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

Appendices B-G

4~~3~~th DRAFT REPORT

October 27~~0~~, 2009

For Discussion Purposes Only

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

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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 a two-year cycle.

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 Initial CARIS Manual – Criteria for the Selection of CARIS Studies, Appendix F.~~,~~

During this process, requests for additional studies from stakeholders are 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 Initial CARIS Manual – 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 will also be used if there are insufficient market-based solutions for the ten-year study period. Additional information can be found in Initial CARIS Manual – 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 response) 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 Initial CARIS Manual – ~~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~~ generic solution. Additional benefit metrics calculated include estimates of reduction in losses, changes in LBMP load payments, ~~costs,~~ changes in generator payments, changes in ICAP costs, changes in e~~E~~mission costs, and changes in TCC payments. Additional details can be found in Initial CARIS Manual – 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 a cursory review of the location for the ~~potential~~ generic solution identifies unusual complexities, a contingency factor will be applied to the costs.

To add 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 report including a discussion of assumptions, inputs, methodology, and results of the analyses. The draft report shall be submitted to both TPAS and the ESPWG for review and comment. Following completion of that review, the draft report shall be sent to the Business Issues Committee and the Management Committee for discussion and action. Following the Management Committee vote, the draft report, with Business Issues Committee and Management Committee input, will be forwarded to the NYISO Board for review and action. Concurrently, the draft report will be provided to the Independent Market Monitor Adviser for his review and consideration. Upon approval by the Board, the NYISO shall issue the Study Phase of the CARIS report 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.

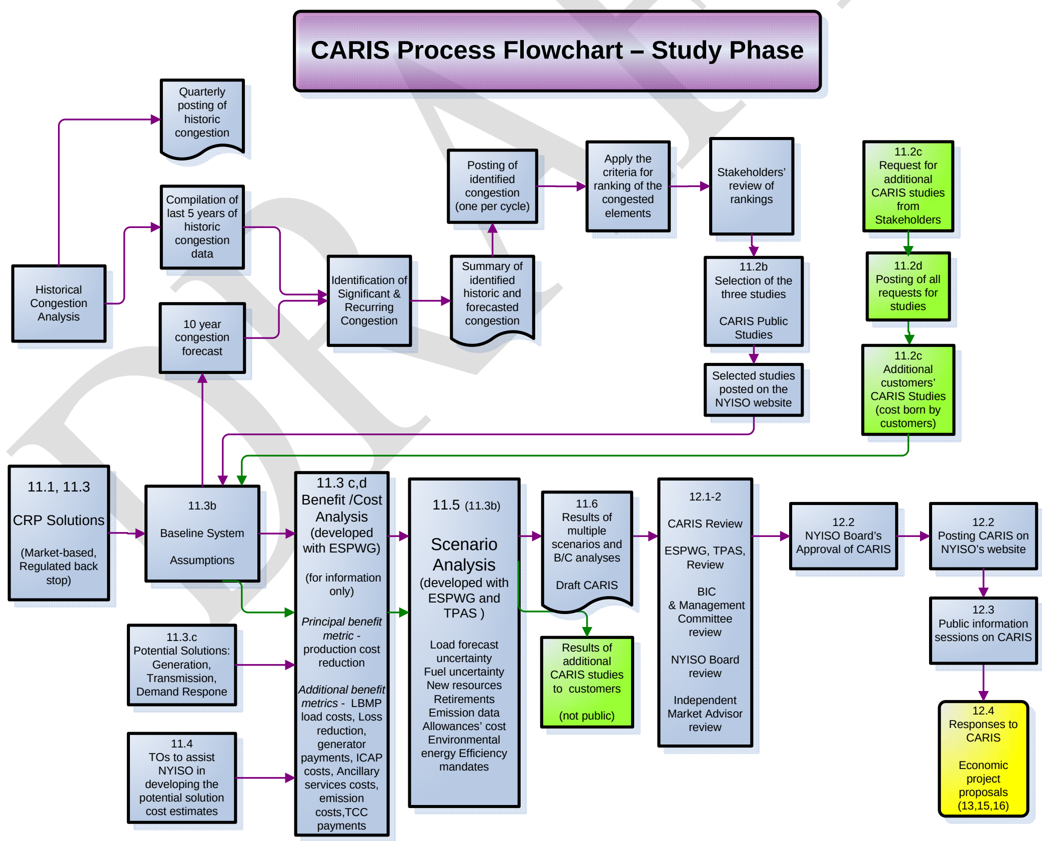


Figure B-1 – Phase 1 or Study Phase of the CARIS Process

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 projects proposed in response ~~s~~ to congestion identified in the CARIS ~~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[1].

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 Benefit/Cost (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 ratio >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 changes in: LBMP load costs, generator payments, ICAP costs, emissions costs, losses and TCC

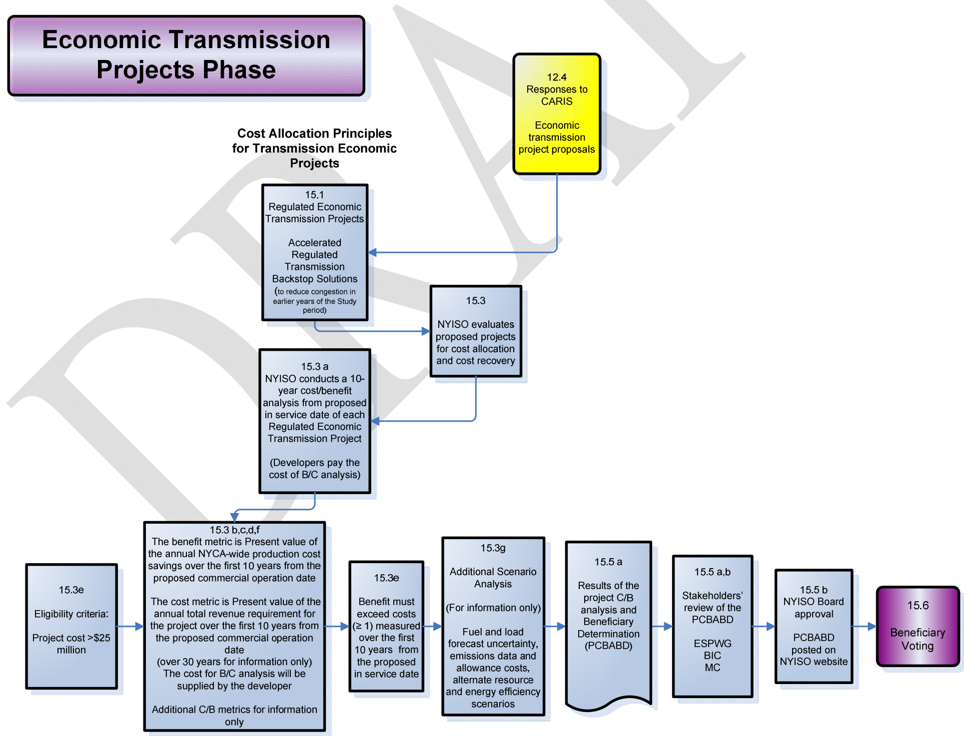
[1] A procedure on the acceleration of regulated backstop solutions is still under the development

revenues. 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 Initial CARIS Manual– 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[2]. 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.



[2] The NYISO benefit/cost analysis will be forwarded to the BIC and to the MC for discussion and action. The beneficiary determination and associated voting percentages will be provided to the BIC and the MC for review and comment, but not approval.

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

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 load serving 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 of 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 CARIS Procedure - 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 the Initial CARIS Manual - Voting Procedures (to be finalized), Appendix F.

If the proposed economic transmission project has a B/C ratio >1 over the first ten years from the proposed commercial operation date of the project, the total capital cost of the proposed project is greater than $25 million, and it 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.

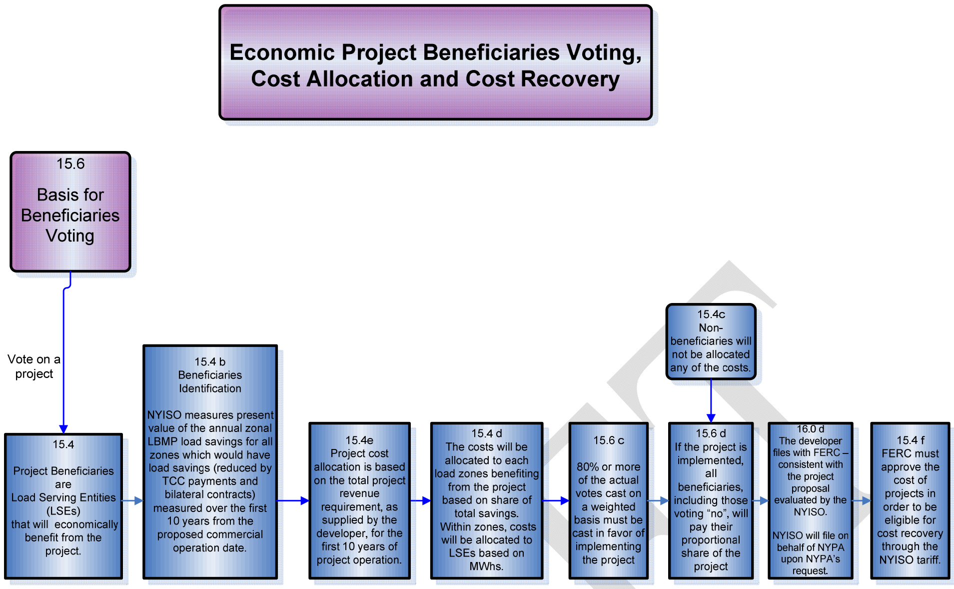


Figure B-3 –Voting, Cost Allocation, and Cost Recovery of the CARIS process

The CARIS procedure to identify beneficiaries of each proposed projects is currently under development. Other Phase 2 procedure under development include: Methodology to extend database beyond the study period (15.3.a); Acceleration of regulated backstop solutions for economic reasons (15.1); and process for specific regulated economic transmission projects proposals (15.3).

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Appendix C – Baseline System Assumptions and Methodology

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, unit heat rates, unit capacities, fuel prices, transmission constraint modeling, load growth and shape representation, both simulated and actual and scheduled interchange values, O&M cost, and environmental cost components. The assumption matrix was developed with the ESPWG.

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

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Parameter	Modeling for CARIS Base Cases	Basis for Recommended Assumptions for CARIS
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)	N/A
Wind Resource Modeling	Existing units derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %. New units	Typical shape for location as per MARS and wind studies.

Parameter	Modeling for CARIS Base Cases	Basis for Recommended Assumptions for CARIS
	from wind shapes from wind study.	
Non-NYPA Hydro Capacity Modeling	Pondage Run of River(Hourly)	N/A
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.	N/A
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).	N/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	N/A
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	N/A
Transmission System Model		
Power Flow Cases	As per CRP	N/A
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 including Athens SPS in 2009 and 2010.
New Transmission Capability	As per CRP	N/A
Internal Controllable Lines (PARs,DC,VFT)	Optimized in simulation	N/A
Neighboring Systems		
Outside World Area Models	Power flow data from CRP, “production” data developed by NYISO with vendor and neighbor input	N/A

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	N/A
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	N/A

Below are descriptions of key data in more detail. The data was developed based on the Tariff and in collaboration with stakeholders.

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~~1.~~Power Flow Data

CARIS uses the network topology, system impedance and transmission line ratings that were developed from the 2009 CRP power flows. The following power flow cases were developed for the CARIS from the 2008 FERC Form 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 and 2017, the power flow cases were based on data provided in the FERC Form 715 2013 Summer Peak Load case. PJM system changes modeled in PJM's 2012 Regional Transmission Expansion Plan (RTEP) Study and NYISO system changes described in the 2009 CRP Study required changes to these power flow cases, such as additional generators and transmission lines, to capture the sequencing of these additional resources. The FERC Form 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 Form 715 Winter 2013/2014 Peak Load case were used for all years assessed in the CARIS.

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~~1.1~~Transmission Model

New York Control Area Model

Figure C-1 below displays the bulk power system for NYCA, which is generally facilities 230 kV and above, but also includes certain 138 kV facilities and a small number of 115 kV facilities. The balance of the facilities 138 kV and lower are considered non-bulk or sub-transmission facilities for purposes of this study. The figure also displays key transmission interfaces for New York.

