated economic transmission project will be allocated to those entities that would economically benefit from implementation of the proposed project. The NYISO will identify the beneficiaries of the proposed project over a ten-year time period commencing with the proposed commercial operation date for the project.

The NYISO will measure the present value and annual zonal LBMP load savings for all load zones which would have a load savings, net of reductions in TCC payments, and bilateral contracts (based on available information) as a result of the implementation of the proposed project. Additional information can be found in Procedure X - Procedure to estimate the TCC revenues, Appendix F. The beneficiaries will be those load zones who experience net benefits measured over the first ten years from the proposed commercial operation date for the project. For each load zone that would benefit from a proposed project, the NYISO will allocate the cost of the project to load based on share of total savings. Within zones, costs will be allocated to Load Serving Entities based on MWhs. Load zones not benefiting from a proposed project will not be allocated any of the costs of the project. There will be no "make whole" payments to non-beneficiaries.

Only Load Serving Entities defined as beneficiaries of a proposed project shall be eligible to vote on a proposed project. The voting share of each Load Serving Entity shall be weighted in accordance with its share of the total project benefits. For the proposed project to proceed, 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. Additional information can be found in Procedure X - Voting Procedures, Appendix F.

If the proposed economic transmission project has a B/C >1 over the first ten years from the proposed commercial operation date of the project, Plus the total capital cost of the proposed project is greater than $25 million, and receives a super-majority (>=80%) of the beneficiaries vote in favor of the project, then the Developer shall have the right to make a filing with FERC, under Section 205 of the Federal Power Act, for approval of its costs associated with implementation of the project. Also, upon request by NYPA, the NYISO will make a filing on behalf of NYPA. FERC must approve the cost of a proposed economic transmission project for that cost to be recovered through the NYISO tariff.

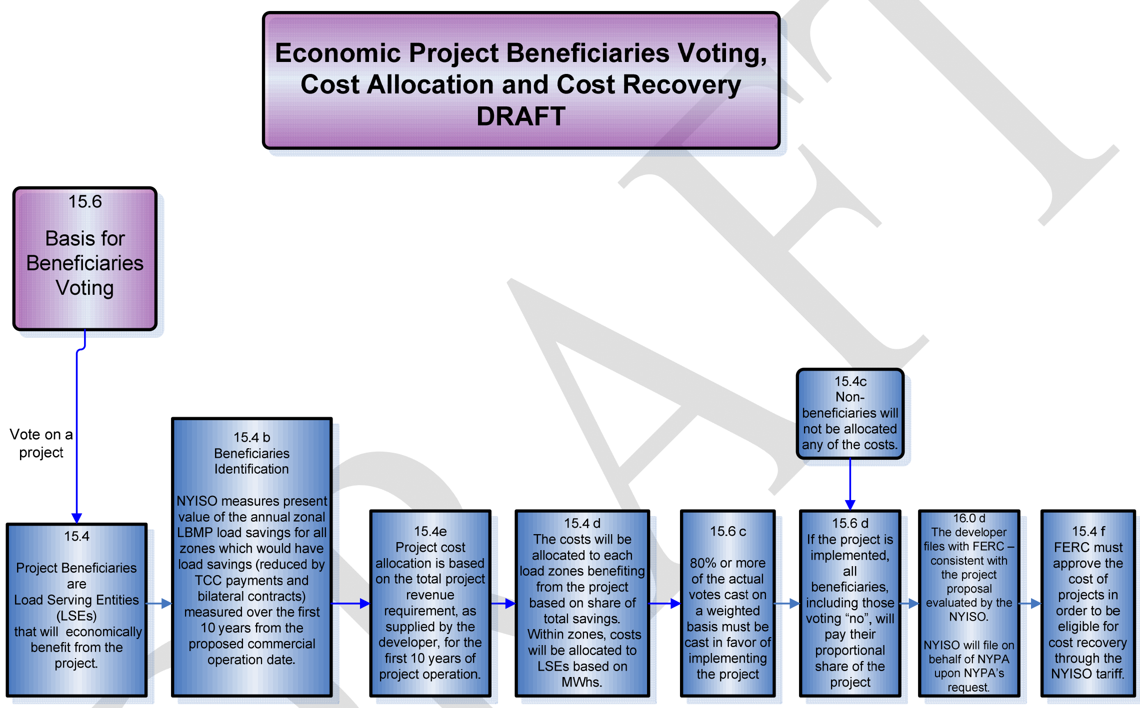

Figure B - 3 –Voting, Cost Allocation, and Cost Recovery of the CARIS process

B.3.1. Voting, Cost Allocation, and Cost Recovery – Procedures

a. Procedure to estimate the TCC revenues – 15.4.b.(iii)
(<u>Pending FERC Approval from May 19, 2009 filing</u>)

The procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process for regulated transmission project cost allocation, which will estimate net reduction in TCC revenues when calculating LBMP load savings to identify beneficiaries of a proposed project. The estimate will reflect the estimated impact of the project on:

- *TSC (Transmission Service Charge) offset applicable to load in each zone*

- *NTAC (NYPA Transmission Adjustment Charge) offset applicable to load in that zone*
- *Congestion rents made to LSEs serving load in each zone that own grandfathered rights/TCC that are not included in the calculation of the TSC and NTAC offsets.*

c. Voting Procedures – 15.6

The voting procedure will be used for the purposes of the Project Phase (Phase 2) of the CARIS process related to the beneficiary voting on a proposed regulated economic transmission project. Only LSEs defined as beneficiaries of a proposed project will be eligible to vote on a proposed project.

