DRAFT for April 23, 2020 ESPWG
2019 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

CARIS - Phase 1

A Report by the
New York Independent System Operator

April 2020

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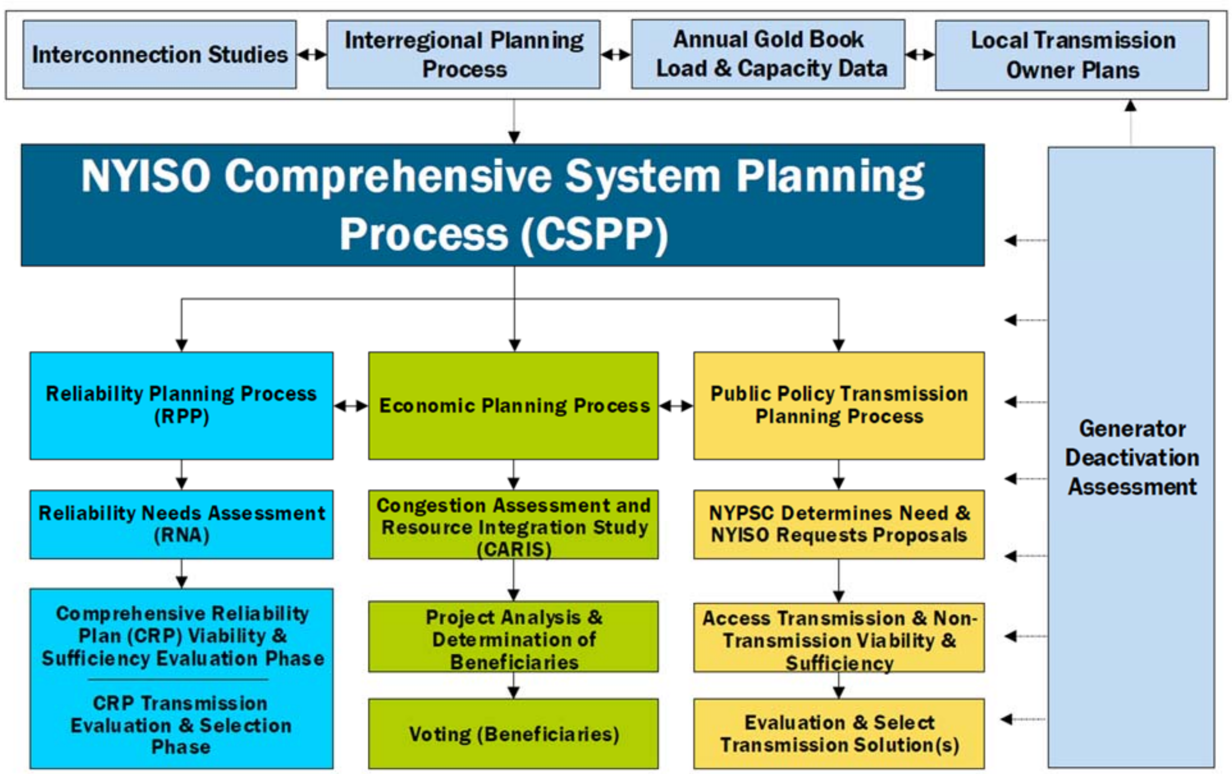
Introduction

Pursuant to Attachment Y of the New York Independent System Operator, Inc. ("NYISO") Open Access Transmission Tariff ("Tariff"), the NYISO has performed the first phase of the 2019 Congestion Assessment and Resource Integration Study ("CARIS"). CARIS is the primary component of the NYISO's Economic Planning Process which is one of the three processes that comprise the NYISO's Comprehensive System Planning Process (see Figure 1). The study assesses both historic and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion.

Figure 1: NYISO Comprehensive System Planning Process



This final Report documents the methodologies and baseline assumptions used in identifying the congested pathways. It presents how the baseline metrics such as system-wide production cost are impacted by solutions to the baseline congestion. These solutions can be considered as upgrades in system topology (new transmission lines), system resource composition (new generation facilities), and system load characteristics (incremental demand response and energy efficiency). The Report concludes with a comparison of the benefits of such generic solutions with high-level cost estimates.

Increasingly, New York State is focused on deploying clean energy resources in support of reducing carbon dioxide emissions from the power sector. The pace of this transition is driven primarily by state policy, notably New York's Climate Leadership and Community Protection Act ("CLCPA"), which, among other things, establishes in law requirements to expand clean and renewable resources supplying the grid and eliminate emissions from the power sector.

In the 2019 CARIS Phase 1 study, the NYISO conducted three studies of the most congested pathways in New York, as prescribed by its tariff. The NYISO also performed supplemental scenarios – including addressing projected resource and demand shift in New York – in order to provide its stakeholders with additional insights into New York Control Area ("NYCA") congestion patterns under system conditions varying from the baseline. These full ten-year (2019-2028) scenarios complement the base ten-year studies. Moreover, the NYISO conducted a single-year scenario for 2030 to analyze the target that 70 percent of end use energy be generated by renewable resources in that year ("70 x 30") included in the CLCPA.

This Report documents the 2019 CARIS Phase 1 study results and provides objective information on the nature of congestion in the NYCA. Developers can use this information to decide whether to proceed with transmission, generation, demand response, or energy efficiency projects. Developers of any type of solution may choose to pursue a project on a merchant basis, or to enter into bilateral contracts with Load-Serving Entities or other parties. Only those Developers proposing transmission solutions to the identified congestion may seek cost-recovery through the NYISO Tariffs in the second phase of the CARIS process ("CARIS Phase 2"). *See* NYISO Open Access Transmission Tariff ("OATT") § 31.5.4. This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

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

The NYISO Staff presented the Phase 1 Study results in a written draft report to the Electric System Planning Working Group and the Transmission Planning Advisory Subcommittee for review. After that review, the draft report was presented to the NYISO's Business Issues Committee and the Management Committee for discussion and action. Finally, the draft report was submitted to the NYISO's Board of

Directors for approval.

Background

Economic Planning Process

The objectives of the economic planning process are to:

1. Project congestion on the New York State Bulk Power Transmission Facilities over the ten-year Comprehensive System Planning Process planning horizon;

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

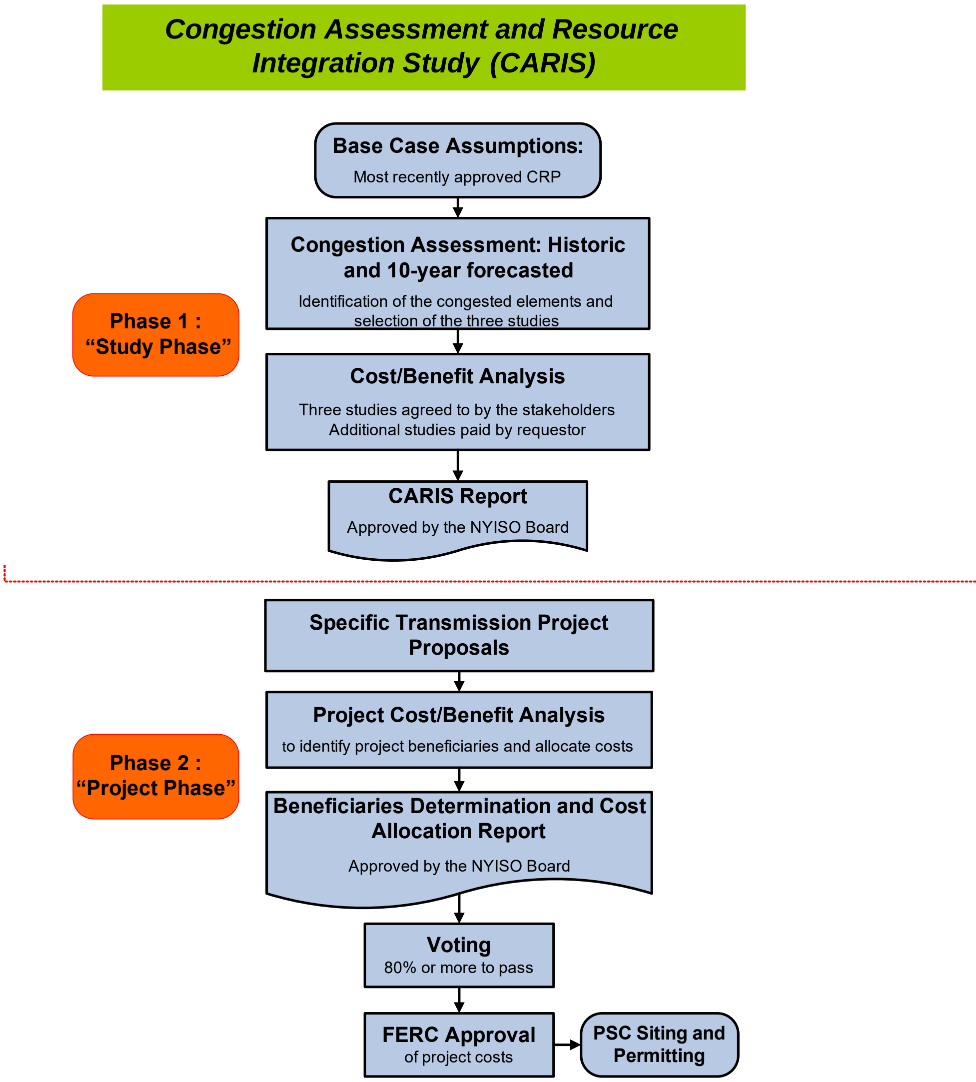
3. Provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner. This process includes providing information to Market Participants, stakeholders and other interested parties on solutions to reduce congestion and to create production cost savings, which are measured in accordance with the Tariff requirements. It also includes a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff.

4. Provide an opportunity for development of market-based solutions to reduce the congestion identified; and

5. Coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

See OATT § 31.1.4. These objectives are achieved through the two phases of the process, which are graphically depicted in Figure 2 below.

Figure 2: Overall CARIS Process Diagram



Phase 1 – Study Phase

Phase 1 of the economic planning process commences after the viability and sufficiency phase of the Comprehensive Reliability Plan is completed, or upon NYISO Board approval of the Comprehensive Reliability Plan should no Reliability Needs be identified in the Reliability Needs Assessment. Market Participants, Developers and other parties provide the data necessary for the development of the CARIS. *See* OATT § 31.3.1.4. The NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts transmission congestion studies based on those elements. In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest projected production cost savings resulting from the relaxation. The NYISO Tariff calls for the top three ranked elements or groupings to be studied. For each of these studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types – generation, transmission, demand response, and energy efficiency – are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, demand response, and energy efficiency resources. Such resources are placed individually in the congested locations on the system to calculate their effects on relieving each of the three most congested elements and the resulting economic benefits.

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

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

Phase 2 – Regulated Economic Transmission Project (RETP) Cost Allocation Phase

Updating and extending the CARIS database for CARIS Phase 2 is conducted after the approval of the CARIS Phase 1 report by the NYISO Board. The Phase 2 model for analysis of specific project proposals will be developed from the CARIS 1 database using an assumptions matrix developed after discussion with Electric System Planning Working Group and with input from the Business Issues Committee. The Phase 2 database will be updated, consistent with the CARIS manual, to reflect all appropriate and agreed upon system modeling changes required for a 10 year extension of the model commencing with the proposed commercial operation date of the project. *See* OATT Section 31.5.4.3.1.

Developers of a potential economic transmission project that has an estimated capital cost in excess of $25 million may seek regulated cost recovery through the NYISO Tariff. Such Developers must submit their projects to the NYISO for a benefit/cost analysis in accordance with the Tariff. The costs for the benefit/cost analysis will be supplied by the Developer of the project as required by the Tariff. Projects are eligible for regulated cost recovery only if the present value of the NYCA-wide production cost savings exceeds the present value of the costs over the first ten years from the proposed commercial operation date for the project. In addition, the present value over the first ten years of LBMP load savings, net of TCC revenues and bilateral contract quantities, must be greater than the present value of the projected project cost revenue requirements for the first ten years of the amortization period.

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

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow Load-Serving Entities to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity ("ICAP") costs, changes in emissions costs, and changes in TCC revenues. *See* OATT § 31.3.1.3.5. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC auction revenues and allocation of congestion rents to the Transmission Owners (for more detail on this metric see the "CARIS Methodology and Metrics" section of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual.[1])

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the Developer after discussions with ESPWG, regarding future uncertainties such as energy and peak demands, fuel prices, new resources, retirements, emissions data and emission allowance costs, as well as other qualitative impacts such as improved system operations, potential environmental regulations, and public policies supporting energy efficiency and the integration of renewable resources. *See* OATT § 31.3.1.5. Although this data may assist and influence how a benefiting Load-Serving Entity

1 See https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/6510ece7-e0a6-7bee-e776-694abf264bae

votes on a project, it will not be used for purposes of cost allocation.

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to the Electric System Planning Working Group for comment. Following that review, the NYISO benefit/cost analysis and beneficiary determination will be forwarded to the Business Issues Committee and Management Committee for discussion and action. Thereafter the benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board of Directors and posted on the NYISO's website, the project will be brought to a special meeting of the beneficiary Load-Serving Entities for an approval vote, utilizing the approved voting procedure (See Section 3.4.5 of the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual). The specific provisions for voting on cost allocation are set forth in the Tariff. Pursuant to the Tariff, "[t]he costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing a project." *See* OATT § 31.5.4.6.3. If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process will not relieve the Developer of the responsibility to file with FERC for approval of the project costs that were presented by the Developer to the voting beneficiaries and with the appropriate state authorities to obtain siting and permitting approval for the project.

CARIS Methodology and Metrics

CARIS Methodology

The first step in the CARIS study is the development of a 15-year assessment of congestion on the NYISO transmission system, comprised of a ten-year look ahead and a five-year look back. For the purposes of conducting the ten-year forward-looking CARIS analysis, the NYISO utilizes MAPS[2] software, executed with a production cost database developed in consultation with the Electric System Planning Working Group. The details and assumptions in developing this database are summarized in Appendix C.

CARIS Metrics

The principal benefit metric for the CARIS Study Phase analysis is the NYCA-wide production cost savings that would result from each of the generic solutions. Additional benefit metrics are analyzed as well, and the results are presented in this report and accompanying appendices for informational purposes only. All benefit metrics are determined by measuring the difference between the projected CARIS Base Case value and a projected solution case value when each generic solution is added. The discount rate of 7.08% used for the present value analysis was the current Weighted Average Cost of Capital for the New York Transmission Owners, weighted by their annual gigawatt hour load in 2018.