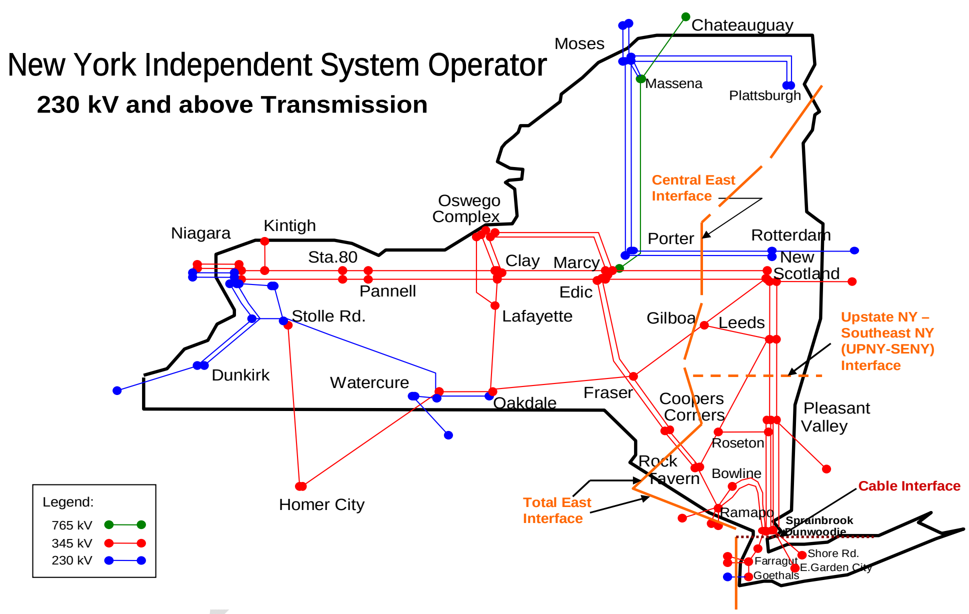

Figure C-1: NYISO 230 kV and above Transmission Map

New York Control Area Changes, Upgrades and Resource Additions

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

a. Caithness Long Island – new 320 MW, Combined Cycle, LIPA, Suffolk, NY, Commercial Operation – 4/2009;

b. BesiCorp – new 660 MW, Combined Cycle, National Grid, Rensselear, NY, proposed Commercial Operation 2/2010;

c. Polleti – 890.7 MW, retirement expected 2/2010;

d. M29 – 345 kV transmission line from an existing station in Yonkers, NY to a new substation in NYC, expected in-service date Summer 2011;

e. Athens Special Protection System (SPS) is scheduled to expire in 2010

f. Linden VFT – proposed commercial operation date December 2009.

External Area Model

The external areas immediately adjacent to the NYCA are also modeled at full representation except for Hydro Quebec (HQ). Those areas include ISO-NE, IESO, and PJM (PJM Classic, AP, AEP, CE, DLCO, DAY and VP). Since HQ is asynchronously tied to the bulk system, proxy buses representing the direct ties from HQ to NYISO and HQ to ISO-NE are modeled. External areas surrounding the above areas are only modeled to capture the impact of loop flows.

Table C-2 illustrates the external transmission limits used in the CARIS Study.

Table C-2: 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
ISO-NE	Boston	4900	4900	4900	4900	4900	4900
ISO-NE	Connecticut-Export	2200	2200	2200	2200	2200	3600
ISO-NE	East-West (NE-NY)	2100	2100	2100	2100	2100	2100
ISO-NE	ISO-NE EXPORT	4000	4000	4000	4000	4000	4000
ISO-NE	ISO-NE-NYISO	1400	1400	1400	1400	1400	1400
ISO-NE	LI – ISO-NE	450	450	450	450	450	450
ISO-NE	ME – NH	1400	1400	1400	1400	1400	1500
ISO-NE	NB – NEPOOL	500	500	500	500	500	500
ISO-NE	North – South	2700	2700	2700	2700	2700	2700
ISO-NE	Norwalk-Stamford	1300	1300	1300	1300	1300	1300
ISO-NE	Orrington South	1050	1050	1050	1050	1050	1050
ISO-NE	SEMA	1450	1450	1450	1450	1450	1450
ISO-NE	SEMA/RI	2200	2200	2200	2200	2200	2200
ISO-NE	South West CT	2350	2350	2350	2350	2350	3650
ISO-NE	Surowiec South	1150	1150	1150	1150	1150	1150

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Area	Interface	2009	2010	2011	2012	2013	2014
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

Two major transmission additions in the PJM area are included in the base cases. The first addition is the TrAIL Line, which is located in PJM and is scheduled to enter commercial operation in 2010. The second addition is the Susquehanna-Roseland 500 kV addition, which is located in PJM and is scheduled to enter commercial operation in 2013.

Hurdle Rates and Interchange Models

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

Two independent 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 the 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 2009-2018 study period. Hurdle rates on several closed and open interfaces were used to model regional power imports, exports and wheel-through transactions. These hurdle rates are frequently used 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 rate values in the CARIS databases are consistent with previous NYISO and consultant studies, and are considered standard industry practice. In addition, the annual NYISO imports are consistent with historic import levels, confirming that NYISO's hurdle rate assumptions are reasonable.

Only energy transactions associated with Unforced Capacity Delivery Rights (UDRs) granted on controllable tie lines were specifically modeled, namely on the NYISO DC tie-lines (Neptune and Cross Sound Cable (CSC)). Flows on those facilities were not subject to hurdle rates and the required firm commitment was modeled in the associated neighboring system. It should be noted that the flow on the CSC line was allowed to reverse direction (i.e., flow toward ISO-NE) but the Neptune flows was restricted to no more than 660 MW in one direction into Long Island. The reverse flow toward PJM was not allowed to occur in the simulation because exports from NYCA to PJM are not presently allowed on Neptune line.

In regard to Interchange, the hourly interchange flow for each interface connecting the NYISO with neighboring control areas, was priced at the LBMP of its corresponding proxy-bus. The summation of all 8760 hours determined the annual cost of the energy for each interface. Table C-3 lists the proxy bus location for each interface.

Table C-3: Interchange LBMP Proxy Bus

Interface	Proxy-Bus
PJM	Keystone
Ontario	Beck
Quebec	Chateauguay
Neptune	Atlantic 230 kV
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor

Interface	Proxy-Bus
PJM	Keystone
Ontario	Beck
Quebec	Chateauguay
Neptune	Atlantic 230kV
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor

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~~2.~~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 in 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 production costs of generators. The incremental cost of generation is the product of the incremental heat rate multiplied by the sum of fuel cost, emissions cost, and variable operation and maintenance expenses

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 US Environmental Protection Agency's (EPA) Clean Air Market Data. Accordingly, this data set was used to calculate unit heat rates and incremental heat rates across each unit's operating range through the use of regression analysis techniques. First, second, and third order polynomials were 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 the 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 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.

CARIS simulation models employ power points which are points in each unit's 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 for each unit.

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

Heat Rates of marginal units in all zones display the expected seasonal patterns with summer months having the highest values. Also, there is a progression by which the monthly averages are the lowest in Zone A. The further east a zone is located, the higher the implied heat rate is. The relative magnitudes of differences across zones are consistent with the differences in the generation fuel-mixes as depicted in Figure C-3.

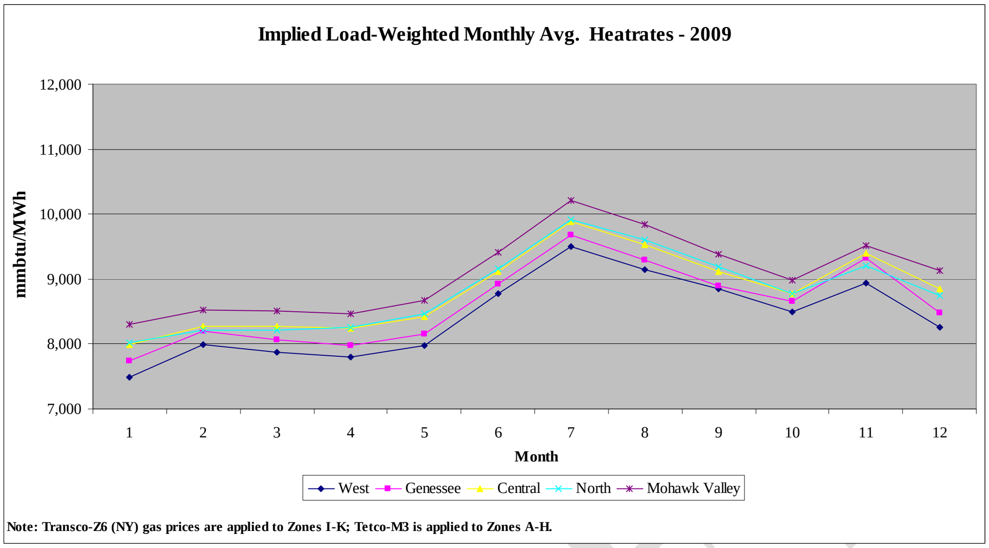

Figure C-3: Implied load-weighted monthly average heat rates for Upstate NY

The implied heat rates for all downstate zones, Figure C-4, display the expected seasonal patterns. The heat rates of marginal units are highest for Millwood (Zone H), Hudson Valley (Zone G), and Long Island (Zone K). With respect to Zones G and J, the difference in assumed gas prices explains the relative heat rate parity during non-winter months, and the divergence during the winter months.

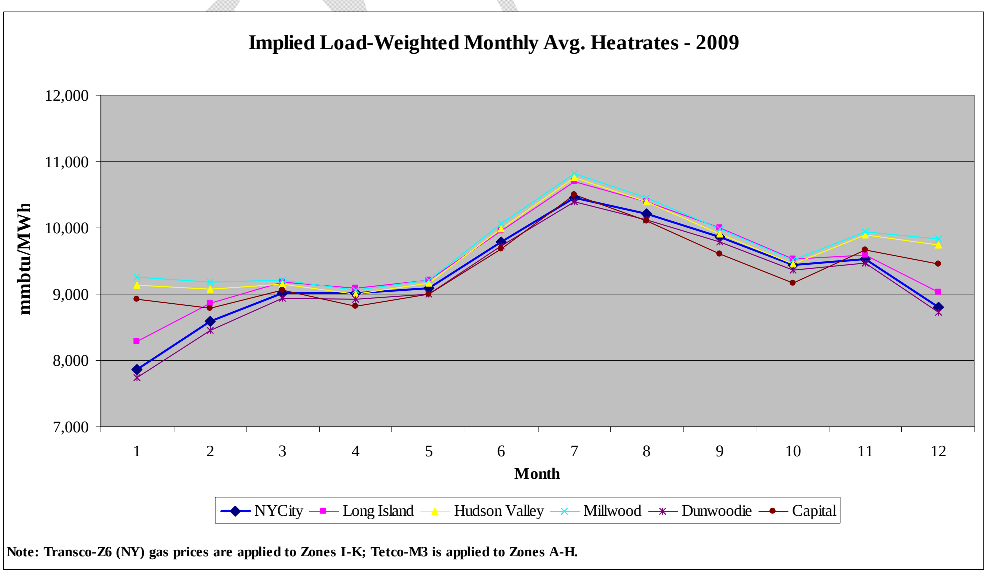

Figure C-4: Implied load-weighted monthly average heat rates for Downstate NY

Fuel forecast

Figures C-5 and C-6 illustrate forecasted oil and natural gas fuel prices for external areas.

