DRAFT for May 22, 2020 ESPWG

2019 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

A Report by the
New York Independent System Operator

May 2020

Caution and Disclaimer

NYISO System Resources and Planning staff can be reached at 518-356-6000 to address any questions regarding this CARIS report or the NYISO's economic planning processes.

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Executive Summary

Overview

With the publication of this 2019 Congestion Assessment and Resource Integration Study ("CARIS"), the New York Independent System Operator, Inc. ("NYISO") has completed the first phase ("CARIS Phase 1") of its two-phase economic planning process.[1] This CARIS Phase 1 report provides information to market participants, policymakers, and other interested parties for their consideration in evaluating projects designed to address transmission congestion identified in the study. The report presents an assessment of historic (2014-2018) and projected (2019-2028) congestion on the New York State bulk power transmission system and provides an analysis of the potential costs and benefits of mitigating that congestion using generic transmission, generation, demand response, and energy efficiency solutions.

The study presents a series of metrics for a wide-range of potential future scenarios. The CARIS base case can be viewed as a "status quo" or "business as usual" case, incorporating only incremental resource changes based on known planned projects with a high degree of certainty. The NYISO also conducted scenario analyses to evaluate the impact on transmission congestion of changed conditions in the base case assumptions. Scenario analyses can provide useful insight on the sensitivity of projected congestion values to differing assumptions included in the base case. The scenarios were selected by the NYISO in collaboration with its stakeholders. The scenarios modify the base case to address variations in key input assumptions like the forecasts of electric demand and fuel price. The highlight of this report is the "70x30" scenario which is based on the policies set forth in the Climate Leadership and Community Protection Act (CLCPA), which mandates that 70% of New York State's end-use energy be generated by renewable energy systems by 2030 ("70x30"). The scenario models two hypothetical build-outs of renewable energy facilities and identifies transmission-constrained pockets throughout New York State that could prevent full utilization of that renewable energy.

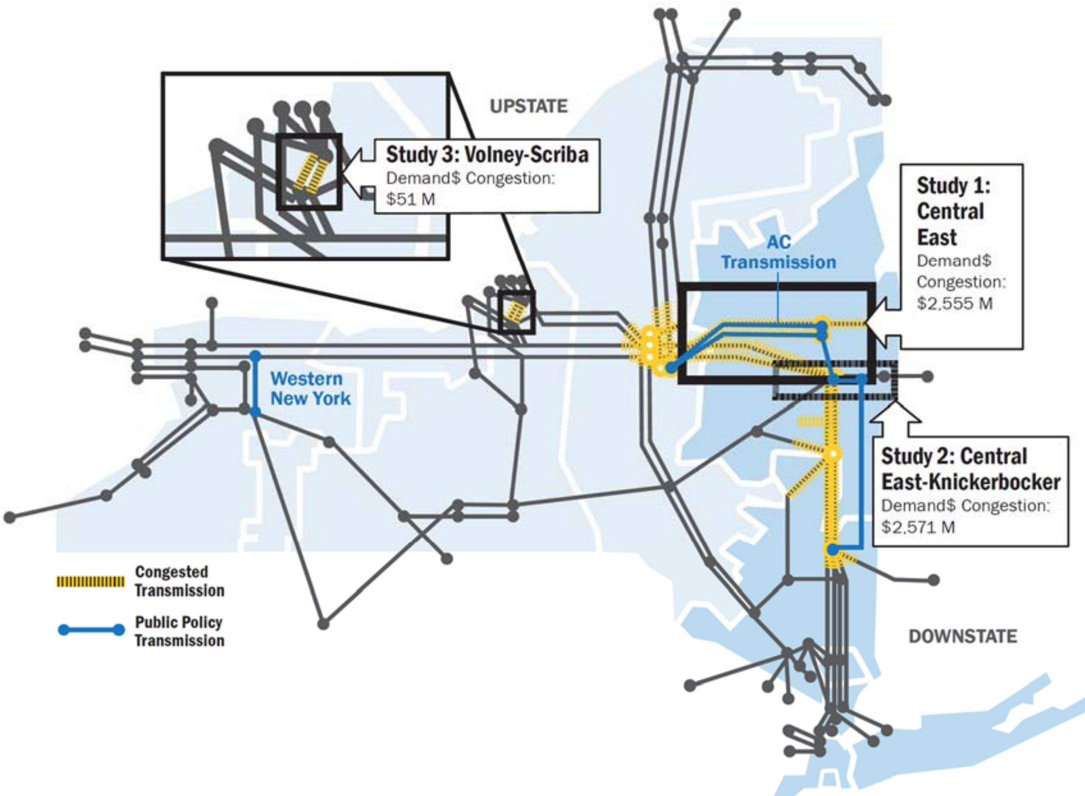
Base Case Findings

The CARIS base case study simulates each hour of each year from 2019 through 2028, incorporating system plans consistent with the 2019-2028 Comprehensive Reliability Plan, issued July 2019. Notably, this CARIS base case includes the Western New York and AC Transmission Public Policy transmission projects that are planned to be in-service in June 1, 2022 and December 31, 2023, respectively. The study assumptions were developed with stakeholders using the best information available when the database was established in August 2019, per CARIS process requirements. The base case results, while

1 Capitalized terms not otherwise defined herein have the meaning set forth in Section 1 and Attachment Y of the NYISO's OATT.

informative to a degree, are borne of a generation-rich system with limited changes to load or resource mix from the existing electric grid, and as a result mirror past studies in identifying limited opportunities for transmission build-out based solely on production-cost reductions. The following map depicts the congestion for the top three congested transmission corridors identified by this CARIS cycle for further study: Study 1) Central East, Study 2) Central East-Knickerbocker, and Study 3) Volney-Scriba.

Figure 1: Base Case Congestion of Top 3 Congested Groupings and Demand Congestion$, 2019-2028 ($2019M)



For each of these corridors and respective studies, the NYISO assessed how production cost, demand congestion, and other economic metrics are impacted by modeling four similarly-sized generic solutions (*i.e.*, transmission, generation, demand response and energy efficiency). The NYISO sizes the modeled generic solutions such that the capacity (MW) of generation, demand response, and energy efficiency result in an equivalent increase in transfer capability across the relevant interface to the transmission solution. For Study 1 and Study 2, this resulted in an increased transfer capability of approximately 400 MW across Central East; for Study 3, this resulted in an increased transfer capability of approximately 200 MW across the Oswego Export interface (Volney-Scriba).

Figure 2: Generic Solutions

Generic Solutions			
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
Miles	85	100	10
GENERATION			
Unit Siting	New Scotland	Pleasant Valley	Volney
Blocks	340 MW	340 MW	340 MW
DEMAND RESPONSE			
Blocks	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW
ENERGY EFFICIENCY			
Blocks	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW

Consensus on the costs for each type of generic solution was achieved through engagement with stakeholders in the NYISO's shared governance process. Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, a range of costs (low, mid, and high) was developed for each type of resource based on publicly available sources. Such costs may differ from those submitted by potential developers in a competitive bidding process.

The sole benefit metric in CARIS, per the NYISO's Tariff, is the reduction in NYCA-wide production costs. Each generic solution was modeled and simulated to determine the resulting production cost savings over the ten year study period as shown in Figure 3. Those savings were compared to the cost estimates to determine benefit/cost ratios. The benefit/cost ratios are summarized from 2019-2023 and 2024-2028 in

Figure **4** to illustrate the shift in benefits for each generic solution following the AC Transmission Public Policy projects entering service at the end of 2023. The NYISO's Tariff does not permit other benefits, such as capacity market savings, to be accounted for in the benefit/cost analysis.

Figure 3: 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

Figure 4: 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	0.18	0.12	0.09
Study 3: Volney-Scriba	0.44	0.30	0.24	0.52	0.35	0.28
Generaton Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.15	0.11	0.09	0.26	0.20	0.16
Study 2: Central East-Knickerbocker	0.15	0.11	0.09	0.24	0.18	0.15
Study 3: Volney-Scriba	0.20	0.15	0.12	0.44	0.33	0.26
Demand Response Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.08	0.06	0.05	0.11	0.08	0.06
Study 2: Central East-Knickerbocker	0.08	0.06	0.05	0.11	0.08	0.06
Study 3: Volney-Scriba	0.17	0.13	0.11	0.25	0.19	0.15
Energy Efficiency Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.32	0.24	0.19	0.43	0.32	0.26
Study 2: Central East-Knickerbocker	0.32	0.24	0.19	0.43	0.32	0.26
Study 3: Volney-Scriba	0.41	0.31	0.25	0.55	0.41	0.33

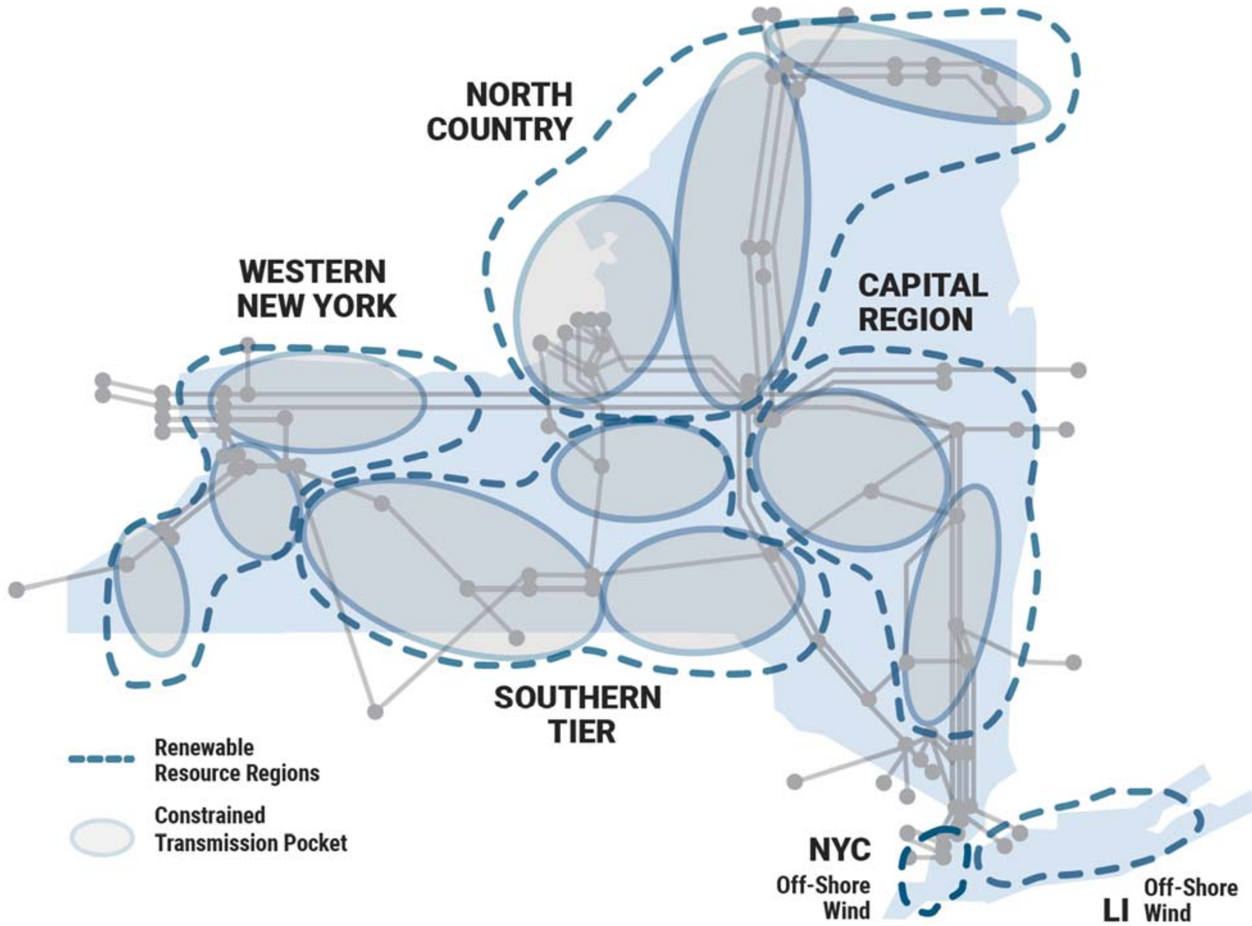
"70x30" Scenario

The CLCPA mandates that New York be served by 70% renewable energy by 2030 ("70x30"), including specific technology-based targets for distributed solar (6,000 MW by 2025), storage (3,000 MW by 2030), and offshore wind (9,000 MW by 2035). Ultimately, the CLCPA establishes that the electric sector will be emission free by 2040. The "70x30" scenario models these targets as projected through 2030 for two potential load forecasts and identifies system constraints, renewable generation curtailments, and other potential operational limitations.

The 70x30 scenario is not intended as a roadmap for compliance with the mandates of the CLCPA, but does provide insights into renewable generation pockets that are likely to form due to limited transmission capability in the areas where wind and solar resources are likely to be constructed. Renewable capacity build-out assumptions were developed in collaboration with stakeholders utilizing the NYISO interconnection queue as a reference point. Approximately 110 sites of land-based wind, offshore wind, and utility-scale solar were added to the system model along with additional behind-the-meter solar across the system. Renewable resources were added to the system until the renewable energy equaled approximately 70% of the energy consumed in New York, taking into consideration the "spillage" of generation over the course of a year. Spillage occurs when there is more generation than load within the New York Control Area, and could take the form of an export to a neighboring system or curtailment of the renewable resource. This process results in a system model of up to approximately 15,000 MW utility-scale solar, 7,500 MW behind-the-meter solar, 8,700 MW land-based wind, and 6,000 MW offshore wind total capacity.

An hour-by-hour simulation of this resource mix was conducted under both "relaxed" conditions (*i.e.*, without transmission constraints) and constrained conditions. By comparing these simulation results, the analysis determines the amount of renewable energy that is curtailed due to transmission constraints. As part of the study effort, a new screening tool was developed to identify transmission constraints on the lower-voltage systems (*e.g.,* 115 kV) that may inhibit the delivery of renewable energy. With this detailed information, the NYISO identified "renewable generation pockets" that are regions in the state where renewable generation resources cannot be fully delivered to consumers statewide due to transmission constraints.

Figure 5: Map of Renewable Generation Pockets



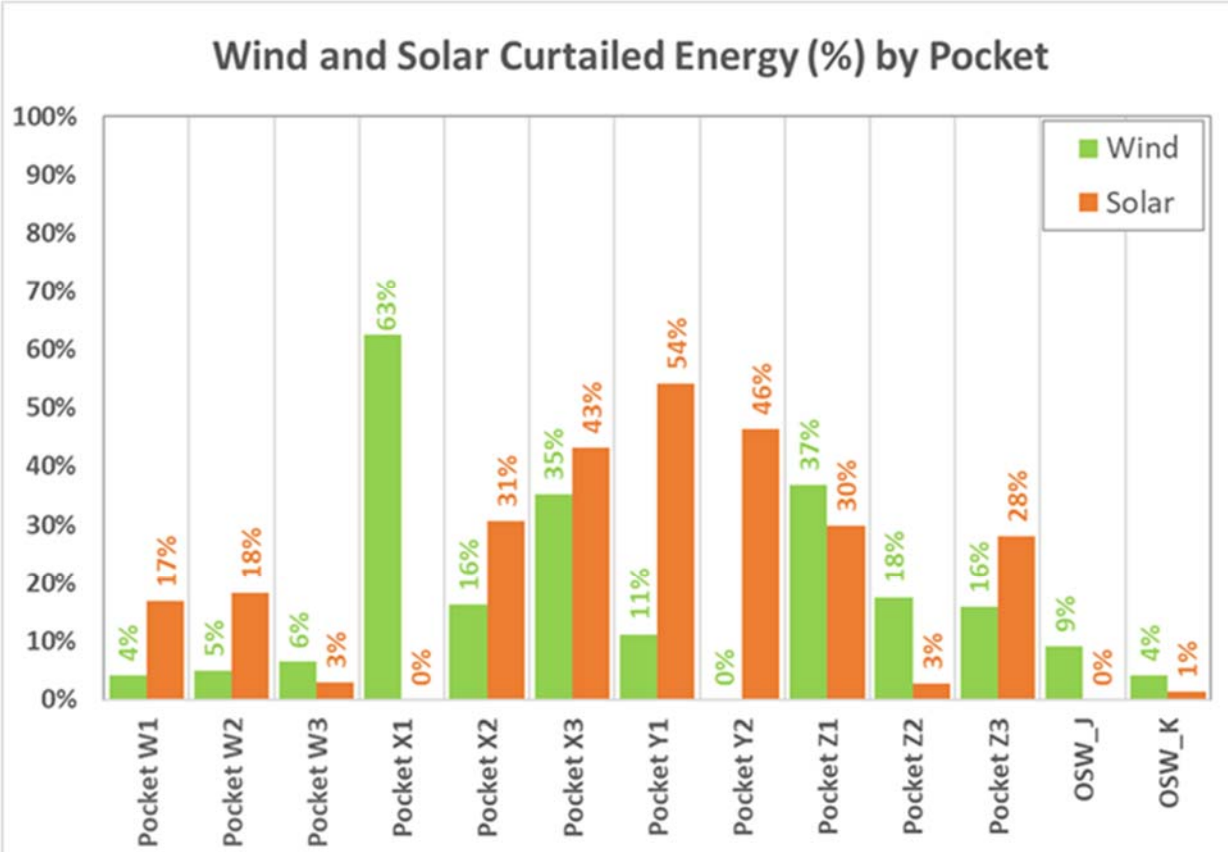
The following renewable resource regions were identified, each of which include constrained transmission pockets:

- **Western New York (Pocket W)**: Western New York constraints, mainly 115 kV in Buffalo and Rochester areas
- **North Country (Pocket X)**: Northern New York constraints, including the 230 kV and 115 kV facilities in the North Country
- **Capital Region (Pocket Y)**: Eastern New York constraints, mainly the 115 kV facilities in the Capital Region
- **Southern Tier (Pocket Z)**: Southern Tier constraints, mainly the 115 kV facilities in the Finger Lakes area
- **Offshore Wind:** offshore wind generation connected to New York City (Zone J) and Long

Island (Zone K)

In this 70x30 scenario, approximately 11% of the annual total potential renewable energy production of 128 TWh is curtailed across the New York system. However, some pockets are much more constrained than others. Figure **6** shows the annual curtailment rates of wind and solar by pocket for the higher energy forecast evaluated in this scenario. Curtailments are driven by the hourly balancing of generation and load subject to transmission constraints. When generation exceeds the transmission limits and load within a pocket in a given hour, the generation output must be reduced, or “curtailed”. For any given hour, the output of a wind or solar plant may range from fully curtailed (zero output) to full output.

Figure 6: Wind and Solar Curtailment by Pocket



This scenario analysis also provides insights into how fossil-fired generation may operate differently in the future. With the substantial addition of intermittent renewable generation, output from the fossil fleet is lower in comparison to the status quo CARIS base case. In many cases, however, the reduced output is accompanied by an increased number of starts indicating the need for a more flexible operating capabilities. Fossil fleet operation can also be highly dependent on transmission constraints. In particular, comparison of operations in the relaxed and constrained cases makes apparent that simple-cycle combustion turbines may run more and start more often due to transmission constraints.

With the overall reduced output from the fossil fleet, the analysis shows that emissions could be significantly reduced due to the renewable generation additions. However, the long-term impact and achievement of economy-wide emission reductions of 40% by 2030 and 85% by 2050, and the emission-free power sector requirement in 2040 are topics beyond this scenario.

Summary of Other Scenarios

Four additional scenario analyses were conducted through incremental changes to specific input assumptions in the base case in order to evaluate the impacts of those scenarios on the top three congested transmission corridors. The additional scenarios provide insight into how the transmission congestion identified in the CARIS base case may change as a result of changes to load levels or natural gas prices.

Changes to natural gas prices had a significant impact on transmission corridor congestion. Upstate and downstate generators are supplied by different pipelines, and changes to the price differential between generators in those regions result in a shift in energy production within the fossil fleet. The high-cost natural gas forecast scenario modeled a 31% increase in fuel prices and the low-cost natural gas forecast scenario modeled a 13% decrease. The table below shows the change in total NYISO congestion as a result of these scenarios.

Energy demand changes in the load forecast scenario had a smaller total impact on transmission corridor congestion than the natural gas forecast scenarios. Of the two load levels evaluated, the high-load forecast had the highest incremental impact. The high-load scenario modeled a 2.7% increase in energy demand while the low-load scenario modeled a 16% decrease. As load changed, so did the commitment of generators that impact the Central East interface limit. The inverse relationship observed between changes in load forecast and congestion on the transmission corridors can be observed in the results table below.

Figure 7: 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%

Key Findings

- The results for the base case are consistent with those in prior CARIS studies. The solutions studied for the top three congested paths offered a measure of congestion relief and production costs savings, but did not result in projects with benefit/cost ratios in excess of 1.0.
- The base case includes the selected AC Transmission Public Policy Projects starting in year 2024. As expected, the congestion level decreased substantially with the AC Transmission projects in-service as compared with prior study years. Central East is still, however, the most congested transmission corridor over the ten-year study period (2019-2028) because of high congestion during the five-year period preceding the AC Transmission projects (2019-2023). Following the energization of the AC Transmission projects, the congestion is substantially reduced and shifts to the Central East-Knickerbocker corridor.
- The "70x30" scenario builds on the base case to model state-mandated policy goals. Results show that renewable generation pockets are likely to develop throughout the state as the existing transmission grid would be overwhelmed by the significant renewable capacity additions. In each of the five major pockets observed, renewable generation is curtailed due to the lack of sufficient bulk and local transmission capability to deliver the power. The results support the conclusion that additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers.
- The level renewable generation investment necessary to achieve 70% renewable end-use energy by 2030 could vary greatly as energy efficiency and electrification adoption unfolds. Two scenarios with varying energy forecasts and associated renewable build-outs were simulated. Both scenarios resulted in the observation that significant transmission constraints exist when adding the necessary volume of renewable generation to achieve the 70% target.
- Energy efficiency initiatives will have significant implications for the level of renewable resources needed to meet the CLCPA goals. For this assessment, utilizing an illustrative set of various renewable sources, nearly 37,600 MW of renewable resources was modeled to approximate a system potentially capable of achievement of the 70x30 policy goal at the base load level. By comparison, nearly 31,000 MW of renewable resources were added to cases with demand reduced by energy efficiency polices.
- The large amount of renewable energy additions to achieve the CLCPA goals would change the operations of the fossil fuel fleet. Overall, the annual output of the fossil fleet would likely decline. The units that are more flexible would be dispatched more often, while the units that

are less so may be dispatched less or not at all. In addition, sensitivity analysis indicates that if the statewide nuclear generation fleet retired, emissions from the fossil fuel fleet would likely increase, making the achievement of longer-term emission reduction policy goals more challenging.