A project is approved when 80 % or more of the actual votes cast on a weighted basis must be cast in favor of implementing the project. Abstentions will not be counted as votes. Voting share of each LSE will be weighted in accordance with its share of total project benefits. If the project is voted on in favor of implementing the project, all beneficiaries, including those voting "no" will pay their proportional share of the cost of the project. If no LSE votes on a proposed project, the project will be rejected. The BIC will approve the list of voting LSEs developed by the NYISO and ESPWG. The Chair of the BIC will oversee voting and announce the results of the vote.

Add Procedure

Appendix C – Baseline System Assumptions

C.1. CARIS Model - Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Implementing CARIS requires the understanding of a significant amount of data. Taken from Section 11 of Schedule Y of the Tariff, *"The CARIS for economic planning will align with the reliability planning process. Each CARIS will use a ten-year planning horizon consistent with the reliability planning horizon. Each CARIS will be based on the most recently concluded and approved CRP. The base case for each CARIS will assume a reliable system for the ten-year planning horizon based upon the CRP."*

The data utilized in the base case simulations for CARIS is based on 2009 CRP/RNA and CARIS Assumption Matrix, Table C - 1, shown below. Major components of data includes base load flow data, fuel prices, unit capacities, transmission constraint modeling, load growth and shape representation, both simulated and real actual and scheduled interchange values, O&M cost, and environmental cost components. The Power Flow Assessment Output is Confidential Energy Infrastructure Information (CEII)) and is subject to CEII rules.

Table C - 1: ***CARIS Assumption Matrix***

Parameter	**Modeling for CARIS Base Cases**	**Basis for Recommended Assumptions for CARIS**
7.2.1.1 Peak Load	Forecast as per 2009 RNA Base. Scenarios for other forecasts.	Based on CRP Peak Forecast Use 2009 Base Case Energy Forecast
Load Shape Model Energy Forecast	2002 Load Shape, constant over ten year period. 2009 RNA Base Case Forecast	2002 load shape is an appropriate representation for this analysis. For base year, use 2002 Load Shape, Adjusted for Energy Forecast if needed **,** Evaluate alternative in future
Load Uncertainty Model	Statewide and zonal model updated to reflect current data., constant over ten year period	Base Level Forecast will be used. Other load uncertainty levels not evaluated.
Generating Unit Capacities	Same as CRP - Per 2009 CRP, updated DMNC test values plus units	Any changes in CRP capacities through time to be represented in CARIS.
New Units	As per the CRP and scaled back according to procedure (Tariff Attachment Y: Section 11.3.b)	

Parameter	Modeling for CARIS Base Cases	Basis for Recommended Assumptions for CARIS
Wind Resource Modeling	Existing units derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %. New units from wind shapes from wind study.	Typical shape for location as per MARS and wind studies.
Non-NYPA Hydro Capacity Modeling	Pondage Run of River(Hourly)	
Special Case Resources	Those sold for the program, discounted to historic availability and distributed according to zonal performance. Assume 15% growth rate for all zones. Modify load SCR/EOP to proportion available SCR by load amount by zone. See SCR determinations in Attachment G.	
EDRP Resources	Those registered for the program, discounted to historic availability (45 % overall). July & August values calculated from 2008 July and August registrations.	Need to define costs associated, firm modifiers vs. price responsive.
External Capacity – Purchases	Based on NYISO forecast. Sensitivity performed to remove contracts and see the effect on LCR-IRM curve. Results should not impinge on IRM. Sensitivity with 20 MW MISO wheel through Ontario to Zone A).	
Retirements	2008 Gold Book over ten year period	As per the CRP
Planned Outages	Per 2009 CRP, based on schedules received by NYISO & adjusted for history., constant over ten year period	As per the CRP
Outage Scheduling Planned	Continue with approximately 150 MW after reviewing last year's data.	As per the maintenance schedules in long term adequacy studies
Gas Turbines Ambient Derate	Continue with approximately 150 MW after reviewing last year's data, constant over ten year period	Reflected only in summer/winter ratings
Environmental Modeling Adders Externalities Allowances	Studied as scenarios. Built into the development of cost curves of resources. Optimization is cost driven.	Any impacts assumed in CRP carried forward. Limits on emissions done through allowances, not hard limits Allowance cost from Chicago Climate Futures Exchange