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

These definitions are consistent with the reporting of historic congestion for the past thirteen years. Demand$ Congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to total payments by load because it includes the energy and losses components of the LBMP.

Principal Benefit Metric[3]

The principal benefit metric for the CARIS Study Phase analysis is the present value of the NYCA-wide production cost savings that are projected to result from implementation of each of the generic congestion

2 GE's Multi-Area Production Simulation software

3 Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

mitigation solutions. The NYCA-wide production cost savings are calculated as those savings associated with generation resources in the NYCA and the costs of incremental imports/exports priced at external proxy generator buses of the solution case. This is consistent with the methodology utilized in prior CARIS cycles. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

$$\text{NYCA-wide Production Cost Savings} = \text{NYCA Generator Production Cost Savings} - \sum \left\{ \left[\frac{\text{Import}}{\text{Export Flow}} \right]_{\text{Solution}} - \left[\frac{\text{Import}}{\text{Export Flow}} \right]_{\text{Base}} \right\} * \text{ProxyLMP}_{\text{Solution}}$$

Where:

$\text{ProxyLMP}_{\text{Solution}}$ is the LMP at one of the external proxy buses;

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

Additional Benefit Metrics

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

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

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

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

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

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

TCC Payments – The TCC payment metric is calculated differently for Phase 1 than it is calculated for Phase 2 of the CARIS process, as described in the NYISO Tariff. The TCC Payment is the change in total congestion rents collected in the day-ahead market. In this CARIS Phase 1, it is calculated as (Demand Congestion Costs + Export Congestion Costs) – (Supply Congestion Costs + Import Congestion Costs). This is not a measure of the Transmission Owners' TCC auction revenues.

Base Case System Assumptions

The implementation of the economic planning process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2019 CARIS Phase 1 Study Period aligns with the ten-year reliability planning horizon for the 2018 Comprehensive Reliability Plan; and study assumptions are based on the 2018 Comprehensive Reliability Plan Base Case and any updates that met the NYISO's inclusion rules as of the August 1, 2019 lock-down date.

The CARIS Base Case can be viewed as a "Business as Usual" case starting with the most recent Reliability Planning Process Base Case and incorporating incremental resource changes based on the NYISO's Reliability Planning Process study inclusion rules.[4] Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis.

Base Case - System Assumptions & Modeling Changes

The key assumptions for the Base Case are presented below:

1. The load and capacity forecasts are updated using the 2019 Load and Capacity Data Report ("Gold Book") baseline forecast for energy and peak demand by Zone for the ten-year Study Period. New resources and changes in resource capacity ratings were incorporated based on the Reliability Needs Assessment inclusion rules.
2. The power flow case uses the 2018 Reliability Planning Process (RPP) case as the starting point and is updated with the latest information from the 2019 Gold Book.
3. The transmission and constraint model utilizes a bulk power system representation for most of the Eastern Interconnection, as described below. The model uses transfer limits and actual operating limits from both the 2018 Reliability Needs Assessment and the 2018 Comprehensive Reliability Plan .
4. The production cost model performs a security constrained economic dispatch of generation resources to serve the load. The production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed by the NYISO from multiple data sets, including public domain information, proprietary forecasts and confidential market information. The model includes scheduled generation maintenance periods

[4] *See* Reliability Planning Process Manual, Manual No. 36, § 3.2.

based on a combination of each unit's planned and forced outage rates.

Figure 3 below contains a summary of the modeling changes that can have significant impacts on the congestion projections.

Figure 3: Major Modeling Inputs and Changes

Major Modeling Inputs	
Input Parameter	**Change from 2017 CARIS**
Load Forecast	Lower
Natural Gas Price Forecast	Lower
CO_2 Price Forecast	Same
NO_X Price Forecast	Ozone NO_X, same; Annual NO_X, lower
SO_2 Price Forecast	Higher
Hurdle Rates	Lower
Modeling Changes	
Description	**Change from 2017 CARIS**
MAPS Software Upgrades	Latest GE MAPS Version 14.300 09/06/2019 Release was used for production cost simulation
PJM/NYISO JOA	Western tie to carry 46% of PJM-NYISO AC Interchange
	5018 line to carry 32% of PJM-NYISO AC Interchange plus 80% of RECO load
	PAR A to carry 7% of PJM-NYISO AC Interchange plus 100MW OBF(operational base flow), PAR B and C are modeled as out of service
	PAR JK to carry 15% of PJM-NYISO AC Interchange minus 100MW OBF
	OBF reduced to zero as of Nov.1, 2019
NY Transmission Upgrades	Erie – South Ripley series reactor(2019)
	Rainey-Corona PAR (2019)
	Leeds Hurley SDU(2020)
	L33P (Ontario PAR) out of service until 1/2022
	Empire State Line Project/Western PP Selected project(2022)
	Selected Segment A and Segment B AC Transmission Projects (2024)
	Expanded monitoring and securing of lower voltage system consistent with NYISO market operations

Figure 4 presents the timeline of projected resource and topology changes that are modeled by the NYISO in each of the cases and that have material impacts on the results.

Figure 4: Timeline of NYCA Modeling Changes for CARIS 2019 Phase 1

Year	Year-to-year Modeling Changes
2019	Riverhead Solar, 20 MW, in-service: 5/1/2019
	Ball Hill Wind, 100MW, in-service: 12/1/2019
2020	Cayuga 1, 151MW, retired on 1/1/2020
	Cricket Valley Energy Center, 1,020 MW, in-service: 3/1/2020
	Indian Point 2, 1,016MW, retired on 4/30/2020
	Cassadaga Wind, 126MW, in-service: 12/1/2020
2021	Taylor Biomass, 19MW, in-service: 4/1/2021
	Indian Point 3, 1,038MW, retired on 4/30/2021
2022	
2023	
2024	Athens SPS retired on 1/2024
2025	
2026	
2027	
2028	

Load and Capacity Forecast

The load and capacity forecast used in the Business as Usual case, provided in Figure 5, was based on the 2019 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard. Appendix C contains similar load and capacity data, broken out by fuel type, for the modeled external control areas.

Figure 5: CARIS 1 Base Case Load and Resource Table

Peak Load (MW)											
Area		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NYCA		32,382	32,202	32,063	31,971	31,700	31,522	31,387	31,246	31,121	31,068
Zone J		11,608	11,651	11,695	11,704	11,608	11,598	11,616	11,616	11,598	11,589
Zone K		5,240	5,134	5,056	5,035	4,969	4,894	4,823	4,758	4,719	4,730
Resources (MW)											
Area	Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NYCA	Capacity	42,056	42,391	42,413	42,417	42,640	42,640	42,640	42,640	42,640	42,640
	SCR	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309
	Total	43,365	43,700	43,722	43,726	43,949	43,949	43,949	43,949	43,949	43,949
Zone J	Capacity	9,559	9,559	9,559	9,559	9,645	9,645	9,645	9,645	9,645	9,645
	SCR	494	494	494	494	494	494	494	494	494	494
	Total	10,053	10,053	10,053	10,053	10,139	10,139	10,139	10,139	10,139	10,139
Zone K	Capacity	5,241	5,241	5,741	5,741	5,741	5,741	5,741	5,741	5,741	5,741
	SCR	48	48	48	48	48	48	48	48	48	48
	Total	5,289	5,289	5,789	5,789	5,789	5,789	5,789	5,789	5,789	5,789

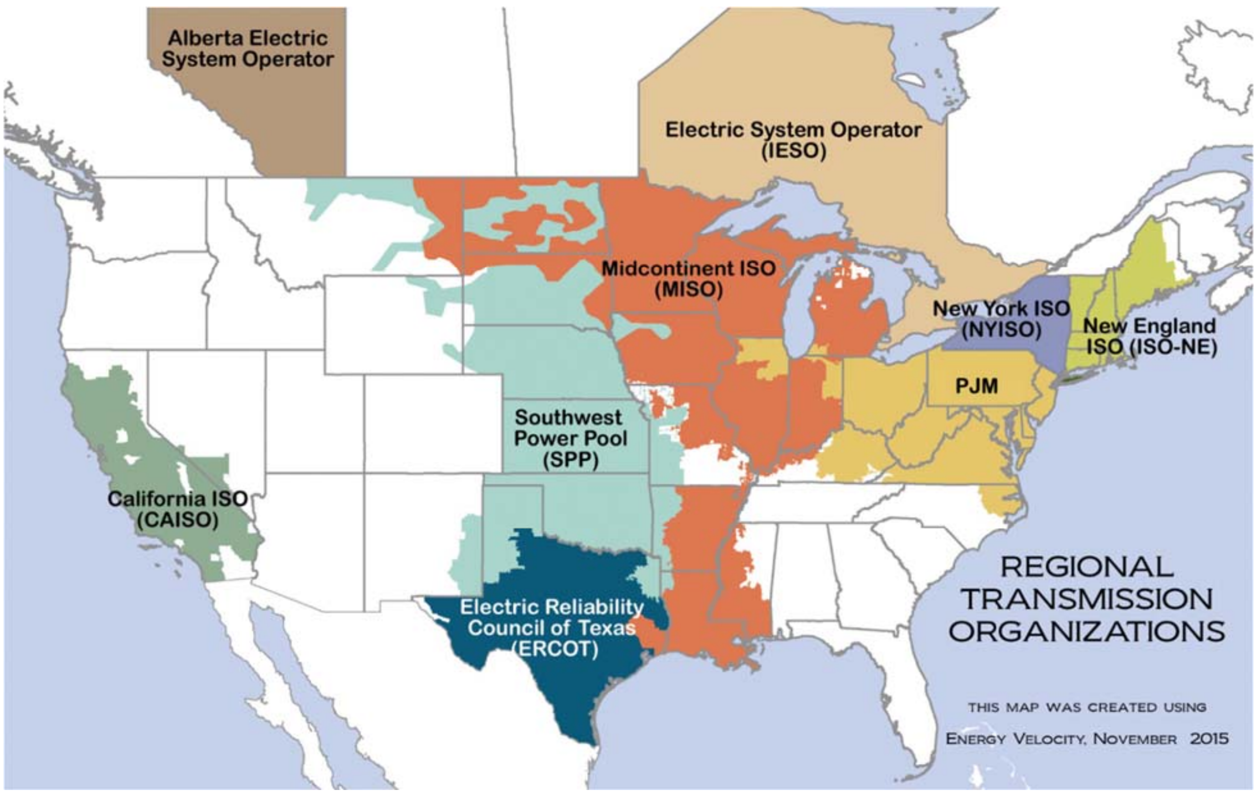
Source: 2019 Gold Book baseline load forecasts from Section I.[5]

5 NYCA "Capacity" values include resources internal to New York, additions, re-ratings, retirements, purchases and sales, and UDRs as presented in the 2019 Gold Book. Zones J and K capacity values include UDRs for the entire capacity of the controllable lines consistent with the 2018 RNA.

Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding the Western Electricity Coordinating Council and Texas. Figure 6 below illustrates the North American Electric Reliability Corporation Regions and Balancing Authorities in the CARIS model. The CARIS model includes an active representation for bulk power systems of the NYISO, ISO-New England, IESO Ontario, and PJM Interconnection Control Areas. The transmission representation of these three neighboring control areas is based off the most recent CRP case and includes changes expected to significantly impact NYCA congestion.

Figure 6: Areas Modeled in CARIS (Include NYISO, ISO-New England, IESO Ontario, and PJM Interconnection)



Source: FERC - https://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf

New York Control Area Transfer Limits

CARIS utilizes normal transfer criteria for MAPS software simulations for determining system production costs. However, for the purpose of calculating the ICAP cost metric, the model adopts emergency transfer criteria for MARS[6] software simulations in order to estimate the projected changes in NYCA and locational reserve margins due to each of the modeled generic solutions. Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using TARA software.[7] Instead, CARIS uses the most limiting monitored lines and contingency sets identified either from analysis using TARA software or from historical binding constraints.

For voltage and stability based limits, the normal and emergency limits are assumed to be the same. For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[8] Central East was modeled with a unit sensitive nomogram reflective of the algorithm utilized by NYISO Operations.[9]

Fuel Forecasts

CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's ("EIA")[10] current national long-term forecast of delivered fuel prices, which is released each spring as part of its Annual Energy Outlook. The figures in this forecast are in nominal dollars. The same fuel forecast is utilized for all study cases and scenarios, except for the high and low natural gas price scenarios.

New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect 'basis' for fuel prices in New York. Key sources of data for estimating the relative differences or 'basis' for fuel-oil prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[11] The regional basis for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook and spot prices for selected trading hubs. The

6 GE's Multi-Area Reliability Simulation software.

7 PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software is a steady-state power flow software tool with modeling capabilities and analytical applications.

8 https://www.nyiso.com/documents/20142/3691079/NYISO_InterfaceLimtsandOperatingStudies.pdf/c0cd6dc2-f666-0b12-2cf8-edba51d0daae

9 https://www.nyiso.com/documents/20142/3692791/CE_VoltageandStability_Limit_ReportFinalOCApproved3-17-2016.pdf

10 www.eia.doe.gov

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

base annual forecast series from the Annual Energy Outlook are then subjected to an adjustment to reflect the New York 'basis' relative to the national delivered prices as described below.

Natural Gas

For the 2019 CARIS study, the New York Control Area is divided into four (4) gas regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

Given that gas-fueled generators in a specific NYCA zone acquire their fuel from several gas-trading hubs, each regional gas price is estimated as a weighted blend of individual hubs – where the weights are the sub-totals of the generators' annual generation megawatt-hour levels. The regional natural gas price blends for the regions are as follows:

- Zones A to E – Dominion South (65%), Columbia (5%), & Dawn (30%);
- Zones F to I – Iroquois Zone 2 (30%), Tennessee Zone 6 (45%), Tetco M3 (20%), & Iroquois Waddington (5%);
- Zone J – Transco Zone 6 (100%);
- Zone K – Iroquois Zone 2 (60%) & Transco Zone 6 (40%)

The forecasted regional 'basis,' otherwise known as the differential between the blended regional price and the national average, is calculated as the 3-year weighted-average of the ratio between the regional price and the national average delivered price from the Short-Term Energy Outlook.[12] Forecasted fuel prices for the gas regions are shown in Figure 7 through Figure 10.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see Annual Energy Outlook 2019, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional bases were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil #2) and Residual (Fuel Oil #6) prices. This analysis suggests that for New York, Distillate and Residual Oil prices will be the same as the national average. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in Figure 7 through Figure 10.