- Sensitivity analysis indicates that energy storage could decrease congestion, and when dispatched effectively, energy storage would help to increase the utilization of the renewable generation, particularly the solar generation tested in this analysis.

Next Steps

Phase 2 of the economic planning process begins following approval of this 2019 CARIS Phase 1 report by the NYISO Board of Directors. In Phase 2, developers are encouraged to propose projects to alleviate the identified congestion. The NYISO will evaluate proposed specific economic transmission projects upon a developer's request to determine the extent such projects alleviate congestion, and whether the projected economic benefits would make the project eligible for cost recovery under the NYISO's Tariff. While the eligibility criterion is production cost savings, zonal LBMP load savings (net of Transmission Congestion Contract ("TCC") revenues and bilateral contracts) is the metric used in Phase 2 for the identification of beneficiary savings and the determinant used for cost allocation to beneficiaries for a transmission project.

For a transmission project to qualify for cost recovery through the NYISO's Tariff, the project has to have:

a) a capital cost of at least $25 million,

b) benefits that outweigh costs over the first ten years of operation, and

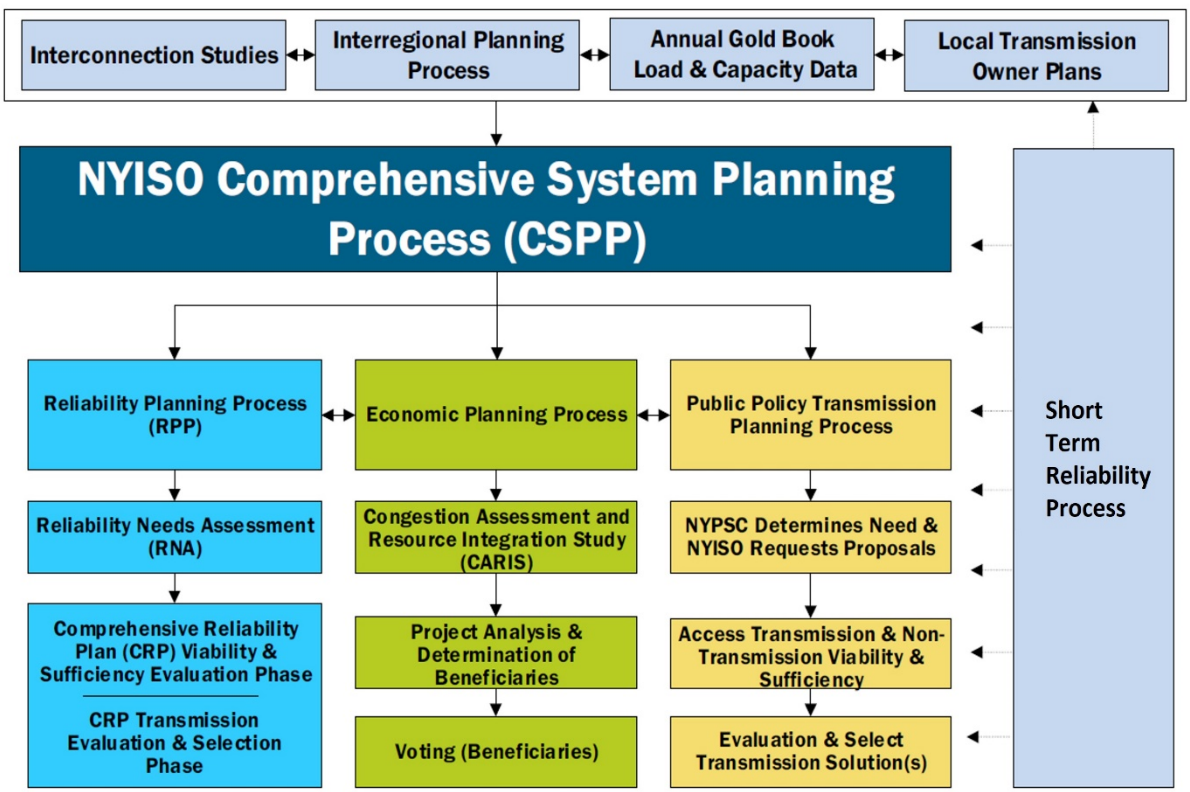
c) received approval to proceed from 80% or more of the actual votes cast by beneficiaries on a weighted basis.

Having met these conditions, the developer will be able to obtain cost recovery of their transmission project through the NYISO's Tariff, subject to the developer's filing with the Federal Energy Regulatory Commission ("FERC") for approval of the project costs and rate treatment.

1. 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 8). The study assesses both historic and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion.

Figure 8: 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.

2. 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;

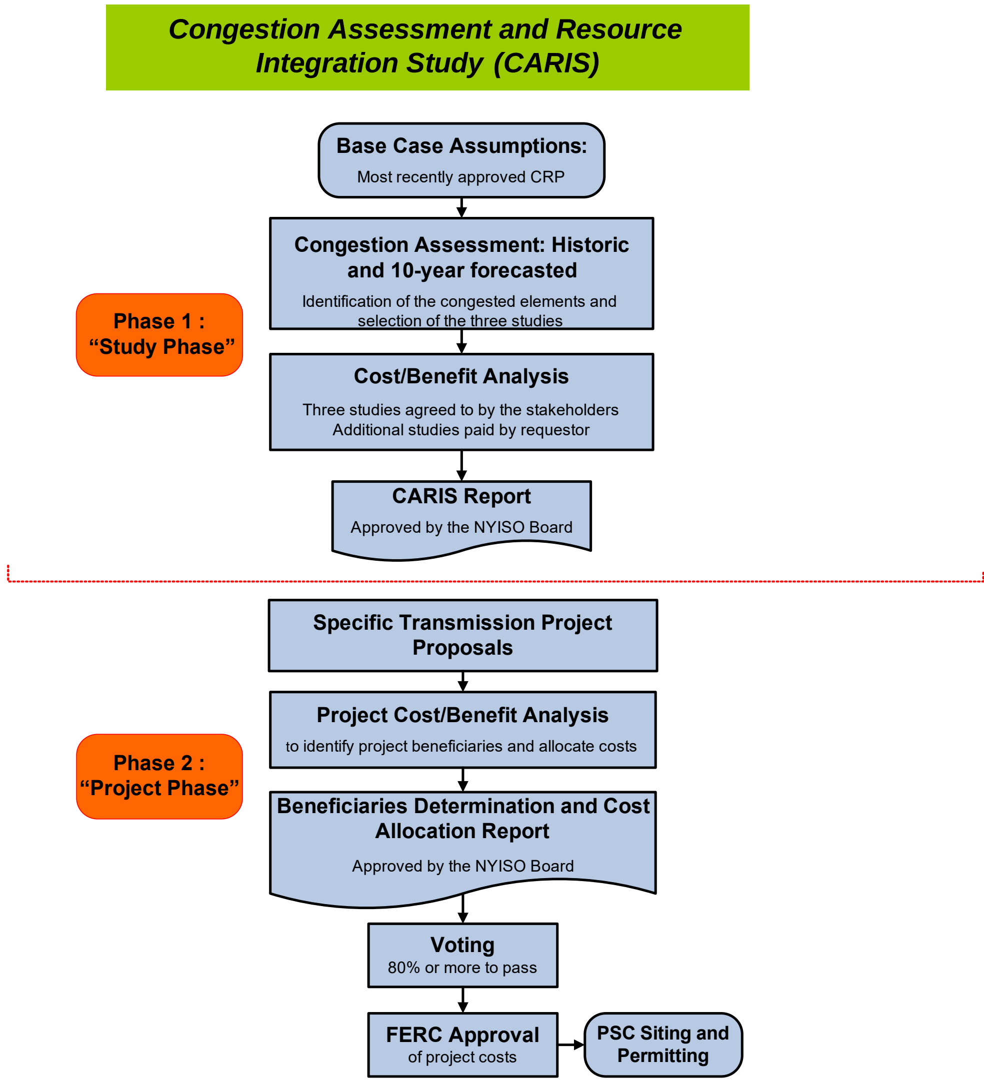
3. Provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner. This process includes providing information to Market Participants, stakeholders and other interested parties on solutions to reduce 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 9 below.

Figure 9: 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.[2])

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

2 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.

3. 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[3] 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[4]

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

3 GE's Multi-Area Production Simulation software

4 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.

4. 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.[5] 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

5 *See* Reliability Planning Process Manual, Manual No. 36, § 3.2.

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

Figure 10 below contains a summary of the modeling changes that can have significant impacts on the congestion projections.

Figure 10: Major Modeling Inputs and Changes

<table>
<tr><th colspan="2">Major Modeling Inputs</th></tr>
<tr><th>Input Parameter</th><th>Change from 2017 CARIS</th></tr>
<tr><td>Load Forecast</td><td>Lower</td></tr>
<tr><td>Natural Gas Price Forecast</td><td>Lower</td></tr>
<tr><td>CO_2 Price Forecast</td><td>Same</td></tr>
<tr><td>NO_X Price Forecast</td><td>Ozone NO_X, same; Annual NO_X, lower</td></tr>
<tr><td>SO_2 Price Forecast</td><td>Higher</td></tr>
<tr><td>Hurdle Rates</td><td>Lower</td></tr>
<tr><th colspan="2">Modeling Changes</th></tr>
<tr><th>Description</th><th>Change from 2017 CARIS</th></tr>
<tr><td>MAPS Software Upgrades</td><td>Latest GE MAPS Version 14.300 09/06/2019 Release was used for production cost simulation</td></tr>
<tr><td rowspan="5">PJM/NYISO JOA</td><td>Western tie to carry 46% of PJM-NYISO AC Interchange</td></tr>
<tr><td>5018 line to carry 32% of PJM-NYISO AC Interchange plus 80% of RECO load</td></tr>
<tr><td>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</td></tr>
<tr><td>PAR JK to carry 15% of PJM-NYISO AC Interchange minus 100MW OBF</td></tr>
<tr><td>OBF reduced to zero as of Nov.1, 2019</td></tr>
<tr><td rowspan="7">NY Transmission Upgrades</td><td>Erie – South Ripley series reactor(2019)</td></tr>
<tr><td>Rainey-Corona PAR (2019)</td></tr>
<tr><td>Leeds Hurley SDU(2020)</td></tr>
<tr><td>L33P (Ontario PAR) out of service until 1/2022</td></tr>
<tr><td>Empire State Line Project/Western PP Selected project(2022)</td></tr>
<tr><td>Selected Segment A and Segment B AC Transmission Projects (2024)</td></tr>
<tr><td>Expanded monitoring and securing of lower voltage system consistent with NYISO market operations</td></tr>
</table>

Figure 11 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 11: 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 12, 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 12: CARIS 1 Base Case Load and Resource Table

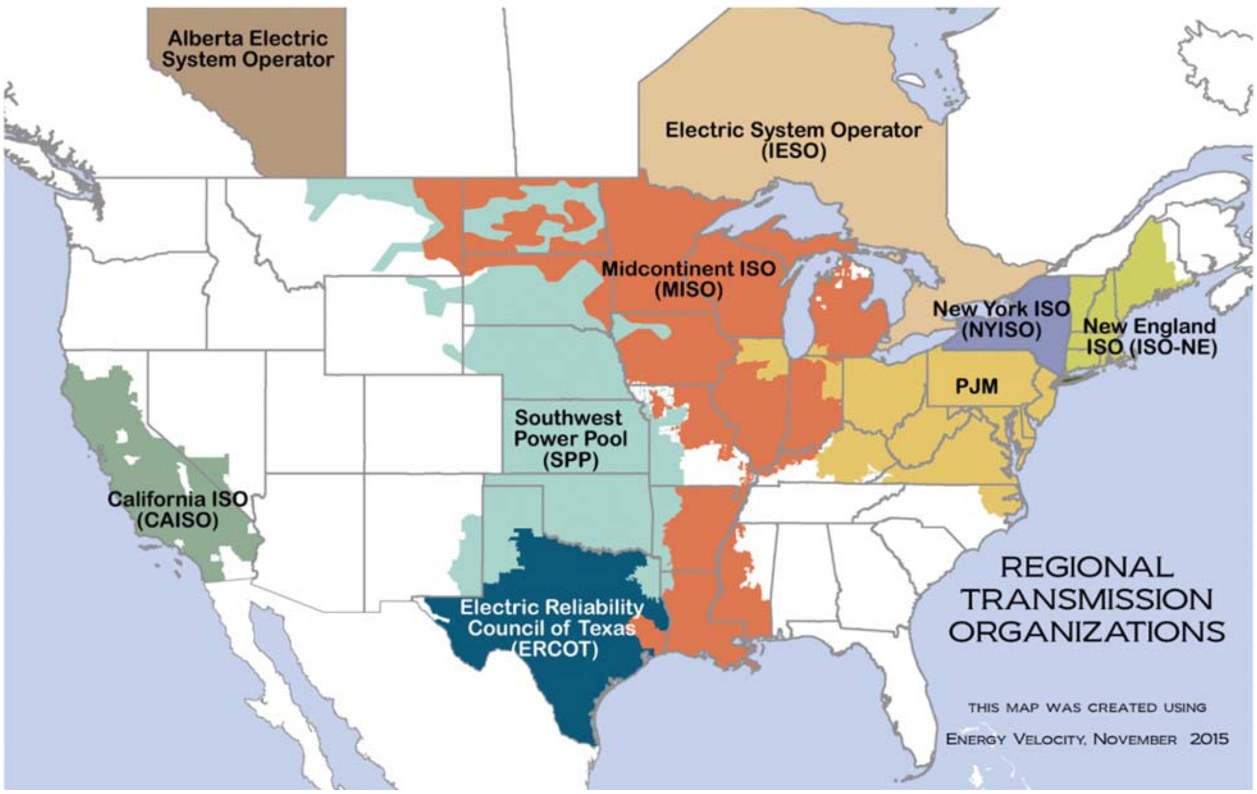
Peak Load (MW)											
Area		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NYCA		32,382	32,202	32,063	31,971	31,700	31,522	31,387	31,246	31,121	31,068
Zone J		11,608	11,651	11,695	11,704	11,608	11,598	11,616	11,616	11,598	11,589
Zone K		5,240	5,134	5,056	5,035	4,969	4,894	4,823	4,758	4,719	4,730
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.[6]

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 13 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 13: 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

6 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.

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[7] 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.[8] 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.[9] Central East was modeled with a unit sensitive nomogram reflective of the algorithm utilized by NYISO Operations.[10]

Fuel Forecasts

CARIS Base Annual Forecast

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's ("EIA")[11] 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.[12] The regional

7 GE's Multi-Area Reliability Simulation software.

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

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

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

11 www.eia.doe.gov

12 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.

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 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.[13] Forecasted fuel prices for the gas regions are shown in Figure 14 through Figure 17.

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 14 through Figure 17.

13 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.

Coal

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.[14] 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.

14 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 14: Forecasted fuel prices for Zones A-E (nominal $)

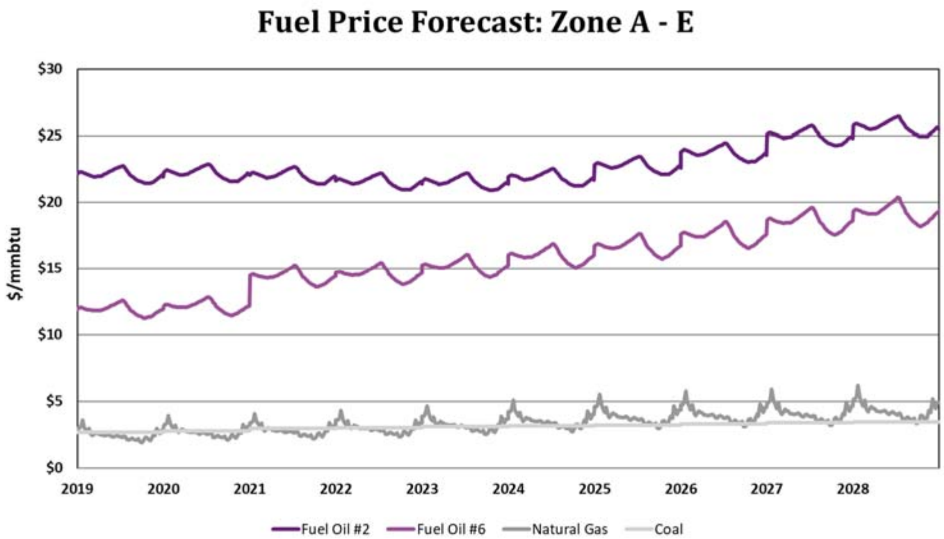


Figure 15: Forecasted fuel prices for Zones F-I (nominal $)

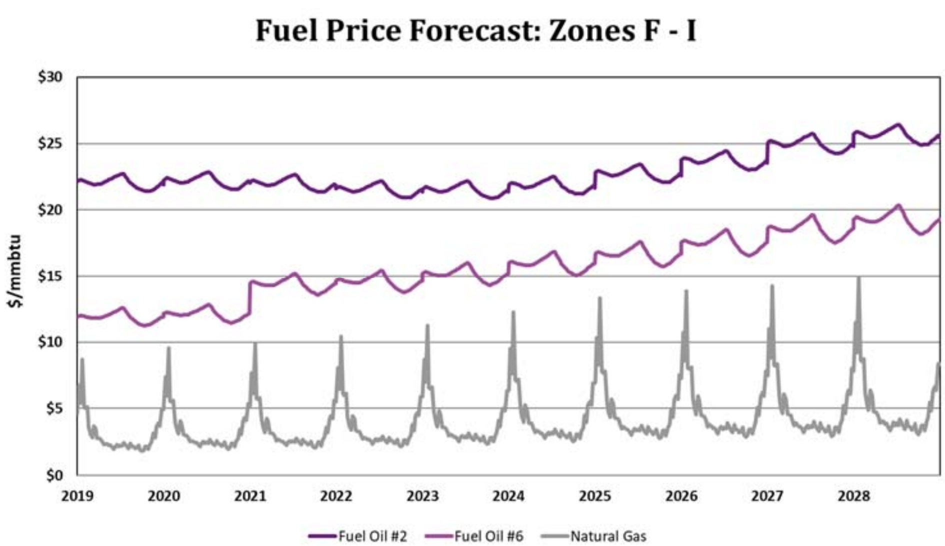


Figure 16: Forecasted fuel prices for Zone J (nominal $)

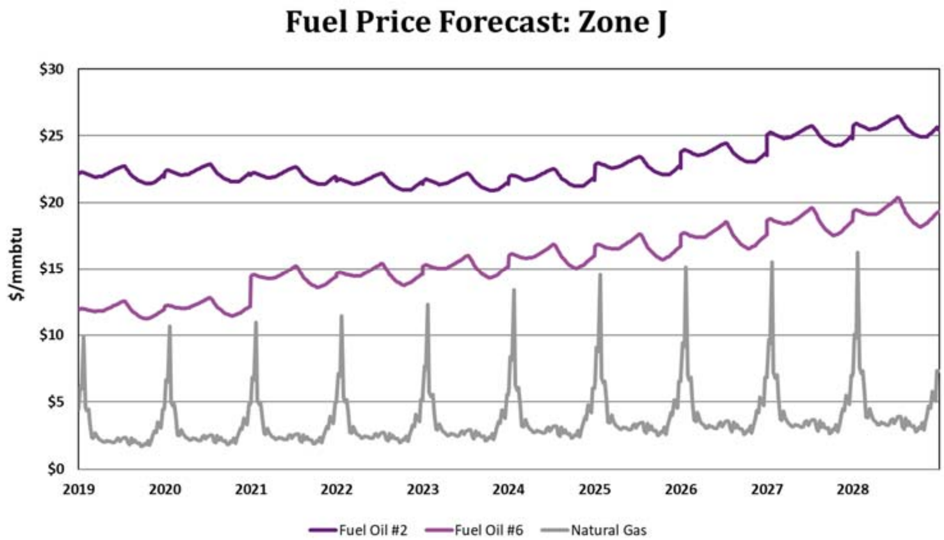
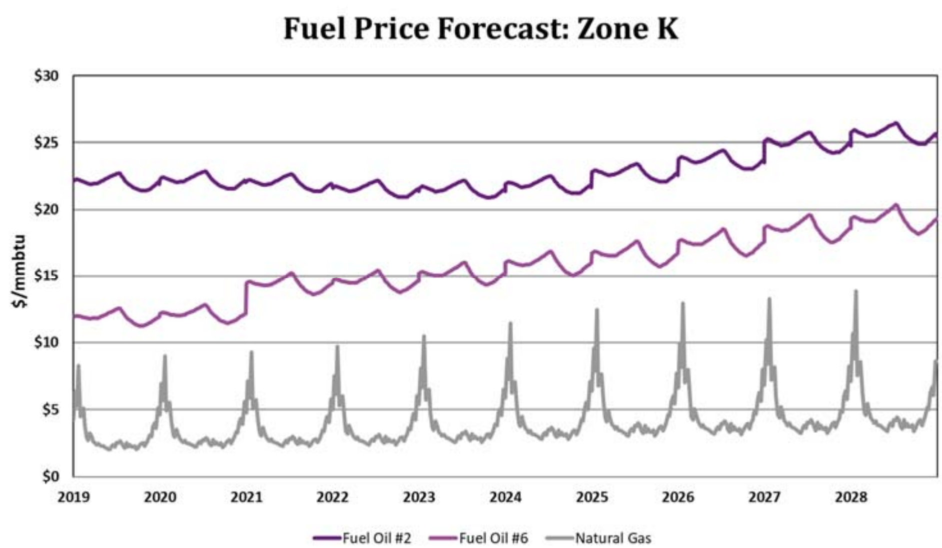


Figure 17: Forecasted fuel prices for Zone K (nominal $)



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[15]. CARIS does not model any IESO Ontario generation as being fueled by either oil or coal.