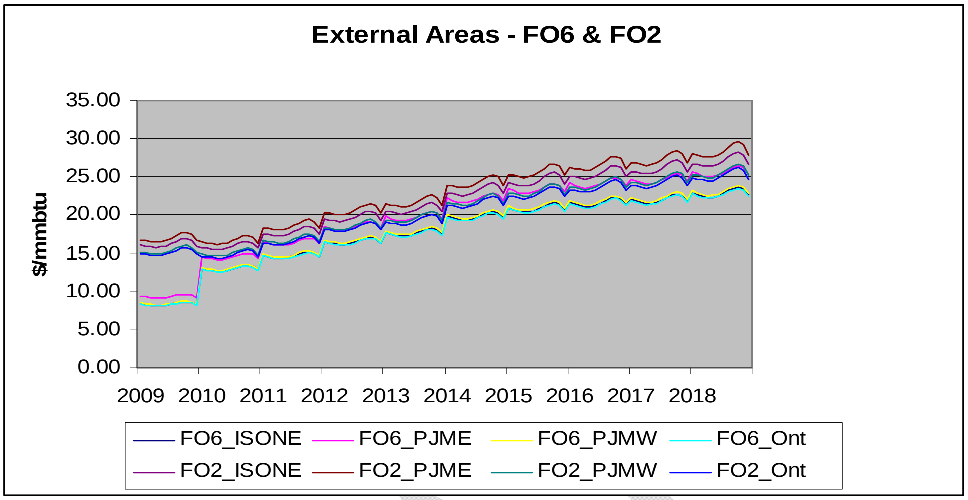

Figure C-5: Forecasted oil fuel prices for ISO-NE, PJM, & Ontario

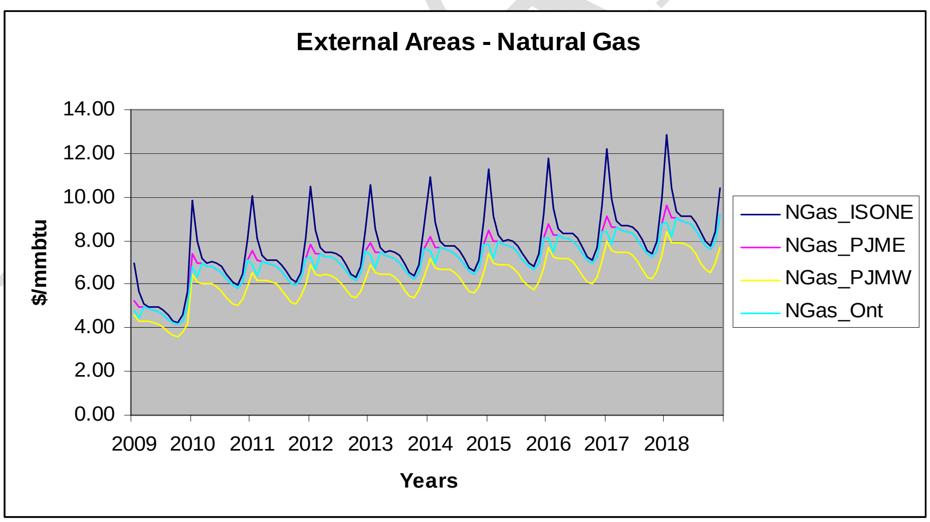

Figure C-6: Forecasted natural gas prices for ISO-NE, PJM, & Ontario

Fuel Switching

Fuel switching capability is widespread within NYCA. In the NYCA, 37% of the 2009 generating capacity, or 14,470 MW, has the ability to burn either oil or gas. There are three-reasons that generating facilities would exercise the capability to burn oil: the first reason is that oil would be the economic fuel of choice, the second reason would be to satisfy reliability rules, and the third reason would be and interruption of the gas supply. Historically, significant quantities of oil have been used at the prices illustrated in Figure C-7.

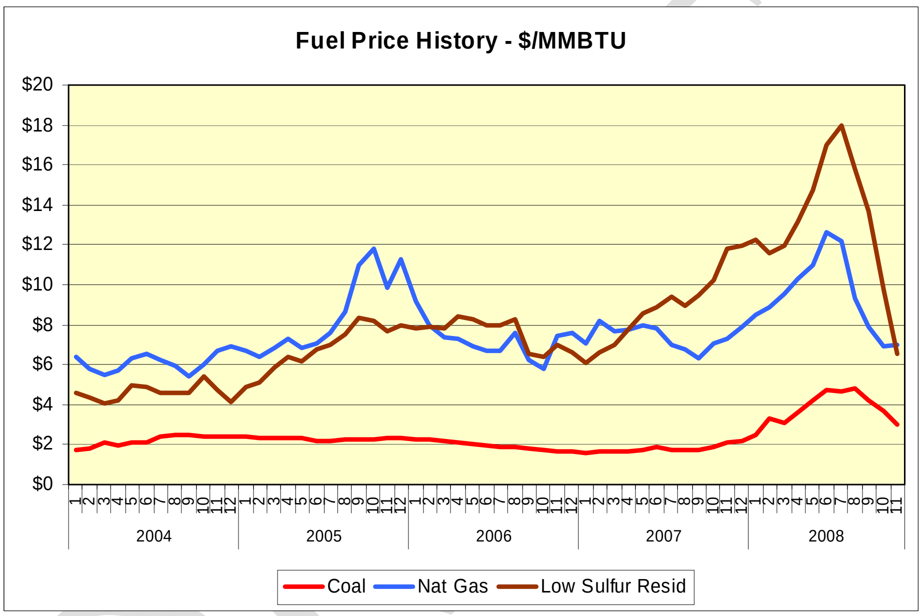

Figure C-7: Historical fuel prices of coal, natural gas, and low sulfur coal

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 State Reliability Council (NYS~~E~~RC) 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 loss becomes critical because it may result in voltage collapse when load levels are high enough. Therefore, criteria are established whereby certain units that are capable of doing so are required to switch to minimum oil burn levels so that in the event of the worst gas system contingency these units stay on-line at minimum generation levels and support system voltage. This MW deficiency must be made up first through the increased use of imports until oil burning units are able to ramp up their output over a longer timeframe. Some new combined cycle gas turbine units in these zones have the ability to "switch-on-the-fly" from gas-burn to oil-burn with a limited loss of output that can be quickly recovered. However, there is the risk that this live switching may not be successful and the unit may trip. Therefore, in many cases, such units are required to switch to burning oil at lower load levels so there is the ability of recovering from an unsuccessful switching. As the generator fleet in these zones has experienced 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, Northport #4 is forced to use oil operation only in summer, and Ravenswood #3 is up to its minimum load levels. For operation at higher load levels, the models simulate these units as dual fuel units that selected the economic fuel.

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, which was modified to include the unforced outage duration.

~~3.~~Generic Solution Cost Matrix

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

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.

During the stakeholder review process, it was noted that the cost for new generation in Zone G may be more closely matched to the costs seen Downstate in (Zones H-I) versus costs seen in Upstate (Zones A-F). In reviewing the generation costs for various Zones that were prepared for the ICAP Demand Curve study reported in the *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator* report~~,~~ with respect to peaking units, the costs for new generation in Zone G falls half way between the costs for Zone F and Zone J. Therefore, the combined cycle generator plant costs for Zone G (exclusive of interconnection costs) are estimated to be the average of the costs for Upstate and Downstate.

The Demand Response resource type costs were based on New York utility EEPS filings for their Demand Side Management programs which consider the potential market value and not actual costs to build or implement DSM[3]. The NYISO will consider developing a customer installed cost approach in future CARIS analysis so that cost estimates for all resource types will be predicting actual cost to implement such a project.

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

Generic solutions cost matrix and assumptions for all three types of solutions are presented in Table C-4 through Table C-7 below.

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[3] The actual cost estimates for Demand Response solutions will be considered in the next CARIS cycle.

Table C - 4: Transmission Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Attachment 1

~~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~~ generic 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.
Note: For future CARIS studies, the NYISO will utilize an additional block size of 138kV, 500MVA for Zone J in order to address potential congested load pockets in NYC and at such time develop the respective cost estimates.

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Table C -5: Generation Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase

Attachment 1

~~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-F	250	$400.0	$5.0	$9.0	$9.0	$5.0	$3.0
G-1 Mid	Zone A-F	250	$330.0	$3.5	$6.0	$6.0	$3.5	$2.0
G-1 Low	Zone A-F	250	$260.0	$2.0	$3.0	$3.0	$2.0	$1.0
G-1 High	Zone G	250	$440.0	$5.0	$9.0	$9.0	$5.0	$3.0
G-1 Mid	Zone G	250	$365.0	$3.5	$6.0	$6.0	$3.5	$2.0
G-1 Low	Zone G	250	$290.0	$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~~ generic 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.
Note: For future CARIS studies, the NYISO will utilize an additional block size of 138kV, 500MVA for Zone J in order to address potential congested load pockets in NYC and at such time develop the respective cost estimates.

Table C -6: 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	UNIT COST
				GENERIC	ADJUSTED FOR ZONE		20%			$/Kw
UPSTATE	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173,000,000	$61,500,000	$99,600,000	$272,600,000	$54,520,000	$200,000	$327,300,000	$1,309
DOWNSTATE	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173,000,000	$61,500,000	$150,000,000	$323,000,000	$64,600,000	$12,000,000	$399,600,000	$1,598
LONG ISLAND	250 MW	GENERIC 2 X 2 X 1 7EA + SCR ($ 938/KW DIR)	$173,000,000	$61,500,000	$149,200,000	$322,200,000	$64,440,000	$1,400,000	$388,000,000	$1,552

Table C - 7: Demand Response Cost Matrix

Base Case Modeling Assumptions for 2009-2018 CARIS Study Phase
Attachment 1
~~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 – Overview of CARIS Modeling

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. In general terms, production cost simulations calculate the hourly production cost of supply resources under security- constrained transmission network and area market conditions.

To estimate the cost of transmission congestion, procedures and protocols were developed by the NYISO. The fundamental idea is to calculate, using the same data and calculation approach as the NYISO's Security Constrained Unit Commitment software (SCUC), 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's Security Constrained Unit Commitment software (SCUC). The congestion cost is then calculated as the difference between the constrained transmission system and the unconstrained transmission system. Annual congestion cost is the sum of daily costs.

Grid View and MAPS

In conducting the CARIS analysis the NYISO utilized both GridView and MAPS as the production cost simulation software. Both GridView and MAPS software tools mimic the operation of the NYISO day ahead electricity market by simulating security constrained unit commitment (SCUC) and economic dispatch of the generation and by monitoring transmission system flows under both normal and contingency conditions. This enables calculation of hourly production costs in light of the constraints imposed by the transmission system on the economic dispatch of generation. Both programs feature the following:

- **Detailed representation of the large scale transmission network.** The transmission system is modeled in terms of individual transmission lines, interfaces (group of lines), phase-angle regulators (PARs), and high voltage direct current (HVDC) lines. Both GridView and MAPS software model voltage and stability considerations through operating nomograms that define how voltage and stability these limits can change hourly as a function of loads, generation, and flows elsewhere on the system.
- **Detailed generation modeling for thermal, hydro, pumped storage, wind, solar etc.** Generation system data capabilities include multi-step cost curves based on heat rates, emission costs, fuel costs, and unit cycling capabilities. The generation units, along with chronological hourly load profiles, are assigned to individual buses on the system. Hourly load profiles are adjusted to meet peak and energy forecasts, which are input entered into the model on a monthly or annual basis. Information on hourly loads at each bus in the system is required to 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.
- **Co-optimization of energy and ancillary services**

- **Post- contingency analysis for any given hourly dispatch**

PROBE -– PoRtfolio Ownership and Bid Evaluation

PROBE software, developed by PowerGEM LLC LLC, is the day-ahead market simulation tool which has been utilized used by the NYISO as an analysis tool to conduct the NYISO's historic congestion analysis. The results of this historic congestion analysis, expressed as a change in production costs, generator payments, load payments and congestion, have been reported on a quarterly basis on the NYISO's website since 2003. The results of PROBE analysis were also used in the benchmarking process of GridView and MAPS.

PROBE software provides market simulation by using uses a Linear Programming-based Security Constrained Economic Dispatch (SCED) and Security Constrained Unit Commitment (SCUC) engine. PROBE uses actual submitted generator parameters, hourly bids and network status (including transmission outages) used by the NYISO to clear the day-ahead market. It performs a simulation for the market "as it was," and then removes all transmission constraints (other constraints such as 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 change in bid production costs, load payments and generation payments. All calculations represent all market segments such as energy, start-up, and ancillary services bids for generators, import/export bids, virtual bids (virtuals), and fixed and price-capped demand bids.

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 was customized to model the NYISO's market rules, including rules regarding co-optimization of energy and ancillary services, mitigation, marginal losses, and other custom market rules.

The major difference between the GridView/MAPS results and PROBE results is that GridView/MAPS did not simulate in this CARIS cycle the following: a) virtual bidding; b) transmission outages; c) fixed load and price-capped load; d) production costs based on mitigated bids; e) Bid Production Cost Guarantee (BPCG) payments; f) co-optimization with ancillary services; g) and externals.

Modeling Validation

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 a NYISO System and Resource Planning team that was not involved in database modeling.