Coal

12 The raw hub-price is 'burdened' by an appropriate level of local taxes and approximate delivery charges. In light of the high price volatility observed during winter months, the 'basis' calculation excludes data for January, February and December.

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted 'basis' for coal. (The published figures do not make a distinction between the different varieties of coal; *i.e.,* bituminous, sub-bituminous, and lignite).

Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, the NYISO estimated seasonal-factors using standard statistical methods.[13] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the 2019 seasonal factors are as follows:

- Natural Gas: Raw daily prices from S&P Global/Platts for the various trading hubs incorporated in the regional price blends.
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. CARIS assumes the same seasonality for both types of fuel oil.

The seasonalized time-series represents the forecasted trend of average monthly prices. Because CARIS uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 53 weekly prices for a given year. Furthermore, "'spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as 5-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they sum to zero.

13 This is a two-step process: First, deviations around a centered 12-month moving average are calculated over the 2014-2018 period; second, the average values of these deviations are normalized to estimate monthly/seasonal factors.

Figure 7: Forecasted fuel prices for Zones A-E (nominal $)

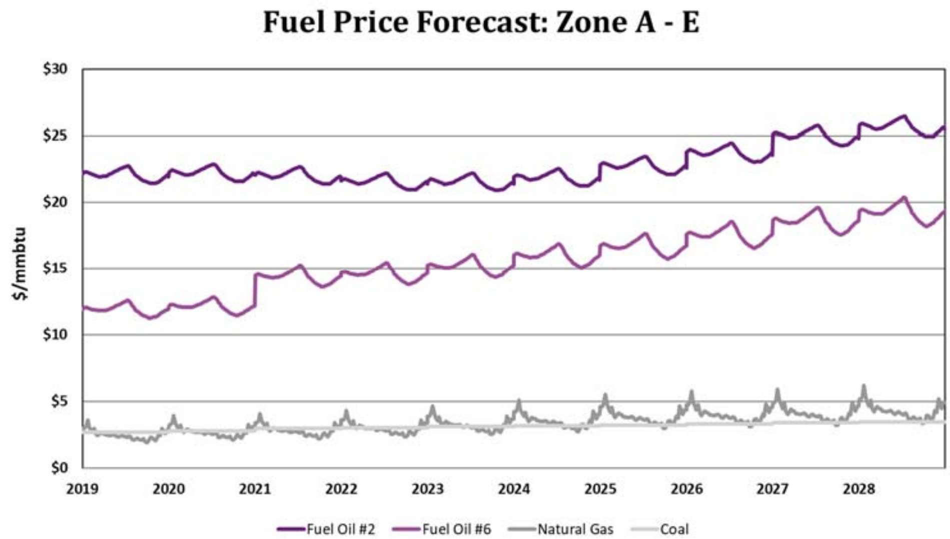


Figure 8: Forecasted fuel prices for Zones F-I (nominal $)

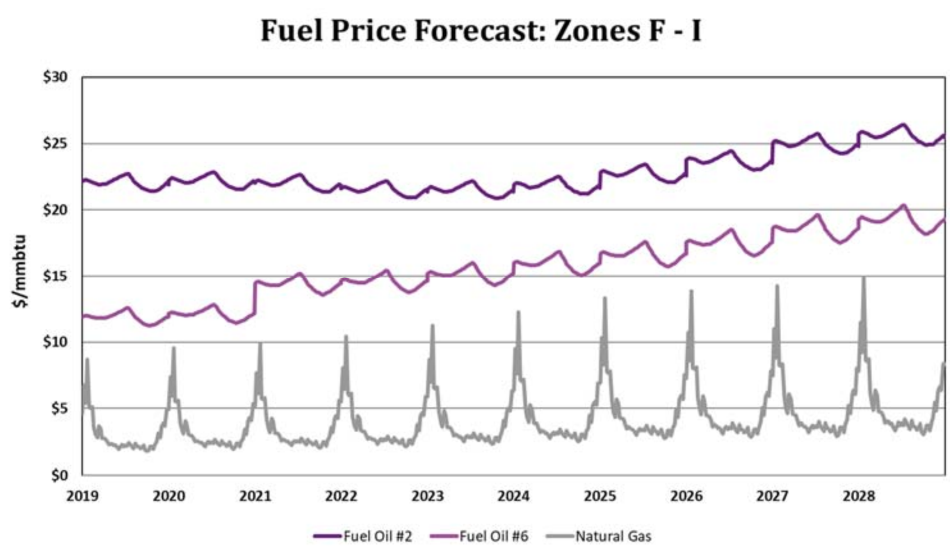


Figure 9: Forecasted fuel prices for Zone J (nominal $)

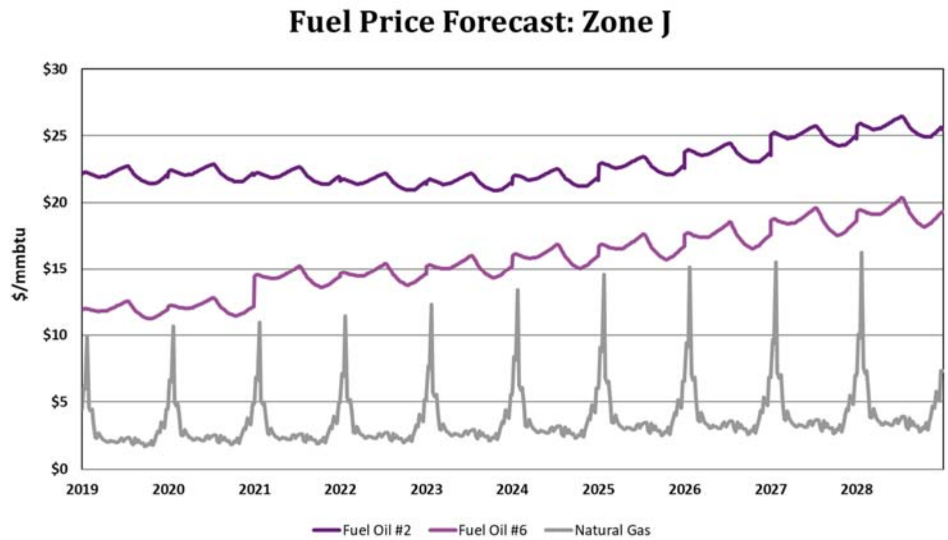
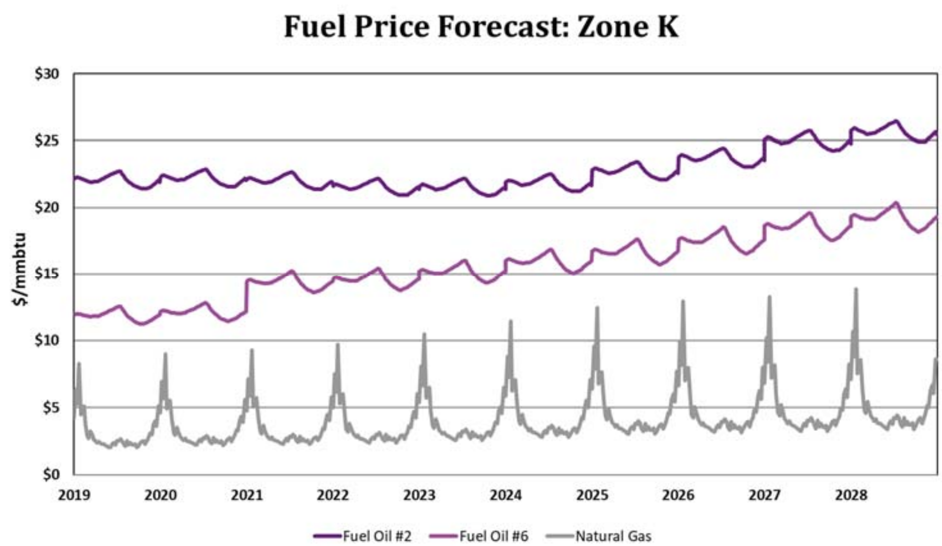


Figure 10: Forecasted fuel prices for Zone K (nominal $)



External Areas Fuel Forecast

The fuel forecasts for the three external Control Areas, ISO-New England, PJM Interconnection and IESO Ontario, were also developed. For each of the fuels, the 'basis' for ISO-New England North, ISO-New England South, PJM-East and PJM-West forecasts are based on the EIA data obtained from the same sources as those used for New York. With respect to the IESO Ontario control area, the relative price of natural gas is based on spot-market data for the Dawn hub obtained from SNL Energy[14]. CARIS does not model any IESO Ontario generation as being fueled by either oil or coal.

14 Copyright © 2018, SNL Financial LLC

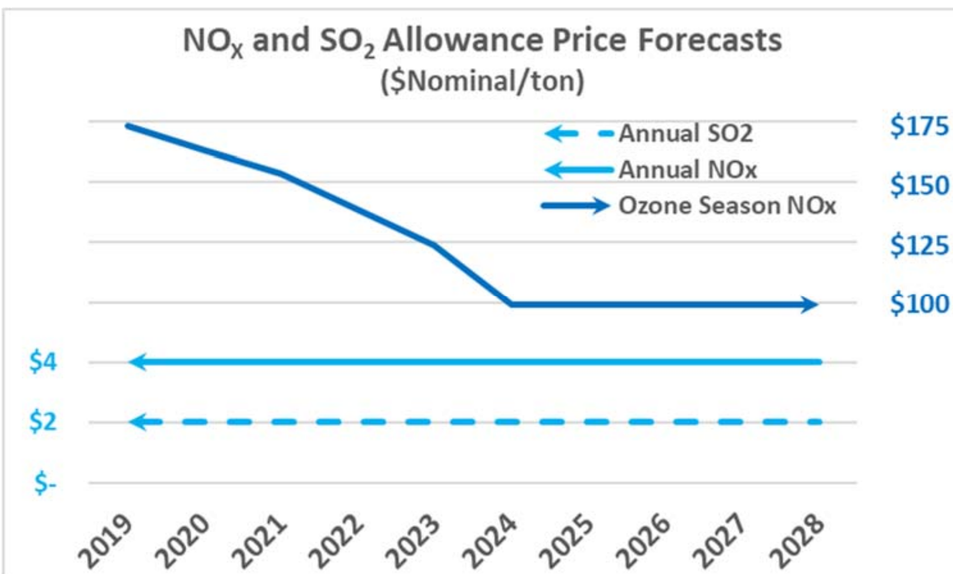
External price forecasts are provided in Appendix C.

Emission Cost Forecast

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

Business-as-Usual case allowance price forecasts for annual and seasonal NO_X and SO_2 emissions are developed using representative prices at the time the assumptions are finalized. The Cross-State Air Pollution Rule NO_X and SO_2 allowances prices reflect the persistent oversupply of annual programs, and the expectation that stricter seasonal limitations in the Cross-State Air Pollution Rule Update will continue to be manageable program-wide, leading to price declines as market participants adjust to new operational limits. Figure 11 shows the assumed NO_X and SO_2 Allowance Price Forecasts used in this study.[15]

Figure 11: NO_X and SO_2 Emission Allowance Price Forecasts



The Regional Greenhouse Gas Initiative (RGGI) program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, Delaware, and New Jersey. Historically, the RGGI market has been oversupplied and prices have remained near the floor. In January 2012, the RGGI States chose to retire all unsold RGGI allowances from the 2009-

15 Annual NO_X allowance prices are used October through May; ozone season NO_X allowance prices in addition to Annual NO_X allowance prices are used in May through September.

2011 compliance period in an effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid-program review in 2012 that became effective in 2014. The emissions cap was reduced to 91 million tons in 2014 and decreases to 78 million tons in 2020.

Following the cap reduction, the emissions cap became binding on the market, thereby triggering the Cost Containment Reserve. In 2014, five million additional CO_2 allowances were sold at auction, followed by an additional ten million Cost Containment Reserve allowances in 2015. In February 2016, the Supreme Court stayed implementation of the EPA Clean Power Plan. The market response to this ruling was a reduction in RGGI prices. RGGI undertook another program review in 2016-2017 proposing additional changes to the program structure, including a 30% cap reduction between 2020 and 2030. An Emission Containment Reserve was added to provide price support by holding back allowances from auction if prices do not exceed predefined threshold levels.

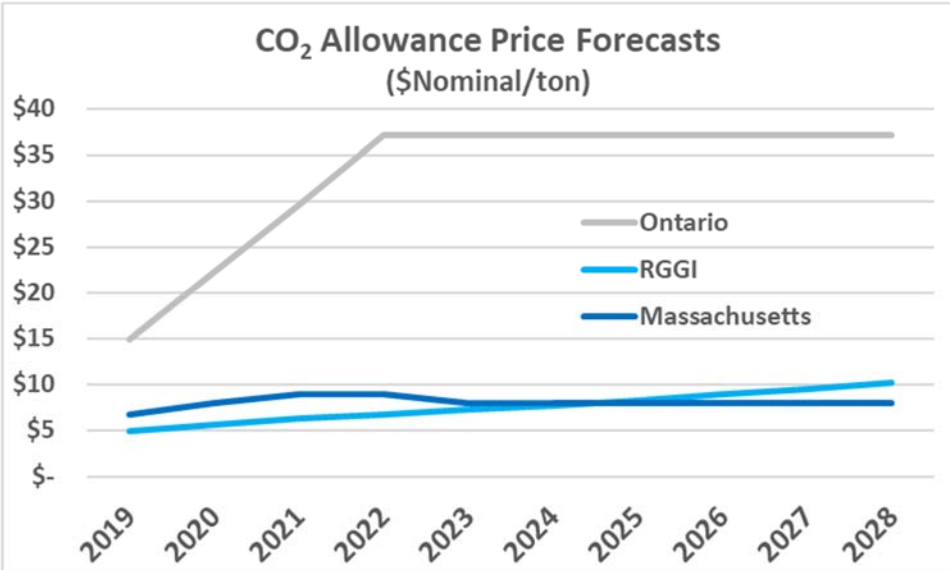
The allowance price forecast assumes that auctions will clear in line with the Emission Containment Reserve trigger price through the study period. In the past, CARIS studies assumed that a federal CO_2 program, similar to the RGGI program, would take effect in 2020, however the expectation of such a program have since dampened and currently no national program is assumed within the 10 year study period. New Jersey has rejoined RGGI in 2020. Virginia has completed legislative action to rejoin RGGI as soon as 2021. Pennsylvania is also considering joining RGGI. When the stated intentions are developed into promulgated rules, it will be timely to include the cost of CO_2 emission allowances in the production models for these states. In this study, only New Jersey is reflected as joining RGGI through application of the RGGI price to generators in the state above 25MW beginning in 2020.