15 Copyright © 2018, SNL Financial LLC

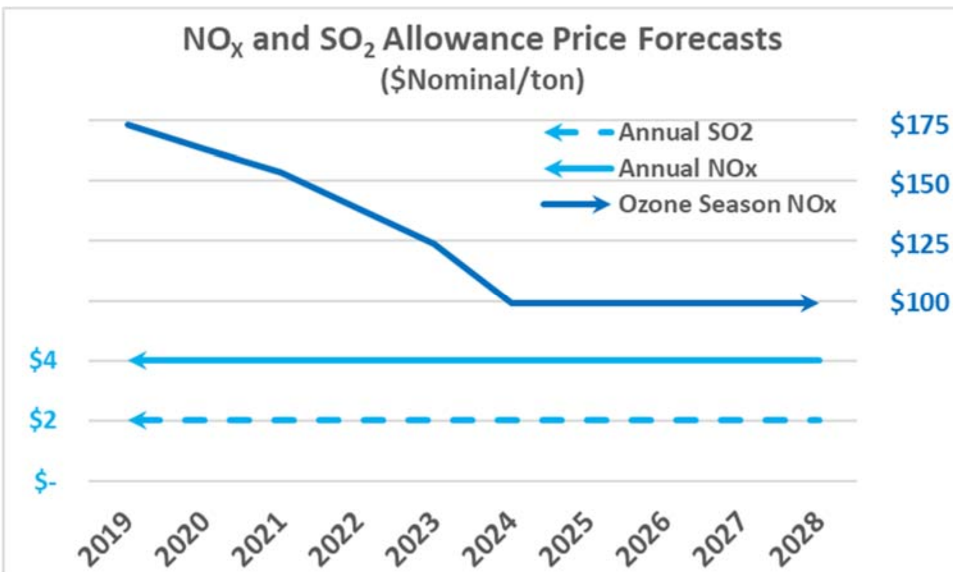
External price forecasts are provided in Appendix C.

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 18 shows the assumed NO_X and SO_2 Allowance Price Forecasts used in this study.[16]

Figure 18: 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-

16 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.

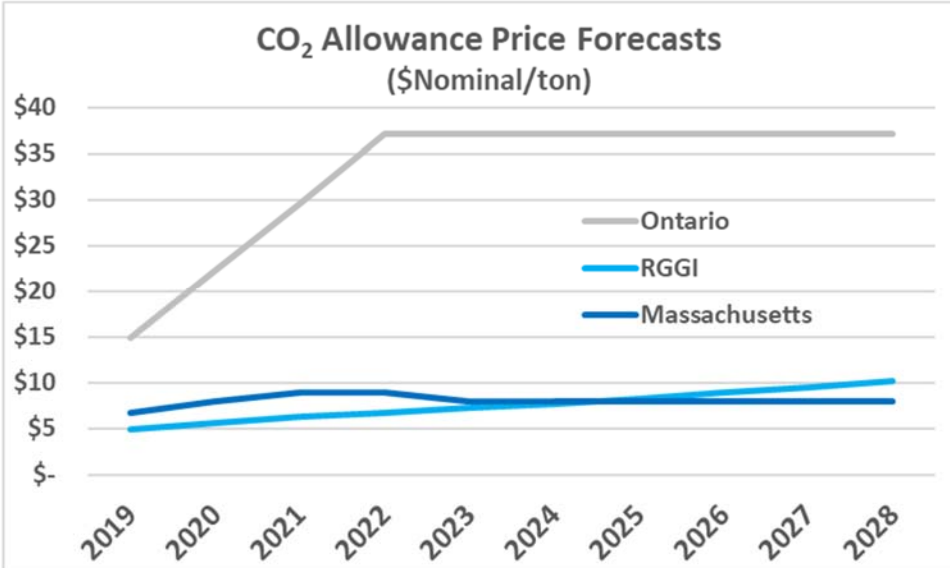
The allowance price forecast assumes that auctions will clear in line with the Emission Containment Reserve trigger price through the study period. In the past, CARIS studies assumed that a federal CO_2 program, similar to the RGGI program, would take effect in 2020, however the expectation of such a 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.[17] 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.[18]

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

Figure 19 shows the emission allowance price forecasts by year in $/ton.

Figure 19: 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. Consensus on the costs for each type of generic solution was achieved through engagement with stakeholders in the NYISO's shared governance process. Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, a range of costs (low, mid, and high) was developed for each type of resource based on publicly available sources. Such costs may differ from those submitted by potential developers in a competitive bidding process. 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 20 through Figure 22.

Figure 20: Transmission Block Sizes[19]

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

Figure 21: Generation Block Sizes[20]

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

Figure 22: 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.

19 Solution size is based on a double-bundled ACSR 1590 KCmil conductor rated for 3,324 amps.
20 Proposed generic unit is a Siemens SGT6-5000F(5).

- 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 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 23.

Figure 23: 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.[21] 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.[22] 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.

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

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

5. "70x30 Scenario" Model Assumptions

Scope

The Climate Leadership and Community Protection Act (CLCPA) mandates that New York consumers be served by 70% renewable energy by 2030 ("70x30"). The CLCPA includes specific technology based targets for distributed solar (6,000 MW by 2025), storage (3,000 MW by 2030), and offshore wind (9,000 MW by 2035), and ultimately establishes that the electric sector will be emissions free by 2040.[23] Significant shifts are expected in both the demand and supply sides of the electric grid, and these changes will affect how the power system is currently planned and operated. To assist the evaluation of these impacts, the CARIS "70x30" scenario kicks off the assessment using production cost simulation tools to provide a "first look." Focusing on the impact to energy flows, these policy targets were modeled for the year of 2030 in order to examine potential system constraints, generator curtailments, and other operational limitations. Subsequent studies, such as 2020 Reliability Needs Assessment, and Climate Change Study Phase II, will build upon the findings of this CARIS scenario, and provide further assessment of CLCPA implementation focusing on other aspects such as transmission security and resource adequacy analysis.

This scenario examines two potential renewable build-out levels for one assumed distribution pattern across the state, as well as multiple sensitivities to gauge the impact of specific drivers. The transmission constraints identified in this assessment are grouped into geographic pockets to pinpoint the specific areas within New York that could experience a generation bottleneck. The generation pockets identified in this study represent the interaction of existing transmission limits and renewable energy (RE) generation with the assumed RE additions across both load levels.

As policy makers advance on the implementation plan of CLCPA, this NYISO assessment is intended to complement their efforts, and is not intended to define the specific steps that must be taken to achieve the policy goals. The boundaries of the generation pockets are for illustration purposes only, and the NYISO will not provide solutions to relieve identified congestion in the pockets in this study.

A number of key modeling assumptions and approaches may have major impact on the results,

23 https://www.nysenate.gov/legislation/bills/2019/s6599

and are described in detail in subsequent sections of this report. To help readers understand the scope of this assessment, considerations that are outside of the scope of this report are described below:

- **Percentage of renewable energy relative to end-use energy –** this study does not define the formula to calculate the percentage of renewable energy relative to end-use energy, (*i.e.,* how to account for 70% renewable energy for the "70 by 30" target). Rather, two potential renewable build-out levels were modeled for corresponding load levels to approximate the potential future resource mix in 2030.

- **Renewable energy modeling**

  I. **Siting and sizing**: New RE generators are modeled as interconnecting to 115 kV or greater bus voltage levels, guided by the NYISO Interconnection Queue. There are many alternative possible interconnection points, but this assessment assumes a single approach for sizing and siting of renewable generation. Impacts of siting generators at lower voltage buses are outside the scope of this study. Nevertheless, the NYISO recognizes that constraints at the distribution level will affect the downstream constraints, which may change the energy flows at the higher voltage level. The principle intent of this study is to analyze transmission bottlenecks and identify constrained pockets rather than define specific location and capacity requirements.

  II. **Operational constraints:** Renewable resources are modeled such that their outputs can change on an hourly basis (as hourly resource modifiers or "HRM") with defined generation profiles for each unit. These generation profiles are synthetically generated resource shapes constructed using publicly available data and tools. This deterministic modeling approach will not capture the uncertainty involved with particular renewable resources. Since the lowest temporal resolution in MAPS is hourly, sub-hourly variation in RE generation is not captured in this study.

- **Constraint impact on curtailment** - These scenario cases secure additional 115 kV constraints obtained from a 'round trip analysis' performed using TARA software. Securing additional contingencies on lower voltage lines and the addition of RE generation results in increases and shifts in the congestion patterns and curtailment of RE generation. Identifying the relationship between specific constraints and the resulting curtailment impacts are beyond the scope of this study. The local transmission system constraints identified in this assessment do not equate to the necessity of upgrading these facilities one by one. There are a number of options to expand the transmission system at the bulk power level and/or at lower voltage levels that could efficiently address the congestions and the curtailment.

- **Transmission system modeling** – This scenario is not an interconnection level assessment of the RE buildouts, and does not review detailed engineering requirements, such as the impacts from N-1-1 contingencies, voltage or stability impacts, capacity deliverability, or impact to the New York system reserve margin. All transmission facilities are assumed in-service, and unscheduled force outages of transmission facilities are not modeled. Due to software limitations, the impacts of outages on congestion are not captured in this study; therefore congestion and curtailment amounts from this analysis are underestimated.
- **Fossil fuel-fired generator modeling** – The modeling of fossil fuel-fired resources in MAPS will commit and dispatch generation in order to: (i) serve load in the absence of sufficient renewable resources, (ii) meet locational reserve requirements, (iii) meet Local Reliability Rules, (iv) serve steam contracts, or (v) reflect operational limitations such as minimum generation levels and minimum generation runtime. The inherent modeling of fossil fuel-fired resources in MAPS does not include: (i) ramp rates and real-time sub-hourly variations, (ii) energy and ancillary service co-optimization; and (iii) fuel availability or gas system constraints. In addition, while regular maintenance outages are included in the model, unscheduled forced outages are not considered.
- **External area representation** – As the neighboring regions develop their own plans to achieve higher renewable generation penetration, those regions' demand, generation supply, and transmission system may change. At the time of this report, the plans for NYISO's neighboring regions are taking shape. Due to lack of detailed information, the external area representation remains consistent with the Base Case.
- **Market bidding -**Unlike the Day Ahead Market, GE-MAPS did not simulate the following: (a) virtual bidding; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments. Similar to the results from Base Case and other Scenarios, the congestions are likely to be underestimated in the 70 by 30 scenario.

- **COVID-19 impacts** – Due to the rapidly evolving nature of the pandemic, the impacts to the load forecast and other economic indicators are difficult to predict, and are not included in this scenario.

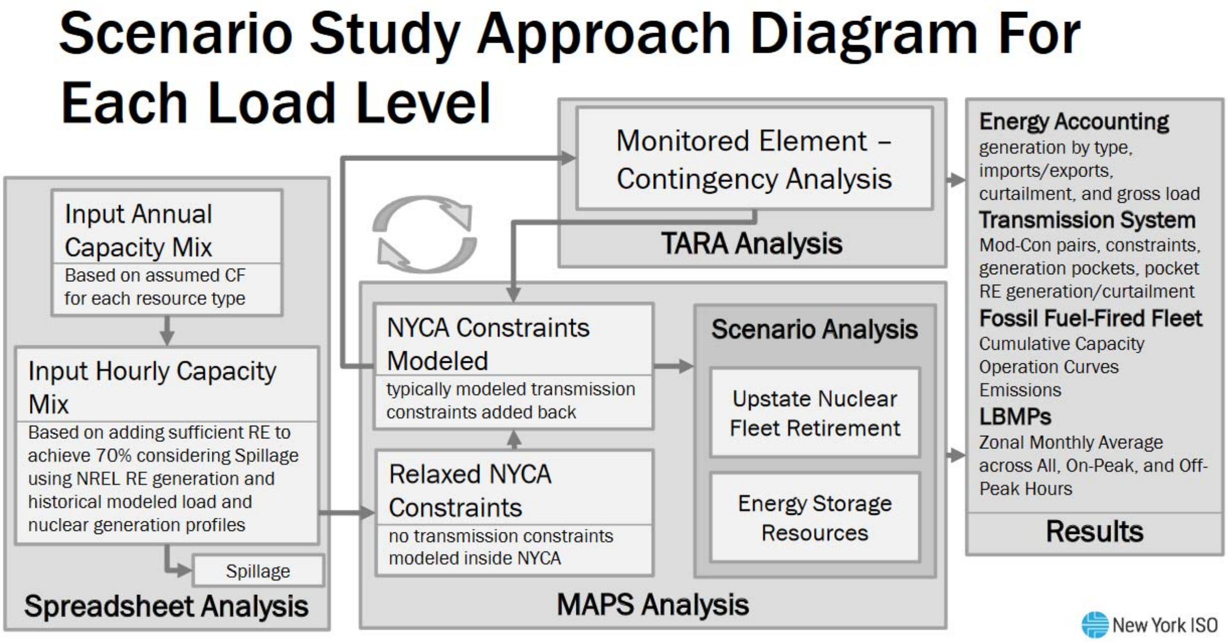
Methodology

Overview

The 70x30 Scenario cases were developed using the following overall study approach, which is also shown graphically in Figure 24:

1. Develop assumptions for the major drivers that could impact transmission congestion patterns:
    a. Develop 70x30 Scenario Load forecast for comparison with the CARIS Base Case forecast
    b. Add renewable generation to approximate achievement of the 70% renewable energy target for each load forecast, considering renewable energy "spillage" (*i.e.,* generation exceeds load)
2. Evaluate system production under "relaxed" conditions:
    a. Model the resulting resource mix in GE-MAPS without internal NYCA transmission system constraints to establish a baseline for the system dispatch when there are no transmission constraints
3. Evaluate the impact of transmission constraints on renewable energy production for the assumed renewable resource mix:
    a. Identify transmission constraints that cause renewable curtailments (*i.e.,* renewable generation pockets)
    b. Quantify the magnitude and frequency of the curtailments for each assumed resource mix
4. Sensitivity analysis to understand impacts to system production and transmission constraints:
    a. Sensitivity analysis of retirement of the entire nuclear fleet
    b. Sensitivity analysis of 3,000 MW of Energy Storage Resources (ESR)
    c. Sensitivity analysis of reduced exports to neighboring regions

Figure 24: 70x30 Scenario Study Approach Process Flow Diagram



Utilizing the above approach at each load level, the NYISO developed the cases shown in Figure 25 as part of the 70x30 Scenario. Sensitivities at each load level/generation mix included the assumed retirement of the entire remaining upstate nuclear generation fleet, and the inclusion of 3,000 MW of energy storage resources (ESR). All sensitivity cases, at both the Base Load and Scenario Load levels assume that: (i) all coal generation is retired, and (ii) generic new gas turbine replacements will be added to address the potential resource deficiencies that may result following implementation of the Peaker Rule, as identified in the 2019-2028 Comprehensive Reliability Plan.

Figure 25: Summary of Sensitivities analyzed in the 70x30 Scenario

Case	Load	Relaxed/ Constrained	Nuclear Senstivity	ESR Sensitivity
Base Case	Base Case	Constrained		
BaseLoad Relaxed	Base Load	Relaxed		
BaseLoad Constrained	Base Load	Constrained		
BaseLoad Constrained NuclearRetired	Base Load	Constrained	Nuclear Retired	
BaseLoad Constrained ESR	Base Load	Constrained		MAPS ESR
BaseLoad Constrained HRM	Base Load	Constrained		External HRM
ScenarioLoad Relaxed	Scenario Load	Relaxed		
ScenarioLoad Constrained	Scenario Load	Constrained		
ScenarioLoad Constrained NuclearRetired	Scenario Load	Constrained	Nuclear Retired	
ScenarioLoad Constrained ESR	Scenario Load	Constrained		MAPS ESR
ScenarioLoad Constrained HRM	Scenario Load	Constrained		External HRM

An additional sensitivity was performed to assess the impact on the assumed capability of neighboring regions to accept NYISO exports in the absence of explicitly modeled RE buildouts within these regions.

MAPS/TARA Constraint Screening

With the addition of large amounts of renewable capacity added throughout New York, the NYISO developed and performed a detailed hourly contingency screening analysis to capture new constraints/overloads that were not captured in the initial Base Case analysis. The hourly production cost simulation of GE-MAPS uses the transmission network model, and it is necessary to pre-define the monitor/contingency pairs in the simulation runs. This process involves creating multiple power flow cases with MAPS hourly results, and performing contingency screening analysis using TARA iteratively so that constraints caused by temporal factors, such as load shape and renewable generation, can be secured in successive MAPS runs.

Figure 26: Roundtrip MAPS/TARA Analysis

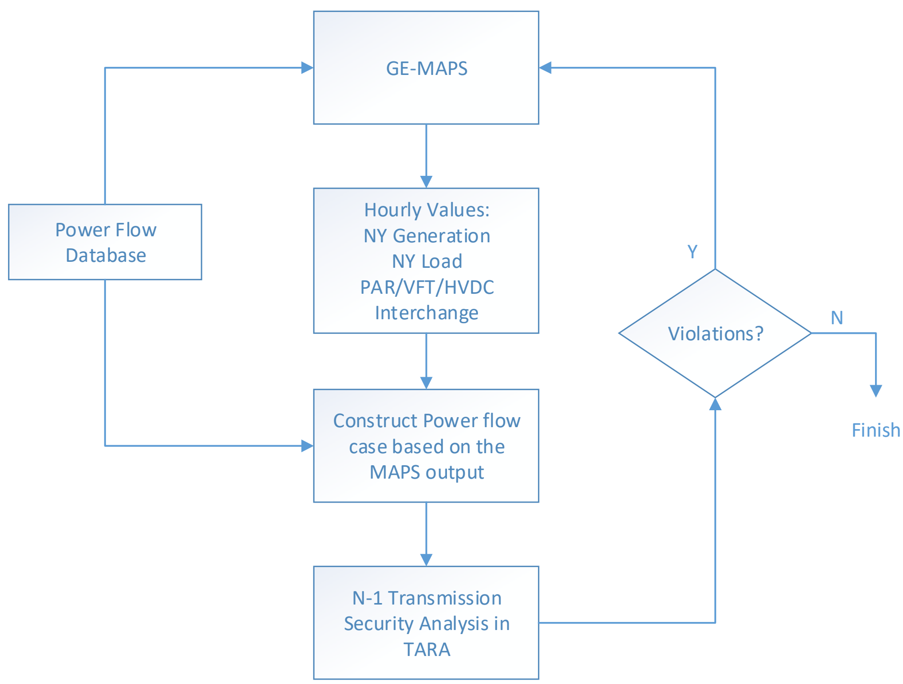


Figure 26 shows the flowchart for Roundtrip MAPS/TARA Analysis. This iterative analysis has three steps:

1. Start with the MAPS production cost run with constraints modeled in the Base Case. The resulting hourly MAPS output is utilized to construct power flow cases and solve in PSS/E using information including hourly NYCA zonal loads, hourly NYCA generation dispatches, and hourly NYCA interchange tie line flows.

2. Perform N-1 transmission security analysis on all created cases in TARA while monitoring NYCA facilities 115kV and above, taking into account all bulk transmission system contingencies as well as local transmission system contingencies. Identify the resulting additional monitored facility/contingency pairs.
3. Add the reported monitored facility and contingency pairs from TARA analysis into the existing production cost database. Secure the expanded monitor facility and contingency pairs in the successive runs.

MAPS output results iteratively interact with TARA analysis until all of the overloaded constraints as reported from TARA are exhaustively modeled within the production cost database.

Assumptions

Demand Forecast

In order to assess the impact of potential policies upon future load levels, an alternate additional zonal hourly forecast was developed for comparison to forecasted load levels in with the 2019 Gold Book. The 70x30 Scenario Load forecast includes non-uniform distribution of energy efficiency and electrification (of space heating and vehicles) across the year and Zones in NYCA. Figure 27 outlines the assumptions across four components of policies and technologies included in the Base Load and 70x30 Scenario Load forecasts. The 70x30 Scenario Load forecast was designed to incorporate state policies through 2030, while the Base Load Forecast correspond to load levels in the CARIS Base Case and 2019 Gold Book for the year 2028 with modified BTM-PV forecast.

Figure 27: Base Load and 70x30 Scenario Load Forecast Assumption Details

Technology/Policy	Base Case Load Forecast	70x30 Scenario Load Forecast
EV	1.3 million Light-duty vehicles by 2030	2.2 million Light-duty vehicles by 2030
Space Heating Electrification	None	2015 estimate of 13,600 GWh in 2015 grows by 50% by 2030 for NYCA
PV	3,000 MWDC behind-the-meter by 2023	6,000 MWDC behind-the-meter by 2025
EE	23,500 GWh of incremental savings by 2030 beyond the 11,000 GWh achieved by 2014	Additional 30,000 GWh* of savings by 2025 beyond 2014 achievements plus around 2,000 GWh/year** for 2026-30

* This target is based on the retail sales of investor-owned utilities implied by the 2015 Gold Book forecast for the year 2025.
** This is based on the targets expressed in the Clean Energy Fund documents.

Salient differences in assumptions of Base Load vs. 70x30 Scenario Load forecasts include:

Electric Vehicles Impact: While the Base Load forecast assumes that electrification of transportation will lead to 1.3 million light-duty vehicles and a modest penetration of medium- and heavy-duty vehicles including trucks, transit buses and school buses, the 70x30 Scenario assumes 2.2 million light-duty vehicles plus a relatively higher penetration of medium- and heavy-duty vehicles.