The following topics were examined as part of data verification:

- Forecasts of hourly load data for NYISO zones and external areas (externals);
- Hourly import and export schedules;
- Transmission system losses;
- Transmission interface transfer limits, contingencies & and nomograms;
- Generator incremental heat rates and emissions rates;
- Modeling of combined cycle units;
- Fuel price forecasts;
- Modeling of pumped storage & and 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, parameters were selected that most closely represented actual unit characteristics.

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 and used to develop scenarios. 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, similar to the first, was performed. 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.

2009 Quarter 1 Results

To be provided in the meeting.

~~The results from the CARIS model compared favorably when compared to actual results. In order to perform the benchmark of the CARIS model behavior, the congestion of the 2009 first quarter results from the Day-Ahead Market (DAM) were compared to the 2009 CARIS database. Many of the input assumptions were not lined up for this benchmark and only the three changes below were made to the 2009 CARIS database:~~

~~1. Reduce the Central East voltage limit from 2600 MW to 2400 MW to model the average value of this limit observed in that period. The value of this limit is highly dependent on transmission availability and system conditions.~~

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~~2. The Ravenswood 3 generating unit (900 MW) was modeled unavailable as the unit was out-of-service during the study period.~~

~~3. The Virtual Supply and Load bids that cleared the DAM were also included.~~

~~The total congestion values by constraints are shown in Table D-XX. Congestion on the Central East interface is within 8% ($106m vs. $98m). The actual congestion in the DAM is 20% higher and this is mainly caused by congestion of $45m on the Dunwoodie - Mt Haven 345kV contingency constraint (71 on 72 line and vice versa), which was not congested in the CARIS model. This congestion could be caused by lower line ratings (in DAM) on these facilities (needs to be checked), a higher load forecast and unavailability of critical generation in the area (due to economics or maintenance).~~

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Database Conversion Certification

The NYISO, in conjunction with the ESPWG, decided that the first CARIS cycle analysis would be performed using both GridView and MAPS simulation tools. To compare the results between the two tools, the NYISO undertook a process of converting the NYISO ABB-GridView database to the NYISO GE-MAPS database. In order to guarantee a correct data conversion, the NYISO developed a converter capable of creating the MAPS input files from the GridView database. In order to guarantee model logic and features consistency, the NYISO worked with GE and ABB to decide which model logic and features to use. The following data was validated: Load annual peaks and energies; installed capacity; the unit full-load costs; and other data, such as minimum up and down time, start-up costs, spinning reserve allocation, and outages. In order to check the quality of the conversion, many random checks were manually made, including interface limits, monitored elements and contingencies. Moreover, the generator shift factor (GSF) matrix was compared to verify that the same load flow was used. Finally, GE provided NYISO with the information to balance the initial condition of the MAPS Generation and Transmission (GT) program. In conclusion, validation of conversion process worked well as all the tests mentioned above passed and the conversion process was deemed successful.

Appendix E –Detailed Results of 2009 CARIS Phase 1

Congestion Assessment – Historic and Projected

One of the features of a Locational Based Marginal Price (LBMP) 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 LBMP'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.

Historic Congestion Assessment

The NYISO reports historic congestion results on its website on a quarterly basis. The cost of congestion commonly reported is the simple sum of the day ahead market LBMP 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 LBMP 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 is the difference between the actual SCUC transmission constrained LBMP'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.

Historic Congestion Metrics

To suit various needs for viewing the impact of congestion, four congestion metrics were developed: Bid Production Cost metric; Congestion Payment metric; Generator Payment metric; and Load Payment metric. All metrics report the difference between a constrained and an unconstrained value.

1. Change in Bid Production Cost (BPC) – 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; LBMPs 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 LBMPs, relieving all or some of the constraints may or may not decrease the market based electricity cost to load. In LBMP 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 LBMP 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 LBMP 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 LBMP 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. BPCG compensates generators that are committed for reliability despite the fact their bids are greater than the LBMP 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:

- LBMP Components: While the LBMP 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 LBMP energy component as the LBMP congestion component decreases. The LBMP 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 LBMPs, as generators trade-off between selling ancillary services or energy.
- Load payments due to congestion are hedged with TCCs, leading to the reported unhedged load payment. In this analysis, it was assumed that all TCCs 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.

Tables E-1 through E-3 present historic Base Case metrics' results.

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Table E - 1: 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)
Genesse	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

Table E -2: 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
Genesse	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

Table E -3: 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
Genesse	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 Assessment

CARIS Metrics

In conducting CARIS analysis, seven metrics are used. The primary metric is the production cost metric and the other six additional metrics are load payments, generator payments, emissions, TCCs, losses, and ICAP metric. All benefit metrics are 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 used for the present value analysis is the current weighted average cost of capital for the NYTOs.

1. NYCA Production Cost Metric

NYCA production cost is the total generation cost of producing power to serve NYCA 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 and Exports evaluated at the proxy busses LBMP values

2. Demand$_Congestion Payment

The congestion values (Demand$_Congestion Payments) are calculated as the congestion component of the LBMP 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 and all hours_ = (ShadowPrice x Zone GSF x Zone Load))

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

3. Generator Payment Metric

Generator payment is also referred to as generator revenues. It represents zonal LBMP 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 LBMP or spot price. The annual generator payment is then the sum of all 8,760 hourly generator payments.

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

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

4. LBMP Load Payment Metric

The LBMP Load Payment metric is the ~~, or LBMP load payment, is the total energy cost to consumers. It is a zonal LBMP based consumer payment.~~ h~~ H~~ourly load-weighted average LBMP price for each zone ~~is calculated and~~ multiplied by ~~with~~ the zonal load ~~to determine the hourly zonal load payment~~. ~~-~~The annual load payment is then the sum of all 8,760 hourly load payments.

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

Zonal LBMP = zonal average load-weighted LMP

Note: actual consumer payments will be net of any TCC hedges or bilateral contracts.

5. TCC metric (Congestion Rent)

The TCC payment metric is determined by calculating congestion rents. Congestion 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

6. ICAP Metric

The MW impact methodology is used in this first CARIS cycle to calculate the ICAP metric. GE's Multi-Area Reliability Simulation program (MARS) was used to determine the impact of each generic solution on the Loss of Load Expectation (LOLE) and the amount of capacity required to bee removed to bring the LOLE back in line with the base case. The generation solutions were modeled by creating a new 500MW combined cycle plant located in the appropriate zone using a two state model and typical NERC eFORD values for its transition rates. The demand response solutions were modeled by reducing the peak for the appropriate zone and increasing the emergency response value. The transmission solutions were modeled by modifying the transfer limits, as noted in Table E-4.

Table E- 4 - MARS Interface Modifications for ICAP Calculations

Central East Transmission Generic Solution	Leeds-Pleasant Valley Transmission Generic Solution	West Central Transmission Generic Solution
Central East-Fraser-Gilboa Interface increased by 400 MW	Central East-Fraser-Gilboa Interface increased by 50~~0~~ MW	West Central Interface Increased by 500 MW
Total East Group Increased by 400 MW	Total East Group Increased by 50~~0~~ MW	Dysinger East Interface Increased by 500 MW
Central East Group Increased by 400 MW	Central East Group Increased by 50~~0~~ MW	
	Zone F to Zone G Increased by 800 MW	
	UPNY-SENY Interface Increased by 350 MW	

When comparing historical values to projected values, one must bear in mind that there are significant differences in assumptions used by the PROBE and CARIS tools. The CARIS tools did not simulate the following: a) virtual bidding; b) transmission outages; c) fixed load and price-capped load; d) production costs based on mitigated bids; e) Bid Production Cost Guarantee (BPCG) payments; f) co-optimization with ancillary services; g) and externals.

Table E-5 below presents the summation of the CARIS metrics base case values over the ten-year study period in nominal ~~2009~~ $.

Table E-5: Projected CARIS Base Case Metrics ~~(nominal 2009 $ Millions)~~

	~~2009~~	~~2010~~	~~2011~~	~~2012~~	~~2013~~	~~2014~~	~~2015~~	~~20~~		
~~**Generator Production Cost ($m)**~~	~~4,095~~	~~5,135~~	~~5,297~~	~~5,560~~	~~5,729~~	~~6,048~~	~~6,346~~	~~6,707~~		
~~**Load Payments ($m)**~~	~~7,620~~	~~10,015~~	~~10,239~~	~~10,739~~	~~11,019~~	~~11,600~~	~~12,066~~	~~12,696~~	~~1~~	
~~**Generator LBMP Payment ($m)**~~	~~6,842~~	~~8,593~~	~~8,727~~	~~9,107~~	~~9,335~~	~~9,826~~	~~10,156~~	~~10,606~~	~~1~~	
~~**Load Payments Losses ($m)**~~	~~1,799~~	~~1,859~~	~~1,810~~	~~1,830~~	~~2,230~~	~~2,215~~	~~2,292~~	~~2,330~~		
~~**SO2 Cost ($m)**~~	~~5~~	~~3~~	~~3~~	~~3~~	~~3~~	~~2~~	~~1~~	~~1~~		
~~**SO2 Emissions (Tons)**~~	~~68,497~~	~~71,252~~	~~71,390~~	~~71,606~~	~~71,517~~	~~71,943~~	~~71,936~~	~~72,360~~	~~7~~	
~~**CO2 Cost ($m)**~~	~~194~~	~~208~~	~~232~~	~~251~~	~~268~~	~~288~~	~~304~~	~~321~~		
~~**CO2 Emissions (1000 Tons)**~~	~~55,435~~	~~53,782~~	~~54,196~~	~~54,350~~	~~54,775~~	~~55,502~~	~~55,685~~	~~56,237~~	~~5~~	

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~~NOx Cost ($m)~~	~~47~~	~~44~~	~~18~~	~~10~~	~~18~~	~~10~~	~~14~~	~~13~~	~~—~~	
~~NOx Emissions (Tons)~~	~~37,468~~	~~38,281~~	~~38,687~~	~~38,927~~	~~39,045~~	~~39,517~~	~~39,567~~	~~39,972~~	~~4~~	
~~LBMP ($/MWh)~~	~~45~~	~~58~~	~~59~~	~~61~~	~~62~~	~~65~~	~~67~~	~~70~~	~~—~~	

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Generator Production Cost ($m)	4,095	5,135	5,297	5,560	5,729	6,048	6,346	6,707	7,026	7,456
Load Payments ($m)	7,620	10,015	10,239	10,739	11,019	11,600	12,066	12,696	13,239	13,972
Generator LBMP Payment ($m)	6,842	8,593	8,727	9,107	9,335	9,826	10,156	10,606	11,012	11,547
Load Payments Losses ($m)	1,799	1,859	1,810	1,830	2,230	2,215	2,292	2,330	2,314	2,133
SO2 Cost ($m)	5	3	3	3	3	2	1	1	1	1
SO2 Emissions (Tons)	68,497	71,252	71,390	71,606	71,517	71,943	71,936	72,360	72,341	72,659
CO2 Cost ($m)	194	208	232	251	268	288	304	321	335	351
CO2 Emissions (1000 Tons)	55,435	53,782	54,196	54,350	54,775	55,502	55,685	56,237	56,533	56,797
NOx Cost ($m)	47	44	18	10	18	10	14	13	12	12
NOx Emissions (Tons)	37,468	38,281	38,687	38,927	39,045	39,517	39,567	39,972	40,377	40,602
LBMP ($/MWh)	45	58	59	61	62	65	67	70	72	76

The projected Base Case congestion metrics in nominal ~~2009 $~~ are shown in ~~**Error! Reference source not found.**~~Tables E-6 through E-16.