Massachusetts began implementing its own single state cap-and-trade program in 2018, which is similar to RGGI but with more restrictive caps applicable to generators located in Massachusetts.[16] MassDEP held the first auction of the new program in December 2018 with CO_2 prices cleared at $6.71 metric ton ($6.09/ton), and more recently in December 2019 clearing above $8/metric ton. Massachusetts allowance prices assumed in this study are incremental to RGGI allowance prices imposed upon Massachusetts's emitting generators. The study assumes a distinct CO_2 allowance price forecast applicable to IESO Ontario generation based upon CO_2 prices in Canada's Greenhouse Gas Pollution Pricing Act.[17]

16 https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774
17 https://www.canlii.org/en/ca/laws/stat/sc-2018-c-12-s-186/latest/sc-2018-c-12-s-186.html

Figure 12 shows the emission allowance price forecasts by year in $/ton.

Figure 12: CO_2 Emission Allowance Price Forecasts



Generic Solutions

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

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

Resource Block Sizes

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

- Block size should reflect a typical size built for the specific resource type and geographic location;
- Block size should be small enough to be additive with reasonable step changes; and

- Blocks sizes should be in comparable proportions between the resource types.

The block sizes selected for each resource type are presented in Figure 13 through Figure 15.

Figure 13: Transmission Block Sizes[18]

Location	Line System Voltage (kV)	Normal Rating (MVA)
Zone C	345	1,986
Zone E-G	345	1,986

Figure 14: Generation Block Sizes[19]

Plant Location	Plant Block Size Capacity (MW)
Zone C	340
Zone F-G	340

Figure 15: EE and DR Block Sizes

Location	Resource Quantity (MW)
Zone F-G	100
Zone J	200

Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types depends on many different parameters and assumptions and without consideration of project feasibility or project-specific costs.

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

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements that meets the required criteria, then the two substations that have the shortest distance

18 Solution size is based on a double-bundled ACSR 1590 KCmil conductor rated for 3,324 amps.

19 Proposed generic unit is a Siemens SGT6-5000F(5).

between the two are selected. Space availability at substations (*i.e.,* room for substation expansion) was not evaluated in this process.

Generation Resource

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

Energy Efficiency

- Block sizes limited to 200 MW or 5% of zonal peak load, whichever is lower. If one zone reaches a limit, energy efficiency may be added to other downstream zones.
- Aggregated at the downstream of the congested elements.
- The total resource increase in megawatts should be comparable to the megawatt increase in transfer capability due to the transmission solution.

Demand Response

- Blocks of demand response modeled at 100 peak hours as reduction in zonal hourly load.
- Use the same block sizes in the same locations as energy efficiency.

Generic Solution Pricing Considerations

Three sets of cost estimates for each of the four resource types are designed to reflect the differences in labor, land and permitting costs among Upstate, Downstate and Long Island, as set forth below. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Figure 16.

Figure 16: Generic Solution Pricing Considerations

Transmission	Generation	Energy Efficiency	Demand Response
Transmission Line Cost per Mile	Equipment	Energy Efficiency Programs	Demand Response Programs
Substation Terminal Costs	Construction Labor & Materials	Customer Implementation Costs	Customer Implementation Costs
System Upgrade Facilities	Electrical Connection & Substation		
	Electrical System Upgrades		
	Gas Interconnect & Reinforcement		
	Engineering & Design		

Low, mid, and high cost estimates for each element were provided to stakeholders for comment. The transmission cost estimates were reviewed by Market Participants, including Transmission Owners; and the estimated cost data for the mid-point of the generation solutions are obtained from the 2016 Demand Curve Reset report. The low and high point of the generic cost estimates for Energy Efficiency were derived from DPS filings on energy efficiency costs from the relevant TOs.[20] Finally, the mid-point of the Demand Response costs was extracted from most recent New York Public Service Commission filings by utilities on Commercial System Relief Program costs and enrollments.[21] This approach establishes a range of cost estimates to address the variability of generic projects. The resulting order of magnitude unit pricing levels are provided in the "Cost Analysis" section below. A more detailed discussion of the cost assumptions and calculations is provided in Appendix E.

20 Case 18-M-0084 – In the Matter of a Comprehensive Energy Efficiency Initiative

21 Case 14-E-0423 – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs

"70x30 Scenario" Model Assumptions

Text to be added at a later date

2019 CARIS Phase 1 Results

This section presents summary level results of the six steps of the 2019 CARIS Phase 1. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

Congestion Assessment

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

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

Historic Congestion

Historic congestion assessments have been conducted at the NYISO since 2005 with metrics and procedures developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. Starting 2018, followed by Tariff changes in Appendix A of Attachment Y to the OATT, only the following historic Day-Ahead Market congestion-related data are reported: (i) LBMP load costs (energy, congestion and losses) by Load Zone; (ii) LBMP payments to generators (energy, congestion and losses) by Load Zone; (iii) congestion cost by constraint; and (iv) congestion cost of each constraint to load (commonly referred to in CARIS as “demand dollar congestion” by constraint). The results of the historic congestion analysis are posted on the NYISO website. For more information on the historical results below see:

https://www.nyiso.com/ny-power-system-information-outlook

Historic congestion costs by zone, expressed as Demand$ Congestion, are presented in Figure

17 indicating that the highest congestion is in New York City and Long Island.

Figure 17: Historic Demand$ Congestion by Zone 2014-2018 (nominal $M)[22]

Zone	2014	2015	2016	2017	2018
West	$36	$83	$116	$63	$65
Genesee	$9	$9	$7	$12	$10
Central	$38	$34	$29	$40	$37
North	$3	$5	$7	$6	$15
Mohawk Valley	$12	$10	$7	$10	$7
Capital	$149	$123	$95	$90	$80
Hudson Valley	$95	$86	$64	$66	$50
Millwood	$30	$26	$19	$21	$16
Dunwoodie	$55	$49	$41	$44	$34
New York City	$531	$459	$378	$443	$405
Long Island	$409	$404	$339	$287	$303
NYCA Total	$1,367	$1,287	$1,102	$1,082	$1,024

Figure 18 below lists historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2014 to 2018. The top congested paths are shown below.

Figure 18: Historic Demand$ Congestion by Constrained Paths 2014-2018 (nominal $M)

Constraint Path	2014	2015	2016	2017	2018	Total
CENTRAL EAST	$1,136	$915	$641	$598	$540	$3,829
DUNWOODIE TO LONG ISLAND	$155	$138	$164	$88	$133	$677
LEEDS PLEASANT VALLEY	$42	$111	$63	$101	$9	$327
EDIC MARCY	$7	$0	$32	$125	$107	$271
PACKARD HUNTLEY	$7	$41	$54	$30	$41	$172
GREENWOOD	$13	$19	$31	$18	$62	$143
DUNWOODIE MOTTHAVEN	$40	$2	$2	$30	$65	$139
NIAGARA PACKARD	$18	$22	$44	$12	$9	$104
EGRDNCTY 138 VALLYSTR 138 1	$20	$18	$8	$17	$20	$82
NEW SCOTLAND LEEDS	$9	$32	$13	$18	$5	$76

* Ranking is based on absolute values.

Projected Future Congestion

Future congestion for the Study Period was determined from a MAPS software simulation using a base case developed with the Electric System Planning Working Group. As reported in the "Historic Congestion" section above, congestion is reported as Demand$ Congestion. MAPS software simulations are highly dependent upon many long-term assumptions, each of which affects the study results. The MAPS software model utilizes input assumptions listed in Appendix C.

22 Reported values do not deduct TCCs. NYCA totals represent the sum of absolute values. DAM data include Virtual Bidding and Planned Transmission Outages.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by Market Operations production software and Planning MAPS software. MAPS software, unlike Market Operations software, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments; and (f) co-optimization with ancillary services. As in prior CARIS cycles, the projected congestion is below historic levels due to the factors cited. Such factors could also lead to lower projections of production cost savings attributable to new projects (*e.g.,* transmission, generation, energy efficiency, demand response) constructed or implemented to address system congestion.

Discussion

Figure 19 presents the projected congestion from 2019 through 2028 by Load Zone. The relative costs of congestion shown in this table indicate that the majority of the projected congestion is in the Downstate zones – NY City and Long Island. Year-to-year changes in congestion reflect changes in the model, which are discussed in the "Baseline System Assumptions" section above.

Figure 19: Projection of Future Demand$ Congestion 2019-2028 by Zone for Base Case (nominal $M)

Demand Congestion ($M)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
West	$87	$55	$36	$4	$1	$9	$11	$12	$11	$8
Genesee	$4	$2	$1	$2	$1	$5	$6	$7	$6	$5
Central	$28	$22	$21	$14	$9	$12	$10	$10	$12	$13
North	$6	$7	$5	$4	$3	$4	$3	$3	$3	$3
Mohawk Valley	$10	$7	$7	$5	$3	$4	$3	$3	$4	$4
Capital	$116	$91	$92	$73	$34	$31	$15	$15	$19	$27
Hudson Valley	$66	$56	$62	$51	$28	$20	$11	$12	$14	$19
Millwood	$20	$17	$18	$15	$8	$6	$3	$3	$4	$6
Dunwoodie	$39	$35	$37	$31	$17	$12	$6	$7	$8	$11
NY City	$392	$349	$356	$292	$165	$132	$78	$87	$106	$131
Long Island	$218	$195	$193	$163	$116	$105	$75	$77	$80	$96
NYCA Total	**$986**	**$838**	**$827**	**$655**	**$387**	**$338**	**$219**	**$235**	**$268**	**$322**

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

Based on the positive Demand$ Congestion costs, the future top congested paths are shown in Figure 20.

Figure 20: Projection of Future Demand$ Congestion 2019-2028 by Constrained Path for Base Case (nominal $M)

Demand Congestion ($M)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CENTRAL EAST	$668	$508	$521	$411	$183	$188	$84	$84	$114	$167
DUNWOODIE TO LONG ISLAND	$41	$36	$28	$25	$25	$31	$25	$26	$25	$28
CHESTR SHOEMAKR	$9	$34	$79	$68	$52	$0	$0	$0	$0	$0
PACKARD 115 NIAGBLVD 115	$85	$53	$29	$0	$0	$0	$0	$0	$0	$0
DUNWOODIE MOTTHAVEN	$8	$9	$10	$7	$5	$14	$13	$14	$18	$15
GREENWOOD	$12	$10	$6	$6	$6	$8	$8	$10	$11	$10
N.WAV115 LOUNS 115	$2	$2	$3	$4	$4	$13	$10	$13	$12	$11
VOLNEY SCRIBA	$6	$7	$6	$7	$7	$6	$5	$7	$9	$9
NORTHPORT PILGRIM	$6	$4	$9	$10	$8	$5	$4	$5	$4	$4
EGRDNCTY 138 VALLYSTR 138 1	$6	$5	$3	$2	$5	$4	$5	$4	$5	$4
FERND 115 W.WDB 115	$2	$5	$10	$9	$9	$1	$0	$0	$1	$2
NIAGARA PACKARD	$19	$16	$10	$0	$0	$0	$0	$0	$0	$0

Ranking of Congested Elements

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

Figure 21 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East, Dunwoodie-Long Island, and Leeds-Pleasant Valley continue to be the paths with the greatest projected congestion. The top elements are evaluated in the next step for selection of the three study cases.

Figure 21: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the 15 Yr Aggregate (Base Case)[23]

[23] The absolute value of congestion is reported.

Present Value of Demand$ Congestion ($2019M)			
Element	Hist. Total	Proj. Total	15Y Total
CENTRAL EAST	$5,021	$2,555	$7,576
DUNWOODIE TO LONG ISLAND	$873	$230	$1,103
LEEDS PLEASANT VALLEY	$423	$9	$432
EDIC MARCY	$317	$0	$317
DUNWOODIE MOTTHAVEN	$172	$83	$254
GREENWOOD	$174	$67	$241
PACKARD HUNTLEY	$215	$0	$215
CHESTR SHOEMAKR	$0	$212	$212
NIAGARA PACKARD	$135	$44	$179
PACKARD 115 NIAGBLVD 115	$0	$166	$166
SCH-NE-NY	$135	$28	$163
EGRDNCTY 138 VALLYSTR 138 1	$105	$33	$139
NEW SCOTLAND LEEDS	$99	$0	$100
E179THST HELLGT ASTORIAE	$48	$15	$63
SHORE_RD 345 SHORE_RD 138 1	$59	$0	$59
VOLNEY SCRIBA	$3	$51	$55
N.WAV115 LOUNS 115	$0	$52	$52

The frequency of actual and projected congestion is shown in Figure 22. The figure presents the actual number of congested hours by constraint, from 2014 through 2018, and projected hours of congestion, from 2019 through 2028. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Figure 22: Number of Congested Hours by Constraint (Base Case)

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
Constraint	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CENTRAL EAST	3,022	4,091	4,636	5,062	4,031	3,145	3,266	2,831	2,649	1,500	1,245	700	723	723	878
DUNWOODIE TO LONG ISLAND	5,583	7,738	6,085	8,212	8,624	7,629	7,833	7,546	7,420	6,812	7,329	6,940	6,682	6,867	6,953
LEEDS PLEASANT VALLEY	384	965	623	982	83	20	17	20	24	28	-	-	-	-	-
GREENWOOD	1,438	7,456	7,347	7,573	7,310	4,431	4,504	4,603	4,797	4,719	4,704	4,592	4,620	4,480	4,471
PACKARD HUNTLEY	308	1,720	1,425	821	818	-	-	-	-	-	-	-	-	-	-
EGRDNCTY 138 VALLYSTR 138 1	5,142	3,191	3,479	6,178	5,442	6,394	5,975	4,757	4,813	4,846	4,937	5,162	5,058	5,102	5,074
NIAGARA PACKARD	-	756	1,279	501	458	253	202	76	38	-	20	-	-	-	-
DUNWOODIE MOTTHAVEN	190	231	134	1,281	2,743	846	922	1,918	1,643	1,537	2,120	2,052	2,048	2,191	2,349
EDIC MARCY	-	11	164	307	312	-	-	-	-	-	-	-	-	-	-
RAINEY VERNON	641	2,073	2,438	2,655	2,700	541	344	287	222	183	250	233	284	261	306
MOTTHAVEN RAINEY	-	80	188	1,900	208	692	718	328	239	97	253	241	168	285	275
STOLLE GARDENVILLE	-	318	429	-	-	25	8	3	-	-	-	-	-	-	-
E179THST HELLGT ASTORIAE	990	1,672	1,864	6,406	6,345	2,838	2,879	1,801	1,993	1,713	1,821	1,585	1,668	1,591	1,285
NEW SCOTLAND LEEDS	173	556	214	314	106	1	-	-	4	2	-	-	-	-	-
SHORE_RD 345 SHORE_RD 138 1	-	505	172	120	56	-	-	-	-	-	-	-	-	-	-
VOLNEY SCRIBA	-	146	46	324	254	1,434	1,593	1,224	1,330	1,444	1,258	1,334	1,486	1,798	1,745