Space Heating Impact: The Base Load forecast assumes an electric-heating load consistent with current usage – *i.e.*, that the overwhelming bulk of heating-related energy consumption is due to resistance heating in relatively older housing stock. However, the 70x30 Scenario models that a growing level of electrification of space heating due to the adoption of heat-pumps (both air-source and ground-source) implies an annual electric heating load that is 50% higher than what it was in 2015 – approximately 19,600 GWh. This approach assumes that current resistance heating will be replaced with the more efficient heat-pumps.

Energy Efficiency Impact: Starting with a cumulative impact of 11,000 GWh through 2014, the Base Load forecast assumes that utility and New York State-guided initiatives will add another 23,500 GWh of savings through 2030. The 70x30 Scenario forecast, on the other hand, adopts energy efficiency targets outlined under the CLCPA that amount to an additional 45,700 GWh beyond what was achieved through 2014 – *i.e.*, a total of 56,700 GWh through 2030.

Behind-the-Meter Photovoltaic (BTM-PV) Impact: Both the Base Load and the 70x30 Scenario adopt the same BTM-PV target, 6,000 MWDC installed by 2030.

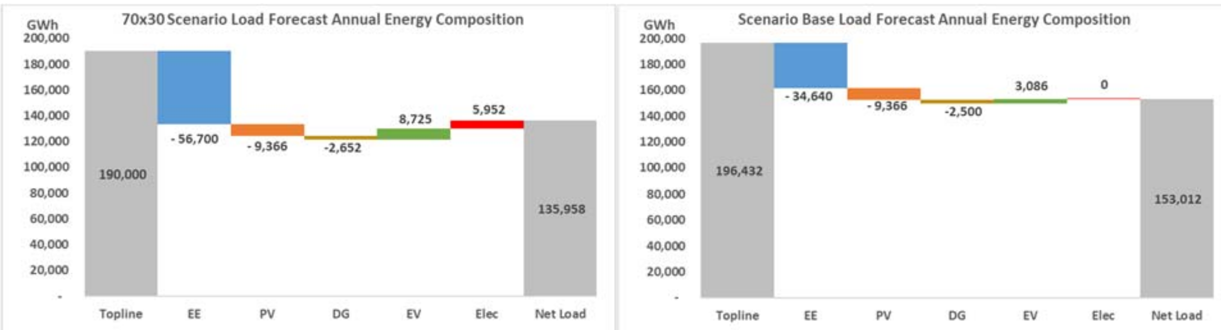
Figure 28: 70x30 Scenario Load and Base Load Forecasts Metrics

Net Load Energy (GWh)	A	B	C	D	E	F	G	H	I	J	K	NYCA
Base Load Forecast	14,590	9,695	15,394	5,337	7,095	11,312	9,544	2,807	5,881	51,749	19,608	153,012
Scenario Load Forecast	13,034	7,757	12,626	5,101	5,694	9,654	7,911	2,848	5,952	46,354	19,026	135,958

Figure 28 shows the zonal Annual Energy net load forecasts for the Scenario Base Load and the 70x30 Scenario Load forecasts. Comparing to the 2019 Goldbook forecast, the salient aspects of the 70x30 Scenario Load forecast are: (a) a lower summer peak largely attributable to efficiency gains in cooling technology, (b) a relatively higher winter peak due to electrification of space heating and transportation, and (c) a noticeably lower annual energy usage due to the considerable impact of energy efficiency that more than offsets the increased load due to electrification. Several upstate Zones become winter peaking by 2030 in the 70x30 Scenario Load forecast even as the state remains summer peaking. Net load includes the impacts of BTM-PV.

Figure 29 exhibits the breakdown of the annual NYCA energy usage in the two forecasts across broad categories impacted by policy and highlights their relative magnitudes. While the impact of BTM-PV is the same in both cases, the lower energy usage in the 70x30 Scenario Load forecast is explained by the reductive effect of aggressive energy efficiency initiatives despite the 14,600 GWh increase in load due to electrification of space heating and transportation.

Figure 29: 70x30 Scenario and Scenario Base Load Forecasts Energy Component Breakdown



In summary, the demand in 2030 could be reduced by 11% (135,958 GWh) compared to business as usual (153,012 GWh) due to the impact of energy efficiency. However, the long-term impact of CLCPA in 2040 and 2050 is likely to increase system demand due to electrification. NYISO continues to monitor and provide long-term forecast data, which is contained in the NYISO's annual Gold Book.

Transmission Modeling

The transmission model is based on the Base Case, and includes additional transmission projects listed below:

1. Empire State Line Project/Western PP selected project,
2. Selected Segment A and Segment B AC Transmission Projects, and
3. The proposed rebuild of Moses-Adirondack 230 kV circuits by NYPA.

The 115 kV facilities secured in the production cost database use normal ratings to secure facilities for (N-0) and short-term emergency (STE) ratings to secure for (N-1) constraints with a 10 MW Capacity Resource Margin assumed. This representation is consistent with the current operational practice on existing 115 kV facilities secured in the NYISO's market model.

The starting point of the contingencies utilized in the study are from 2019 NERC TPL-001-4 planning assessments. Considering the significant resource shift assumed in the 70 by 30 scenario, system conditions will be different and new system constraints could arise. Approximately 1,000 new contingencies were identified and in the MAPS/TARA contingency screening process, and were used in the GE-MAPS hourly simulations for the 70 by 30 scenario.

Renewable Energy Generation Modeling

A principle component of the 70x30 Scenario is the development of the renewable energy resource capacity mix assumed in the modeled cases. Assumptions regarding the resource technology mix, the siting locations, and the hourly profiles utilized in these scenario cases are discussed in this section.

CLCPA resource targets include 6,000 MW of BTM-PV by 2025, 3,000 MW of ESR by 2030, and 9,000 MW of off shore wind (OSW) by 2035. For the 70x30 Scenario the assumed capacity of OSW (6,098 MW) and BTM-PV (7,542 MW) are informed by the CLCPA targets. A separate sensitivity was performed to evaluate the impact of ESRs. Land-based wind (LBW) and utility-scale solar (UPV) resources were added to reach a nominal 70% RE capacity mix using the approach described in this section.

An additional assumption in the 70x30 Scenario cases relates to the direct importation of hydroelectric generation in NYCA. These cases assume that Hydro-Quebec imports count as renewable energy towards the 70% CLCPA target. In addition, an assumed generic incremental HVDC connection of 1,310 MW between HQ and NYC is included in these cases and also counts as RE towards the 70% target. The dispatch of the generic HVDC facility was modeled by scaling the existing HQ dispatch profile. Without this assumption, the amount of RE capacity placed in New York would increase due to two major factors: 1) the hydro RE import has relatively high capacity factor compared to land-based wind (LBW) or utility-scale solar PV (UPV), and 2) the import is assumed to inject into NYC without going through in-state transmission constraints. An estimated combination of 6 GW of LBW and UPV or 3 GW of solely OSW, could replace this incremental HVDC injection, though either alternative would likely increase curtailment and congestions.

The assumed gap in RE generation and the 70% target were satisfied with equal amounts of added UPV and LBW. This process was initially performed on an annual energy basis, using nominal fleet capacity factor assumptions to estimate expected energy output of the assumed RE resources. The results of the initial annual calculation are shown in Figure 30, where percentage of renewable energy (%RE) is the ratio of RE to gross load.

Figure 30: Initial Annual Capacity Mix at Scenario Load

	OSW	LBW	UPV	BTM-PV	Hydro	Hydro Imports	RE	Net Load	Gross Load	%RE
Base Case Capacity (MW)	-	2,212	77	4,011						
Additional Capacity (MW)	6,098	1,641	6,345	3,531						
2030 Capacity (MW)	6,098	3,853	6,422	7,542						
2030 Capacity Factor (%)	44%	30%	18%	14%						
2030 Calculated Energy (GWh)	23,344	10,126	10,126	9,366	28,832	19,941	101,735	135,970	145,335	70%

However, recognizing the disparity in the hourly production of renewable energy and the NYCA load level, the NYISO developed an additional step to examine the 70% requirement on an hourly basis, prior to modeling in MAPS. The hourly approach considers the impact of assumed nuclear generation and input RE profiles in relation to the hourly load level to define the RE capacity mix to include in these scenario cases.

Hourly input renewable energy production profiles were primarily obtained from databases created for the purpose of modeling RE generation in forward-looking grid modeling studies. BTM-PV profiles have been created to model distributed solar resources in the CARIS Base Case. In the 70x30 Scenario cases, the Base Case BTM-PV shapes were scaled to match the assumed annual output. More information on the Base Case modeling assumptions are presented elsewhere in this report. UPV shapes for New York were obtained from NREL's Solar Power Data for Integration Studies[24] database by aggregating five-minute "actual" data to the hourly level.

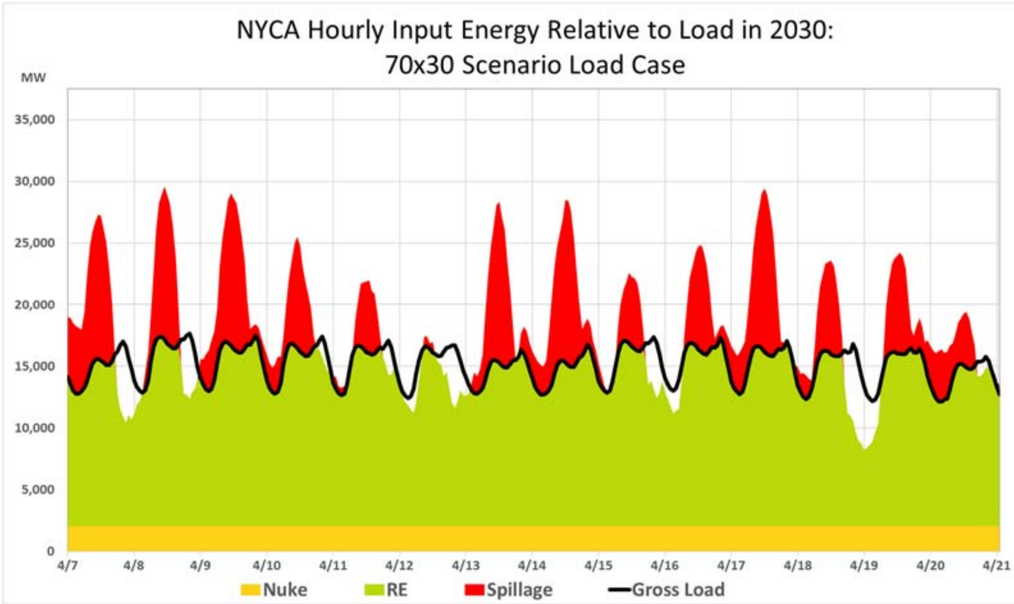
LBW and OSW profiles relevant to potential sites within New York and offshore in the New York Bight in the Atlantic Ocean were obtained via NREL's Wind Toolkit.[25] Five-minute production profiles were obtained across hundreds of individual sites in the database and aggregated to the hourly level. Sites were geographically aggregated to the county and/or zonal level for ease of modeling LBW additions. Offshore NREL wind sites were clustered into groups to represent generic OSW project level additions as well as to explicitly represent currently contracted OSW projects (*i.e.*, the South Fork, Sunrise, and Empire OSW projects).

Spillage occurs when there is more generation than load within the New York Control Area, and could take the form of an export to a neighboring system or curtailment of the renewable resource. Figure 31 displays an example of a two-week period to illustrate the hourly approach. Comparison of the input nuclear generation and renewable energy profiles to the hourly load on the NYCA level allows the over-generation of renewables, or "spillage," to be identified. Final capacity mixes were

24 https://www.nrel.gov/grid/solar-power-data.html
25 https://www.nrel.gov/grid/wind-toolkit.html

defined when annual aggregate RE production (*i.e.*, the green area in Figure 31) represents 70% of the area under the gross load line.

Figure 31: Hourly Input Approach Illustration



The assumption that the UPV and LBW would have nominally equal amounts of input RE persisted in the hourly analysis as well, and resulted in the annual energy balance shown in Figure 32, including the calculated spillage. The values in this table are derived from simulating the zonal RE generation mix using hourly input profiles and comparing the generation profiles to the load profile on an hourly basis within a simple spreadsheet calculation. The percentage of renewable energy is calculated as the ratio of total annual renewable energy input (RE_{input}) less spillage compared to the total annual gross load. Here, gross load includes the load served by BTM-PV.

Figure 32: Hourly Input Approach Energy Balance Results[26]

	OSW	LBW	UPV	BTM-PV	Hydro	Hydro Imports	RE_{Input}	Spillage	Gross Load	%RE
Scenario Load	23,359	16,874	16,651	9,366	28,702	19,941	114,892	12,605	145,324	70%
Base Load	23,359	23,233	23,264	9,366	28,702	19,941	127,864	13,524	162,378	70%

The corresponding capacities are developed by incorporating assumptions related to the zonal capacity distribution of each RE technology type. Total assumed OSW capacity is split between Zones J and K on a load (energy) ratio share. The BTM-PV is represented as a scaling of the assumed BTM-PV capacity distribution within the Base Case. OSW and BTM-PV are consistently

26 Including the additional generic 1,310 MW HVDC from HQ

modeled at both load levels as shown in Figure 32 and Figure 34.

The assumed zonal capacity distribution of recently awarded contracts resulting from NYSERDA administered solicitations for Tier 1 RECs is leveraged to distribute LBW and UPV capacity on a zonal basis. Figure 33 displays the assumed capacity distribution of incremental utility resources as a percentage of the full NYCA MW addition for both UPV and LBW.

Figure 33: Assumed Zonal Capacity Distribution for Incremental Land Based Bulk Resources

Nameplate Capacity Distribution												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
UPV	27%	3%	20%	0%	10%	25%	15%	0%	0%	0%	0%	100%
LBW	30%	5%	30%	15%	20%	0%	0%	0%	0%	0%	0%	100%

Combining the assumed total LBW and UPV energy from Figure 32 with the assumed zonal capacity distribution (in Figure 33) and hourly RE profiles allows the final zonal capacity distribution for each RE generation type to be computed. The results of this tabulation are shown in Figure 34 as the total RE capacity at the Scenario Load and Base Load levels modeled in the 70x30 Scenario cases. Each RE capacity mix was modeled consistently across all scenario cases for the load levels identified. A total of nearly 31,000 MW of renewable generation is modeled within New York for the Scenario Load level, while a total of nearly 37,600 MW is modeled at the Base Load level.

Figure 34: Total Zonal Capacity of Renewable Generation in 70x30 Scenario Case at Two Load Levels Studied (MW)[27]

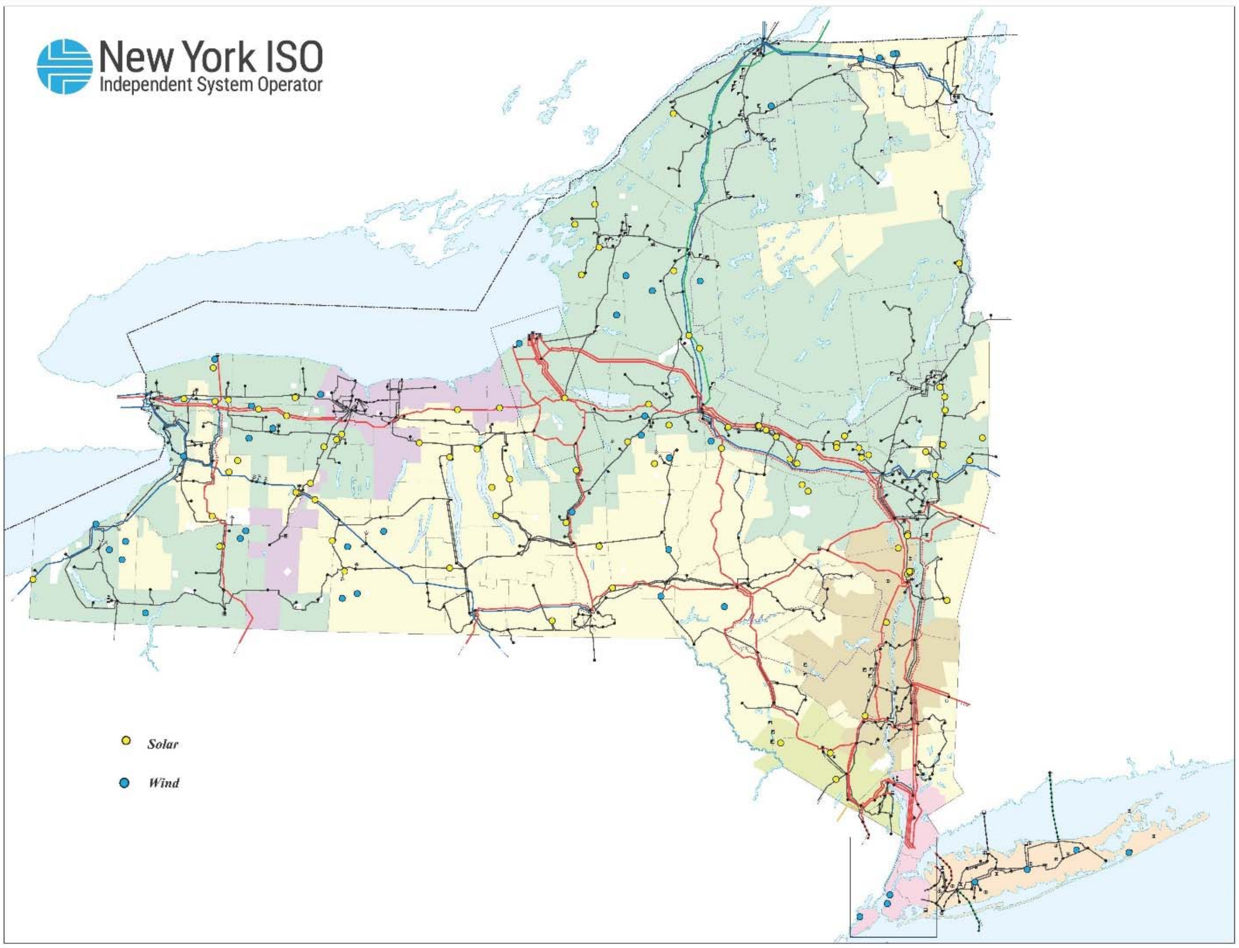
70x30 Scenario Load				
2030 MW	OSW	LBW	UPV	BTM-PV
A		1,640	3,162	995
B		207	361	298
C		1,765	1,972	836
D		1,383		76
E		1,482	1,247	901
F			2,563	1,131
G			1,450	961
H				89
I				130
J	4,320			950
K	1,778		77	1,176
NYCA	6,098	6,476	10,831	7,542

Base Load				
2030 MW	OSW	LBW	UPV	BTM-PV
A		2,286	4,432	995
B		314	505	298
C		2,411	2,765	836
D		1,762		76
E		2,000	1,747	901
F			3,592	1,131
G			2,032	961
H				89
I				130
J	4,320			950
K	1,778		77	1,176
NYCA	6,098	8,772	15,150	7,542

[27] Not including the additional 1,310 MW generic HVDC from HQ.

Individual projects were located at over 110 sites in the MAPS model by utilizing project level information from the Interconnection Queue.[28] This approach preserves the capacity distribution by RE type within a Zone by distributing the total zonal capacity by type on a *pro-rata* basis to the Interconnection Queue project locations based on total zonal capacity in the Interconnection Queue. For projects that propose points of interconnection at new substations, the nearest existing substation was assumed as the point of interconnection in the scenario cases. The location and type of generators included in the capacity build out are shown in Figure 35.

Figure 35: 70x30 Scenario Renewable Buildout Map



[28] https://www.nyiso.com/documents/20142/11738080/11_70x30_RE_Buildout_BaseLoad_ESPWG_2020-04-06.xlsx/a4528988-44a6-573e-7525-36dd1559a2d1

6. 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 36 indicating that the highest congestion is in New York City and Long Island.

Figure 36: Historic Demand$ Congestion by Zone 2014-2018 (nominal $M)[29]

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 37 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 37: 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

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

affects the study results. The MAPS software model utilizes input assumptions listed in Appendix C.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by 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 38 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 38: 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 39.

Figure 39: 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 40 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 40: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the 15 Yr Aggregate (Base Case)[30]

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 41. 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 41: 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

30 The absolute value of congestion is reported.

Identifying the CARIS Studies

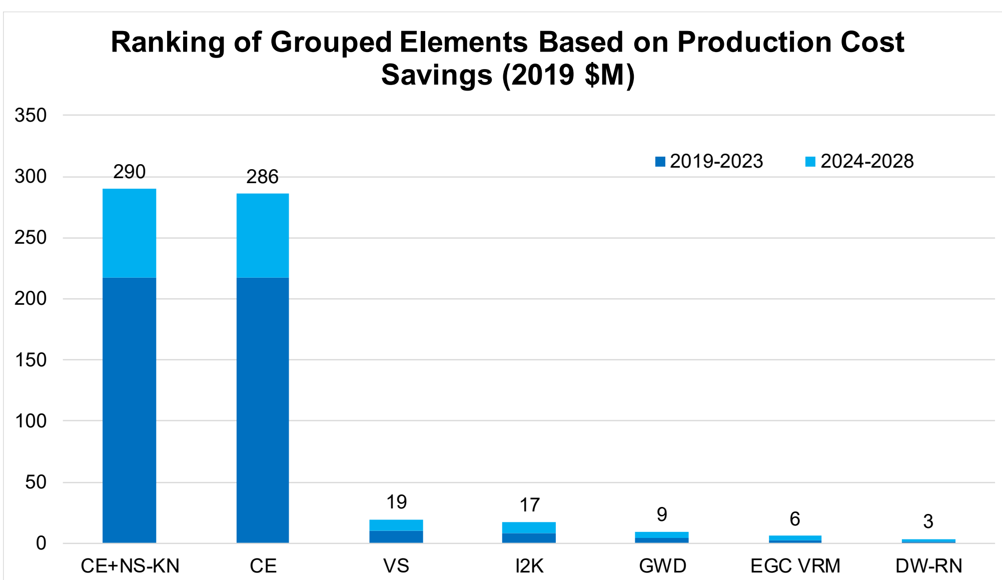
Selection of the Studies

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.[31] 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 42.