Parameter	Modeling for CARIS Base Cases	Basis for Recommended Assumptions for CARIS
Commitment and Dispatch Options Operating Reserves	Each Balancing Authority Commits separately Hurdle Rates are employed for commitment and dispatch Operating Reserves as per NYCA requirements	
Fuel Price Forecast	EIA data obtained quarterly, adjusted for seasonality on monthly basis, monthly volatility based on historical patterns	NYISO to calibrate forecast based on public information and historical data
Cost Curve Development	Developed from Heat Rate Curve, Fuel Price forecast, environmental adders, penalty factors	Allowances from Chicago Climate Futures Exchange, Heat Rate development under discussion, confidential issues
Heat Rates NYCA External Systems	Developed from vendor supplied data and fuel input data matched with MWhr data for NYCA	
Local Reliability Rules	List and develop appropriate nomograms	Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits
Energy Storage Gilboa PSH Lewiston PSH	Gilboa and Lewiston scheduled against NYCA	
Transmission System Model		
Power Flow Cases	As per CRP	
Interface Limits Monitored/contingency pairs Nomograms Joint, Grouping Unit Sensitive Voltage	Transfer limit analysis done in RNA/CRP for critical interfaces. External system limits from input from neighboring systems.	Based on historical congestion, planning study results, NERC book of flowgates, PROBE/SCUC list of active/potential constraints, Special Protections Systems?
New Transmission Capability	As per CRP	
Internal Controllable Lines (PARs,DC,VFT)	Optimized in simulation	
Neighboring Systems		
Outside World Area Models	Power flow data from CRP, "production" data developed by NYISO with vendor and neighbor input	

Parameter	Modeling for CARIS Base Cases	Basis for Recommended Assumptions for CARIS
Fuel Forecast	Linked with NYCA forecast	
External Capacity Load Forecast	Firm and grandfathered are included. Neighboring systems data reviewed and held at required reserve margin	Neighboring systems modeled consistent with reserve margins in the RNA/CRP analysis
System representation in Simulation	HQ modeled as load/gen pair Full Representation/Participation - NYISO - NE-ISO - IESO - PJM Classic & <u>Full Representation:</u> NYISO,NEISO,IESO,PJM (PJM Classic, AP,AEP,CE,DLCO,DAY,VP) <u>Proxy Bus:</u> HQ-NYISO, HQ-NEISO <u>Transmission Only/Zeroed Out:</u> MECS,FE,SPP, MAR, NIPS,OVEC,TVA, FRCC,SERC,ERCOT,WECC	
External Controllable Lines (PARs,DC,VFT, Radial lines)	A,B,C and J,K "wheel" Both sets set at 600 min, 1200 max, imbalance monitored Ramapo +/- 1000 MW Norwalk +/- 100 MW L33,34 - +/- 300 MW PV20 – 130, 0 MW Neptune and CSC as per CRP firm X 24 hrs, economy remainder	

Below are descriptions of key data in more detail. The data was developed based on the OATT and in collaboration with stakeholders. Input assumptions based on the 2009 RNA/CRP

C.1. Generic Solution Cost Matrix

A potential generic solution was determined by NYISO utilizing each resource type (generation, transmission, and demand response) as required in Tariff attachment Y Section 11.3c. The development of the generic solutions and their costs were accomplished by using a cost matrix methodology. 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. The block sizes, assumptions and cost estimates were vetted through the stakeholder process at the ESPWG.

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 NY. The order of magnitude cost estimates took into account the cost differences between geographical areas within NY. Three sets of costs were developed that are reflective of the differences in labor, land and permitting costs between Upstate, Downstate and Long Island.

All costs were reviewed by the Transmission Owners and Market Participants 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. It should be noted that the Demand Response resource type costs were based on New York utility filings for their Demand Side Management programs. The NYISO will consider utilizing a customer installed cost approach in future CARIS analysis.
Estimates included in the Potential Generic Solution Cost Matrix should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates.

Generic Solutions Cost Matrix

Table C - 2: Transmission Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Potential Generic Solution
Transmission Cost Matrix
Order of Magnitude Unit Prices

(Estimates should not be assumed reflective or predictive of actual project costs)

		Transmission					Substation	
Item #	**Location**	**Line System Voltage (kV)**	**Block Ampacity (Amp)**	**Block Capacity (MVA)**	**Construction Type**	**Transmission Cost ($M/Mile)**	**Line Terminal Addition per Substation ($M)**	**System Upgrade Facilities ($M)**
T-1 High	Zone A-G	345	1673	1000	Overhead	$5.0	$9.0	$9.0
T-1 Mid	Zone A-G	345	1673	1000	Overhead	$3.5	$6.0	$6.0
T-1 Low	Zone A-G	345	1673	1000	Overhead	$2.0	$3.0	$3.0
T-2 High	Zone H-J	345	1673	1000	Undergrd	$25.0	$40.0	$50.0
T-2 Mid	Zone H-J	345	1673	1000	Undergrd	$20.0	$25.0	$30.0
T-2 Low	Zone H-J	345	1673	1000	Undergrd	$15.0	$10.0	$10.0
T-3 High	Zone K	138	2092	500	Undergrd	$20.0	$20.0	$25.0
T-3 Mid	Zone K	138	2092	500	Undergrd	$15.0	$12.0	$15.0
T-3 Low	Zone K	138	2092	500	Undergrd	$10.0	$4.0	$5.0

Assumptions:

1. ***Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input, a review of recent proposed transmission projects in NY, and reaching consensus at the ESPWG.***

2. Lines constructed within Zones A through G will be comprised of single circuit AC overhead construction.

3. Lines constructed within Zones H through K will be comprised of AC underground cable construction.

4. The transmission line will be interconnected into an existing 345kV substation for Zones A-J and 138kV for Zone K.

5. The cost for lines that cross between Zones G and Zones H or I will be pro-rated as overhead or underground based on the mileage of the line included within each Zone.