Table E - 6: Projected Production Costs (2004-2008) by Zone

Generator Production Cost m$	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	311	327	334	346	354	369	382	390	411	415
Genesse	56	56	56	57	59	61	66	68	69	74
Central	674	733	734	759	785	817	858	887	915	959
North	88	118	121	128	130	136	141	148	155	164
Mohawk Valley	22	27	30	32	34	37	40	43	42	51
Capital	597	1,018	1,032	1,088	1,108	1,156	1,200	1,257	1,303	1,387
Hudson Valley	114	149	157	172	173	187	194	205	216	233
Millwood	205	201	199	205	210	215	230	236	241	249
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NYCity	1,344	1,479	1,543	1,609	1,658	1,770	1,858	1,977	2,082	2,171
Long Island	483	611	648	680	696	741	764	806	846	902
NYISO Total	**3,895**	**4,718**	**4,855**	**5,075**	**5,208**	**5,489**	**5,732**	**6,017**	**6,279**	**6,607**
Interchange ~~face~~ Flow Value	200	417	441	485	520	559	615	690	748	849
Aggregate NYISO	**4,095**	**5,135**	**5,297**	**5,560**	**5,729**	**6,048**	**6,346**	**6,707**	**7,026**	**7,456**

Table E - ~~6~~7: Projected Load Payments (2009-2018) by Zone

Load Payments - m$	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	645	800	806	836	852	898	929	963	998	1050
Genessee	416	531	532	553	555	589	613	639	666	695
Central	695	890	898	933	965	1014	1049	1094	1136	1202

North	288	369	374	389	402	421	433	448	463	491
Mohawk Valley	317	413	417	435	448	470	486	505	524	541
Capital	515	672	677	713	733	770	801	842	884	935
Hudson Valley	504	669	692	725	743	781	810	849	888	940
Millwood	126	168	175	184	189	198	205	215	225	240
Dunwoodie	305	405	419	437	446	464	478	498	519	552
NYCity	2692	3627	3744	3966	4100	4350	4565	4864	5088	5377
Long Island	1117	1473	1505	1569	1585	1645	1696	1779	1849	1950
NYISO Total	**7,620**	**10,015**	**10,239**	**10,739**	**11,019**	**11,600**	**12,066**	**12,696**	**13,239**	**13,972**

Table E - ~~7~~8: Projected Generator Payment (2009-2018) by Zone

Generator LBMP Payment - m$

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	1083	1369	1374	1425	1440	1516	1565	1615	1666	1733
Genessee	193	243	244	254	253	266	275	285	291	290
Central	1357	1705	1710	1782	1842	1928	1985	2062	2129	2247
North	395	511	514	536	553	580	598	621	644	664
Mohawk Valley	141	182	183	191	198	209	216	225	231	248
Capital	780	1189	1177	1236	1274	1337	1385	1447	1501	1585
Hudson Valley	191	265	279	299	303	322	331	349	369	394
Millwood	796	1037	1065	1115	1131	1176	1212	1263	1306	1380
Dunwoodie	0	0	0	0	0	0	0	0	0	1
NYCity	1374	1436	1484	1541	1594	1698	1773	1882	1975	2055
Long Island	533	656	695	726	747	794	815	855	899	950
NYISO Total	**6,842**	**8,593**	**8,727**	**9,107**	**9,335**	**9,826**	**10,156**	**10,606**	**11,012**	**11,547**

Table E - ~~8~~9: Projected Losses Payment (2009-2018) by Zone

Load Payments Losses (M$)										
Zone	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	(18.54)	(43.45)	(44.73)	(47.85)	(43.97)	(45.35)	(44.81)	(47.67)	(50.84)	(56.71)
Genesse	(4.20)	(8.75)	(9.15)	(10.00)	(8.82)	(8.39)	(7.63)	(8.04)	(8.22)	(9.81)
Central	3.42	1.30	1.22	0.93	2.86	3.03	3.62	3.86	4.05	5.71

North	(2.29)	(4.62)	(4.67)	(5.08)	(4.82)	(4.37)	(4.29)	(4.79)	(5.17)	(3.48)
Mohawk Valley	10.70	12.28	12.39	12.88	13.39	14.15	14.70	15.25	15.98	16.15
Capital	27.96	36.08	36.69	38.90	39.22	40.66	41.83	44.14	46.62	50.82
Hudson Valley	41.49	57.72	58.43	61.45	62.03	64.40	65.73	69.16	72.14	75.80
Millwood	11.29	15.97	16.15	17.00	17.34	17.91	18.29	19.24	20.09	21.57
Dunwoodie	28.64	40.27	40.32	42.21	42.59	43.71	44.44	46.47	48.24	51.12
NYCity	272.32	387.30	389.95	415.07	425.07	445.60	459.90	490.24	510.89	540.20
Long Island	123.47	173.62	171.74	179.40	178.46	182.61	185.77	195.38	201.80	205.35
NYISO Total	494.27	667.71	668.35	704.90	723.36	753.97	777.56	823.24	855.57	896.72
IESO Total	(58.73)	(244.93)	(257.91)	(286.66)	(244.11)	(218.21)	(194.66)	(225.69)	(249.78)	(274.17)
PJM Total	935.50	786.68	747.23	725.89	1,074.96	985.83	1,012.61	1,024.61	982.96	708.36
NEISO	427.70	649.46	651.87	685.52	675.74	693.03	696.23	708.33	725.19	802.48
Total	1,798.73	1,858.92	1,809.55	1,829.65	2,229.94	2,214.62	2,291.74	2,330.49	2,313.94	2,133.39

Table E - ~~9~~10: Projected SO2 Emission Costs (2009-2018) by Zone

SO2 Cost - $ m	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	1.57	1.23	1.01	1.02	1.02	0.83	0.51	0.46	0.45	0.44
Genessee	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Central	1.18	1.01	0.83	0.83	0.83	0.67	0.42	0.37	0.36	0.36
North	0.13	0.07	0.06	0.06	0.07	0.05	0.03	0.03	0.03	0.03
Mohawk Valley	0.13	0.10	0.08	0.08	0.08	0.07	0.04	0.04	0.04	0.04
Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hudson Valley	0.94	0.69	0.57	0.57	0.57	0.47	0.29	0.26	0.25	0.25
Millwood	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Dunwoodie	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NYCity	0.05	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Long Island	0.52	0.30	0.26	0.26	0.27	0.22	0.13	0.12	0.12	0.12
NYISO Total	**4.52**	**3.43**	**2.84**	**2.85**	**2.86**	**2.33**	**1.43**	**1.29**	**1.26**	**1.25**

Table E - ~~10~~11: Projected SO2 Emission Tons (2009-2018) by Zone

SO2 Emissions (Tons)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	23790	25490	25475	25594	25415	25544	25482	25596	25572	25559
Genessee	0	0	0	0	0	0	0	0	0	1
Central	17870	21015	20855	20808	20769	20805	20880	20956	20797	21093
North	1896	1525	1518	1534	1629	1676	1700	1703	1760	1700
Mohawk Valley	1999	2085	2085	2092	2085	2086	2087	2093	2081	2087
Capital	68	81	81	81	82	83	84	85	84	87
Hudson Valley	14257	14321	14309	14409	14335	14386	14405	14502	14504	14567
Millwood	12	12	12	12	12	12	12	12	12	12
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NYCity	785	527	554	507	491	508	522	549	584	621
Long Island	7819	6196	6500	6569	6697	6841	6764	6864	6945	6932
NYISO Total	**68,497**	**71,252**	**71,390**	**71,606**	**71,517**	**71,943**	**71,936**	**72,360**	**72,341**	**72,659**

Table E - ~~11~~12: Projected CO2 Emission Costs (2009-2018) by Zone

CO2 Cost - $ m	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	44.98	51.85	57.49	62.29	65.83	69.90	73.63	77.16	80.36	83.80
Genessee	0.20	0.19	0.22	0.24	0.28	0.30	0.34	0.38	0.28	0.50
Central	30.25	33.59	37.11	40.03	42.89	45.67	48.20	50.51	52.54	54.97
North	3.65	3.86	4.31	4.73	5.09	5.47	5.84	6.23	6.61	7.11
Mohawk Valley	2.29	2.66	3.00	3.30	3.56	3.86	4.13	4.40	4.55	5.09
Capital	24.76	33.49	36.97	40.23	43.04	45.88	48.62	51.14	53.04	56.04
Hudson Valley	12.48	14.43	16.18	17.80	18.79	20.15	21.26	22.46	23.60	24.81
Millwood	1.54	1.70	1.88	2.04	2.16	2.28	2.40	2.52	2.61	2.72
Dunwoodie	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NYCity	53.06	45.01	50.73	54.25	58.45	63.22	67.28	71.60	75.37	78.35
Long Island	20.81	20.81	24.06	26.18	28.31	30.75	32.33	34.16	36.11	37.61
NYISO Total	**194.02**	**207.60**	**231.96**	**251.10**	**268.40**	**287.50**	**304.04**	**320.55**	**335.07**	**351.00**

Table E - ~~12~~13: Projected CO2 Emission Tons (2009-2018) by Zone

SO2 Emissions (Tons)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	23790	25490	25475	25594	25415	25544	25482	25596	25572	25559
Genessee	0	0	0	0	0	0	0	0	0	1
Central	17870	21015	20855	20808	20769	20805	20880	20956	20797	21093
North	1896	1525	1518	1534	1629	1676	1700	1703	1760	1700
Mohawk Valley	1999	2085	2085	2092	2085	2086	2087	2093	2081	2087
Capital	68	81	81	81	82	83	84	85	84	87
Hudson Valley	14257	14321	14309	14409	14335	14386	14405	14502	14504	14567
Millwood	12	12	12	12	12	12	12	12	12	12
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NYCity	785	527	554	507	491	508	522	549	584	621
Long Island	7819	6196	6500	6569	6697	6841	6764	6864	6945	6932
NYISO Total	**68,497**	**71,252**	**71,390**	**71,606**	**71,517**	**71,943**	**71,936**	**72,360**	**72,341**	**72,659**

Table E - ~~13~~14: Projected NOx Emission Costs (2009-2018) by Zone

NOx Cost - $ m	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
West	13.89	13.16	5.26	3.12	5.38	2.82	3.97	3.88	3.60	3.51
Genessee	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Central	10.38	11.04	4.41	2.61	4.52	2.37	3.33	3.26	3.01	2.95
North	0.29	0.25	0.10	0.07	0.12	0.07	0.10	0.11	0.11	0.13
Mohawk Valley	0.15	0.15	0.07	0.04	0.08	0.05	0.07	0.08	0.07	0.09
Capital	2.12	2.34	0.93	0.56	0.97	0.51	0.72	0.71	0.65	0.65
Hudson Valley	5.88	5.68	2.33	1.42	2.43	1.30	1.82	1.81	1.72	1.68
Millwood	1.31	1.19	0.48	0.28	0.49	0.25	0.36	0.35	0.32	0.31
Dunwoodie	-	-	-	-	-	-	-	-	-	-
NYCity	4.07	2.64	1.08	0.63	1.10	0.59	0.84	0.84	0.80	0.79
Long Island	8.72	7.11	2.94	1.75	3.07	1.64	2.29	2.26	2.10	2.06
NYISO Total	**46.83**	**43.60**	**17.61**	**10.48**	**18.17**	**9.61**	**13.52**	**13.32**	**12.39**	**12.19**

Table E - ~~14~~15: Projected NOx Tons (2009-2018) by Zone

NOx Emissions (Tons)										
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	11112	11552	11557	11596	11566	11614	11611	11656	11725	11693
Genessee	23	23	23	23	25	27	28	30	23	36
Central	8302	9694	9682	9691	9701	9737	9756	9791	9798	9829
North	232	223	229	248	263	286	306	342	371	447
Mohawk Valley	119	132	145	161	174	195	209	230	236	305
Capital	1696	2058	2045	2064	2087	2111	2120	2135	2128	2160
Hudson Valley	4707	4989	5127	5254	5231	5346	5336	5439	5601	5601
Millwood	1047	1047	1047	1050	1047	1047	1047	1050	1047	1047
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NYCity	3253	2320	2368	2324	2354	2425	2456	2528	2610	2624
Long Island	6977	6242	6463	6515	6596	6730	6698	6771	6836	6860
NYISO Total	**37,468**	**38,281**	**38,687**	**38,927**	**39,045**	**39,517**	**39,567**	**39,972**	**40,377**	**40,602**

Table E - ~~15~~16: Projected Zonal LBMP (2009-2018) by Zone

LBMP $/MWh										
Zone	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
West	41.1	50.7	51.0	52.8	53.6	56.1	57.8	59.6	61.4	63.9
Genessee	41.9	52.9	53.2	55.2	55.2	57.9	59.7	61.6	63.5	66.1
Central	42.7	54.1	54.5	56.6	58.3	60.9	62.6	64.8	67.1	70.8
North	42.1	53.4	53.8	55.9	57.5	60.2	62.0	64.1	66.4	70.2
Mohawk Valley	44.0	55.8	56.2	58.4	60.1	62.7	64.6	66.9	69.3	72.9
Capital	45.2	58.3	58.6	61.2	62.4	65.0	67.1	69.7	72.5	76.3
Hudson Valley	46.8	60.7	62.1	64.8	66.0	68.7	70.8	73.5	76.3	80.4
Millwood	47.1	61.4	63.1	65.9	67.0	69.7	71.8	74.6	77.4	81.8
Dunwoodie	47.4	61.8	63.5	66.3	67.4	70.1	72.3	75.1	77.9	82.3
NYCity	48.3	63.6	64.8	67.7	69.0	71.9	74.3	77.5	80.6	84.4
Long Island	48.6	64.1	65.4	68.2	69.3	71.9	74.1	77.1	80.0	84.1
NYISO Total	**45.03**	**57.90**	**58.75**	**61.19**	**62.33**	**65.01**	**67.02**	**69.51**	**72.04**	**75.74**

Selection of Three Studies

The selection of the three CARIS studies is a two-step process as described below.