Figure 42: Ranking of Grouped Elements Based on Production Cost Savings ($2019M)



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

31 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 43 and Figure 44 present the Base Case congestion associated with each of the three studies in nominal and real terms.

Figure 43: Demand$ Congestion for the Three CARIS Studies (nominal $M)

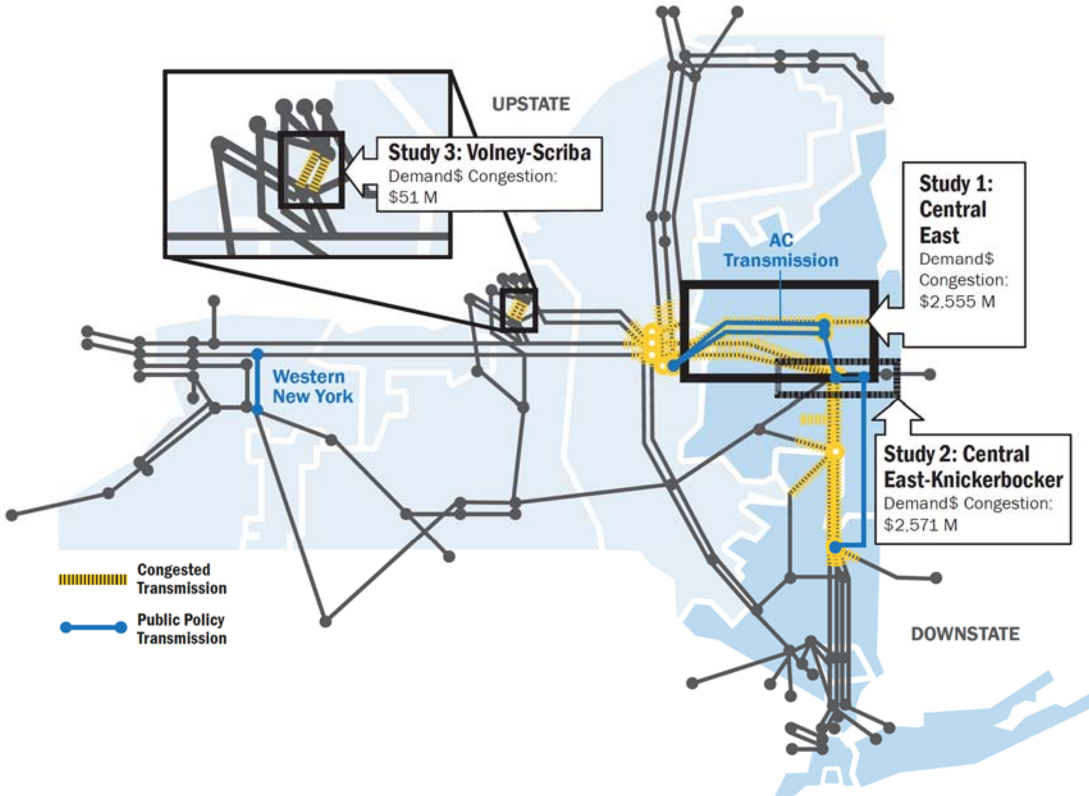
Study	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Study 1: Central East	668	508	521	411	183	188	84	84	114	167
Study 2: Central East-Knickerbocker	668	508	521	411	183	192	87	91	120	173
Study 3: Volney Scriba	6	7	6	7	7	6	5	7	9	9

Figure 44: 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 45.

Figure 45: Base Case Congestion of Top 3 Congested Groupings, 2019-2028 ($2019M)



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 47, Figure 50, and Figure 53 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 48, Figure 51, and Figure 54 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 46 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 43 representing the level of congestion of Study 1 before the solutions.

Figure 46: 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 47 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 47: 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 48 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 48: 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 46. As presented in Figure 48 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 49 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 49: 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 50 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 50: 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 51 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 51: 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 52 shows the Demand$ Congestion of Volney-Scriba for 2023 and 2028 before and after each of the generic solutions is applied.

Figure 52: 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 53 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 53: 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 54 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 54: 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 52. As presented in Figure 54, 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 55.

Figure 55: 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,[32] using a discount rate of 7.08%, and the 16% carrying charge rate, yielding a capital cost recovery factor equal to 1.16.

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 56 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.

32 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.

Figure 56: Generic Generation with Overnight Costs, Demand Response, and Energy Efficiency Solution Costs for Each Study[33]

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 57: 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 58 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

33 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 58: 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 59 shows the benefit/cost ratios for each study and each generic solution.

Figure 59: 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	0.18	0.12	0.09
Study 3: Volney-Scriba	0.44	0.30	0.24	0.52	0.35	0.28
Generaton Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.15	0.11	0.09	0.26	0.20	0.16
Study 2: Central East-Knickerbocker	0.15	0.11	0.09	0.24	0.18	0.15
Study 3: Volney-Scriba	0.20	0.15	0.12	0.44	0.33	0.26
Demand Response Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.08	0.06	0.05	0.11	0.08	0.06
Study 2: Central East-Knickerbocker	0.08	0.06	0.05	0.11	0.08	0.06
Study 3: Volney-Scriba	0.17	0.13	0.11	0.25	0.19	0.15
Energy Efficiency Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.32	0.24	0.19	0.43	0.32	0.26
Study 2: Central East-Knickerbocker	0.32	0.24	0.19	0.43	0.32	0.26
Study 3: Volney-Scriba	0.41	0.31	0.25	0.55	0.41	0.33

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 60, Figure 61, Figure 62 and Figure 63 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.[34] The procedure for determining the megawatt impacts, as prescribed in the NYISO Tariff[35], 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

34 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

35 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 60: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs ($2019M)[36]

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 61: 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

36 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.

Figure 62: Cumulative ICAP Impact ($2019M)

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 63 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 63: 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

7. 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.

Base Case Scenarios

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 K.

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[37] implying 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 K.

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 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.

Figure 64 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.

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

Figure 64: 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 65 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 66 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 65: 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 66: 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 67 through Figure 69 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 67: Scenario Impact on Central East Congestion

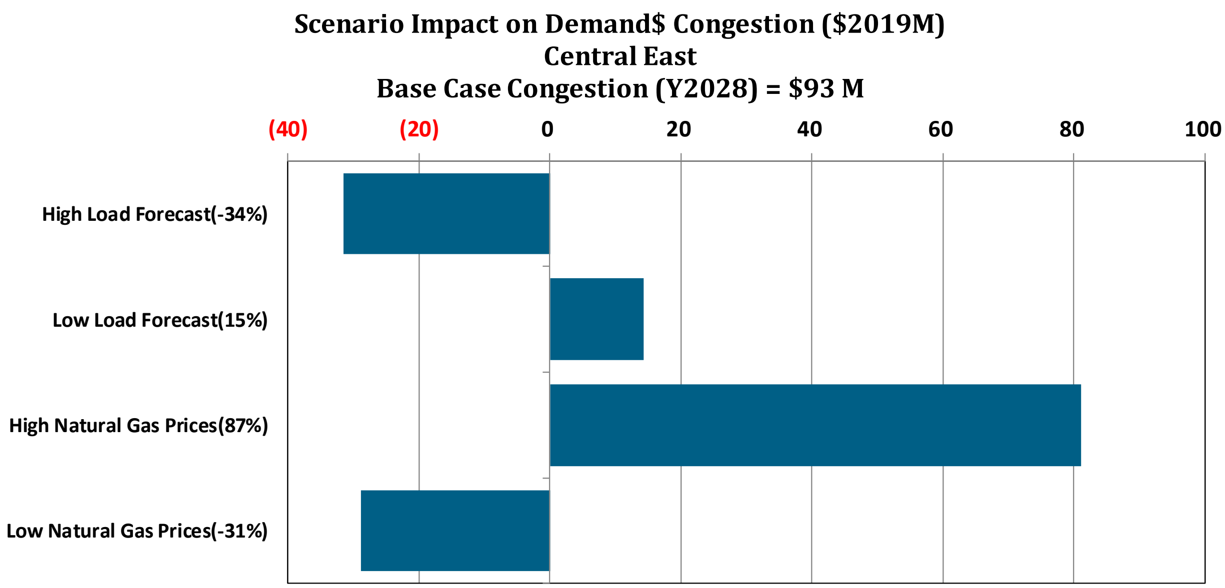


Figure 68: Scenario Impact on Central East - Knickerbocker Congestion

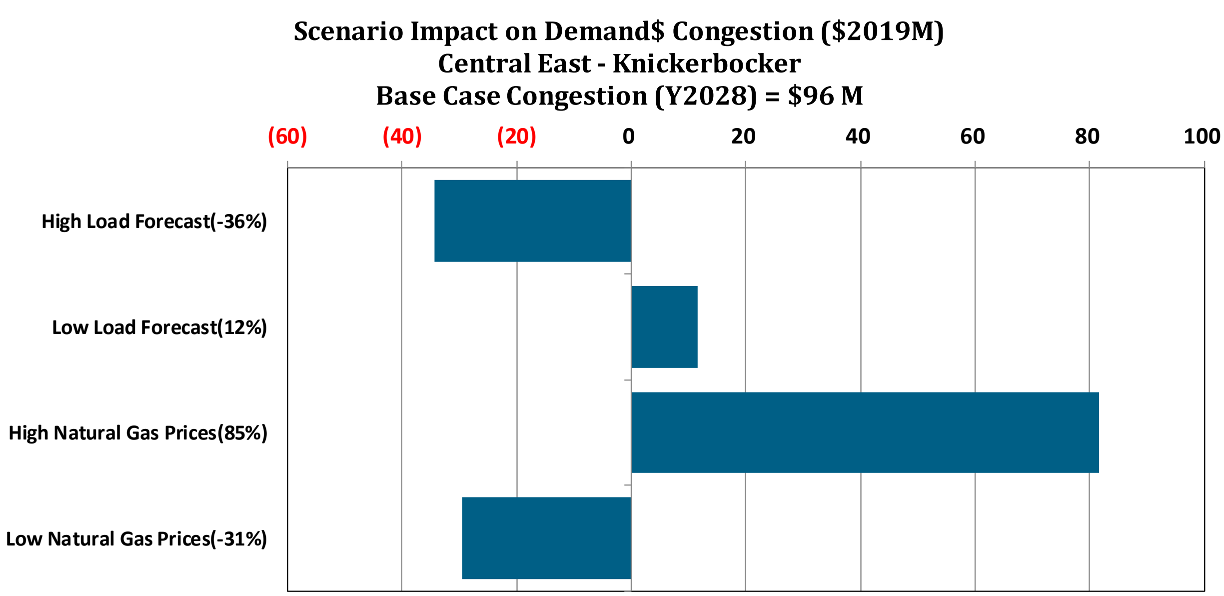
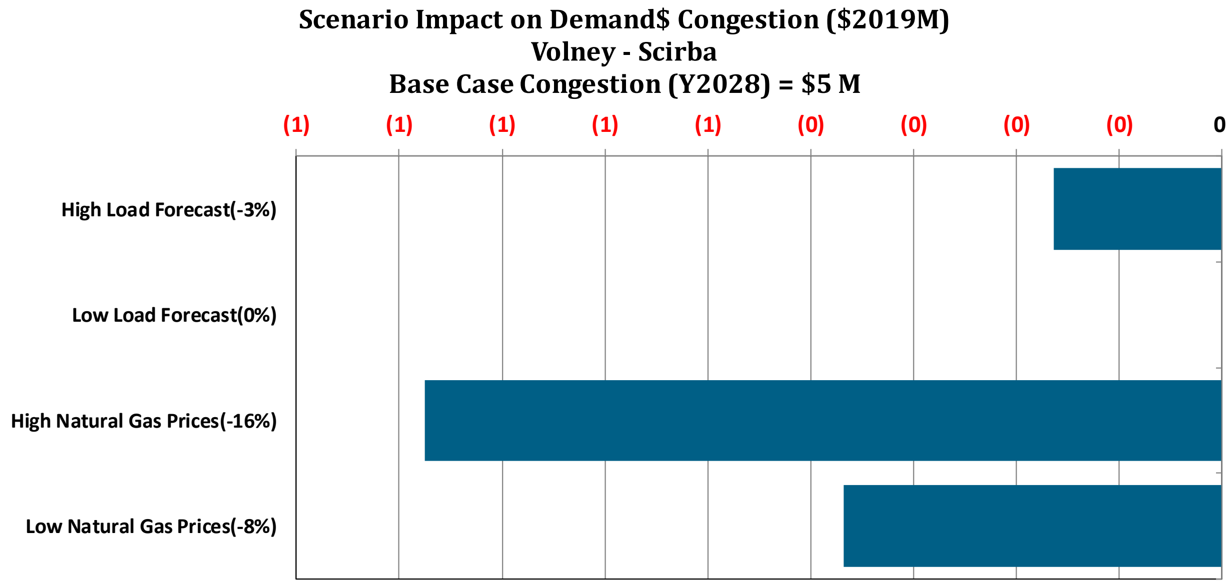


Figure 69: Scenario Impact on Volney - Scriba Congestion



"70x30" Scenario

The 2019 CARIS 70x30 Scenario consists of a series of sensitivity cases to study the impact of transmission constraints on a potential hypothetical RE build out which otherwise may achieve a 70% renewable energy mix, as described in the Renewable Energy Generation Modeling section. This study does not define the formula to calculate the percentage of renewable energy relative to end-use energy, (*i.e.,* how to account for 70% renewable energy for the "70 by 30" target). The findings are intended to provide insight of the extent to which transmission constraints may prevent the delivery of renewable energy to New York consumers.

Transmission Relaxation and NYCA Constraint Modeling Comparison

To understand the impact of existing transmission limits on the delivery of higher levels of renewable energy, cases were first run with the NYCA internal transmission system limits "relaxed". This modeling approach is the equivalent of having infinite transmission capability within the NYCA, which provides an understanding of "ideal" system behavior. In the "constrained" cases the NYCA transmission limits are all reset to their values in the Base Case.

Comparison of Energy

Annual generation by type, net imports by neighboring area, curtailment, and gross load output from each case in GWh are shown in Figure 70 as well as the comparison between the relaxed and constrained cases at the Scenario Load and Base Load levels.

Figure 70: Base, Relaxed, and Constrained Case Annual Energy Results

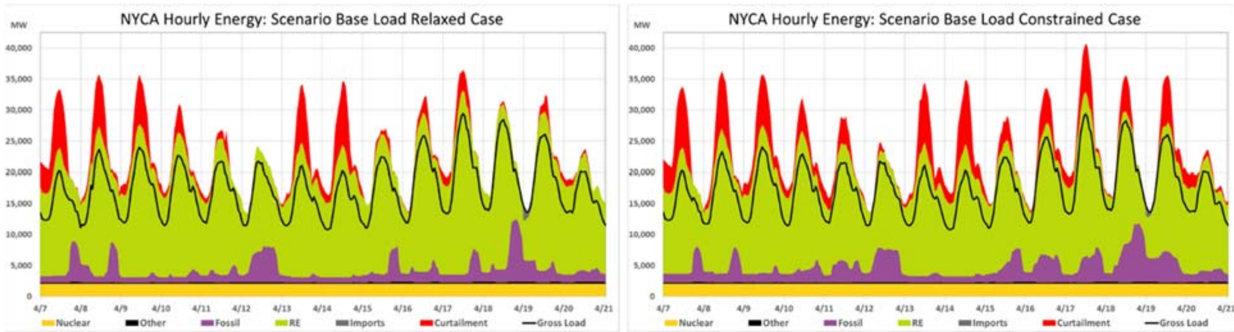
Energy (GWh)	Base Case	ScenarioLoad Relaxed	ScenarioLoad Constrained	BaseLoad Relaxed	BaseLoad Constrained
Nuclear	27,091	27,435	27,433	27,436	27,433
Other	2,368	2,164	2,110	2,158	2,102
Fossil	69,028	26,390	28,185	31,268	35,181
Hydro	28,832	28,082	28,050	27,974	28,020
Hydro Imports	11,564	19,803	19,775	19,780	19,769
LBW	5,038	13,960	13,290	19,243	17,117
OSW	-	22,775	21,625	22,656	21,592
UPV	115	14,764	12,666	21,782	17,982
BTM-PV	4,988	9,269	9,266	9,302	9,327
Pumped Storage	(447)	(878)	(822)	(930)	(868)
Storage	-	-	-	-	-
IESO Net Imports	(2,862)	(5,550)	(5,817)	(6,030)	(6,250)
ISONE Net Imports	(535)	(7,791)	(6,418)	(6,710)	(5,073)
PJM Net Imports	12,239	(5,479)	(4,446)	(5,996)	(4,528)
Renewable Generation	50,537	108,653	104,672	120,736	113,808
Curtailment	0	6,218	10,151	7,124	14,020
Non-Renewable Generation	98,488	55,990	57,728	60,861	64,717
GrossLoad	157,418	144,948	144,897	161,934	161,807

Relaxation of the transmission constraints results in reductions in fossil generation and curtailments with an increase in RE generation and net exports (*i.e.,* negative net imports). In order to examine the system condition more closely, four two-week periods across the annual hourly simulations were reviewed that are representative of combinations of RE generation and load levels:

- January: during winter peak load and low renewable generation period
- April: during spring low net load period (high renewable generation during low load)
- July: during summer peak load period
- October: during fall low load and low renewable generation period

A closer examination reveals that relaxing transmission constraints on an hourly basis mirrors the outcomes in the annual energy comparisons. Generally, the results are consistent across the seasons and are provided in the appendix for both load levels. Figure 71 displays NYCA generation output, curtailment, and gross load over a two-week period in early April in the relaxed and constrained cases at the Base Load level.

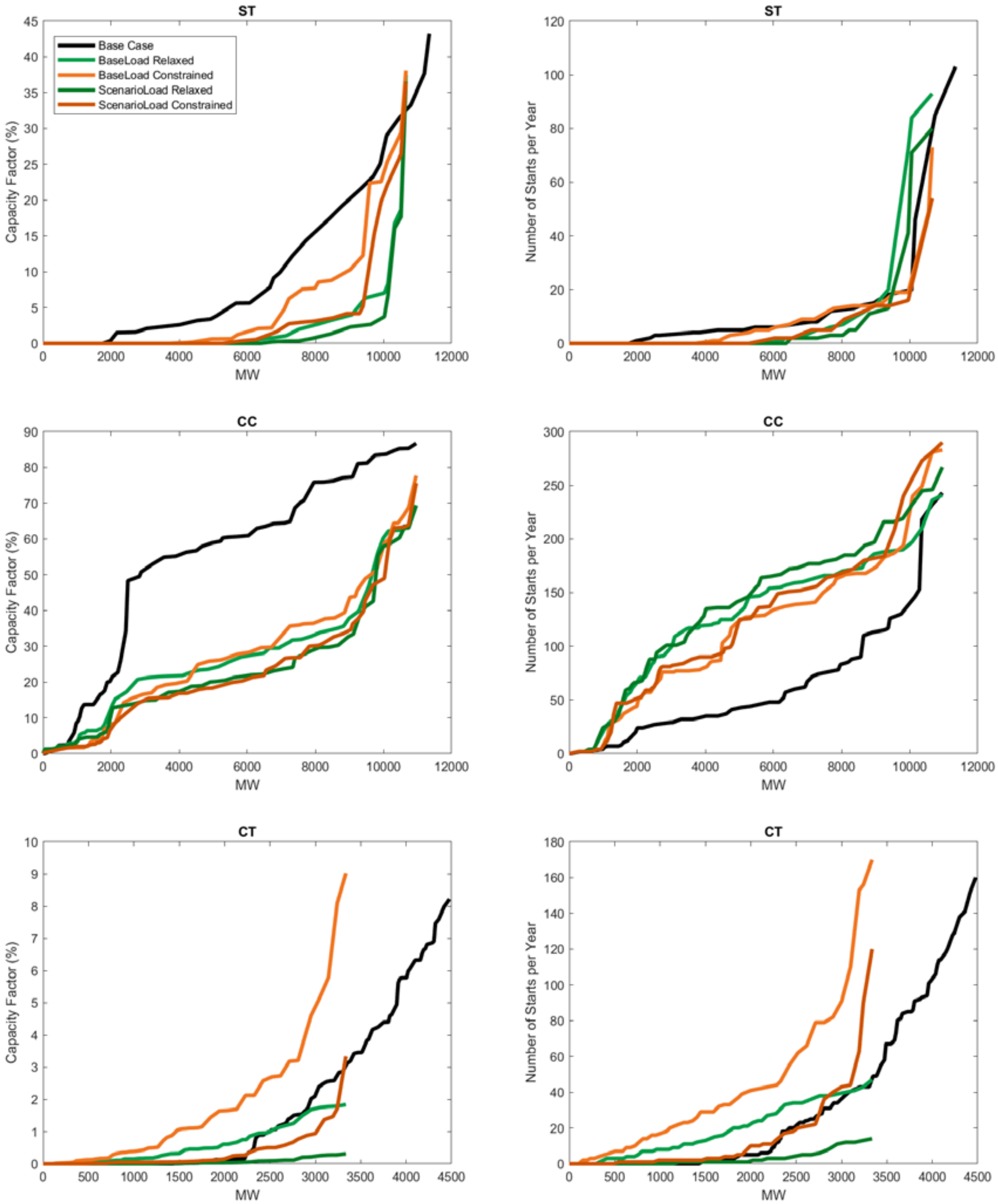
Figure 71: Base Load Relaxed and Constrained Cases Hourly Results across a Low Net Load Period



Comparison of Fossil Fleet Operations

The impact of increased RE, transmission system modeling assumptions, and differing load profiles could impact the operation of the fossil fuel-fired fleet. Cumulative capacity curves display the amount of capacity that operated at or below a given parameter value, as each point on the curve represents one unit's annual operation. To concisely illustrate independent operational aspects of fossil generator operations, the unit level annual capacity factors and number of unit starts are displayed in the figures below.