6. The line can be permitted and constructed utilizing the shortest distance between the two selected substations.

7. The existing substation selected as the interconnection point consists of open air construction and has sufficient space within the fenced yard for adding a new breaker and a half bay for the new line terminal. If the selected substation is Gas-Insulated, a factor of 4 times will be applied to the base substation terminal costs.

8. The control house at the existing substations selected as the interconnection point has sufficient space for installing the new protection and communication equipment for the new line terminal.

9. Estimates include costs for material, construction labor, engineering labor, permits, testing and commissioning. The estimates do not include Allowance of Funds During Construction (AFDC)

10. The cost per mile includes a range to account for the variable land and permitting costs associated with a project such as utilizing an existing ROW, expanding an existing ROW or obtaining new ROW.

11. The substation line terminal costs include a range to account for necessary protection and communication equipment.

12. System Upgrade Facilities costs include a range to account for line terminal relay upgrades and replacement of overdutied breakers.

13. If upon a cursory review of 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, etc. Field inspections will not be completed as part of the cursory review.

Table C - 3: Generation Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Potential Generic Solution
Generation Cost Matrix
Order of Magnitude Unit Costs

(Estimates should not be assumed reflective or predictive of actual project costs)

Item #	Plant Location	Plant Block Size Capacity (MW)	Plant Cost per Block Size ($M)	Electric Unit Transmission Cost ($M/Mile)	Substation Terminal Cost ($M)	System Upgrade Facilities ($M)	Gas Unit Transmission Cost ($M/Mile)	Gas Regulator Station Cost ($M)
G-1 High	Zone A-G	250	$400.0	$5.0	$9.0	$9.0	$5.0	$3.0
G-1 Mid	Zone A-G	250	$330.0	$3.5	$6.0	$6.0	$3.5	$2.0
G-1 Low	Zone A-G	250	$260.0	$2.0	$3.0	$3.0	$2.0	$1.0
G-2 High	Zone H-J	250	$480.0	$25.0	$40.0	$50.0	$20.0	$3.0
G-2 Mid	Zone H-J	250	$400.0	$20.0	$25.0	$30.0	$15.0	$2.0
G-2 Low	Zone H-J	250	$320.0	$15.0	$10.0	$10.0	$10.0	$1.0
G-3 High	Zone K	250	$470.0	$20.0	$20.0	$25.0	$5.0	$3.0
G-3 Mid	Zone K	250	$390.0	$15.0	$12.0	$15.0	$3.5	$2.0
G-3 Low	Zone K	250	$310.0	$10.0	$4.0	$5.0	$2.0	$1.0

Assumptions

1. ***Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input, a review of recent proposed generation projects in NY, and reaching consensus at the ESPWG.***

2. It is assumed that the plant will be gas combined cycle type. Configured as a 2 x 1 7EA block with selective catalytic reduction (SCRs), total generation 250MW.

3. The plant cost includes real estate and permitting.

4. The plant cost includes generator step-up transformer and generator substation yard including associated protection and communication equipment.

5. The plant will be interconnected into an existing 345kV substation for Zones A-J and 138kV for Zone K.

6. The generator lead will be rated 345kV, 1673A, 1000MVA for Zones A-J and 138kV, 2092A, 500MVA for Long Island. The generator lead will be built with overhead construction for Zones A-G and underground construction for Zones H-K.
7. It is assumed that the existing substation selected as the interconnection point consists of open-air construction and has sufficient space within the fenced yard for adding a new breaker and a half bay for the new line terminal. If the selected substation is gas-insulated, a factor of 4 times will be applied to the base substation terminal costs.

8. It is assumed that the plant will require a 10in dia. gas line extension to bring a 450 psig gas supply to the plant and a single gas regulator station per block along with gas conditioning, startup gas heaters and metering. It is assumed that an adequate gas supply is available.

9. It is assumed that the existing substation selected as the interconnection point and outgoing transmission lines has adequate rating to interconnect new generation.

10. It is assumed that the control house at the existing substation selected as the interconnection point has sufficient space for installing the new protection and communication equipment for the new line terminal.
11. It is assumed that the generator lead and gas line can be permitted and constructed utilizing the shortest distance.

12. It is assumed that the ROW is generally unobstructed and significant relocation of underground interferences is not required and that rock excavation is not required.

13. It is assumed that the ROW does not require mitigation of environmentally sensitive areas.

14. Estimates include costs for material, construction labor, engineering labor, permits, testing and commissioning. The estimates do not include Allowance of Funds During Construction (AFDC)
15. The plant cost includes a range to account for the variable land and permitting costs associate a project.