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In Step 1, both historic and projected congestion elements for a fifteen year period are ranked in ascending order based on the calculated present value of Demand$ Congestion. Initially the top five positive and top two negative congested elements are identified for further consideration. This initial list is then revised to include any orphaned elements if their projected congestion is higher than other elements' project congestion. The elements are removed from the list which shows a significant decline thus indicating a diminishing return. The remaining top five congested elements are then further considered for inclusion in Step 2.

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In Step 2, the top five congested elements from Step 1 are relieved independently to identify the grouped elements and to calculate the production cost savings for each group. The top congested elements are relieved by increasing their limit to 9999 for a mid and horizon year. The primary constraint will be assessed for grouping with a new element if the new element is electrically adjacent to the primary element and in the top five of congested elements based on Demand$ Congestion. If the new element meets these criteria, then process will be repeated again with the new element's limit also increased to 9999 to identify any additional electrically adjacent elements that become significantly congested. The elements are grouped if the production cost savings are increased by 50% or more. If after the initial grouping the production cost savings is not more than $3 Million, then the primary element is eliminated from the list. If more than three grouped elements meet all the criteria, then the three with the most production cost savings are selected as the three studies. The production cost savings based on modifying an existing element's limit will be different than that achieved when applying a transmission solution since an impedance value for a line is not being introduced..~~The selection of the three CARIS studies is a two-step process. In Step 1, both historic and projected congestion data for each constrained element is compiled and congested elements are ranked in ascending order based on the calculated present value. In Step 2, the top five congested elements from Step 1 are relieved independently to identify the grouped elements and production cost savings for each group are calculated. Grouped elements are then ranked based on the highest production cost savings. The top three congested groupings represent the three CARIS studies.~~ ~~Make more narrative. Add the limit vs. impedance change discussion.~~

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~~Step 1 - Selection of Elements for Study Consideration~~

~~Prioritization~~

~~•Line up historic congested elements and projected elements for a fifteen year period based on Demand$ Congestion~~

~~•Identify elements that:~~

~~•Are common to both~~

~~•Are missing from one or the other (orphaned)~~

~~•Show negative projected congestion~~

~~•Are exceptions for diminishing returns~~

~~•Calculate Present Value of congestion (using Demand$ Congestion metric) for common elements, sort and identify top five for candidates for relaxing test~~

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~~Review the exceptions :~~

~~•Diminishing returns - if a congested element shows a significant decline, exclude from list~~

~~•Negative congestion – Rank on absolute value and add top two as candidates~~

~~•Orphaned – Compare ranking value to just the 10 years of projected above and if greater substitute~~

~~•Given all of the considerations in the above, identify the top five elements.~~

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~~Step 2 - –Grouping Elements for CARIS Studies~~

~~In order to identify additional elements that may have a significant impact on congestion, each element being studied in Step 1is relieved independently of each other by replacing its limit with 9999 for a mid and horizon year (2013 and 2017).~~

~~The resultant list of top congested elements from the two years of analysis will be reviewed to determine:~~

~~The resultant reduction in total NYCA congestion~~

~~If any additional new elements become congested~~

~~Significant increase in the other primary element's congestion~~

~~Production cost savings from the relaxation~~

~~The primary constraint will be assessed for grouping with a new element if the new element is:~~

~~electrically adjacent to the primary element~~

~~in the top five of congested elements based on Demand$ Congestion~~

~~If passes above, the new element's limit will also be increased to 9999~~

~~Elements are grouped if the production cost savings increases by 50% or more~~

~~Repeat process if other additional elements pass above criteria~~

~~If after an initial grouping, the change in total NYCA production cost is not more than 3 million dollars, the original primary constraint will be removed from the list~~

~~If more than three groupings are revealed, the three groupings with the highest improvement in production cost savings will be selected as the three studies.~~

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Table E-~~16~~ 17 shows the Dollar Demand Congestion for the Base Case and the relaxation cases for year 2013 and 2017. None of the relaxation tests resulted in an increase in congestion on an electrically adjacent line except for Leeds-Pleasant Valley. The relaxation of the Leeds-Pleasant Valley line did result in an increase in congestion on the Leeds-New Scotland line. However, the increased congestion is not enough to place it in the top five congested elements. Therefore, it is not grouped with the Leeds-Pleasant Valley line for the study.

Table E-~~16~~17: Dollar Demand Congestion Results for Relaxation of Top Congested Elements

Total Congestion Demand Payment (M$)	*Type*	*2013 BASE CASE*	*Relax Central East*	*Relax Leeds-Pleasant Valley*	*Relax Mott Haven-Rainy*	*Relax West Central*	*2017 BASE CASE*	*Relax Central East*	*Relax Leeds-Pleasant Valley*	*Relax Mott Haven-Rainy*	*Relax West Central*
ATHENS_PLESANT VALLEY	Contingency	220	223	-	224	237	236	243	-	247	255
CENTRAL EAST	Interface	67	-	81	67	108	126	-	149	124	181
WEST CENTRAL-OP	Interface	(53)	(59)	(66)	(52)	-	(64)	(75)	(75)	(63)	-
NY MTHAVN-RAINY Q12	Contingency	6	5	11	-	5	15	14	23	-	15
DUNWOODIE_SHORE RD_345	Contingency	7	7	12	6	7	8	7	14	6	9
ASTORIA W 138-HELLGATE5_138	Contingency	2	2	2	2	2	5	5	5	5	5
LEEDS3_NEW SCOTLAND_345	Contingency	1	1	8	1	1	0	1	7	0	1

Table E-1~~7~~8 shows the change in production cost when the top elements are relieved. Leeds to Pleasant Valley, Central East and West Central have the highest production cost savings and are therefore selected as the three studies.

Table E-1~~7~~8: Production Cost Changed Due to Relaxation of Primary Element

	2013	2017
ATHENS_PLEASANT VALLEY	13.1	14.8
CENTRAL EAST	3.3	5.3
WEST CENTRAL-OP	9.1	9.7
NY MRHAVN-RAINY Q12	-0.08	6.4

E.3. ~~Potential~~ Generic Solutions

Modeling Modifications

Upon selection of the ~~potential~~ generic solutions for each resource type for each grouped elements studied, the ~~potential~~ generic solutions are individually modeled in the base case in order to determine its impact on congestion of the grouped elements. It is assumed that the generic ~~potential~~ solution is installed in the first study year. This allows for the calculation of the full ten-year production cost and additional metrics resulting from the ~~potential~~ generic solution.

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

Initially, one single "block" size for each resource type is modeled. If a majority of the congestion of the grouped elements being studied is not relieved, then the installation of an additional block is considered. However, if adding the additional block results in a diminishing rate of return, or is not feasible, then it is not included.

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.

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- 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.
- The costs of the System Upgrade Facilities to maintain reliability are not included in the cost /benefit analysis.

Grouped Congested Elements ~~Potential~~ Solutions

One block of each resource type was applied to each congested grouping. It was determined that installation of one block of transmission solution for each congested grouping studied relieved the majority of the congestion. Installing one block of generation did not result in a significant reduction of congestion for all of congested elements being studied. Therefore, a second block of generation was installed for each. Installing the second block of generation still did not result in a majority of the congestion being relieved. However, a third block was not installed due to a diminishing rate of return. Installing one block of demand respond response resulted in minimal congested relief on the congested grouping being studied and even increased the congestion for the Central East interface. This is due to the demand response solution being applied through out the Zonal area and not to the bus located downstream of the congestion. However, the implementation of demand response will result in a reduction in production cost. Adding a second block of demand response was not installed since this would exceed 10% of the zonal load and thus would unlikely be achievable. The following sections outline the specific solutions developed for each congested grouping being studied.

Study#1 - Pleasant Valley – Leeds

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Since the Pleasant Valley - Leeds 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 345 kV line from Leeds to Pleasant Valley- 39 Miles
- Generation: Install a new 500 MW Plant at Pleasant Valley
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone G (200 MW is less than 10% of Zone G's peak load)

Table E-189~~7~~ shows the comparison of the resulting dollar demand congestion between the base case and generic ~~potential~~ solution for years 2013 and 2017.

Table E-189~~7~~: Dollar Demand Congestion Comparison for Leeds – Pleasant Valley for Block Size Determination

Leeds Pleasant Valley- Congestion $ Demand

	2013			2017		
	Base Case	Solution Case	% Change	Base Case	Solution Case	% Change
Transmission	220.0	0.0	100%	236.0	0.0	100%
Generation- 1 Block	220.0	191.0	13%	236.0	204.0	14%
Generation – 2 Blocks	220.0	157.4	28%	236.0	165.8	30%
Demand Response	220.0	213.5	3%	236.0	227.7	4%

Table E-~~19~~ 20 presents the change in the number of congested hours by constraints after each of the three generic solutions has been applied. Negative values imply a reduction in congested hours.

Table E-~~19~~20: Change in Number of Congested Hours

Study #1 – Leeds - Pleasant Valley

	Change in # of Congested Hours: Transmission Solution									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CENTRAL EAST	198	65	365	372	202	208	167	171	174	121
ATHENS_PLTVLLEY	(681)	(860)	(2289)	(2381)	(2154)	(2148)	(2087)	(2123)	(2017)	(2094)
NY MOTTHAVEN-RAINEY	124	140	322	362	300	312	275	304	256	336
DUNWOODIE_SHORE RD	232	84	607	694	614	549	506	516	518	474
WEST CENTRAL-OP	(1)	32	36	59	412	354	278	306	326	342

	Change in # of Congested Hours: Generation Solution									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CENTRAL EAST	(196)	(120)	(21)	23	2	(16)	(21)	(17)	(43)	(45)
ATHENS_PLTVLLEY	(197)	(342)	(482)	(535)	(440)	(494)	(517)	(503)	(475)	(466)
NY MOTTHAVEN-RAINEY	386	535	396	491	439	494	521	531	541	590
DUNWOODIE_SHORE RD	698	635	707	830	752	830	805	817	727	770
WEST CENTRAL-OP	0	(4)	5	19	10	32	(33)	(23)	(27)	(7)

	Change in # of Congested Hours: DR & EE Solution									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
CENTRAL EAST	(19)	(1)	0	(9)	0	(6)	4	(5)	4	(13)
ATHENS_PLTVLLEY	(19)	(6)	7	(20)	(21)	(30)	(14)	(25)	(16)	(7)
NY MOTTHAVEN-RAINEY	49	46	44	80	59	60	55	50	44	82
DUNWOODIE_SHORE RD	128	53	89	98	97	74	105	99	83	88
WEST CENTRAL-OP	(1)	2	7	4	(16)	2	(39)	(18)	(11)	(18)

Note: Negative values imply a reduction.

Study #2 - Central East

In order to determine the upstream and downstream locations needed for the ~~potential~~ solutions for relieving the congestion on the Central East Interface, all the elements that comprise this interface were examined as shown in Table E-21~~0~~. Two lines of this interface met the guideline of tying into an existing 345 kV substation: Edic to New Scotland and Marcy to New Scotland. Edic to New Scotland line was chosen based on shorter mileage.

Table E-~~20~~21~~:~~ 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

~~Potential g~~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 500 MW Plant at New Scotland
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone F (200 MW is less than 10% of Zone F's peak load)

Table E-~~19~~ 2~~1~~2 shows the comparison of the resulting dollar demand congestion between the Base Case and generic ~~potential~~ solution for years 2013 and 2017~~.—~~.