Identifying the CARIS Studies

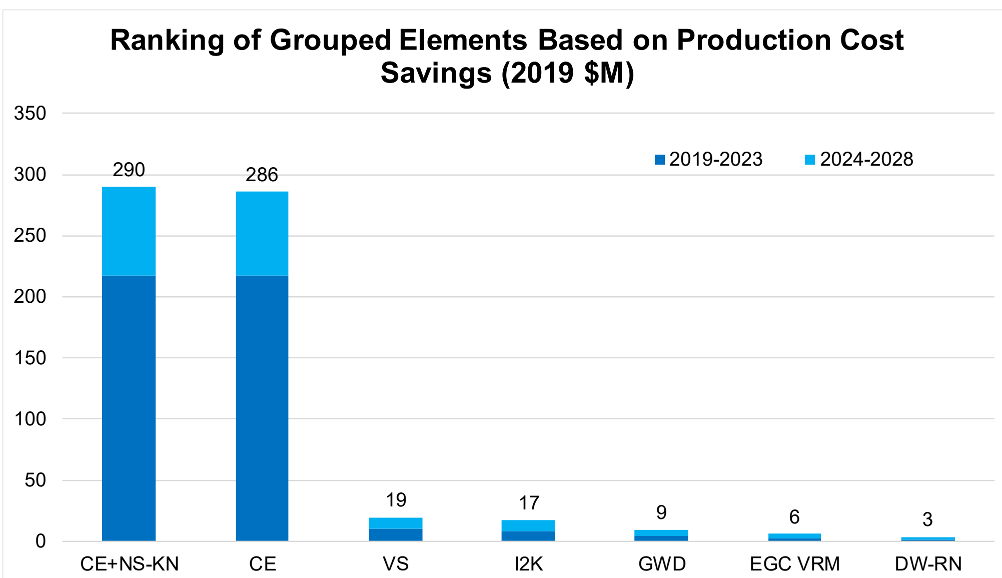
Selection of the Studies

Selection of the CARIS studies is a two-step process in which the top ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints.[24] The resultant grouping of elements for each of the top ranked constraints is utilized to determine the CARIS studies. For the purpose of this selection exercise, the Base Case, as described above in the "Base Case Modeling Assumptions" section, was utilized.

In Step 1, the top five congested elements for the fifteen-year period (both historic (5 years) and projected (10 years)) are ranked in descending order based on the calculated present value of Demand$ Congestion for further assessment.

In Step 2, the top congested elements from Step 1 are relieved independently by relaxing their limits. This is to determine if any of the congested elements need to be grouped with other elements, depending on whether new elements appear as limiting with significant congestion when a primary element is relieved. See Appendix E for a more detailed discussion. The assessed element groupings are then ranked based upon the highest change in production cost, as presented in Figure 23.

Figure 23: Ranking of Grouped Elements Based on Production Cost Savings ($2019M)



Per the NYISO Tariff, the three ranked interface groupings with the largest change in

[24] Additional detail on the selection of the CARIS studies is provided in Appendix E.

production cost are then selected as the set of CARIS studies. For the 2019 CARIS Phase 1, these are Central East-New Scotland-Knickerbocker (“CE+NS-KN”), Central East (“CE”) and Volney-Scriba (“VS”). Other interfaces with noted changes in production cost are I to K (“I2K”), the Greenwood Load Pocket (“GWD”), East Garden Center-Valley Stream (“EGC VRM”), and Dunwoodie-Rainey (“DW-RN”).

Figure 24 and Figure 25 present the Base Case congestion associated with each of the three studies in nominal and real terms.

Figure 24: Demand$ Congestion for the Three CARIS Studies (nominal $M)

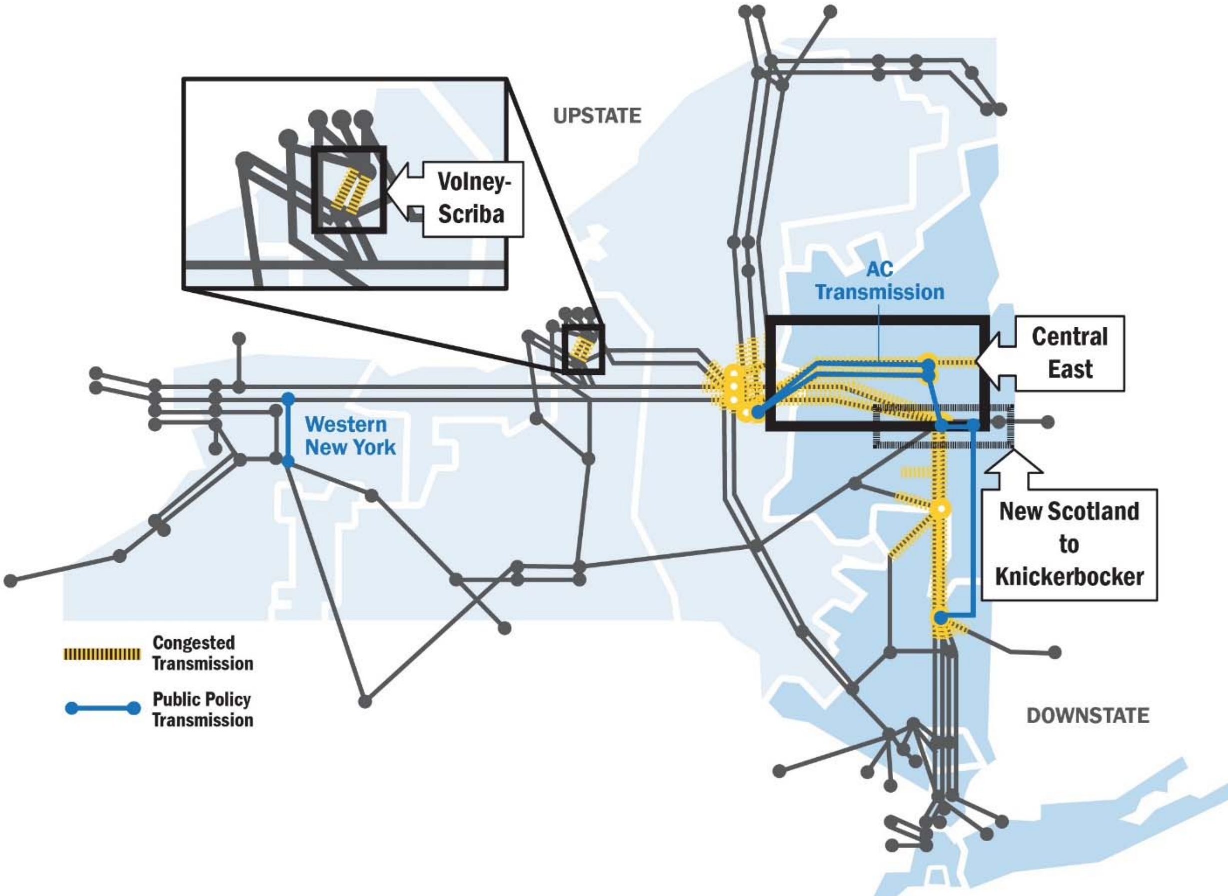
Study	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Study 1: Central East	668	508	521	411	183	188	84	84	114	167
Study 2: Central East-Knickerbocker	668	508	521	411	183	192	87	91	120	173
Study 3: Volney Scriba	6	7	6	7	7	6	5	7	9	9

Figure 25: Demand$ Congestion for the Three CARIS Studies ($2019M)

Study	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Study 1: Central East	691	491	470	347	144	139	57	54	69	93
Study 2: Central East-Knickerbocker	691	491	470	347	144	141	60	58	72	96
Study 3: Volney Scriba	6	6	6	6	5	4	4	4	5	5

The location of the top three congested groupings, along with the present value of congestion (in 2019 dollars) for the three studies, is presented in Figure 26.

Figure 26: Base Case Congestion of Top 3 Congested Groupings, 2019-2028 ($2019M)



Study 1: Central East
Demand$ Congestion: 2,555 ($2019M)

Study 2: Central East-Knickerbocker
Demand$ Congestion: 2,571 ($2019M)

Study 3: Volney-Scriba
Demand$ Congestion: 51 ($2019M)

Generic Solutions to Congestion

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

Concerning the generic solutions, it is important to note the following:

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

The discount rate of 7.08% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital for the New York Transmission Owners. The weighted average is based on the utilities' annual gigawatt hour energy consumption for 2018.

Figure 28, Figure 31, and Figure 34 present the impact of each of the solutions on Demand$ Congestion for each of the studies in 2019$. Transmission has the greatest impact on reducing Demand$ Congestion (24% to 100%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution had negligible impact on Demand$ Congestion (<2%) for studies 1 and 2 except for study 3 (89%) as the generic unit did not displace significant generation in the Base Case. This is attributable in studies 1 and 2 to a resource-rich environment downstream of the constraints, including Indian Point Energy Center (up to 2021), the Bayonne expansion, and the new Cricket Valley and CPV Valley combined-cycle facilities. In study 3 (Volney-Scriba), the generic generation solution is sited directly downstream of the congested element which helps in pushing back the flow on the congested line, hence relieving most of the congestion. The demand response solution had nearly no impact on Demand$ Congestion (<1%) since this solution is essentially a limited summer season resource and, as such, is not operational during the winter hours in which Central East is most heavily congested. The energy efficiency solution, reducing load across the full year, reduced Demand$ Congestion by about 6% across all three studies.

Figure 29, Figure 32, and Figure 35 present the impact of each of the solutions on production costs for each of the studies in 2019$. Transmission had higher impacts than the generation solutions in studies 1 and 2. For study 3, the generation solution has the higher impact on production cost. The impact of the transmission solution on production costs ranges from $22M - $117M. The generation solution reduced production costs by $103M - $137M. The demand response solution resulted in the least production cost savings ($9M - $17M), again, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution shows the largest production cost savings (by $530M - $1,061M) because it directly reduces the energy production requirements.

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

Study 1: Central East

The following generic solutions were applied for the Central East Study under base conditions. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Edic to New Scotland, 85 Miles. The new line increases the Central East voltage transfer limit by about 400 MW. Cost estimates are: $340M (low); $510M (mid); and $638M (high).
- Generation: A new 340 MW Plant at New Scotland. Cost estimates are: $450M (low); $600M (mid); and $750M (high).
- Demand Response: 100 MW Demand Response in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $203M (low); $270M (mid); and $338M (high).
- Energy Efficiency: 100 MW Energy Efficiency in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $2,985M (low); $3,980M (mid); and $4,975M (high).

Figure 27 shows the Demand$ Congestion of Central East for 2023 and 2028 before and after each of the generic solutions is applied. The Base Case congestion numbers, $183M for 2023 and $167M for 2028, are taken directly from Figure 24 representing the level of congestion of Study 1 before the solutions.

Figure 27: Demand$ Congestion Comparison for Study 1 (nominal $M)

Study 1: Central East						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	183	135	(26%)	167	97	(42%)
Generation-340MW	183	161	(12%)	167	175	5%
Demand Response-400MW	183	182	(1%)	167	168	1%
Energy Efficiency-400MW	183	168	(8%)	167	156	(7%)

Figure 28 shows the Demand$ Congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 28: Demand$ Congestion Comparison for Study 1 ($2019M)

Study 1: Central East												
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	%Change
Transmission	(139)	(133)	(103)	(67)	(38)	(66)	(30)	(29)	(31)	(39)	(675)	(26%)
Generation-340MW	(20)	7	(3)	(10)	(17)	(4)	3	(7)	(3)	4	(51)	(2%)
Demand Response-400MW	1	0	0	1	(1)	(0)	1	(0)	0	1	4	0%
Energy Efficiency-400MW	(33)	(27)	(28)	(20)	(12)	(13)	(5)	(12)	(5)	(6)	(159)	(6%)

Figure 29 shows the production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 29: NYCA-wide Production Cost Savings for Study 1 ($2019M)

Study 1: Central East											
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Transmission	(22)	(20)	(20)	(15)	(9)	(7)	(6)	(5)	(5)	(6)	(115)
Generation-340MW	(2)	(7)	(12)	(15)	(11)	(9)	(7)	(10)	(13)	(17)	(103)
Demand Response-400MW	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(17)
Energy Efficiency-400MW	(108)	(109)	(110)	(107)	(108)	(106)	(107)	(106)	(101)	(98)	(1,061)

Note: Totals may differ from sum of annual values due to rounding.

The Edic-New Scotland 345 kV transmission solution is projected to relieve the congestion across Central East Interface by 26% in 2023 and 42% in 2028 respectively, as shown in Figure 27. As presented in Figure 29 total ten year NYCA-wide production cost savings is $115 million (2019$) as the result of better utilization of economic generation in the state made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to reduce congestion by 12% in 2023 and increase congestion by 5% in 2028. The ten-year production cost savings of $103 million (2019$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J demand response solution is projected to have no significant impact on congestion in 2023 and 2028, while the ten-year total production cost savings is $17 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G and J energy efficiency solution is projected to reduce congestion by 8% in 2023 and 7% in 2028, while the ten-year total production cost saving is $1,061 million (2019$). The relatively large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. For this reason, energy efficiency solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 2: Central East -Knickerbocker

The following generic solutions were applied for the Central East-Knickerbocker study. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Edic to New Scotland to Knickerbocker, 100 Miles (85 miles 345 kV circuit same as Study 1, additional 15 miles from New Scotland to Knickerbocker assumed in service after 2024). The new line increases the Central East voltage limit by approximately 400 MW. Cost estimates are: $400M (low); $600M (mid); and $750M (high) for the entire 100 mile solution over 10 years.
- Generation: A new 340 MW Plant at Pleasant Valley. Cost estimates are: $505M (low); $675M (mid); and $845M (high).
- Demand Response: 100 MW Demand Response in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $203M (low); $270M (mid); and $338M (high).
- Energy Efficiency: 100 MW Energy Efficiency in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $2,985M (low); $3,980M (mid); and $4,975M (high).

Figure 30 shows the Demand$ Congestion of Central East-New Scotland-Knickerbocker for 2023 and 2028 before and after each of the generic solutions is applied.