16. The cost per mile includes a range to account for the variable land and permitting costs associated with a project such as utilizing an existing ROW, expanding an existing ROW or obtaining new ROW.
17. The substation line terminal costs include a range to account for necessary protection and communication equipment.

18. System Upgrade Facilities costs include a range to account for line terminal relay upgrades and replacement of overdutied breakers.

19. The transmission and gas transmission unit cost will be applied during the study as necessary dependent on the location of the congestion location to be studied.
20. If upon a cursory review of 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, etc. Field inspections will not be completed as part of the cursory review.

Table C - 4: GENERATOR COST PER UNIT - 2009 PRICE LEVEL

GENERATOR COST PER UNIT - 2009 PRICE LEVEL									
	DESCRIPTION	REFERENCE USED	MATL	LABOR		SUBTOTAL DIRECT COST	PROJECT INDIRECTS	LAND AND PERMITTING	TOTAL WITH PROJECT INDIRECTS
			M$	GENERIC M$	ADJUSTED FOR ZONE M$	M$	20%	M$	
UPSTATE	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173.0	$61.5	$99.6	$272.6	$54.5	$0.2	$327.3
DOWN STATE	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173.0	$61.5	$150.0	$323.0	$64.6	$12.0	$399.6
LONG ISLAND	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173.0	$61.5	$149.2	$322.2	$64.4	$1.4	$388.0

Table C - 5: Demand Response Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Potential Generic Solution
Demand Response
Order of Magnitude Unit Costs

(Estimates should not be assumed reflective or predictive of actual project costs)

Item #	Demand Response Block Size (MW)	Portfolio Type	Location	Unit Cost ($M/MW)	Total Portfolio Cost ($M)
D-1 High	100	Energy Efficiency	Zone A-G	$4.2	$420

D-1 Mid	100	Energy Efficiency	Zone A-G	$2.8	$280
D-1 Low	100	Energy Efficiency	Zone A-G	$1.4	$140
D-2 High	100	Demand Response	Zone A-G	$1.6	$158
D-2 Mid	100	Demand Response	Zone A-G	$1.1	$105
D-2 Low	100	Demand Response	Zone A-G	$0.5	$53
D-3 High	100	Energy Efficiency	Zone H-J	$5.7	$570
D-3 Mid	100	Energy Efficiency	Zone H-J	$3.8	$380
D-3 Low	100	Energy Efficiency	Zone H-J	$1.9	$190
D-4 High	100	Demand Response	Zone H-J	$2.1	$210
D-4 Mid	100	Demand Response	Zone H-J	$1.4	$140
D-4 Low	100	Demand Response	Zone H-J	$0.7	$70
D-5 High	100	Energy Efficiency	Zone K	$3.9	$390
D-5 Mid	100	Energy Efficiency	Zone K	$2.6	$260
D-5 Low	100	Energy Efficiency	Zone K	$1.3	$130
D-6 High	100	Demand Response	Zone K	$2.7	$270
D-6 Mid	100	Demand Response	Zone K	$1.8	$180
D-6 Low	100	Demand Response	Zone K	$0.9	$90

Assumptions

1. ***Estimates herein should not be utilized for purposes outside of the CARIS process. Also, these estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these generic solution order of magnitude estimates. Estimate ranges were identified after Transmission Owner input and reaching consensus at the ESPWG.***

2. Costs are based on representative NY utilities' Demand Side Management filings.

3. Expected peak demand impact was used to scale the present value of the total portfolio budget to produce 100MW peak reduction.

4. Costs from each portfolio are based on 10 years of peak demand reduction.

5. Cost estimation is developed by dividing each year's cost by the peak demand reduction for that year and then calculating the present value of the $/MW over a 10 year period.

6. The range is derived from the utility filings as the "Low" and the "Mid" and "High" represents 2 and 3 times the "Low", respectively.

7. Due to a lack of Demand Response filing data for Upstate, it is assumed that the Upstate costs will be 75% of the Downstate costs. This is representative of the cost difference between to the Energy Efficiency programs for the two areas.

Appendix D – CARIS Benchmarking

Benchmarking Process

Appendix E – 2009 Detail Analyses of CARIS Phase 1

E.1. Congestion Assessment – Historic and Projected

One of the features of a Locational Marginal Price (LMP) based market is the ability to identify grid locations that are difficult to serve with economic generation due to transmission bottlenecks (constraints) and quantify the cost of this congestion. The NYISO calculates and publishes LMP's with three components:

1. Energy component – Marginal electricity cost without the adjusted cost of congestion and losses.
2. Congestion component – Cost of out-of merit generation dispatch relative to an assumed unconstrained reference point at Marcy substation.
3. Losses component – Cost for supplying the losses from the accessible marginal generators to the grid point in question.