Figure 72: Base Load Relaxed and Constrained Cases Fossil Fleet Cumulative Capacity Curves



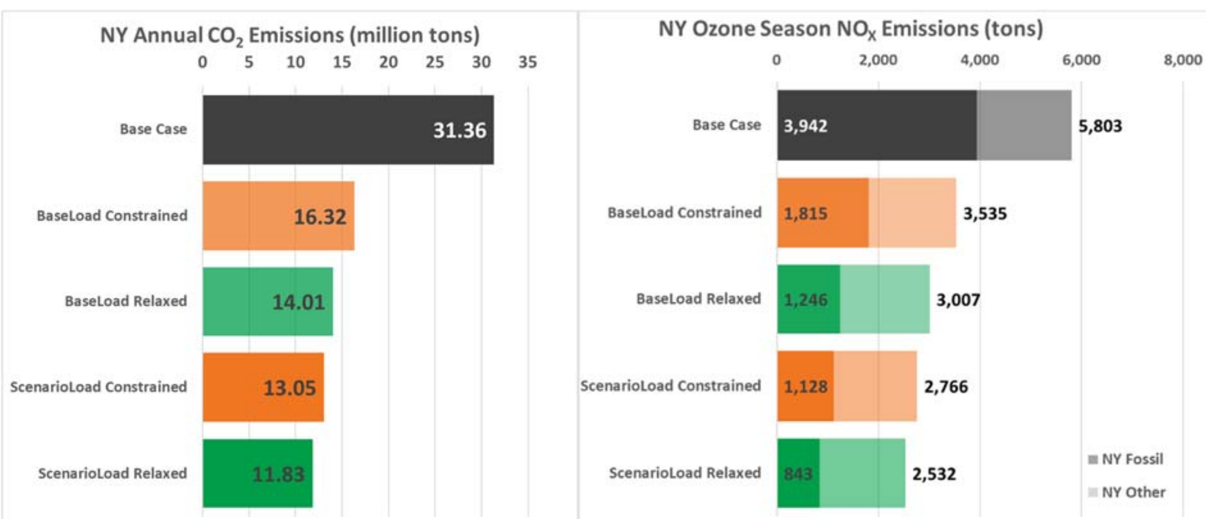
With the substantial addition of intermittent renewable generation modeled in the scenario cases, output from the fossil fleet is lower in comparison to the Base Case, however in many cases the reduced output is accompanied by an increased number of starts indicating the need for a more flexible operating regimen. With lower load, as represented in the Scenario Load case, fossil output is lower compared to the higher Base Load case. The fossil fleet dispatch can also be highly dependent on transmission constraints. In particular, comparison of simple-cycle combustion turbine (CT) operation between the relaxed and constrained cases makes apparent that CTs may run more and start more often due to transmission constraints.

In short, the large amount of intermittent renewable energy additions will change the operations of the existing fossil fleet. It is likely that the units that are more flexible will be dispatched more often, while the units that are less so may not be dispatched as often or at all.

Comparison of Emissions

Carbon dioxide (CO_2) emissions decrease significantly across the scenario cases due to lower loads, increased RE output, and corresponding decreased fossil fleet operations relative to the Base Case. The higher loads in the Base Load cases relative to the Scenario Load cases also result in comparatively higher emission levels. The modest emission reductions observed between the constrained and relaxed cases can partially be explained by the relative increase in exports in the relaxed cases which are partially met with increased fossil generation in state. The emissions of ozone season NO_X are split between fossil and other generators by type. Here and elsewhere in the report 'Other' refers to methane (biogas), refuse (solid waste), and wood fuel-fired generators. As no changes in assumptions were made for this fleet of generators in the scenario cases, their emissions are similar across all cases including the Base Case. These 'Other' associated NO_X emissions become a significant portion of projected ozone season NO_X emissions as the fossil emissions decrease.

Figure 73: Base Load Relaxed and Constrained Cases CO_2 and Ozone Season NO_X Emissions Projections



The assessment shows that emissions could be significantly reduced due to the RE generation additions. However, the long-term impact and achievement of economy-wide emission reductions of 40% by 2030 and 85% by 2050, and the emission-free power sector requirement in 2040 are topics beyond this scenario. These topics will likely be the subjects of future studies, including the NYISO Climate Change Impact and Resilience Study.

Summary of Congestion, Curtailment, and Generation Pockets

The primary purpose of the 70x30 scenario is identifying transmission constraints that may prevent the delivery of renewable energy to achieve the policy target. Combining the congestion and constraint results from sensitivity cases, generation pockets are identified in areas within NYCA to illustrate transmission constraints that could prevent fully utilizing renewable generation.

The resulting renewable curtailment in the scenario could result from a combination of drivers, including: (i) resource siting location, (ii) size of renewable buildout, (iii) the congestion pattern of transmission constraints, and (iv) existing thermal unit operations. Renewable generation located upstream of transmission constraints is more likely to be curtailed compared with those located at downstream of the constraints. In general, renewable curtailments due to transmission constraints include constraints inside generation pockets, tie line constraints, and constraints outside of generation pockets.

Overall, the constraints on the bulk system level remain largely consistent pre- and post-RE build-out, but certain existing constraints could be more congested due to resource shifts. The most congested element in the NYCA system remains Central East, though the congestion has been significantly reduced with the addition of AC Transmission Public Policy projects. In general, the bulk power system is more interconnected, and designed to transfer large amounts of power. The underlying lower voltage system, however, was designed to serve load in the local area and in most cases not designed to deliver power to the bulk system. Much of the renewable generation build-out modeled in this scenario is constrained by the underlying system before the power ever reaches the bulk system. Figure 74 summarizes the NYCA demand congestion for bulk level constraints in the Base Case, Scenario Load, and Base Load cases.

Figure 74: 70x30 Scenario bulk level constraints demand congestion summary (Nominal $M)

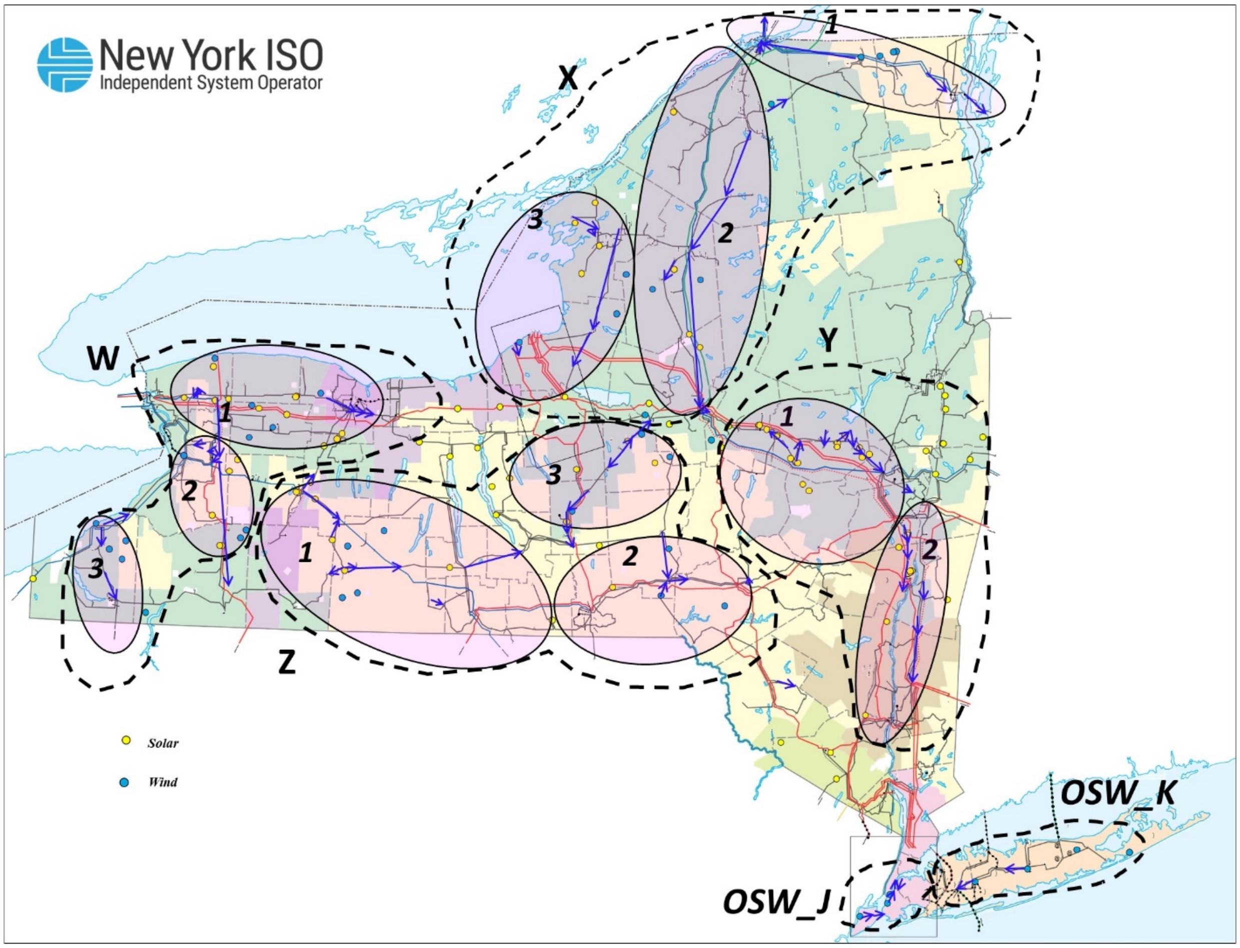
Constraints	Base Case	Scenario Load	Base Load
CENTRAL EAST	167	464	577
NEW SCOTLAND KNCKRBOC	5	113	161
PRNCTWN NEW SCOTLAND	-	57	112
DUNWOODIE TO LONG ISLAND	28	66	56
ISONE-NYISO	4	47	36
SUGARLOAF 138 RAMAPO 138	-	26	59
GREENWOOD	10	18	26
PJM-NYISO	2	19	18
N.WAVERLY LOUNS	11	7	20
DUNWOODIE MOTTHAVEN	15	1	13
EGRDNCTY 138 VALLYSTR 138 1	4	6	7
RAINEY VERNON	0	2	5
CRICKET VALLEY PLSNTVLY	3	0	0
E179THST HELLGT ASTORIAE	1	0	1
FARRAGUT GOWANUS	-	0	2
LOUNS STAGECOA	0	1	0
MOTTHAVEN RAINEY	0	0	0

Due to the resource shift, new constraints appear, and mostly at the lower kV level, mainly on the 115 kV network. To better understand the impacts from these new constraints, generation pockets are identified based on their geographical locations, and for each pocket, the following information and data is provided:

- Congested transmission facilities: the terminals of the transmission facilities and the voltage levels are listed to identify the constraint elements that result in the most congestion in this assessment;
- Congested hours: the hours that these transmission facilities in the pocket experience congestion and the hours are listed facility by facility. This is the number of hours out of the annual total of 8,760 hours. The higher the number, the more likely this transmission facility constrains the renewable generation from being fully utilized; and
- Curtailed energy percentage: the total curtailed energy for the generators in the pocket divided by the total energy, and counted by the resource type, such as hydro and land based wind. The higher the number, the less renewable generation in this pocket can be utilized by the load. The Input RE in GWh is also provided to put the curtailed energy (%) into context.

Figure 75 depicts the renewable generation pockets identified in this study.

Figure 75: Renewable Generation Pockets



The generation pocket assignments are based off two main considerations; renewable generation buildout location, and the constraints congestion results from both the Scenario Load and Base Load levels. Each pocket depicts a geographic grouping of renewable generation, and the transmission constraints in a local area are further highlighted in sub-pocket. Generation in a pocket but not near the transmission constraints are not counted in sub-pockets. The arrow direction is the binding direction in MAPS.

The generation pockets identified in this analysis include:

- **Western NY (Pocket W)**: Western NY constraints, mainly 115 kV in Buffalo and Rochester areas:
    1) **W1**: Niagara-Orleans-Rochester Wind (115 kV)
    2) **W2**: Buffalo Erie region Wind & Solar(115 kV)
    3) **W3**: Chautauqua Wind & Solar(115kV)

- **North Country (Pocket X)**: Northern NY constraints, including the 230 kV and 115 kV facilities in the North Country:
  1) **X1:** North Area Wind (mainly 230 kV in Clinton County)
  2) **X2**: Mohawk Area Wind & Solar (mainly 115 kV in Lewis County)
  3) **X3**: Mohawk Area Wind & Solar (115 kV in Jefferson & Oswego Counties)
- **Capital Region (Pocket Y)**: Eastern NY constraints, mainly the 115 kV facilities in the Capital Region:
  1) **Y1**: Capital Region Solar Generation (115 kV in Montgomery County)
  2) **Y2**: Hudson Valley Corridor (115 kV)
- **Southern Tier (Pocket Z)**: Southern Tier constraints, mainly the 115 kV constraints in the Finger Lakes area:
  1) **Z1**: Finger Lakes Region Wind & Solar (115 kV)
  2) **Z2**: Southern Tier Transmission Corridor (115kV)
  3) **Z3**: Central and Mohawk Area Wind and Solar (115kV)
- **Offshore Wind:** offshore wind generation connected to New York City (Zone J) and Long Island (Zone K)

RE generation capacity by generation pockets assignment is shown in Figure 76 and Figure 77 by generator type in the Base Load and Scenario Load level cases, respectively. A majority of the RE capacity is located in pockets in upstate New York and represents varying blends of RE capacity types.

Figure 76: Generation Pocket Renewable Energy Capacity in Scenario Load Cases

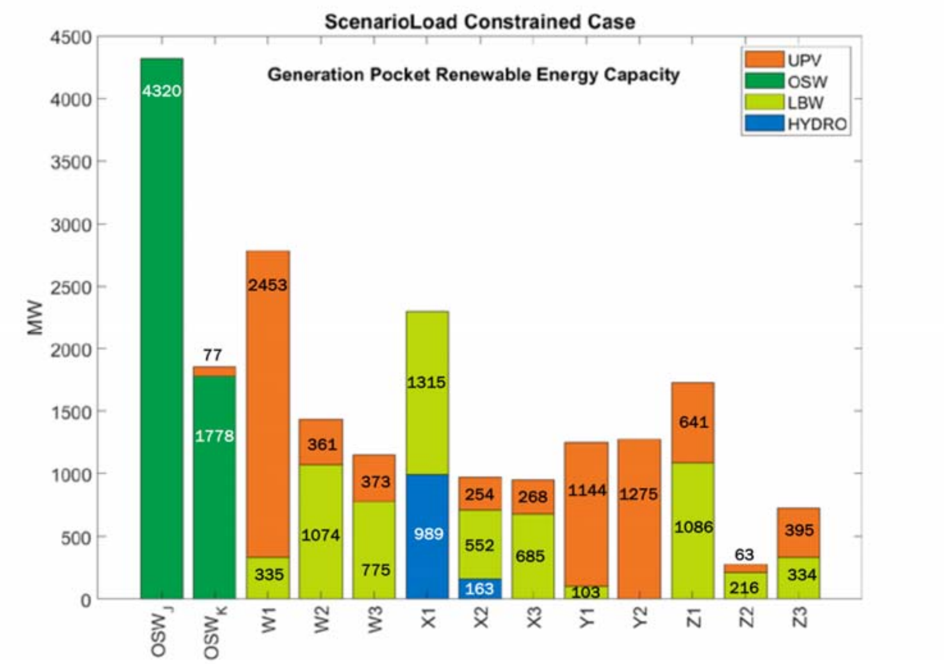
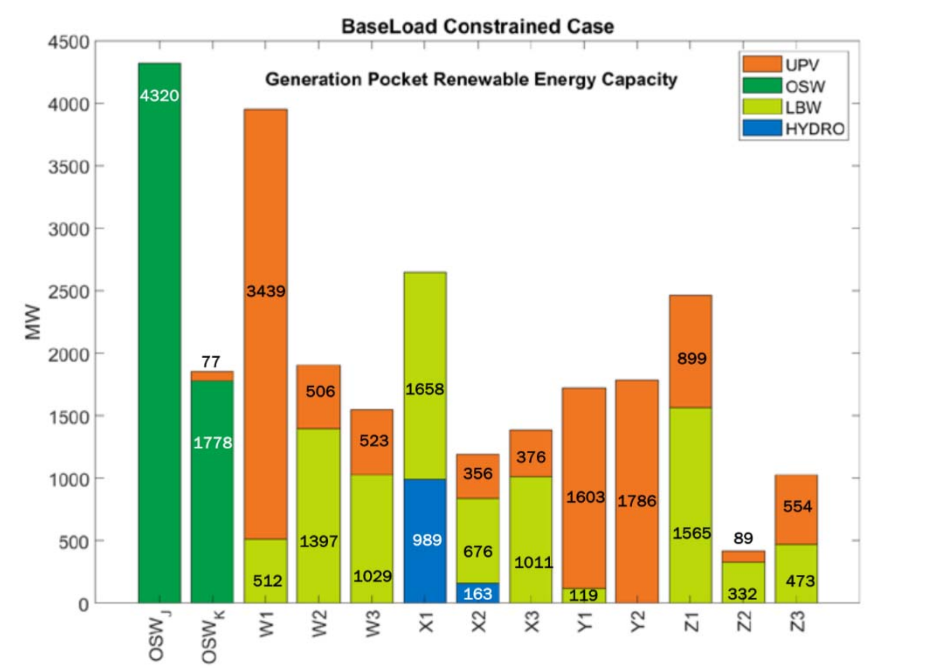


Figure 77: Generation Pocket Renewable Energy Capacity in Base Load Cases

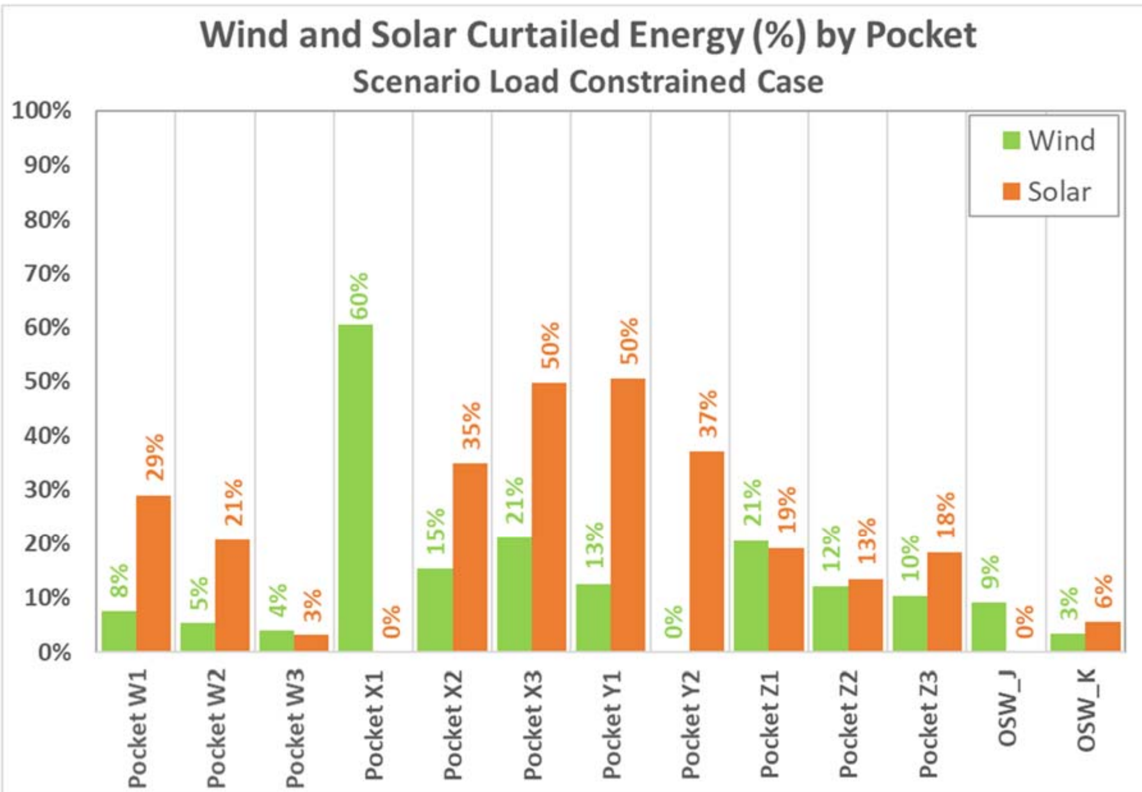


Each RE generator is associated with an hourly generation profile for modeling purposes. Owing to the local load, RE generation, local transmission system topology and loading, and system transmission system conditions, a portion of potential RE generator output may be curtailed within the simulations. This is particularly prevalent when RE generators are located upstream of transmission bottlenecks or in local regions with limited export capability. As described above, the

NYISO identified 13 renewable generation pockets based upon the combination of RE output and transmission system modeling assumptions. Aggregate RE curtailments within these generation pockets represents approximately 90% of the NYCA RE curtailments observed across the scenario cases.