Figure 30: Demand$ Congestion Comparison for Study 2 (nominal $M)

Study 2: Central East-Knickerbocker						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	183	135	(26%)	173	126	(27%)
Generation-340MW	183	161	(12%)	173	176	2%
Demand Response-400MW	183	182	(1%)	173	168	(3%)
Energy Efficiency-400MW	183	168	(8%)	173	163	(6%)

Figure 31 shows the Demand$ Congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 31: Demand$ Congestion Comparison for Study 2 ($2019M)

Study 2: Central East-Knickerbocker												
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	%Change
Transmission	(139)	(133)	(103)	(67)	(38)	(46)	(22)	(20)	(20)	(26)	(614)	(24%)
Generation-340MW	(15)	9	0	(8)	(18)	4	4	(4)	1	2	(25)	(1%)
Demand Response-400MW	1	0	0	1	(1)	(0)	1	(0)	0	1	4	0%
Energy Efficiency-400MW	(33)	(27)	(28)	(20)	(12)	(11)	(4)	(13)	(4)	(5)	(156)	(6%)

Figure 32 shows the NYCA-wide production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 32: NYCA-wide Production Cost Savings for Study 2 ($2019M)

Study 2: Central East-Knickerbocker											
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Transmission	(22)	(20)	(20)	(15)	(9)	(8)	(6)	(5)	(6)	(6)	(117)
Generation-340MW	(2)	(8)	(13)	(16)	(12)	(9)	(7)	(11)	(14)	(18)	(110)
Demand Response-400MW	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(17)
Energy Efficiency-400MW	(108)	(109)	(110)	(107)	(108)	(106)	(107)	(106)	(101)	(98)	(1,061)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Edic-New Scotland-Knickerbocker line is projected to relieve the Central East-Knickerbocker congestion by 26% in 2023 and 27% in 2028. The total ten-year production cost savings of $117 million (2019$) are again due to increased use of lower cost generation in upstate and increased levels of imports compared to the Base Case.

The generation solution is projected to reduce congestion by 12% in 2023 and increase congestion by 2% in 2028. The ten-year production cost savings of $110 million (2019$) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J demand response solution is projected to have a negligible impact on congestion in 2023 and in 2028, while the ten-year total production cost saving is $17 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J Energy Efficiency solution is projected to reduce congestion by 8% in 2023 and 6% in 2028, while the ten-year total production cost saving is $1,061 million (2019$). The relative large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. Energy efficiency solutions typically show greater reductions in production cost than the generation, transmission and demand response solutions because load is reduced in all hours, reducing the total megawatt hours required to serve load.

Study 3: Volney-Scriba (Base Conditions)

The following generic solutions were applied for the Volney-Scriba Study. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Volney to Scriba, 10 Miles. Cost estimates are: $40M (low); $60M (mid); and $75M (high).
- Generation: A new 340 MW Plant at Volney. Cost estimates are: $395M (low); $525M (mid); and $655M (high).
- Demand Response: 100 MW Demand Response in Zone F; 100 MW in Zone G. Cost estimates are $38M (low); $50M (mid); and $63M (high).
- Energy Efficiency: 100 MW Energy Efficiency in Zone F; 100 MW in Zone G. Cost estimates are $1,204M (low); $1,605M (mid); and $2,006M (high).

Figure 33 shows the Demand$ Congestion of Volney-Scriba for 2023 and 2028 before and after each of the generic solutions is applied.

Figure 33: Demand$ Congestion Comparison for Study 3 (nominal $M)

Study 3: Volney Scriba						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	7	0	(100%)	9	0	(100%)
Generation-340MW	7	1	(86%)	9	0	-
Demand Response-200MW	7	7	(3%)	9	9	(3%)
Energy Efficiency-200MW	7	7	(4%)	9	8	(6%)

Figure 34 shows the Demand$ Congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Volney-Scriba study after generic solutions were applied.

Figure 34: Demand$ Congestion Comparison for Study 3 ($2019M)

Study 3: Volney Scriba												
Resource Type	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**	**%Change**
Transmission	(6)	(6)	(6)	(6)	(5)	(4)	(4)	(4)	(5)	(5)	(51)	(100%)
Generation-340MW	(4)	(5)	(5)	(5)	(5)	(4)	(4)	(4)	(5)	(5)	(46)	(89%)
Demand Response-200MW	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(1%)
Energy Efficiency-200MW	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)	(5%)

Figure 35 shows the NYCA-wide production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Voleny-Scriba study after the generic solutions were applied.

Figure 35: NYCA-wide Production Cost Savings for Study 3 ($2019M)

Study 3: Volney Scriba											
Resource Type	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Transmission	(2)	(3)	(2)	(2)	(2)	(2)	(3)	(2)	(2)	(2)	(22)
Generation-340MW	(1)	(9)	(12)	(15)	(16)	(12)	(13)	(15)	(20)	(23)	(137)
Demand Response-200MW	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(9)
Energy Efficiency-200MW	(54)	(55)	(55)	(54)	(54)	(52)	(54)	(53)	(50)	(49)	(530)

Note: Totals may differ from sum of annual values due to rounding.

The Volney-Scriba 345 kV transmission solution is projected to relieve the congestion across existing Volney-Scriba corridor completely in both 2023 and 2028, as shown in Figure 33. As presented in Figure 35, total ten-year NYCA-wide production cost savings is $22 million (2019$) as the result of better utilization of economic generation in the state.

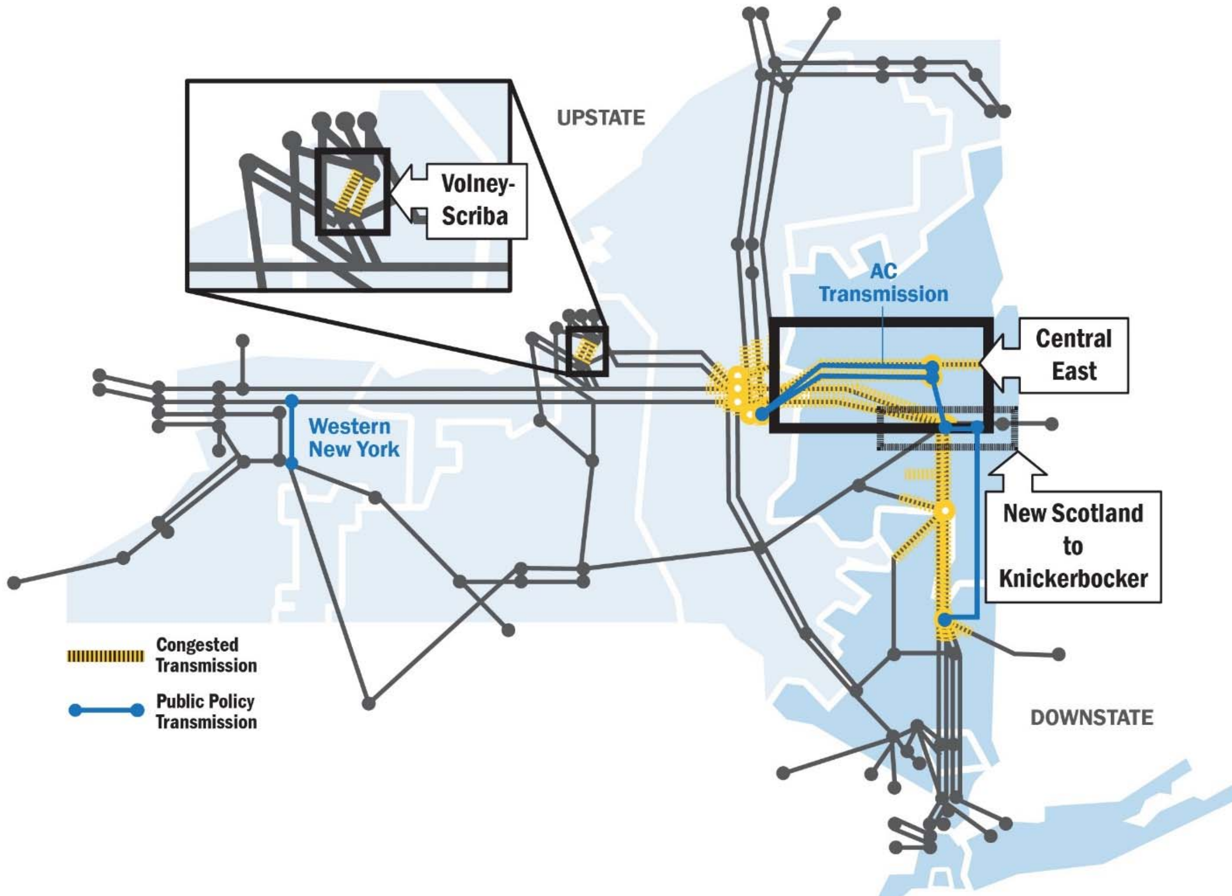
The generation solution is projected to reduce congestion by 86% in 2023 and does not impact line congestion in 2028. The ten-year production cost savings of $137 million (2019$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions can replace less efficient NYCA generation upstream of the load centers, which can have the effect of reducing differentials across the constraints. The displacement of certain Capital Zone generation, however, may lower the Central East voltage transfer limit and actually increase congestion under certain circumstances. The running of lower-cost generation will in general lower production cost as well.

The Zones F and G demand response solution is projected to have a negligible impact on congestion in 2023 and 2028, while the ten-year total production cost saving is $9 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F and G Energy Efficiency solution is projected to reduce congestion by 4% in 2023 and 6% in 2028, while the ten-year total production cost saving is $530 million (2019$). The relatively large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. For this reason, energy efficiency solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

The NYCA-wide production cost savings of the four generic solutions for the three studies are summarized and shown in Figure 36.

Figure 36: Total NYCA-wide Production Cost Savings 2019-2028 ($2019M)



Study 1: Central East	
Solution	**Production Cost Savings ($2019M)**
Transmission	115
Generation	103
Demand Response	17
Energy Efficiency	1,061

Study 2: Central East-Knickerbocker	
Solution	**Production Cost Savings ($2019M)**
Transmission	117
Generation	110
Demand Response	17
Energy Efficiency	1,061

Study 3: Volney-Scriba	
Solution	**Production Cost Savings ($2019M)**
Transmission	22
Generation	137
Demand Response	9
Energy Efficiency	530

Benefit/Cost Analysis

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

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

The 16% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed O&M, and depreciation (assuming a straight-line 30-year method). The calculation of the appropriate capital recovery factor, and, hence, the benefit/cost ratio, is based on the first ten years of the 30-year period,[25] using a discount rate of 7.08%, and the 16% carrying charge rate, yielding a capital cost recovery factor equal to 1.16.

25 The carrying charge rate of 16% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.5.3.3.4.

Costs for the demand response and energy efficiency solutions are intended to be comparable to the overnight installation costs of a generic transmission facility or generating unit and, therefore, represent equipment purchase and installation costs. Recognizing that these costs vary by region, zonal-specific costs were developed utilizing Transmission Owner data reported to the NYPSC in energy efficiency and demand response proceedings.

Cost Analysis

Figure 37 includes the total cost estimate for each generic solution based on the unit pricing and the detailed cost breakdown for each solution included in Appendix E. Such costs may differ from those submitted by potential developers in a competitive bidding process. The costs represent simplified estimates of overnight installation costs, and do not include any of the many complicating factors that could be faced by individual projects. Ongoing fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital cost recovery factor.

Figure 37: Generic Generation with Overnight Costs, Demand Response, and Energy Efficiency Solution Costs for Each Study[26]

Generic Solutions Cost Summary ($M)			
Studies	**Central East (Study 1)**	**Central East-Knickerbocker (Study 2)**	**Volney-Scriba (Study 3)**
GENERATION			
Unit Siting	New Scotland	Pleasant Valley	Volney
# of 340 MW Blocks	1	1	1
High	$750	$845	$655
Mid	$600	$675	$525
Low	$450	$505	$395
DEMAND RESPONSE			
Location (# of Blocks)	F(1), G(1), and J(2)	F(1), G(1), and J(2)	F(1) and G(1)
Total # Blocks	4	4	2
High	$338	$338	$63
Mid	$270	$270	$50
Low	$203	$203	$38
ENERGY EFFICIENCY			
Location (# of Blocks)	F(1), G(1), and J(2)	F(1), G(1), and J(2)	F(1) and G(1)
Total # Blocks	4	4	2
High	$4,975	$4,975	$2,006
Mid	$3,980	$3,980	$1,605
Low	$2,985	$2,985	$1,204

Figure 38: Generic Transmission Solution Overnight Costs for Each Study

Generic Solutions Cost Summary ($M)			
Studies	**Central East (Study 1)**	**Central East-Knickerbocker (Study 2)**	**Volney-Scriba (Study 3)**
TRANSMISSION			
Transmission Path	Edic-New Scotland	Edic-New Scotland-Knickerbocker	Volney-Scriba
Voltage	345 kV	345 kV	345 kV
2019-2023			
Miles	85	85	10
High	$638	$638	$75
Mid	$510	$510	$60
Low	$340	$340	$40
2024-2028			
Miles	85	100	10
High	$638	$750	$75
Mid	$510	$600	$60
Low	$340	$400	$40

Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Figure 39 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the three studies, the Energy Efficiency solution produced

26 Appendix E contains a more detailed description of the derivation of the generic solution costs.

the highest production cost savings because it directly reduces the energy production requirements. Similarly, in studies 1 and 2, the transmission solutions produced higher production cost savings than generation. In all cases, the Demand Response solution had the least impact on production cost savings due to the limited hours impacted by the solution.