The cost of congestion commonly reported is the simple sum of the day ahead market LMP congestion component times the amount of load being affected (positively or negatively) by congestion (later referred to as "congestion payments"). While this congestion cost is relatively simple to calculate, this value is generally felt to be an over-simplified and deceiving congestion impact metric because:

1. This calculation does not incorporate the effect of supply and demand response when congestion is removed.
2. The congestion cost is relative to an assumed uncongested reference point. If this reference point is moved, the congestion cost is shifted to the LMP energy component. The congestion versus energy cost calculation becomes arbitrary depending on the reference point chosen.

To better measure the true cost of transmission congestion, analysis tools and protocols were developed by the NYISO. The fundamental idea is to calculate what the day-ahead hourly clearing prices would be if there were **no** transmission constraints, using the same data and calculation approach as the NYISO Security Constrained Unit Commitment software (SCUC). The congestion cost then is the difference between the actual SCUC transmission constrained LMP's, loads, and bids, and the same calculation with all transmission constraints ignored. Annual cost is the sum of daily costs.

The reported numbers are the result of a simulation of the NYCA market using the hourly bids and network status actually used by NYISO to clear the day-ahead market. The simulation performs a security constrained unit commitment for the market "as it was", then removes all transmission constraints (other constraints such as desired net interchange (DNI), generator ramp rates and minimum run times are still enforced). Unit commitment and dispatch are then recalculated for this unconstrained scenario with no changes in bids from those actually submitted. The constrained and unconstrained results are compared to derive the cost of congestion. All calculations represent all market segments (e.g., fixed load, virtual load and generation, imports and exports), and actual hour-by-hour network status. The unconstrained scenario fixes the amount of virtual load and generation at their original MW levels.

The major differences between the historical and projected congestion values are:

a. Historical congestion values include virtual bidding and projected congestion values do not; and
b. Historical congestion values include the impact of transmission outages and projected congestion values do not.

Congestion Metrics

To suit various needs for viewing the impact of congestion, four congestion metrics were developed. All metrics report the difference between a constrained and an unconstrained value.

1. Change in Production Cost – This is the primary congestion impact metric chosen for use by the NYISO Operating Committee. The calculation compares the total production cost, based on mitigated bids, with and without transmission constraints limiting the unit commitment and dispatch. This measures the economic inefficiency introduced by the existence of transmission bottlenecks. In a sense, this is the *societal cost* of transmission congestion. A positive number means that transmission congestion increased electricity production cost.

An advantage of this metric is that production cost will always decrease when constraints are removed. The direct objective of SCUC is to minimize bid production cost; LMP's are the result of the commitment and dispatch that result from achieving this objective under generating unit and transmission constrained conditions. Since SCUC does not directly attempt to minimize LMP's, relieving all or some of the constraints may or may not decrease the market based electricity cost to load. In LMP markets, the load in a location pays the marginal price of the supply at that location, not the bid price. The result of constraint relief in an LMP market depends on how much load is affected, where the load is, and the response of supply and demand as constraints are relieved.

2. Change in Congestion Payments – This calculation, the sum of the LMP congestion component times the load affected, ignores the energy cost change as constraints are removed. With no simulation truly required to arrive at this congestion impact metric (the congestion cost in an unconstrained market is 0), this is the *accounting cost* of congestion.

Congestion payments can be hedged with transmission congestion contracts (TCC's) resulting in the unhedged congestion numbers reported. For this analysis, it was assumed that all TCC's are owned by load and are available for hedging congestion payments. A positive number means congestion increases load cost.

3. Change in Generation Payments –In addition to the LMP payments to generation (or other supply sources such as virtual generation, or imports), generators are also paid a Bid Production Cost Guarantee (BPCG) and for Ancillary Services (AS). BPCG compensates generators that are committed for reliability despite the fact their bids are greater than the LMP at the generator location. This can happen if ramp rates, minimum

run times or other limits force unit operation, which minimizes overall production cost, even including BPCG payments. A positive number means generation payments went up due to congestion.

4. Change in Load Payments – This metric is the opposite side of the generation payments calculation. The calculation uses simulation to include the local energy cost response when transmission constraints are removed. Where the first congestion metric measures efficiency, this metric determines how much more New York load actually pays due to congestion and the market design; that is, the *bills impact*. The load payments congestion impact includes the effect of all market segments that can change when transmission constraints are relieved. These segments are:

- LMP Components: While the LMP congestion component will be pushed to zero when no transmission constraints exist, the unbottled generation will sell more energy at a slightly higher price (in accordance with the bid curves), albeit at a lower bid than the units put on out-of-merit in the transmission limited case. This results in a likely increase in the LMP energy component as the LMP congestion component decreases. The LMP loss component will also change depending on the location and prices of the generation unbottled when constraints are relieved. Ancillary service costs (e.g., reserves) also affect LMP's, as generators trade-off between selling ancillary services or energy.
- Load payments due to congestion are hedged with TCC's, leading to the reported unhedged load payment. In this analysis, it was assumed that all TCC's were credited to load. The TCC auction cost is ignored, as it is part of the Transmission Service Charge (TSC).
- TCC shortfall – In the event of a TCC shortfall (or surplus), the load pays for the imbalance. As transmission constraints are relieved or removed the imbalance changes. While the shortfall may be compensated for elsewhere in the TSC, from a congestion impact perspective this is considered a load cost. Although the NYISO OATT describes details of the allocation of shortfall by transmission owner, for this analysis shortfall is stated for the NYCA only.
- Schedule 1 imbalances – In accordance with the NYISO OATT, imbalances of energy and loss payments are a component of the OATT defined Schedule 1 payments. Relieving or eliminating transmission constraints affects these payments, and is thus considered a congestion impact in this analysis. Like shortfall, this analysis states the Schedule 1 effect for the NYCA only. A positive number means congestion increases load payments.