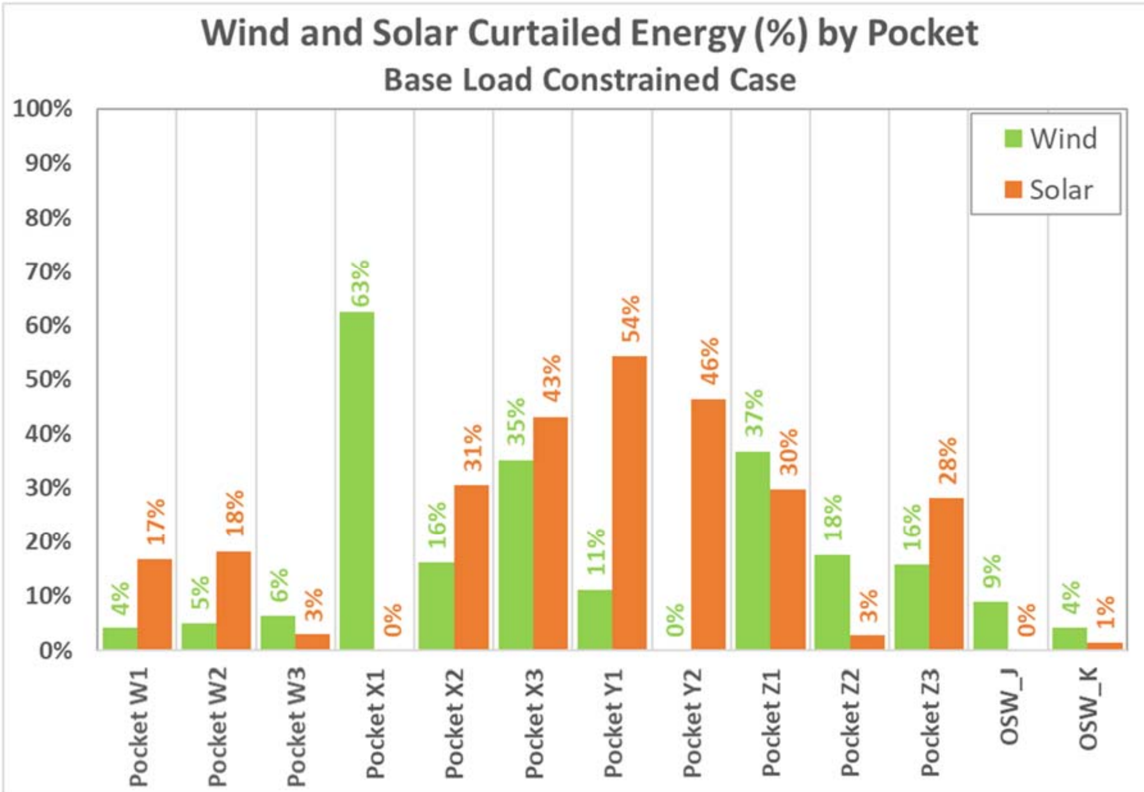
Figure 78 displays the summary of the generation pocket curtailments as a percentage of input RE energy by type across the generation pockets identified. In depth results for each pocket, including congested hours, input RE, and curtailed energy percentage are reviewed in the following section. Additional detailed generator pocket information is available on the NYISO website.[38]

Figure 78: Curtailed Energy Percentage by Pocket Summary in Scenario Load Constrained Case



38 Annual metrics provided in https://www.nyiso.com/documents/20142/12126107/04%20CARIS2019_70x30Scenario_CaseOutputByTypeByPocket.csv/9a37bf26-d879-504f-271b-5ad7093b86ac and hourly information provided in https://www.nyiso.com/documents/20142/12126107/04%20CARIS2019_70x30Scenario_HourlyPocketInformation.xls/f10ab987-2171-a477-f51a-f59d9720203f

Figure 79: Curtailed Energy Percentage by Pocket Summary in Base Load Constrained Case



The simulation shows that generation pockets result from both the existing renewable resources and the large amount of additional resources. Four major pockets are observed in areas of land-based renewable resources: Western New York, North Country, Capital Region, and Southern Tier. In particular, North Country exhibits the highest level of curtailment by percentage, the highest curtailed energy by GWh, and the most frequent congested hours. These curtailments are generally due to lack of a strongly interconnected network to deliver power, at both bulk power and local system levels. Two additional pockets are observed in areas of offshore wind connecting to New York City (Zone J) and Long Island (Zone K) due to transmission constraints on the existing grid after the power is brought to shore.

Figure 80 summarizes the total renewable capacity (MW), the total input energy by renewable resources (GWh), and total curtailed energy by renewable resources (GWh) in each generation pocket. Further details for each sub-pocket is discussed in the section below.

Figure 80: Pocket Summary Table

Base Load	W	X	Y	Z	OSW_J	OSW_K
total renewable capacity (MW)	7,405	5,229	3,508	3,911	4,320	1,855
total input energy (GWh)	14,572	17,761	5,836	9,137	16,100	7,373
total curtailed energy (GWh)	1,421	4,411	2,807	2,703	1,462	306

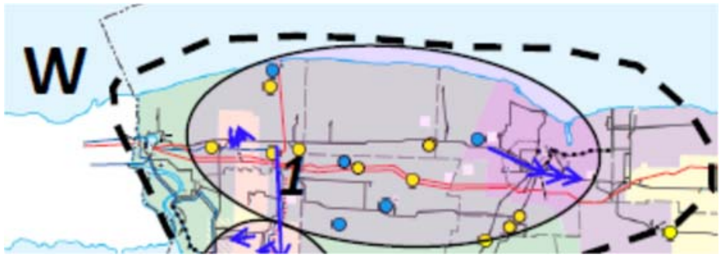
Scenario Load	W	X	Y	Z	OSW_J	OSW_K
total renewable capacity (MW)	5,371	4,227	2,522	2,735	4,320	1,855
total input energy (GWh)	10,515	15,483	4,215	6,311	16,100	7,373
total curtailed energy (GWh)	1,453	3,115	1,749	1,130	1,484	255

Discussion of each Renewable Generation Pocket

Western New York (Pocket W): Significant hydro generation (Niagara) is already located in this pocket prior to the renewable generation additions in this study. Large additions of UPV are assumed in this pocket, particularly in the sub-pocket W1, and result in curtailments. Though the curtailment percentage is not as high as other pockets, the transmission facilities in this pocket could experience frequent congested hours.

Pocket W1 Summary:

Figure 81: Pocket W1 Congestion and Curtailment Summary



Pocket W1

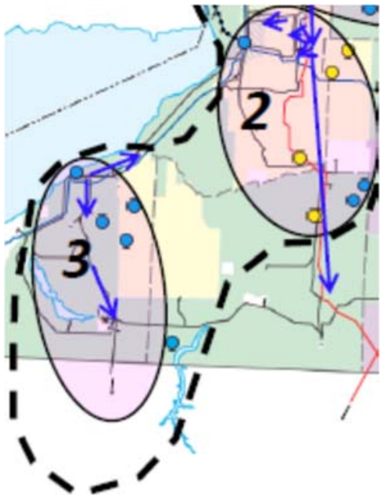
Congested Hours	Scenario Load	Base Load
Q545A_DY 345.00-Q545A_DY 345.00	4,525	3,191
Q545A_ES 345.00-5MILE345 345.00	541	776
HINMN115 115.00-LOCKPORT 115.00	199	1
HINMN115 115.00-HARIS115 115.00	86	1
MORTIMER 115.00-SWDN-113 115.00	19	512
S135 115.00-S230 115 115.00	3,222	2,575
STA 89 115.00-PTSFD-25 115.00	301	431
PANNELLI 115.00-PTSFD-24 115.00	184	344
ROBIN115 115.00-A.LUD TP 115.00	-	1,065
ARS TAP 115.00-S82-1115 115.00	250	344
NIAGAR2W 230.00-NIAG115E 115.00	71	57

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	975	1,497	8%	4%
UPV	3,452	4,838	29%	17%

Pocket W1 is located in Niagara-Orleans-Rochester area. UPV is curtailed at 29% and 17% for the Scenario Load and Base Load cases respectively in this pocket due to the significant solar buildout around Dysinger/Somerset area, which is located upstream of the 345 kV transmission corridor, as shown in Figure 81.

Pocket W2 Summary:

Figure 82: Pocket W2 Congestion and Curtailment Summary



Pocket W2

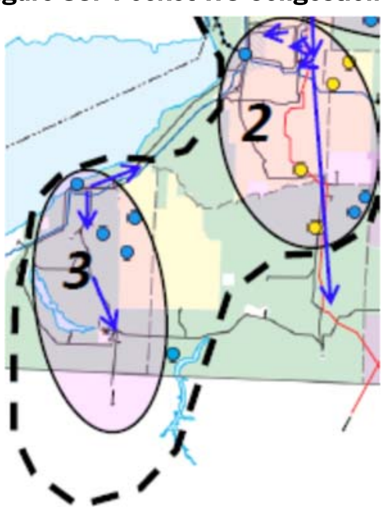
Congested Hours	Scenario Load	Base Load
STOLE115 115.00-GIRD115 115.00	594	495
DEPEW115 115.00-ERIE 115 115.00	227	519
STOLE115 115.00-STOLE345 345.00	124	218
CLSP-181 115.00-YNG-181 115.00	50	25
SPVL-151 115.00-ARCADE 115.00	-	54
ERIE 115 115.00-PAVMT115 115.00	15	50

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	2,882	3,837	5%	5%
UPV	583	817	21%	18%

Pocket W2 is located in the Buffalo area. UPV is curtailed at 21% and 18% for the Scenario Load and Base Load cases respectively in this pocket due to transmission limitations that constrain the ability of renewable generation to serve load in Buffalo area, as shown in Figure 82.

Pocket W3 Summary:

Figure 83: Pocket W3 Congestion and Curtailment Summary



Pocket W3

Congested Hours	Scenario Load	Base Load
FALCONER 115.00-MOON-161 115.00	718	1,272
EDNK-161 115.00-ARKWRIGH 115.00	270	645
EDNK-162 115.00-ARKWRIGH 115.00	15	71
SLVRC141 115.00-DUNKIRK1 115.00	29	226

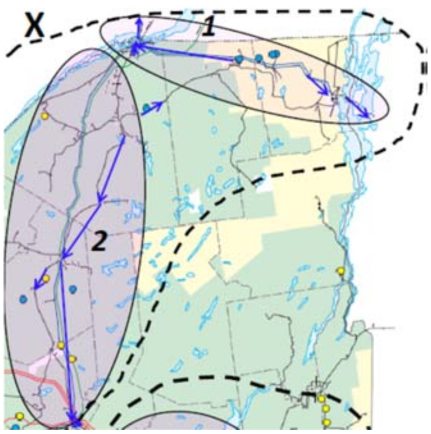
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	2,099	2,847	4%	6%
UPV	525	737	3%	3%

Pocket W3 is located in Chautauqua County. LBW is curtailed at 4% and 6% for the Scenario Load and Base Load cases respectively in this pocket due to wind resources being mostly located upstream of the 115kV transmission corridor, as shown in Figure 83.

North Country (Pocket X): This pocket already had significant hydro and wind plants prior to the additions assumed in these scenarios. In general, the wind and solar generation in this pocket experience very high curtailment percentage, and the transmission facilities in this pocket see the most congested hours among all pockets. This is mainly due to lack of strongly interconnected bulk power transmission facilities, and the geographical proximity to exporting constraints to Ontario and New England.

Pocket X1 Summary:

Figure 84: Pocket X1 Congestion and Curtailment Summary



Pocket X1

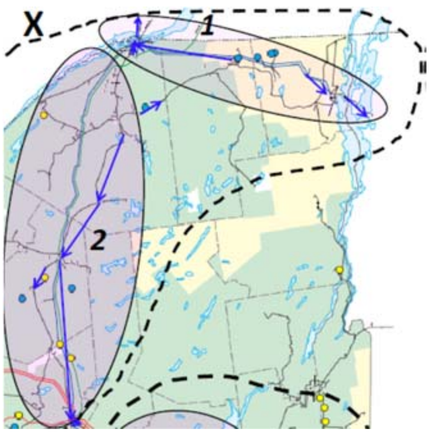
Congested Hours	Scenario Load	Base Load
TIE-LINES: NORTH -VT	8,113	8,014
NorthTie: OH-NY	8,751	8,755
ALCOA-NM 115.00-ALCOA N 115.00	839	766
DULEY 230.00-PLAT T#1 230.00	217	490
ALCOA-NM 115.00-DENNISON 115.00	387	355
MOSES W 230.00-WILLIS E 230.00	19	90

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
Hydro	7,638	7,638	3%	3%
LBW	3,104	3,966	60%	63%

Pocket X1 is generally located in Clinton County in the North Country. Land Based Wind generators are curtailed 60% and 63% for Scenario Load and Base Load cases respectively in this pocket due to the wind being located much closer to the transmission constraints shown in Figure 84 compared with existing hydro generation. In this pocket, the two tie-line constraints connecting with ISO-NE toward the east side and connecting with Ontario toward the west side show significant congested hours in both the Scenario Load and Base Load cases. The 230 kV line between Duley and Plattsburg is also highly congested from wind generation existing to other areas in NYCA. The two constraints in the Alcoa/Dennison area are mainly due to constrained renewable generation to serve load in the Alcoa area.

Pocket X2 Summary:

Figure 85: Pocket X2 Congestion and Curtailment Summary



Pocket X2

Congested Hours	Scenario Load	Base Load
BREMEN 115.00-BU+LY+MO 115.00	1,025	2,233
LOWVILLE 115.00-BOONVL 115.00	633	1,712
BRNS FLS 115.00-TAYLORVL 115.00	170	238
BRNS FLS 115.00-HIGLEY 115.00	63	107
EDIC 345.00-PORTER 2 230.00	11	17
PORTER 2 230.00-ADRON B2 230.00	5	9
NICHOLVL 115.00-PARISHVL 115.00	33	7

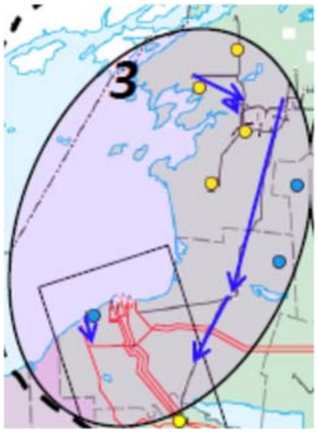
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
Hydro	960	960	18%	16%
LBW	1,354	1,661	15%	16%
UPV	336	471	35%	31%

Pocket X2 is located in Lewis County of the Mohawk Area. UPV is curtailed at 35% and 31% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located at upstream of the 115 kV transmission constraints(Brown Falls – Taylorville – Boonville), as shown in Figure 85. Hydro experiences considerable curtailment in this pocket, at 18% and 16% for the respective load scenarios, due to generation proximity to congested paths.

The 115 kV constraints in Pocket X2 are in parallel with the 230 kV corridor constraints from Adirondack to Porter. The renewable generation modeled in this pocket is mainly interconnected to the 115 kV system, therefore the congestion occurs more on the 115 kV versus 230 kV facilities in this pocket. Note that the congestion currently observed in the 230 kV path is mainly caused by transmission outages on the parallel Moses – Adirondack path. Due to software limitations, these outages and associated congestion are not captured in this study; therefore congestion and curtailment amounts from this analysis are underestimated.

Pocket X3 Summary:

Figure 86: Pocket X3 Congestion and Curtailment Summary



Pocket X3

Congested Hours	Scenario Load	Base Load
HTHSE HL 115.00-MALLORY 115.00	2,530	3,718
HMMRMILL 115.00-WINE CRK 115.00	457	1,448
COFFEEN 115.00-E WTRTWN 115.00	535	883
COFFEEN 115.00-LYMETP 115.00	3	87
HTHSE HL 115.00-COPEN_PO 115.00	18	4
COFFEEN 115.00-GLEN PRK 115.00	706	1,156

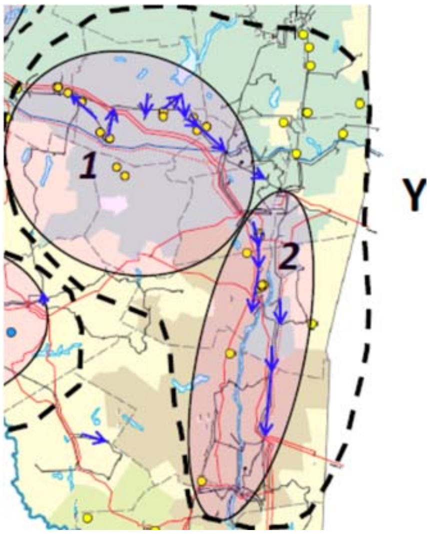
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	1,735	2,567	21%	35%
UPV	356	498	50%	43%

Pocket X3 is located in Jefferson & Oswego Counties. UPV is curtailed at 50% and 43% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located upstream of the 115kV transmission constraints, as shown in Figure 86. These limitations directly increase the utilization of the neighboring transmission facilities.

Capital Region (Pocket Y): This pocket encompasses the Mohawk Valley and upper Hudson Valley regions, centered on the Albany metro area. A large amount of solar generation, mainly UPV, is modeled in this pocket, particularly on the 115 kV network. These new resources experience high levels of curtailment on the 115 kV network, which is generally not designed for high levels of generation injection.

Pocket Y1 Summary:

Figure 87: Pocket Y1 Congestion and Curtailment Summary



Pocket Y1

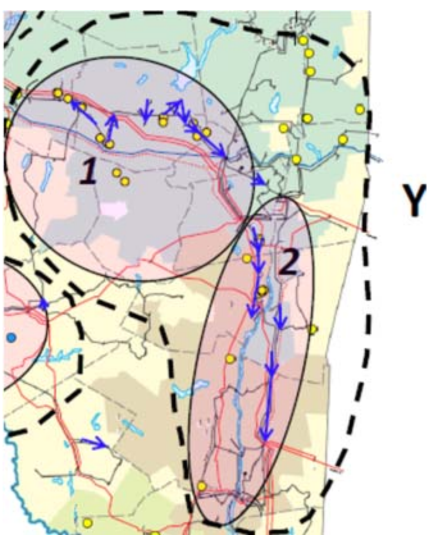
Congested Hours	Scenario Load	Base Load
RTRDM1 115.00-AMST 115 115.00	2,392	2,814
STONER 115.00-VAIL TAP 115.00	2,037	2,259
INGHAM-E 115.00-ST JOHNS 115.00	508	1,454
CHURCH-W 115.00-VAIL TAP 115.00	1,034	1,509
CLINTON 115.00-TAP T79 115.00	293	725
CHURCH-E 115.00-MAPLEAV1 115.00	293	543
AMST 115 115.00-CHURCH-E 115.00	149	302
CENTER-N 115.00-MECO 115 115.00	20	170
EVERETT 115.00-WOLF RD 115.00	149	7

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	247	286	13%	11%
UPV	1,826	2,557	50%	54%

Pocket Y1 is located in the vicinity of the Mohawk Valley of the Capital Region. UPV is curtailed at 50% and 54% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located upstream of the 115 kV transmission constraints, as shown in Figure 87. The 115 kV transmission corridor runs in parallel with the 345 kV corridor utilized by Segment A of the AC Transmission Public Policy projects.

Pocket Y2 Summary:

Figure 88: Pocket Y2 Congestion and Curtailment Summary



Pocket Y2

Congested Hours	Scenario Load	Base Load
N.CAT. 1 115.00-CHURCHTO 115.00	2,079	2,371
MILAN 115.00-PL.VAL 1 115.00	1,913	2,256
OW CRN E 115.00-BOC 7T 115.00	151	93
MILAN 115.00-BL STR E 115.00	145	282
JMC1+7TP 115.00-BLUECIRC 115.00	-	213
JMC2+9TP 115.00-OC W +MG 115.00	17	54
ADM 115.00-HUDSON 115.00	12	74
N.CAT. 1 115.00-BOC 2T 115.00	-	22

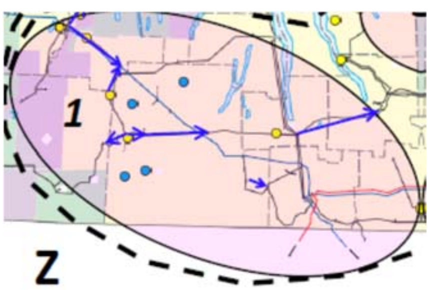
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
UPV	2,142	2,993	37%	46%

Pocket Y2 is located in the upper Hudson Valley corridor. UPV is curtailed at 37% and 46% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located at upstream of the 115 kV transmission constraints corridor as shown in Figure 88. The 115 kV transmission corridor runs in parallel with the 345 kV corridors utilized by Segment B of the AC Transmission Public Policy projects.

<u>Southern Tier (Pocket Z):</u> Large amounts of UPV and LBW are assumed to be added in this pocket, particularly in the sub-pocket of Z1. In general, the wind and solar generation in this pocket experience high levels of curtailments, and the transmission facilities in this pocket show high levels of congested hours. This congestion results mainly from the lack of strongly interconnected bulk power transmission facilities near injection points, and the 115 kV network was not designed for large power transfers.

<u>Pocket Z1 Summary:</u>

Figure 89: Pocket Z1 Congestion and Curtailment Summary



Pocket Z1

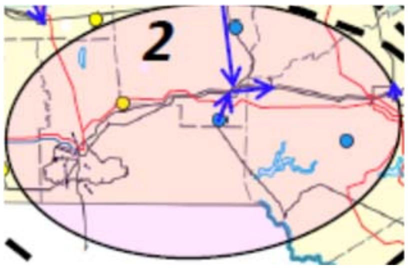
Congested Hours	Scenario Load	Base Load
HICK 115 115.00-WERIE115 115.00	1,966	3,115
BATH 115 115.00-HOWARD11 115.00	1,438	2,694
BENET115 115.00-PALMT115 115.00	1,456	1,738
MEYER115 115.00-S.PER115 115.00	1,371	2,307
S.PER115 115.00-S PERRY 230.00	-	20
S.PER115 115.00-STA 162 115.00	-	1
STA 162 115.00-STA 158S 115.00	304	466
MEYER115 115.00-MORAI115 115.00	611	847
BENET115 115.00-HOWARD11 115.00	346	893
CODNT115 115.00-MONTR115 115.00	2	12

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	3,064	4,479	21%	37%
UPV	1,073	1,503	19%	30%

Pocket Z1 is generally located in Finger Lakes Region. LBW is curtailed at 21% and 37% for the Scenario Load and Base Load cases respectively in this pocket due to the wind buildout being mostly located upstream of the 115 kV transmission corridor near the Benet area, as shown in Figure 89.

Pocket Z2 Summary:

Figure 90: Pocket Z2 Congestion and Curtailment Summary



Pocket Z2

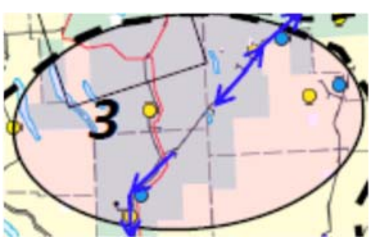
Congested Hours	Scenario Load	Base Load
DELHI115 115.00-DEL T115 115.00	994	301
JENN 115 115.00-SIDNT115 115.00	575	2,018
JENN 115 115.00-AFTON115 115.00	-	48
E.NOR115 115.00-JENN 115 115.00	6	190
STILV115 115.00-AFTON115 115.00	-	40
W.WDB115 115.00-FERND115 115.00	17	60

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	531	817	12%	18%
UPV	107	149	13%	3%

Pocket Z2 is located in the Southern Tier Region. LBW is curtailed at 12% and 18% for the Scenario Load and Base Load cases respectively in this pocket due to the wind buildout being mostly located upstream of the 115 kV transmission corridor, as shown in Figure 90.