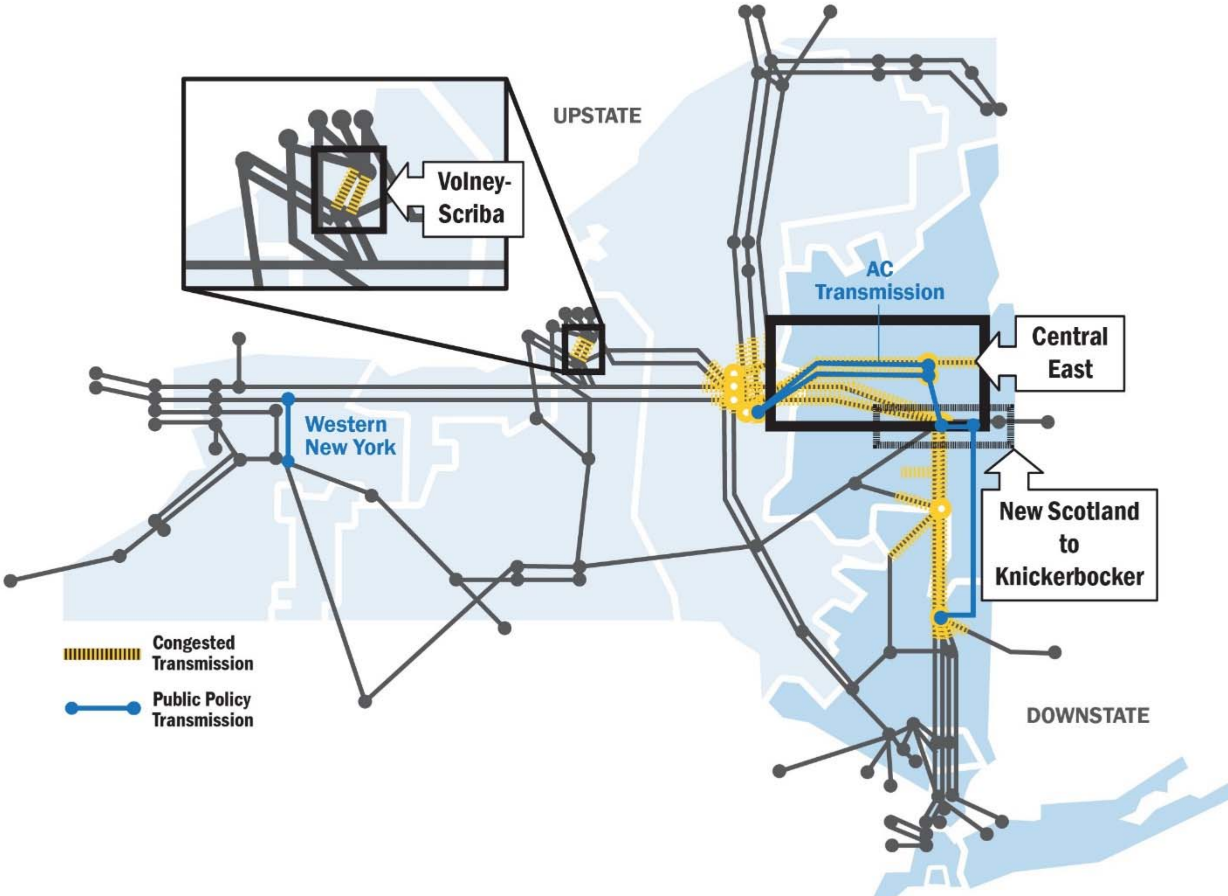
Figure 39: Production Cost Generic Solutions Savings 2019-2028 ($2019M)

Study	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Ten-Year Production Cost Savings (2019 $M)				
Study 1: Central East	115	103	17	1,061
Study 2: Central East-Knickerbocker	117	110	17	1,061
Study 3: Volney-Scriba	22	137	9	530
Production Cost Savings 2019-2023 (2019 $M)				
Study 1: Central East	86	46	9	542
Study 2: Central East-Knickerbocker	86	51	9	542
Study 3: Volney-Scriba	12	54	4	272
Production Cost Savings 2024-2028 (2019 $M)				
Study 1: Central East	29	57	8	519
Study 2: Central East-Knickerbocker	31	59	8	519
Study 3: Volney-Scriba	10	83	4	258

Benefit/Cost Ratios

Figure 40 shows the benefit/cost ratios for each study and each generic solution.

Figure 40: Benefit/Cost Ratios (High, Mid, and Low Cost Estimate Ranges)



Study	2019-2023			2024-2028		
Transmission Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.37	0.25	0.20	0.18	0.12	0.09
Study 2: Central East-Knickerbocker	0.37	0.25	0.20	0.16	0.11	0.09
Study 3: Volney-Scriba	0.44	0.30	0.24	0.52	0.35	0.28

Study 1: Central East			
Solution	**Low**	**Mid**	**High**
Generation	0.20	0.15	0.12
Demand Response	0.08	0.06	0.05
Energy Efficiency	0.36	0.27	0.21

Study 2: Central East-Knickerbocker			
Solution	**Low**	**Mid**	**High**
Generation	0.19	0.14	0.11
Demand Response	0.08	0.06	0.05
Energy Efficiency	0.36	0.27	0.21

Study 3: Volney Scriba			
Solution	**Low**	**Mid**	**High**
Generation	0.30	0.23	0.18
Demand Response	0.24	0.18	0.14
Energy Efficiency	0.44	0.33	0.26

Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Figure 41, Figure 42, Figure 43 and Figure 44 to show the ten-year total change in: (a) generator payments; (b) LBMP load payments; (c) TCC payments (congestion rents); (d) losses; (e) emission costs/tons; and (f) ICAP MW and cost impact, after the generic solutions are applied. The values represent the generic solution case values less the Base Case values for all the metrics except for the ICAP metric. While all but the ICAP metric result from the production cost simulation program, the ICAP metric is computed using the latest available information from the installed reserve margin locational capacity requirement and the ICAP Demand Curves.[27] The procedure for determining the megawatt impacts, as prescribed in the NYISO Tariff[28], are used to forecast changes to such reserve requirements that would be expected with the addition of the actual generic solutions. However, the procedure does not replicate the methodology employed in determining the Installed Reserve Margin and Locational Capacity Requirements.

For Variant 1 ("V1"), the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the sum of the

27 https://www.nyiso.com/documents/20142/5624348/ICAP-Translation-of-Demand-Curve-Summer-2019.pdf/e1988852-3fcf-281c-4ac7-dff12d078507 ;
https://www.nyiso.com/documents/20142/4461032/011519%20ICAPWG%20final-LCRs2.pdf/bdfc4d6e-d360-f863-df58-57e623546d09

28 Section 31.3.1.3.5.6 of the NYISO OATT.

megawatt impact. For Variant 2 ("V2"), the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by fifty percent (50%) of the assumed amount of NYCA Installed Capacity available. Details on the ICAP metric calculations and 10 years of results are provided in Appendix E.

Figure 41: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs ($2019M)[29]

Study	Solution	LOAD PAYMENT	NYCA LOAD PAYMENT	EXPORT PAYMENT	GENERATOR PAYMENT	NYCA GENERATOR PAYMENT	IMPORT PAYMENT	TCC PAYMENT	LOSSES COSTS
TRANSMISSION SOLUTIONS									
Study 1: Central East	Edic-New Scotland	$215	$112	$103	$233	$214	$20	($212)	($25)
Study 2: Central East-Knickerbocker	Edic-New Scotland-Knickerbocker	$264	$141	$123	$271	$251	$20	($206)	($16)
Study 3: Volney Scriba	Volney-Scriba	($54)	($72)	$18	$384	$398	($15)	($432)	$13
GENERATION SOLUTIONS									
Study 1: Central East	New Scotland	($117)	($176)	$59	($88)	($11)	($77)	($26)	$17
Study 2: Central East-Knickerbocker	Pleasant Valley	($109)	($163)	$55	($61)	$13	($74)	($38)	($17)
Study 3: Volney Scriba	Volney	($228)	($313)	$85	$122	$234	($111)	($319)	$55
DEMAND RESPONSE SOLUTIONS									
Study 1: Central East	F(100) G(100) J(200)	($69)	($70)	$1	($51)	($47)	($4)	($15)	($3)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	($69)	($70)	$1	($51)	($47)	($4)	($15)	($3)
Study 3: Volney Scriba	F(100) G(100)	($29)	($30)	$1	($23)	($21)	($2)	($5)	($1)
ENERGY EFFICIENCY SOLUTIONS									
Study 1: Central East	F(100) G(100) J(200)	($1,316)	($1,497)	$182	($1,165)	($1,002)	($163)	($99)	($64)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	($1,316)	($1,497)	$182	($1,165)	($1,002)	($163)	($99)	($64)
Study 3: Volney Scriba	F(100) G(100)	($612)	($715)	$103	($562)	($475)	($87)	($43)	($12)

Note: A negative number implies a reduction in payments

Figure 42: Year 2028 ICAP MW Impact

Study	Solution	MW Impact (MW)			
		J	G-J	K	NYCA
Study 1: Central East	**Transmission**	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	142	212	77	574
	Demand Response	122	182	66	493
Study 2: Central East-Knickerbocker	**Transmission**	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	142	212	77	574
	Demand Response	122	182	66	493
Study 3: Volney Scriba	**Transmission**	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	36	54	19	145
	Demand Response	30	44	16	120

Figure 43: Cumulative ICAP Impact ($2019M)

29 Load Payments and Generator Payments are Tariff-defined additional metrics. The NYCA Load Payment and Export Payment values provide a breakdown of Load Payments by internal and external loads. The NYCA Generator Payment and Import Payment provide a breakdown of Generator Payments by internal and external generators.

Study	Solution	ICAP Saving ($2019M)	
		V1	V2
Study 1: Central East	Transmission	0	0
	Generation	66	524
	Energy Efficiency	173	1,345
	Demand Response	149	1,158
Study 2: Central East-Knickerbocker	Transmission	0	0
	Generation	66	524
	Energy Efficiency	173	1,345
	Demand Response	149	1,158
Study 3: Volney Scriba	Transmission	0	0
	Generation	66	524
	Energy Efficiency	44	347
	Demand Response	36	288

The ten-year changes in total New York emissions resulting from the application of generic solutions are reported in Figure 44 below. The Base Case ten-year emission totals for NYCA are: CO_2 = 321,297 thousand-tons, SO_2 = 16,791 tons and NO_X = 118,674 tons. The study results reveal that all of the generic solutions impact emissions by less than 4% for CO_2 emissions. Energy efficiency had the most significant impact with reductions in the 1.6%-3.5% range. Generation solutions slightly increased the CO_2 emissions in the range of 0.4% - 0.5% due an increase in New York generation and an associated decrease in imports. Demand response had reductions of less than 0.1% in CO_2 emissions. SO_2 emission impacts ranged from an increase of 13% for the Study 2 transmission solution to a reduction of 1.8% for the Study 3 generation solution. The NO_X emission impacts ranged from an increase of 6.2% for the Study 1 generation solution to a reduction of 3.4% for the energy efficiency solution in Studies 1 and 2.

Figure 44: Ten-Year Change in NYCA SO_2, CO_2, and NO_X Emissions

Study	Solution	SO_2		CO_2		NOx	
		Tons	Cost ($2019M)	1000 Tons	Cost ($2019M)	Tons	Cost ($2019M)
TRANSMISSION SOLUTIONS							
Study 1: Central East	Edic-New Scotland	2,071	$0	455	$3	381	$0
Study 2: Central East-Knickerbocker	Edic-New Scotland-Knickerbocker	2,189	$0	650	$4	465	$0
Study 3: Volney Scriba	Volney-Scriba	203	$0	163	$1	(387)	$0
GENERATION SOLUTIONS							
Study 1: Central East	New Scotland	615	$0	1,319	$8	738	$0
Study 2: Central East-Knickerbocker	Pleasant Valley	563	$0	1,149	$7	462	$0
Study 3: Volney Scriba	Volney	(303)	$0	1,718	$10	632	$0
DEMAND RESPONSE SOLUTIONS							
Study 1: Central East	F(100) G(100) J(200)	6	$0	(173)	($1)	(221)	$0
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	6	$0	(173)	($1)	(221)	$0
Study 3: Volney Scriba	F(100) G(100)	(52)	$0	(77)	$0	(66)	$0
ENERGY EFFICIENCY SOLUTIONS							
Study 1: Central East	F(100) G(100) J(200)	(153)	$0	(11,177)	($61)	(4,043)	$0
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	(153)	$0	(11,177)	($61)	(4,043)	$0
Study 3: Volney Scriba	F(100) G(100)	(14)	$0	(5,234)	($29)	(1,567)	$0

Scenario Analysis

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

A forecast of congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the magnitude of congestion costs. The CARIS scenarios were presented to Electric System Planning Working Group and modified based upon the input received and the availability of NYISO resources. The objective of the scenario analysis is to determine how congestion patterns are influenced by variables that differ from their Base Case values. The simulations were conducted for the horizon year 2028 for fuel and load forecast scenarios, and year 2030 for the 70x30 scenario.

The following section describes each of the scenarios studied in CARIS Phase 1. The scenarios consider the effects of changes to the Base Case, and the data presented is the change in metrics relative to the Base Case.

Scenario 1: Higher Load Forecast

This scenario examined the impact of a higher load forecast on the cost of congestion. The Higher Load Forecast assumes higher penetration of Electric Vehicles as compared to the Baseline forecast in the 2019 Gold Book and partial electrification of Space Heating. While the 2019 Gold Book reflects a statewide adoption of around 1.2 million light-duty vehicles by 2028, this forecast assumes around 2 million. Rising penetration of heat-pumps is projected to raise energy usage for space-heating by around 35%. With all other assumptions being the same as the Base Case forecast, the combination of these two factors imply that the annual NYCA energy forecast for 2028 will be 2.7% higher than the 2019 Gold Book forecast. The forecasted figures by NYCA Load Zone for the Higher load forecast are presented in Appendix J.

Scenario 2: Lower Load Forecast

This scenario examined the impact of a lower load forecast on the cost of congestion. The Lower Load Forecast is based on greater impacts attributable to Energy Efficiency and behind-the-meter photovoltaic installations, as compared to the Baseline forecast in the 2019 Gold Book. The Energy Efficiency impacts incorporated in the forecast reflect the attainment of targets delineated in the Climate Leadership & Community Protection Act and the New Efficiency white paper[30] implying

30 https://www.nyserda.ny.gov/About/Publications/New-Efficiency

incremental savings of 30,000 GWh by 2025 above what was achieved through 2014 plus around 2,000 GWh per year over 2026-28. While the Base Case forecast reflects the installation of just over four GWDC of solar PV capacity by 2028, the Lower Load Forecast assumes a level 75% higher than that. With all other assumptions being the same as in the case of the Base Case forecast, the combination of these two factors imply that the annual NYCA energy forecast will be over 16% lower in 2028. The forecasted loads by NYCA Load Zone for the Lower Load Forecast are presented in Appendix J.

Scenario 3: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than the Base Case. In this scenario, the NYISO utilized the high-range gas price forecast provided by the EIA in its 2019 Annual Energy Outlook. Consequently, as compared to the Base Case, the high natural gas price case uses prices approximately 31% higher for the NYCA.

Scenario 4: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than the Base Case. In this scenario, the NYISO utilized the low-range gas price forecast provided by the the EIA in its 2019 Annual Energy Outlook. Consequently, as compared to the Base Case, the low natural gas price case uses prices around 13% lower for the NYCA.