.

The historic and projected congestion metrics are shown in Table E - 1 through Table E - 7.

Table E - 1: Historic and Projected Congestion Metrics (2004-2018)

YEAR	CARIS Metrics - DAM bid based[(1)] million$				NYCA Actual GWh		
	Load Payment	Generator Payment	Production Cost[(2)]	Congestion	Demand	Generation	Interchange
2004	10,059	8,615	N/A	831	160,211	147,171	13,040

2005	15,314	13,153	N/A	1,382	167,208	153,265	13,943
2006	11,969	10,241	N/A	1,541	162,237	148,359	13,878
2007	12,831	10,840	N/A	1,451	167,341	150,407	16,934
2008	15,485	12,178	N/A	2,540	165,613	144,619	20,994
	PROJECTED				**PROJECTED**		
2009	7,409	6,772	4,206	118	168,128	158,034	10,094
2010	9,817	8,714	5,159	119	169,747	155,017	14,730
2011	10,046	8,894	5,309	128	170,954	155,679	15,274
2012	10,520	9,269	5,578	140	171,927	155,939	15,988
2013	10,760	9,471	5,739	94	173,156	156,723	16,433
2014	11,343	10,000	6,074	99	174,800	158,246	16,553
2015	11,786	10,333	6,361	113	176,177	158,513	17,664
2016	12,369	10,779	6,678	134	178,250	159,559	18,691
2017	12,910	11,222	7,041	154	179,283	160,061	19,222
2018	13,618	11,638	7,190	186	180,427	158,571	21,856

(1) Source: Annual Congestion Report

(2) Market Reports reports Bid Production Cost values, which are negative numbers caused by a high number of negative market bids (Nuclear Units and other Bilaterals)

Table E - 2: Historic Congestion Demand Payment (2004-2008) by Zone

Congestion Demand Payment m$					
	Historical				
Area	**2004**	**2005**	**2006**	**2007**	**2008**
West	(0.66)	(4.93)	0.90	(14.10)	(25.15)
Genessee	0.52	(1.33)	1.62	(14.01)	(9.42)
Central	0.49	(1.18)	3.46	9.41	18.42
North	(0.03)	(1.12)	(0.15)	(0.25)	(1.75)
Mohawk Valley	0.10	(0.34)	2.14	4.57	9.84
Capital	7.48	19.31	27.20	73.75	143.40
Hudson Valley	4.87	19.94	54.40	86.86	175.45
Millwood	2.74	11.81	26.73	30.78	78.02
Dunwoodie	4.39	23.56	44.11	56.12	124.41
NYCity	581.84	808.65	672.90	700.03	1402.66
Long Island	229.47	507.96	708.16	517.93	624.44
Total	**831.2**	**1,382.3**	**1,541.5**	**1,451.1**	**2,540.3**

Historical Congestion Source: PROBE DAM quarterly reports
DAM data include Virtual bidding & Transmission planned outages
Projected Congestion Source: NYISO CARIS Base Cases

Table E - 3: Projected Congestion Demand Payment (2009-2018) by Zone

Congestion Demand Payment m$										
	Projected									
Area	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	(12.64)	(15.37)	(15.71)	(17.29)	(24.33)	(22.25)	(23.64)	(26.59)	(29.25)	(34.21)

Genessee	(5.21)	(4.34)	(4.29)	(4.33)	(13.41)	(12.01)	(12.91)	(14.90)	(17.03)	(21.14)
Central	0.29	1.13	1.29	1.33	0.18	0.47	0.12	0.01	0.19	(0.55)
North	0.49	0.21	0.24	0.32	0.18	0.14	0.20	0.32	0.38	0.81
Mohawk Valley	0.93	0.69	0.80	0.89	0.57	0.64	0.69	0.81	0.98	1.04
Capital	6.92	5.74	6.91	8.47	6.07	6.82	8.39	10.87	13.97	16.86
Hudson Valley	9.90	8.06	9.77	11.03	8.73	9.09	10.45	12.66	15.23	18.92
Millwood	3.05	2.51	3.03	3.38	2.71	2.77	3.18	3.82	4.54	5.64
Dunwoodie	7.14	5.66	6.81	7.60	6.07	6.20	7.03	8.36	9.84	12.27
NYCity	66.41	45.39	49.93	56.43	43.18	46.63	57.42	69.52	82.54	103.38
Long Island	40.44	69.09	69.00	72.58	63.89	60.78	61.85	69.00	72.25	82.73
Total	**117.7**	**118.8**	**127.8**	**140.4**	**93.8**	**99.3**	**112.8**	**133.9**	**153.6**	**185.7**