Table E-~~19~~2~~1~~2: Dollar Demand Congestion Comparison for Central East for Block Size Determination

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Central East- Congestion $ Demand

	2013			2017		
	Base Case	Solution Case	% Change	Base Case	Solution Case	% Change
Transmission	67.0	19.2	71%	125.6	49.5	61%
Generation-1 Block	67.0	53.0	21%	125.6	108.0	14%
Generation – 2 Blocks	67.0	39.6	41%	125.6	85.8	32%
Demand Response	67.0	57.1	15%	125.6	115.2	8%

Table E-~~22~~ 23 presents the change in the number of congested hours by constraints after each of the three generic solutions has been applied. Negative values imply a reduction in congested hours.

Table E-~~22~~23: Change in Number of Congested Hours

Study #2 - Central East

	Change in # of Congested Hours: Transmission Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	(647)	(799)	(721)	(753)	(680)	(667)	(696)	(686)	(679)	(753)
ATHENS_PLTVLLEY	245	390	476	414	387	375	431	402	396	441
NY MOTTHAVEN-RAINEY	12	(30)	(4)	6	(5)	(47)	(44)	(25)	(46)	(20)
DUNWOODIE_SHORE RD	(41)	(76)	(119)	(138)	(99)	(136)	(57)	(74)	(161)	(118)
WEST CENTRAL-OP	(2)	95	96	103	135	126	144	195	171	119

	Change in # of Congested Hours: Generation Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	(469)	(373)	(384)	(362)	(320)	(342)	(376)	(348)	(343)	(328)
ATHENS_PLTVLLEY	418	437	616	612	638	663	661	671	728	728
NY MOTTHAVEN-RAINEY	211	213	137	141	155	148	151	145	200	265
DUNWOODIE_SHORE RD	347	257	116	206	172	211	202	231	156	221
WEST CENTRAL-OP	0	6	3	(23)	(194)	(160)	(164)	(161)	(159)	(186)

	Change in # of Congested Hours: DR & EE Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	(94)	(82)	(83)	(89)	(73)	(71)	(88)	(90)	(87)	(82)
ATHENS_PLTVLLEY	34	62	101	75	85	76	104	109	86	93
NY MOTTHAVEN-RAINEY	16	34	26	34	18	29	21	34	26	35
DUNWOODIE_SHORE RD	53	40	46	94	37	31	59	103	40	42
WEST CENTRAL-OP	(2)	4	2	(2)	(26)	(2)	(39)	(29)	(40)	(45)

Note: Negative values imply a reduction.

Study #3 - West Central

In order to determine the upstream and downstream locations needed to develop the ~~potential~~ solutions for relieving the congestion on the West Central Interface, the elements that make up this interface were examined, Table E-~~23~~24. This interface includes two lines which meet the guideline of tying into an existing 345 kV substation, namely the Pannell to Clay 345 kV lines. However, upon testing the impact of a new generic line between Pannell and Clay, no improvement in voltage performance was observed. Recognizing that the voltage problem may be more a function of local system problems and that West Central is tightly coupled with the Dysenger East interface, a new circuit from Niagara to Clay was inserted and the voltage limit improved by over 500 MW. This was chosen to stay within the procedures for generics, although it is recognized that other bulk power system solutions may exist as well.

Table E-2~~03~~4: Elements which Comprise the West Central Interface

Interface-Name	From Bus Number	From Bus Name	From Bus kV	To Bus Num	To Bus Name	To Bus kV	Branch Circuit
WEST CENTRAL-OP	130764	MEYER230	230	130767	STOLE230	230	1
WEST CENTRAL-OP	130926	WOLCOT34	34.5	149122	C708 LD	34.5	1
WEST CENTRAL-OP	131242	MACDN115	115	149026	QUAKER (Sta #121)	115	1
WEST CENTRAL-OP	131243	SLEIG115	115	149004	S121 B#2	115	1
WEST CENTRAL-OP	131243	SLEIG115	115	149005	CLYDE199 (Sta #199)	115	1
WEST CENTRAL-OP	131251	BROWNS C	34.5	131252	CLYDE 34	34.5	1
WEST CENTRAL-OP	131344	PALMT115	115	135260	ANDOVER1	115	1
WEST CENTRAL-OP	131345	S.PER115	115	149010	STA 162	115	1
WEST CENTRAL-OP	135860	LAWLER-1	115	135861	MORTIMER (sta #82)	115	1
WEST CENTRAL-OP	135861	MORTIMER (Sta #82)	115	136213	LAWLER-2	115	1
WEST CENTRAL-OP	136150	CLAY	345	149001	PANNELL3 (Sta #122)	345	1
WEST CENTRAL-OP	136150	CLAY	345	149001	PANNELL3 (Sta #122)	345	2
WEST CENTRAL-OP	136167	HOOKRD	115	149074	STA127	34.5	1
WEST CENTRAL-OP	136183	CLTNCORN	115	149005	CLYDE199	115	1
WEST CENTRAL-OP	136194	FARMGTN1	115	149075	FARMNGTN	34.5	1
WEST CENTRAL-OP	136197	FRMGTN-4	115	149146	S168	12	1
WEST CENTRAL-OP	136197	FRMGTN-4	115	149025	PANNELLI (Sta #122)	115	1
WEST CENTRAL-OP	149118	CLYDE 34	34.5	149005	CLYDE199 (Sta #199)	115	1
WEST CENTRAL-OP	149141	FRMNGT2	34.5	136197	FRMGTN-4	115	1

This interface includes only one line which meets the guideline of tying into an existing 345kV substation. This is the Pannell to Clay 345kV line. Therefore, the ~~potential~~ generic solutions for relieving the West Central Interface for each resource types are as follows:

- Transmission: A new 345kV line from Niagara to Pannell to Clay: 149 Miles
- Generation: Install a new 5000 MW Plant at Clay
- Demand Response: Install 100 MW Demand Response and 100 MW Energy Efficiency in Zone C (200 MW is less than 10% of Zone C's peak load)

Table E-21~~4~~5~~0~~ shows the comparison of the resulting dollar demand congestion between the base case and generic ~~potential~~ solution for years 2013 and 2017.

Table E-21~~4~~5~~0~~: Dollar Demand Congestion Comparison for West Central for Block Size Determination

~~**West Central- Congestion $ Demand**~~

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~~-~~	~~2013~~			~~2018~~		
~~-~~	~~Base Case~~	~~Solution Case~~	~~% Change~~	~~Base Case~~	~~Solution Case~~	~~% Change~~
~~Transmission~~	~~52.6~~	~~10.4~~	~~80%~~	~~86.5~~	~~15.6~~	~~82%~~
~~Generation-1 Block~~	~~52.6~~	~~-~~	~~100%~~	~~86.5~~	~~-~~	~~100%~~

~~Generation – 2 Blocks~~	~~52.6~~	~~40.3~~	~~23%~~	~~86.5~~	~~67.4~~	~~22%~~
~~Demand Response~~	~~52.6~~	~~49.5~~	~~6%~~	~~86.5~~	~~81.5~~	~~6%~~

West Central- Congestion $ Demand

	2013			2017		
	Base Case	Solution Case	% Change	Base Case	Solution Case	% Change
Transmission	52.6	10.4	80%	63.6	13.7	78%
Generation- 1 Block	52.6	47.0	11%	63.6	56.0	12%
Generation – 2 Blocks	52.6	40.3	23%	63.6	46.7	27%
Demand Response	52.6	49.5	6%	63.6	58.6	8%

Table E-~~25~~ 26 presents the change in the number of congested hours by constraints after each of the three generic solutions has been applied. Negative values imply a reduction in congested hours.

Table E-~~25~~26: Change in Number of Congested Hours

Study #3 - West Central										
	Change in # of Congested Hours: Transmission Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	164	431	361	415	665	625	559	583	560	657
ATHENS_PLTVLLEY	37	56	114	102	269	238	204	239	211	235
NY MOTTHAVEN-RAINEY	71	46	10	80	47	31	49	34	47	109
DUNWOODIE_SHORE RD	(33)	19	(10)	37	70	104	59	86	76	172
WEST CENTRAL-OP	(5)	(266)	(312)	(387)	(1800)	(1718)	(1577)	(1613)	(1568)	(1840)
	Change in # of Congested Hours: Generation Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	514	448	343	369	436	475	474	451	387	457
ATHENS_PLTVLLEY	102	88	201	169	221	239	283	273	279	268
NY MOTTHAVEN-RAINEY	102	142	94	144	115	106	146	155	176	221
DUNWOODIE_SHORE RD	274	214	104	162	154	209	187	199	169	224
WEST CENTRAL-OP	(4)	(97)	(107)	(138)	(398)	(286)	(326)	(368)	(354)	(370)
	Change in # of Congested Hours: DR & EE Solution									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
CENTRAL EAST	85	113	69	80	107	106	123	95	100	106

ATHENS_PLTVLLEY	13	27	59	22	53	38	72	67	59	50
NY MOTTHAVEN-RAINEY	(7)	24	28	32	18	35	36	25	31	35
DUNWOODIE_SHORE RD	54	20	38	45	53	27	55	63	29	51
WEST CENTRAL-OP	(1)	(30)	(20)	(31)	(86)	(68)	(104)	(86)	(114)	(82)
Note: Negative values imply a reduction.										

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 based upon the assumptions contained in this report.

- The NYISO makes no representations regarding the adequacy or accuracy of the benefit/cost ratios.~~does not guarantee that the benefit to cost ratio determined for the generic solutions can be achieved.~~

Tables E-~~21~~ 2267 through E-~~24~~ 25930 present ~~potential~~ generic solutions overnight installation costs ~~costs~~ associated with each study. On-going operation and maintenance costs are not included.

~~Overnight costs, present value~~

Table E-~~21~~2267: ~~Potential~~ Generic Solution Costs for Each Study

~~Potential~~ Generic Solution Cost Summary ($M)

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

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

Low	$531	$591	$531

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

Table E-~~22~~23~~7~~8: ~~Potential~~ Generic Solutions for Study #1 - Leeds to Pleasant Valley

~~Potential~~ Generic Solution for Study #1 - Leeds to Pleasant Valley

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

~~Potential~~ Transmission Solution: Leeds to Pleasant Valley

Item #	Quantity	Unit Pricing ($M)	Total ($M)
T-1 High			
Transmission Line (Miles)	39	$5.0	$195.0
Substation Line Terminal	2	$9.0	$18.0
System Upgrade	1	$9.0	$9.0
Total High Transmission Solution Cost			***$222.0***
T-1 Mid			
Transmission Line (Miles)	39	$3.5	$136.5
Substation Line Terminal	2	$6.0	$12.0
System Upgrade	1	$6.0	$6.0
Total Mid Transmission Solution Cost			***$154.5***
T-1 Low			
Transmission Line (Miles)	39	$2.0	$78.0
Substation Line Terminal	2	$3.0	$6.0

System Upgrade	1	$3.0	$3.0
Total Low Transmission Solution Cost			***$87.0***

~~Potential~~ Generation Solution: Pleasant Valley

Item #	Quantity	Unit Pricing ($M)	Total ($M)
G-1 High			
Plant (250 MW Blocks)	2	$440.0	$880.0
Electric Transmission Line (Miles)	1	$5.0	$5.0
Substation Terminal	1	$9.0	$9.0
System Upgrade Facilities	1	$9.0	$9.0
Gas Transmission Line (Miles)	1	$5.0	$5.0
Gas Regulator Station	1	$3.0	$3.0
Total High Generation Solution Cost			***$911.0***
G-1 Mid			
Plant (250 MW Blocks)	2	$365.0	$730.0
Electric Transmission Line (Miles)	1	$3.5	$3.5
Substation Terminal	1	$6.0	$6.0
System Upgrade Facilities	1	$6.0	$6.0
Gas Transmission Line (Miles)	1	$3.5	$3.5
Gas Regulator Station	1	$2.0	$2.0
Total Mid Generation Solution Cost			***$751.0***
G-1 Low			
Plant (250 MW Blocks)	2	$290.0	$580.0
Electric Transmission Line (Miles)	1	$2.0	$2.0
Substation Terminal	1	$3.0	$3.0
System Upgrade Facilities	1	$3.0	$3.0
Gas Transmission Line (Miles)	1	$2.0	$2.0
Gas Regulator Station	1	$1.0	$1.0
Total Low Generation Solution Cost			***$591.0***

~~Potential~~ Demanda Réponse Solution: Zone G

Item #	Quantity	Unit Pricing ($M)	Total ($M)
D-1 High			
Energy Efficiency (100 MW Blocks)	1	$420.0	***$420.0***
D-2 High			
Demand Response (100 MW Blocks)	1	$160.0	***$160.0***
Total High Demand Response Solution Costs			***$580.0***
D-1 Mid			
Energy Efficiency (100 MW Blocks)	1	$280.0	***$280.0***