Scenario 5: “70x30” Scenario

Text to be added at a later date

Figure 45 presents the impact of four scenarios selected for study. Those impacts are expressed as the change in congestion costs between the Base Case and the scenario case.

Figure 45: Comparison of Base Case and Scenario Cases, 2028 (nominal $M)

Demand Congestion ($M)	High Load	Low Load	High Natural Gas	Low Natural Gas
CENTRAL EAST	(56)	26	145	(52)
DUNWOODIE TO LONG ISLAND	14	(2)	10	(3)
CHESTR SHOEMAKR	0	0	0	0
PACKARD 115 NIAGBLVD 115	(0)	(0)	(0)	(0)
DUNWOODIE MOTTHAVEN	(3)	(10)	10	(1)
GREENWOOD	(3)	(8)	4	(1)
N.WAV115 LOUNS 115	(1)	4	(11)	3
VOLNEY SCRIBA	(0)	(6)	(1)	(1)
NORTHPORT PILGRIM	(1)	(4)	(3)	1
EGRDNCTY 138 VALLYSTR 138 1	2	(3)	2	(1)
FERND 115 W.WDB 115	0	(2)	1	(1)
NIAGARA PACKARD	0	0	0	0
CE-NSL-KB	(61)	21	146	(53)

Figure 46 below presents a summary of how each of the three transmission groupings chosen for the Base Case study is affected by each of the scenarios for 2028. Figure 47 presents the percentage impact on Demand$ Congestion for each of the scenarios for each of the constraints. As shown, among the scenarios studied, the level of natural gas prices continues to be positively correlated with congestion cost as gas prices directly drives the level of price separation between Downstate and Upstate New York.

Figure 46: Impact on Demand$ Congestion ($2019M)

Constraints	Scenarios: Change in 2028 Demand$ Congestion from Base Case ($2019M)			
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices
Central East	(32)	14	81	(29)
Central East-Knickerbocker	(34)	12	82	(29)
Volney-Scriba	(0)	0	(1)	(0)

Figure 47: Impact on Demand$ Congestion (%)

Constraints	Scenarios: Change in 2028 Demand$ Congestion from Base Case (%)			
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices
Central East	-34%	15%	87%	-31%
Central East-Knickerbocker	-36%	12%	85%	-31%
Volney-Scriba	-3%	0%	-16%	-8%

Figure 48 through Figure 50 show the congestion impact results of the four scenarios performed. While the figure above shows the congestion impact from the scenarios for each of the most congested constraints, the figures below separately show how each of the three transmission groupings chosen for study are affected by each of the scenarios. In each case the bars represent the change in Demand$ Congestion between the Base Case and the scenario case.

Figure 48: Scenario Impact on Central East Congestion

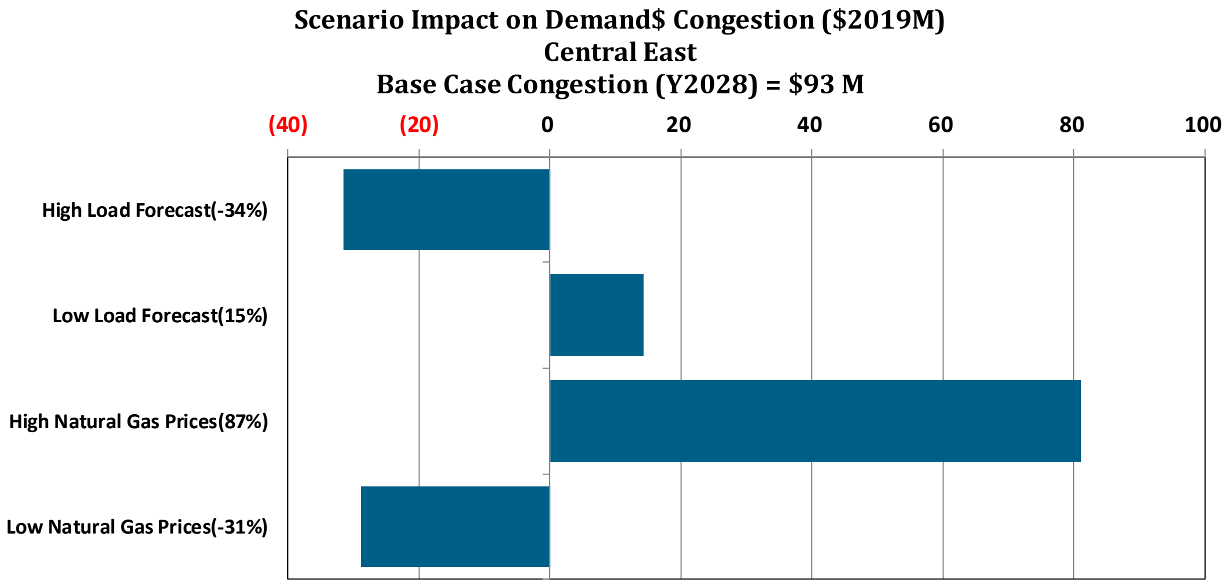


Figure 49: Scenario Impact on Central East - Knickerbocker Congestion

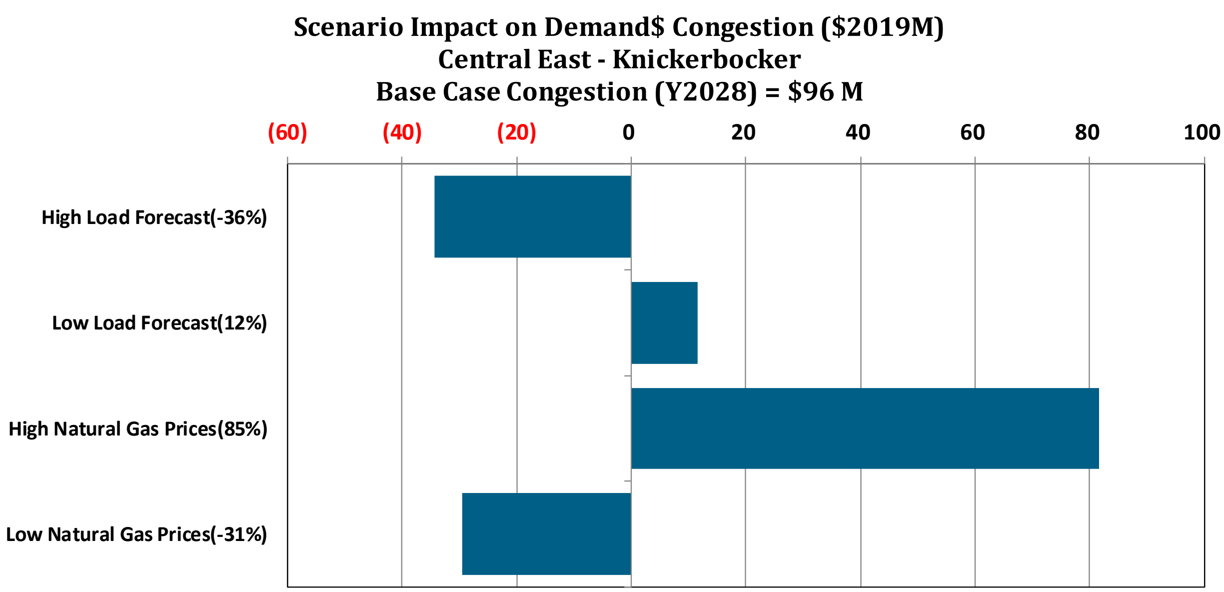
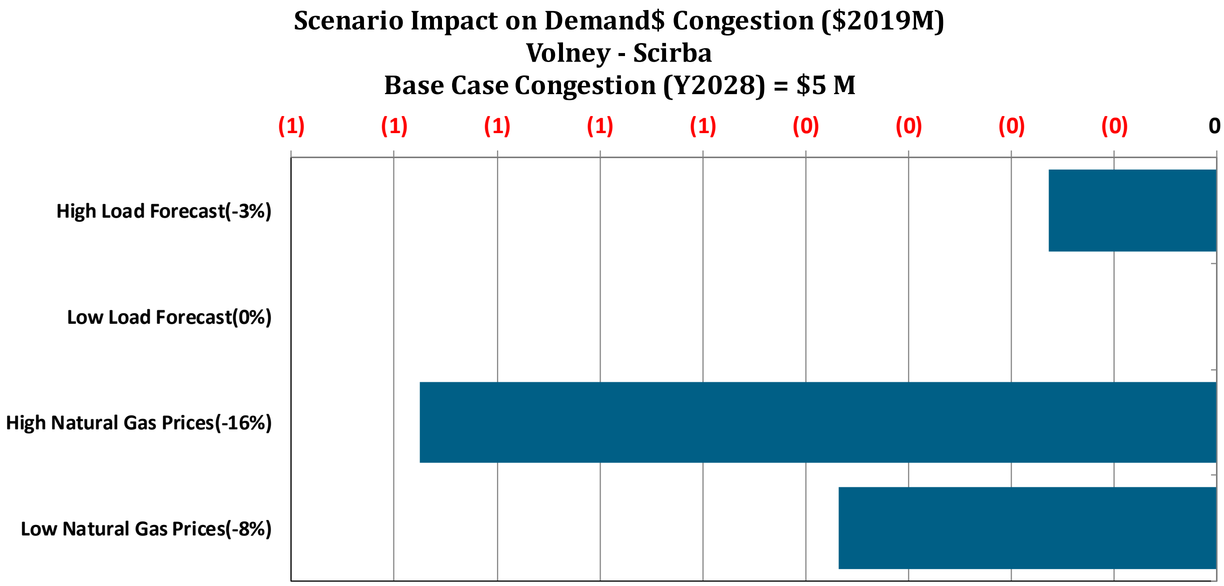


Figure 50: Scenario Impact on Volney - Scriba Congestion


Scenario Impact on Demand$ Congestion ($2019M)
Volney - Scirba
Base Case Congestion (Y2028) = $5 M
(1)
(1)
(1)
(1)
(1)
(0)
(0)
(0)
(0)
0
High Load Forecast(-3%)
Low Load Forecast(0%)
High Natural Gas Prices(-16%)
Low Natural Gas Prices(-8%)

2019 CARIS Findings – Study Phase

The CARIS identified three study areas by considering both historic and forecasted congestion patterns in the NYCA. The NYISO identified those monitored elements that have historically displayed high levels of congestion. It then utilized the MAPS software production cost model to identify those elements that would experience congestion through the 2019-2028 Study Period and identified the Central East through New-Scotland - Knickerbocker corridors as the most constrained areas of the NYCA system. In order to estimate the economic impact of alleviating the identified congestion, four generic solutions were applied to each of the three study areas, production costs savings were estimated, and benefit/cost ratios were calculated based on a range of generic costs.

Figure 51 shows the projected congestion for each of the three studies.

Figure 51: Base Case Projected Congestion 2019-2028

Study	Ten-Year Demand$ Congestion	
	Nominal ($M)	Present Value ($2019M)
Study 1: Central East	2,929	2,555
Study 2: Central East-Knickerbocker	2,955	2,571
Study 3: Volney-Scriba	67	51

The application of the generic solutions in all three studies result in production cost savings expressed in 2019 present values, as shown in Figure 52.

Figure 52: Production Cost Savings 2019-2028 ($2019M)

Study	Ten-Year Production Cost Savings ($2019M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East	115	103	17	1,061
Study 2: Central East-Knickerbocker	117	110	17	1,061
Study 3: Volney-Scriba	22	137	9	530

In Phase 1, CARIS compares the present value of the production cost savings benefit over the ten-year Study Period to the present value of fixed costs based on a 16% carrying cost charge, for transmission and generation solutions, to determine a benefit/cost ratio, as presented in Figure 53. A Capital Recovery Factor is not applied to demand response or energy efficiency solutions. See Appendix E for a detailed explanation.

Figure 53: Benefit/Cost Ratios

Study	Solution	Cost Category		
		Low	Mid	High
Study 1: Central East	Transmission	0.29	0.19	0.16
	Generation	0.20	0.15	0.12
	Demand Response	0.08	0.06	0.05
	Energy Efficiency	0.36	0.27	0.21
Study 2: Central East-Knickerbocker	Transmission	0.28	0.18	0.15
	Generation	0.19	0.14	0.11
	Demand Response	0.08	0.06	0.05
	Energy Efficiency	0.36	0.27	0.21
Study 3: Volney-Scriba	Transmission	0.47	0.32	0.25
	Generation	0.30	0.23	0.18
	Demand Response	0.24	0.18	0.14
	Energy Efficiency	0.44	0.33	0.26

This CARIS Phase 1 study provides: (a) projections of congestion in the NYCA system; (b) present values of ten-year production cost savings ranging from $9M to $1,061M resulting from the application of various generic transmission, generation, energy efficiency and demand response solutions; and (c) the benefit/cost ratios as low as 0.05 to as high as 0.47 depending on the high-medium-low generic project cost estimates. For each of the studies, none of the solutions produced a benefit/cost ratio greater than one in each of the cost estimate categories, reflecting the fact that their projected costs outweighed their estimated production cost savings over the Study Period.

As noted, the benefits captured in the benefit/cost ratios are limited to production cost savings. Other potential quantitative benefits, such as lower capacity market costs and enhanced system reliability, and qualitative impacts, such as the furtherance of public policy objectives, are not considered in the calculation.

Key Findings

Text to be added at a later date

Next Steps

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

Additional CARIS Studies

In addition to the reported CARIS studies, any interested party may request an additional study of congestion on the NYCA bulk power system. *See* OATT § 31.3.1.2.3. Those studies can analyze the benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs.

Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board of Directors. *See* OATT § 31.3.2.4. The model for CARIS Phase 2 studies would include known changes to the system configuration that meet Base Case inclusion rules and would be updated with any new load forecasts, fuel costs, and emission costs projections upon review and discussion by stakeholders. Phase 2 will provide a benefit/cost assessment for each specific transmission project that is submitted by Developers who seek regulated cost recovery under the NYISO's Tariff.

Transmission projects seeking regulated cost recovery will be further assessed by the NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff.[31] To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority (> 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. *See* OATT § 31.5.4.3.5. Additional details on the Phase 2 process can be found in the Economic Planning Manual.[32]

Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a Developer seeks cost recovery, will determine beneficiaries and conduct cost allocation calculations. The results of the Phase 2 analyses will provide a basis for beneficiary

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

32 https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/0734b96b-3dcd-a8e8-4596-1dd41235b5f4

voting on each proposed transmission project.

The next CARIS cycle is scheduled to begin in 2021.