Table E - 4: Historical Load Payment (2004-2008) by Zone

Load Payment m$					
	Historical				
Area	**2004**	**2005**	**2006**	**2007**	**2008**
West	855	1,196	868	983	1,061
Genessee	741	874	649	668	754
Central	717	1,097	779	928	1,060
North	288	473	351	413	474
Mohawk Valley	359	551	400	443	469
Capital	735	1,022	720	818	1,008
Hudson Valley	498	883	761	864	1,114
Millwood	207	344	252	263	385
Dunwoodie	452	544	442	494	706
NYCity	3,665	5,739	4,394	4,696	5,919
Long Island	1,540	2,591	2,353	2,261	2,535
Total	**10,059**	**15,314**	**11,969**	**12,831**	**15,485**

Historical Load Payment Source: PROBE DAM quarterly reports
DAM data include Virtual bidding & Transmission planned outages
Projected Congestion Source: NYISO CARIS Base Cases

Table E - 5: Projected Load Payment (2009-2018) by Zone

Load Payment m$										
	Projected									
Area	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	624	807	820	852	873	922	954	990	1,029	1,086
Genessee	404	534	541	563	570	606	630	657	686	719
Central	679	897	915	951	975	1,027	1,063	1,107	1,151	1,212
North	285	376	384	400	410	430	442	458	473	501
Mohawk Valley	309	415	424	442	451	474	490	509	528	544
Capital	506	670	685	720	737	776	807	846	889	942
Hudson	492	655	674	705	720	759	787	824	863	911

Valley										
Millwood	123	164	169	177	182	191	198	207	217	230
Dunwoodie	298	394	404	420	428	446	460	479	500	528
NYCity	2,593	3,441	3,545	3,746	3,858	4,098	4,291	4,550	4,762	5,043
Long Island	1,096	1,464	1,486	1,546	1,556	1,616	1,663	1,743	1,811	1,902
Total	**7,409**	**9,817**	**10,046**	**10,520**	**10,760**	**11,343**	**11,786**	**12,369**	**12,910**	**13,618**

Table E - 6: Historical Generator Payment (2004-2008)

Generator Payment m$					
	Historical				
Area	**2004**	**2005**	**2006**	**2007**	**2008**
West	1,356	1,971	1,530	1,630	1,701
Genessee	314	435	418	491	476
Central	1,493	2,282	1,612	1,753	1,825
North	543	760	633	659	779
Mohawk Valley	150	336	230	206	234
Capital	415	747	704	883	1,175
Hudson Valley	1,093	1,174	533	571	532
Millwood	900	1,371	1,145	1,252	1,725
Dunwoodie	22	88	56	39	39
NYCity	1,291	2,308	1,895	2,072	2,405
Long Island	1,036	1,682	1,485	1,282	1,286
Total	**8,615**	**13,153**	**10,241**	**10,840**	**12,178**

Historical Generator Payment Source: PROBE DAM quarterly reports
DAM data include Virtual bidding & Transmission planned outages
Projected Congestion Source: NYISO CARIS Base Cases

Table E - 7: Projected Generator Payment (2009-2018) by Zone

Generator Payment m$										
	Projected									
Area	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	1,000	1,324	1,343	1,396	1,419	1,495	1,543	1,596	1,653	1,736
Genessee	191	250	255	265	266	280	289	300	308	310
Central	1,346	1,722	1,750	1,823	1,868	1,965	2,025	2,100	2,181	2,280
North	363	476	485	505	520	550	570	591	622	635
Mohawk Valley	146	191	194	203	207	217	226	235	243	257
Capital	716	1,000	1,017	1,063	1,086	1,143	1,178	1,232	1,277	1,330
Hudson Valley	198	283	291	309	312	333	342	362	386	388
Millwood	777	1,017	1,035	1,082	1,094	1,142	1,176	1,224	1,268	1,335
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NYCity	1,482	1,709	1,761	1,834	1,900	2,029	2,121	2,239	2,342	2,457
Long Island	552	743	764	790	798	845	864	900	942	911
Total	**6,772**	**8,714**	**8,894**	**9,269**	**9,471**	**10,000**	**10,333**	**10,779**	**11,222**	**11,638**

E.2. Selection of three studies

E.3. Potential Generic Solutions

E.4. Benefit/Cost Analysis (including additional metrics)

Disclaimers

- No verification has been completed to determine if the generic solution can be built within the generic cost estimate ranges.

- The generic solutions analysis is performed to provide a rough estimate of the benefit to cost opportunity.

- The NYISO does not guarantee that the benefit to cost ratio determined for the generic solutions can be achieved.

E.4.1. Primary Metric Results

E.4.2. Additional Metrics Results

E5. Scenario Analysis

Appendix F – CARIS Manual (link)

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

Appendix G - 2009 RNA and CRP Reports (link)

The 2009 RNA and CRP reports can be found through the following links:

http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/RNA_2009_Final_1_13_09.pdf

http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP__FINAL_5-19-09.pdf