D-2 Mid			
Demand Response (100 MW Blocks)	1	$110.0	***$110.0***
Total Mid Demand Response Solution Costs			***$390.0***

D-1 Low			
Energy Efficiency (100 MW Blocks)	1	$140.0	***$140.0***
D-2 Low			
Demand Response (100 MW Blocks)	1	$50.0	***$50.0***
Total Low Demand Response Solution Costs			***$190.0***

Table E-~~23~~2489: ~~Potential~~ Generic Solutions for Study #2 – Central East

~~Potential~~ Generic Solution
Central East

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

~~Potential~~ Transmission Solution: Edic to New Scotland

Item #	Quantity	Unit Pricing ($M)	Total ($M)
T-1 High			
Transmission Line (Miles)	90	$5.0	$450.0
Substation Line Terminal	2	$9.0	$18.0
System Upgrade	1	$9.0	$9.0
Total High Transmission Solution Cost			***$477.0***
T-1 Mid			
Transmission Line (Miles)	90	$3.5	$315.0
Substation Line Terminal	2	$6.0	$12.0
System Upgrade	1	$6.0	$6.0
Total Mid Transmission Solution Cost			***$333.0***
T-1 Low			
Transmission Line (Miles)	90	$2.0	$180.0

Substation Line Terminal	2	$3.0	$6.0
System Upgrade	1	$3.0	$3.0
Total Low Transmission Solution Cost			***$189.0***

~~Potential~~ Generation Solution: New Scotland

Item #	Quantity	Unit Pricing ($M)	Total ($M)
G-1 High			
Plant (250 MW Blocks)	2	$400.0	$800.0
Electric Transmission Line (Miles)	1	$5.0	$5.0
Substation Terminal	1	$9.0	$9.0
System Upgrade Facilities	1	$9.0	$9.0
Gas Transmission Line (Miles)	1	$5.0	$5.0
Gas Regulator Station	1	$3.0	$3.0
Total High Generation Solution Cost			***$831.0***
G-1 Mid			
Plant (250 MW Blocks)	2	$330.0	$660.0
Electric Transmission Line (Miles)	1	$3.5	$3.5
Substation Terminal	1	$6.0	$6.0
System Upgrade Facilities	1	$6.0	$6.0
Gas Transmission Line (Miles)	1	$3.5	$3.5
Gas Regulator Station	1	$2.0	$2.0
Total Mid Generation Solution Cost			***$681.0***
G-1 Low			
Plant (250 MW Blocks)	2	$260.0	$520.0
Electric Transmission Line (Miles)	1	$2.0	$2.0
Substation Terminal	1	$3.0	$3.0
System Upgrade Facilities	1	$3.0	$3.0
Gas Transmission Line (Miles)	1	$2.0	$2.0
Gas Regulator Station	1	$1.0	$1.0
Total Low Generation Solution Cost			***$531.0***

~~Potential~~ Demand Response Solution: Zone F

Item #	Quantity	Unit Pricing ($M)	Total ($M)
D-1 High			
Energy Efficiency (100 MW Blocks)	1	$420.0	***$420.0***
D-2 High			
Demand Response (100 MW Blocks)	1	$160.0	***$160.0***
Total High Demand Response Solution Costs			***$580.0***
D-1 Mid			

Energy Efficiency (100 MW Blocks)	1	$280.0	***$280.0***
D-2 Mid			
Demand Response (100 MW Blocks)	1	$110.0	***$110.0***
Total Mid Demand Response Solution Costs			***$390.0***

D-1 Low			
Energy Efficiency (100 MW Blocks)	1	$140.0	***$140.0***
D-2 Low			
Demand Response (100 MW Blocks)	1	$50.0	***$50.0***
Total Low Demand Response Solution Costs			***$190.0***

Table E-~~24~~25930: ~~Potential~~ Generic Solutions for Study #3 – West Central

~~Potential~~ Generic Solution
West Central

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

~~Potential~~ Transmission Solution: Niagara to Pannell to Clay

Item #	Quantity	Unit Pricing ($M)	Total ($M)
T-1 High			
Transmission Line (Miles)	149	$5.0	$745.0
Substation Line Terminal	4	$9.0	$36.0
System Upgrade	1	$9.0	$9.0
Total High Transmission Solution Cost			***$790.0***
T-1 Mid			
Transmission Line (Miles)	149	$3.5	$521.5
Substation Line Terminal	4	$6.0	$24.0
System Upgrade	1	$6.0	$6.0
Total Mid Transmission Solution Cost			***$551.5***
T-1 Low			
Transmission Line (Miles)	149	$2.0	$298.0
Substation Line Terminal	4	$3.0	$12.0

System Upgrade	1	$3.0	$3.0
Total Low Transmission Solution Cost			***$313.0***

~~Potential~~ Generation Solution: Clay

Item #	Quantity	Unit Pricing ($M)	Total ($M)
G-1 High			
Plant (250 MW Blocks)	2	$400.0	$800.0
Electric Transmission Line (Miles)	1	$5.0	$5.0
Substation Terminal	1	$9.0	$9.0
System Upgrade Facilities	1	$9.0	$9.0
Gas Transmission Line (Miles)	1	$5.0	$5.0
Gas Regulator Station	1	$3.0	$3.0
Total High Generation Solution Cost			***$831.0***
G-1 Mid			
Plant (250 MW Blocks)	2	$330.0	$660.0
Electric Transmission Line (Miles)	1	$3.5	$3.5
Substation Terminal	1	$6.0	$6.0
System Upgrade Facilities	1	$6.0	$6.0
Gas Transmission Line (Miles)	1	$3.5	$3.5
Gas Regulator Station	1	$2.0	$2.0
Total Mid Generation Solution Cost			***$681.0***
G-1 Low			
Plant (250 MW Blocks)	2	$260.0	$520.0
Electric Transmission Line (Miles)	1	$2.0	$2.0
Substation Terminal	1	$3.0	$3.0
System Upgrade Facilities	1	$3.0	$3.0
Gas Transmission Line (Miles)	1	$2.0	$2.0
Gas Regulator Station	1	$1.0	$1.0
Total Low Generation Solution Cost			***$531.0***

~~Potential~~ Demand Response Solution: Zone C

Item #	Quantity	Unit Pricing ($M)	Total ($M)
D-1 High			
Energy Efficiency (100 MW Blocks)	1	$420.0	***$420.0***
D-2 High			
Demand Response (100 MW Blocks)	1	$160.0	***$160.0***
Total High Demand Response Solution Costs			***$580.0***
D-1 Mid			
Energy Efficiency (100 MW Blocks)	1	$280.0	***$280.0***

D-2 Mid			
Demand Response (100 MW Blocks)	1	$110.0	***$110.0***
Total Mid Demand Response Solution Costs			***$390.0***

D-1 Low			
Energy Efficiency (100 MW Blocks)	1	$140.0	***$140.0***
D-2 Low			
Demand Response (100 MW Blocks)	1	$50.0	***$50.0***
Total Low Demand Response Solution Costs			***$190.0***

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E.4. Additional Metrics

Comment [A1]: New description of metrics calculation

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The write-up below attempts to bring the additional metrics numbers together for the reader. The relationship between the metrics is explained. In addition the calculation of change in the values of the additional metrics is also demonstrated and a reference is included to where these meatrics are discussed.

The equation below describes the relationship between the additional metrics:

Load Payment = Generation Payment + Congestion Rent + Residual Losses

The Load and Generation Payment and the congestion Rent values above are the global or system values from the simulation model. For the CARIS model the system include PJM, IESO-Ontario, NYISO and ISO-NE. In the Day-Ahead-Market, interchange with the neighboring markets is modeled at a simple PROXY bus and many of the interchange or PROXY metrics cannot be easily determined.

Load Payment as calculated in CARIS models represents the total annual amount collected by an ISO from the load. These annual values cover the three types of charges passed on to the load, i.e. energy, congestion and losses

A similar breakdown also applies to the Generator LBMP Payments (or Generator Revenues) and, accordingly, equal the annual amount paid to generators for providing electricity for energy, congestion and losses. However, in CARIS the generator payments do not include

Bid Production Cost Guarantees (BPCG) and other payments as per NYISO tariff as is the case in DAM settlements.

The calculations of the change in additional metrics reported in this report for the Base Case and the Leeds-Pleasant Valley transmission solution are shown in Table E-31. The values in the third tables represent the change in these values. The reader is directed to follow the notes in each table below to the pages where these results are referred to in the report.

~~As shown in the tables below, t~~The load payment is consistently higher than the generator payments every year. The remainder is a payment due to Residual Losses, which is then returned to the loads and/or transmission owners depending on the market settlements structure. Also, the values in the "Load Congestion Pay" and the "Load Losses Pay" columns are both components of the value listed in the "Load Pay" column. They are shown separately because one of two is identified in the TARIFF as an additional metric "Load Losses Pay" and the other "Load Congestion Pay" value was used to identify the highest ranked congestion elements. For this reason the change in the "Load congestion Pay" is not reported in any of the CARIS results table except in this section.

The congestion rent values are also listed for the base case and the Leeds-Pleasant Valley solution case and the change in this value is also listed in the third table.– The change in the congestion rent values substituted the TCC metric called for in the TARIFF for CARIS phase 1.

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Table E-31~~0~~: Base Case Additional Metrics (in nominal $ Millions)

CARIS Base Case - Additional Metrics Values - NYCA based					
M$	Gen Revenue [2]	Load Pay [3]	Congestion Rent [4]	Load Losses Pay [5]	Load Congestion Pay [6]
2009	6,842	7,620	314	494	130
2010	8,593	10,015	604	668	319
2011	8,727	10,239	692	668	443
2012	9,107	10,739	745	705	488
2013	9,335	11,019	729	723	396
2014	9,826	11,600	758	754	410
2015	10,156	12,066	785	778	452
2016	10,606	12,696	867	823	513
2017	11,012	13,239	926	856	563
2018	11,547	13,972	975	897	593
Total	**95,750**	**113,204**	**7,395**	**7,366**	**4,307**

CARIS Study 1 Leeds-Pleasant Valley Solution - Additional Metrics Values - NYCA based					
M$	Gen Revenue	Load Pay	Congestion Rent	Load Losses Pay	Load Congestion Pay
2009	6,850	7,621	301	478	108
2010	8,613	10,020	584	645	289
2011	8,762	10,233	605	660	280
2012	9,144	10,734	654	696	323
2013	9,370	11,006	643	713	206
2014	9,856	11,587	678	741	231
2015	10,186	12,052	704	763	275
2016	10,636	12,682	783	807	331
2017	11,045	13,227	841	839	374
2018	11,596	13,968	864	884	344
Total	**96,056**	**113,128**	**6,657**	**7,226**	**2,760**

CARIS Study 1 Leeds-Pleasant Valley Solution - Change in Additional Metrics Values - NYCA based					
M$	Gen Revenue	Load Pay	Congestion Rent	Load Losses Pay	Load Congestion Pay
2009	7	1	(13)	(17)	(21)
2010	19	5	(20)	(23)	(30)
2011	34	(6)	(87)	(8)	(163)
2012	37	(5)	(91)	(9)	(165)
2013	35	(13)	(86)	(10)	(191)
2014	30	(13)	(80)	(13)	(179)
2015	30	(13)	(81)	(14)	(178)
2016	30	(14)	(83)	(16)	(182)
2017	33	(12)	(85)	(16)	(189)
2018	49	(5)	(111)	(12)	(249)
Total [1]	**306**	**(76)**	**(738)**	**(139)**	**(1,547)**

Notes	1	Total change in the Additional Metrics values for 2009-2019 are listed in Table 5-14 on Page 44
	2	Annual Load Payment values for CARIS Base Case are listed in Table E-7 on Page E-9
	3	Annual Generator Payment values for CARIS Base Case are listed in Table E-6 on Page E-8
	4	Congestion Rent is the sum of Congestion Rent on all binding constraints. Only changres in Congestion Rent for each solution is listed in Table 5-14
	5	Annual Load Losses Payment values for CARIS Base Case are listed in Table E-8 on Page E-9
	6	Annual Load Congestion Payment values for CARIS Base Case are listed in Table 5-4 on Page 33

Appendix F – Initial 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