Pocket Z3 Summary:

Figure 91: Pocket Z3 Congestion and Curtailment Summary



Pocket Z3

Congested Hours	Scenario Load	Base Load
CORTLAND 115.00-TULLER H 115.00	14	476
CLARKCRN 115.00-TULLER H 115.00	-	895
DELPHI 115.00-OM-FENNR 115.00	-	123
CORTLAND 115.00-LABRADOR 115.00	75	431
WHITMAN 115.00-ONEIDA 115.00	1,816	2,905
WHITMAN 115.00-FEN-WIND 115.00	290	506

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	883	1,276	10%	16%
UPV	653	913	18%	28%

Pocket Z3 is located in Central New York Region. UPV is curtailed at 18% and 28% for the Scenario Load and Base Load cases respectively in this pocket due to the solar buildout being mostly located upstream of the 115 kV transmission corridor, as shown in Figure 91.

Off-Shore Wind in Zone J: Offshore Wind is curtailed at 9% for both the Scenario Load and Base Load cases in this pocket due to the wind resources being mostly located upstream of the 138 kV and 345 kV transmission corridors, as shown in Figure 92. There are three injection points in New York City, at the Freshkills 345 kV substation, Gowanus 345 kV substation, and Farragut 345 kV substation. The majority of the OSW curtailment results from the injection at the Freshkills substation in the Staten Island load pocket, which is constrained by the 138 kV facility from Freshkills to Willow Brook.

The study also shows that the OSW resources are much higher than the load in the Staten Island load pocket, as well as being constrained by the identified transmission facilities. Accordingly, the OSW resources cannot be transmitted out of the load pocket.

Figure 92: New York City Offshore Wind Congestion and Curtailment Summary

OSW_J

Congested Hours	Scenario Load	Base Load
WILOWBK2 138.00-FRESH KI 138.00	3,774	4,662
FARRAGUT 345.00-GOWANUS 345.00	2,273	2,250
E13ST 45 345.00-FARRAGUT 345.00	211	198
WILOWBK1 138.00-FRESH KI 138.00	116	97
RAINEY W 345.00-FARRAGUT 345.00	23	54

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
OSW	16,100	16,100	9%	9%

<u>**Off-Shore Wind in Zone K:**</u> Offshore Wind is curtailed at 3% and 4% for both the Scenario Load and Base Load cases in this pocket due to the new wind resources being mostly located upstream of the 138 kV transmission corridor, as shown in Figure 93. There are four injection points in Long Island; the Holbrook 138 kV substation, Brookhaven 138 kV substation, Ruland Road 138 kV substation, and East Hampton 69 kV substation. The majority of the OSW curtailment on Long Island results from the injection at Holbrook substation that is constrained by the 138 kV facility from Holbrook to Ronkonk.

Figure 93: Long Island Offshore Wind Congestion and Curtailment Summary

OSW_K

Congested Hours			Scenario Load	Base Load
HOLBROOK	138.00-RONKONK	138.00	2,032	2,102
NEWBRGE	138.00-RULND RD	138.00	236	314

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
OSW	7,259	7,259	3%	4%
UPV	115	115	6%	1%

Nuclear Generation Retirement Sensitivity

The nuclear generation fleet, which is comprised of the Nine Mile I, Nine Mile II, Ginna and FitzPatrick facilities, are expected to continue in operation until at least March 2029 under the state support provided by Zero Emission Credit Requirements contained in the Clean Energy Standard. These units may continue in operation beyond 2029 and this sensitivity analysis should not be interpreted as forecasting their deactivation. This sensitivity examines what may be the impacts on the system generation output if those units discontinued operations under the Scenario Load and Base Load conditions in 2030. The existing nuclear generation fleet provides emission-free base-load generation with limited dispatch flexibility. Removal of large, consistent supply resources would result in higher utilization of a combination of intermittent and conventional generation. Figure 94 shows the annual energy by unit type and net imports across cases with and without the nuclear units in operation.

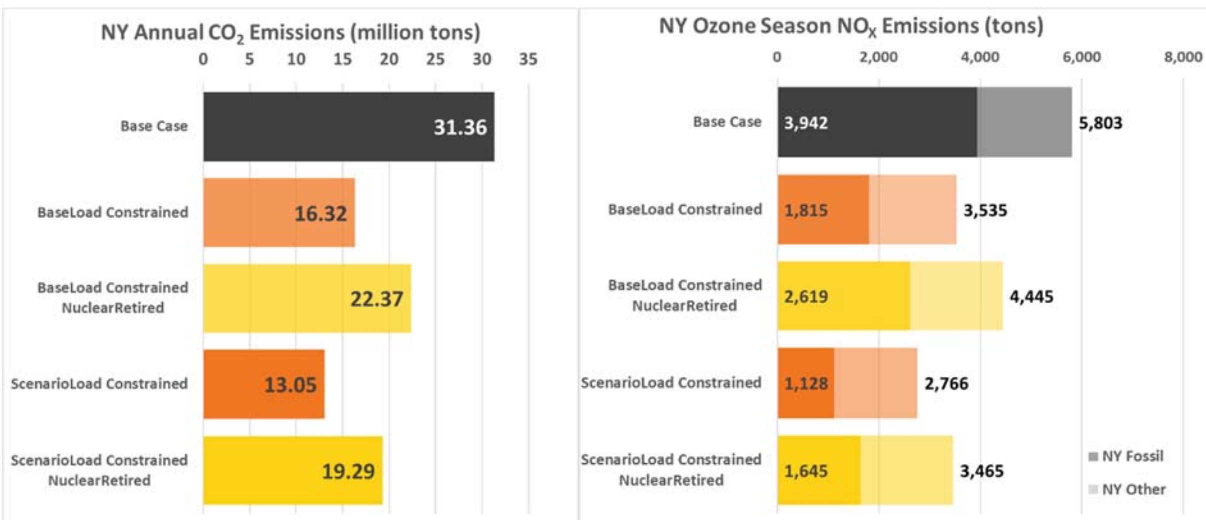
Figure 94: Base, Constrained, and Nuclear Retirement Sensitivity Case Annual Energy Results

Energy (GWh)	Base Case	ScenarioLoad Constrained	ScenarioLoad Constrained NuclearRetired	BaseLoad Constrained	BaseLoad Constrained NuclearRetired
Nuclear	27,091	27,433	-	27,433	-
Other	2,368	2,110	2,270	2,102	2,263
Fossil	69,028	28,185	42,924	35,181	49,448
Hydro	28,832	28,050	28,448	28,020	28,413
Hydro Imports	11,564	19,775	19,897	19,769	19,910
LBW	5,038	13,290	14,879	17,117	18,751
OSW	-	21,625	21,714	21,592	21,750
UPV	115	12,666	14,527	17,982	19,342
BTM-PV	4,988	9,266	9,356	9,327	9,359
Pumped Storage	(447)	(822)	(988)	(868)	(959)
Storage	-	-	-	-	-
IESO Net Imports	(2,862)	(5,817)	(4,090)	(6,250)	(4,264)
ISONE Net Imports	(535)	(6,418)	(4,385)	(5,073)	(2,867)
PJM Net Imports	12,239	(4,446)	287	(4,528)	591
Renewable Generation	50,537	104,672	108,821	113,808	117,525
Curtailment	0	10,151	6,069	14,020	10,338
Non-Renewable Generation	98,488	57,728	45,194	64,717	51,712
GrossLoad	157,418	144,897	144,838	161,807	161,733

With deactivation of the nuclear generation fleet, the model exhibits a significant increase in fossil fuel generation in the Scenario Load and Base Load cases, mostly in the downstate region. The model also reveals an increase in wind and solar output from upstate renewables that are able to utilize transmission capability previously consumed by the nuclear generation, while offshore wind output remains mostly consistent due to local congestion. The cases with the nuclear fleet retired also have notable reductions in exports to external regions across both the Scenario and Base Load levels.

Increased operation of fossil units in cases with the nuclear generation fleet retired results in increased in CO_2 and NO_X emissions, as shown in Figure 95. Emission levels are lower in the Scenario Load case compared the Base Load case owing to lower load and corresponding lower operation of fossil fuel generation.

Figure 95: Nuclear Retirement Sensitivity Case CO_2 and Ozone Season NO_X Emissions Projections



Energy Storage Resources (ESR) Sensitivity

State policies, including the CLCPA, support the installation of 3,000 MW of Energy Storage Resources (ESR) in New York by 2030. ESR modeling in production cost simulation is in the development stage at the time of this assessment, and the NYISO investigated different dispatch models, namely ESR method and hourly resource modifier (HRM) method. The detailed modeling approach and comparison of results are included in an appendix. For illustrative purposes, this section of the report focuses on HRM method, and the targeted impact examination of a small amount of ESR capacity to minimize curtailment from individual collocated RE generators in a generation pocket.

In the HRM approach all ESR are assumed to be four-hour duration with 85% round trip efficiency, meaning that ESR can discharge 85% of the energy consumed from charging. Results of the study conducted for the NYSERDA Energy Storage Roadmap[39] were used to inform the zonal MW capacity levels. ESRs were added to the model as a distributed resource at the load buses, on a zonal basis as shown in Figure 39.

Figure 96: Assumed ESR Zonal Power Capacity

Nameplate Capacity Distribution (MW)												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
ESR	150	90	120	180	120	240	100	100	100	1,320	480	3,000

The primary impact of including ESR as a distributed resource in MAPS is a reduction in fossil generation, exports, and curtailments, with an observed increase in RE generation of approximately 1,000 GWh, or 0.9%. Figure 97 displays the annual energy composition of generation, net imports, curtailments, and gross load. Storage resources in the table are shown as net generation values (*i.e.*, net generation = discharge – charge), similar to the calculation of net generation for pumped storage resources.

Figure 97: Energy Storage Resource Sensitivity Case Results Energy Results (GWh)

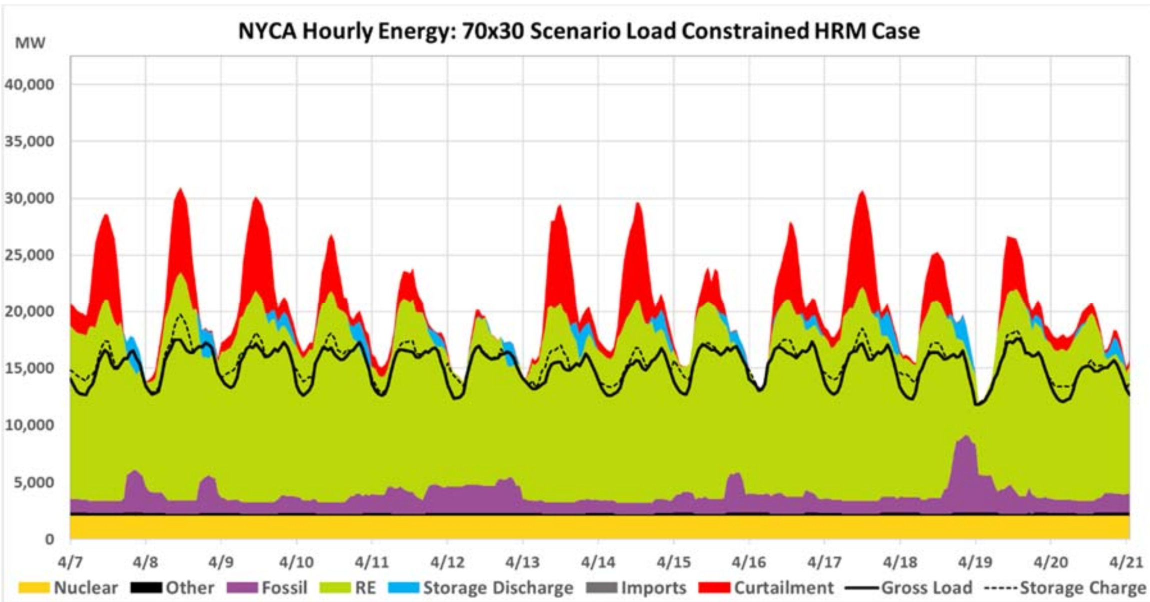
Energy (GWh)	ScenarioLoad Constrained	ScenarioLoad Constrained HRM	BaseLoad Constrained	BaseLoad Constrained HRM
Nuclear	27,433	27,434	27,433	27,435
Other	2,110	2,126	2,102	2,117
Fossil	28,185	26,294	35,181	33,603
Hydro	28,050	28,114	28,020	28,091
Hydro Imports	19,775	19,808	19,769	19,808
LBW	13,290	13,532	17,117	17,376
OSW	21,625	21,743	21,592	21,821
UPV	12,666	13,124	17,982	18,350
BTM-PV	9,266	9,288	9,327	9,329
Pumped Storage	(822)	(630)	(868)	(671)
Storage	-	(693)	-	(756)
IESO Net Imports	(5,817)	(5,755)	(6,250)	(6,145)
ISONE Net Imports	(6,418)	(5,847)	(5,073)	(4,723)
PJM Net Imports	(4,446)	(3,648)	(4,528)	(3,838)
Renewable Generation	104,672	105,609	113,808	114,775
Curtailment	10,151	9,266	14,020	13,097
Non-Renewable Generation	57,728	55,853	64,717	63,155
GrossLoad	144,897	144,888	161,807	161,797

Graphs over two week sample periods, as shown in Figure 98, display the impacts of ESR on fossil, renewable, imports, and curtailments on an hourly granularity. Modeling distributed ESR resulted in less fossil generation during low net load periods compared, as ESR typically reduces

[39] documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2A1BFBC9-85B4-4DAE-BCAE-164B21B0DC3D}

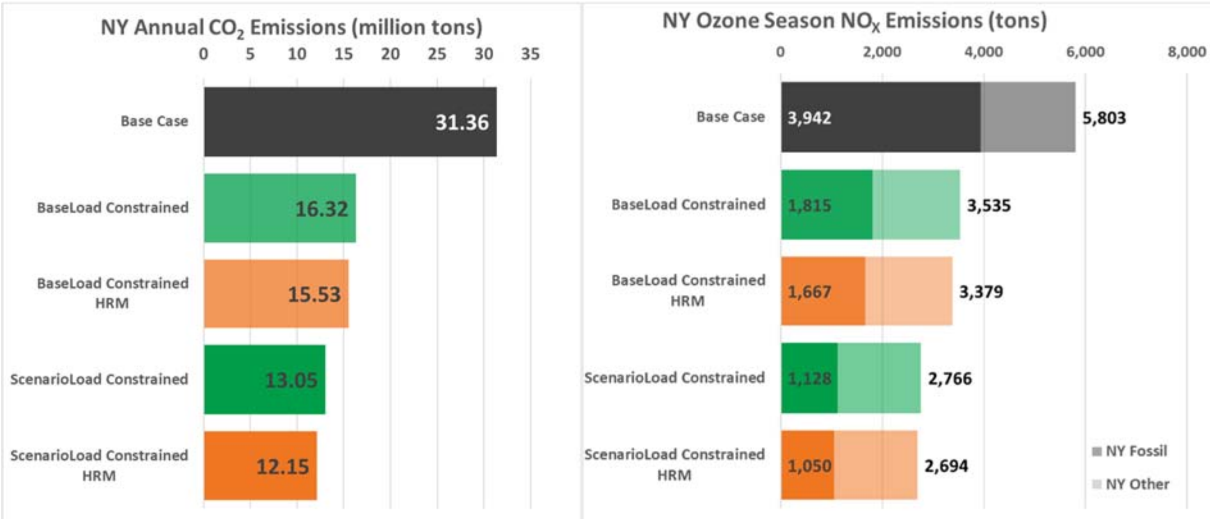
peak fossil demand levels. It was also observed that some (mostly winter) hours during which ESR was charging were also hours when NYCA was a net importer. This implies that the increase charging demand could increase imports and fossil generation in some hours relative to a case without ESR. Renewable curtailments also decreased compared to cases without ESR.

Figure 98: HRM Energy Storage Resource Hourly Results across a Spring Low Net Load Period



The introduction of ESR does not inherently result in a reduction in emissions or output of fossil generators because ESR overall increase energy demand due to losses associated in the cycle from charging to discharging. Figure 99 the CO2 and NO_X emissions of generators located in New York across the scenario cases and the Base Case. Emissions across all scenario cases decrease substantially from the Base Case results. The additional reduction of the distributed storage model are relatively small in comparison.

Figure 99: Energy Storage Resource Sensitivity Case CO_2 and Ozone Season NO_X Emissions Projections



An additional sensitivity examined the impact of ESR on RE curtailments in generation pockets. Generally speaking, solar generation profiles are more regular from day to day compared to wind generation, and relatively easier to identify a dispatch pattern for ESR. As a starting point, this investigative analysis focused on the impact of ESR in conjunction with solar generation.

In the Capital Region Pocket Y1, five UPV generators with the highest level of curtailed energy from the Scenario Load constrained case were chosen for this sensitivity. The five UPV units and their curtailed energy data is shown in Figure 100. An 8,760 hourly dispatch profile was created for each ESR unit to charge with the curtailed energy from the associated RE unit. In the absence of any curtailment of its associated RE unit, ESR would inject its stored energy into the transmission network. The ESR dispatch profiles were also limited by the power, energy, and efficiency constraints on the ESR itself. All ESR in these cases assumed an 85% charge-to-discharge cycle efficiency.

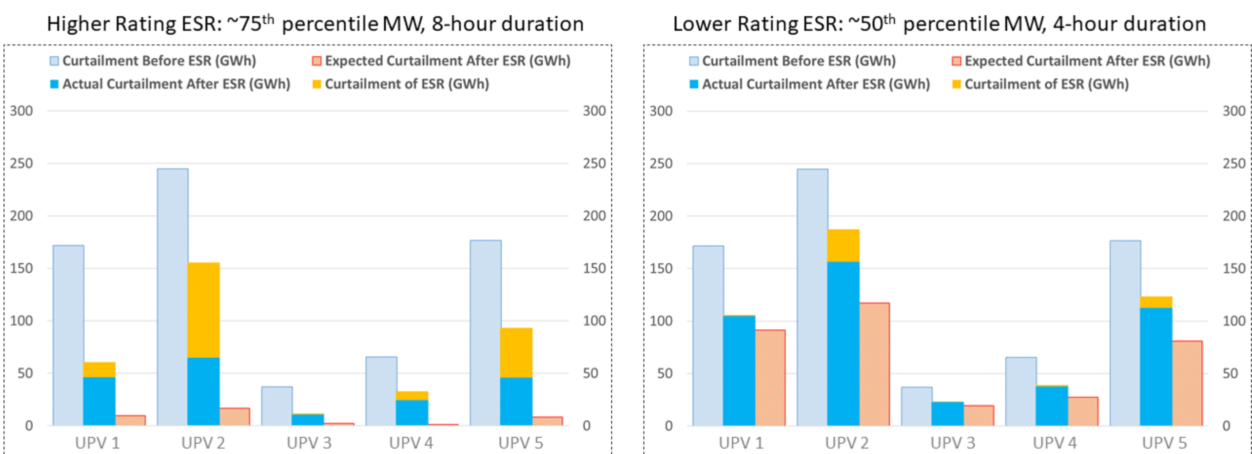
Figure 100: Information on Pocket RE Generator and Collocated ESR Capacity

RE unit	Capacity (MW)	Higher ESR Capacity (75th percentile) (MW)	Lower ESR Capacity (50th percentile) (MW)
UPV1	213	150	85
UPV2	196	130	100
UPV3	109	80	35
UPV4	87	70	40
UPV5	174	125	90

The power rating of the ESR was selected to capture approximately 75th and 50th percentiles of the hourly curtailments of each RE unit. The two power ratings of each ESR used in this sensitivity are shown in Figure 100.

ESR dispatch profiles were included in a MAPS simulation as hourly resource modifiers (HRM) collocated with the associated RE unit. Figure 101 shows the curtailment results for two MAPS simulations with two ESR rating levels (*i.e.*, higher and lower rated ESR units). It can be seen in Figure 101 that the MAPS simulation resulted in curtailment of ESR injections because the network constraints still existed in the absence of energy from the RE units. Lower ratings of ESR also resulted in higher curtailments from the associated renewable units with lower associated ESR curtailments. These results are based upon the modeling assumption that ESR discharge begins immediately following the end of each UPV curtailment event. The modeling did not attempt to optimize the temporal discharge within the inter-curtailment intervals each night. UPV curtailments were targeted as UPV follows a more characteristic and predictable diurnal pattern when compared to modeled wind curtailments. This ESR algorithm minimizes RE curtailment to determine how much curtailment may also be addressed by transmission and does not target production cost or profit optimization for ESR using LBMP differences.

Figure 101: Curtailment Results for Pocket RE Generator Collocated ESR Sensitivity Cases



These results show that while ESR can help in reducing curtailments in constrained pockets to some extent, the transmission limitations in the pockets cannot directly be solved with ESR. Ultimately, MAPS will curtail either the ESR injection or some other renewable unit if sufficient transmission capability to export from the pocket does not exist. Depending upon the temporal differences in wind and solar curtailment events and the ESR parameters, differing amounts of curtailments may be addressed by either ESR and/or transmission upgrades.

Reduced Export Sensitivity

Based on stakeholder feedback, the NYISO performed an additional sensitivity to examine the impact of reduced exports to external regions (PJM, IESO and ISO-NE) on scenario study results. External areas will likely experience demand and resource shifts while different regions are moving towards their own individual renewable and emission reduction targets. The detailed plans of the neighboring areas are not available at the time of this report. Lacking such information, the 70x30 scenario does not assume any renewable generation growth in the neighboring systems beyond limited additions prescribed by inclusion rules assumed in the Base Case analysis. The additional sensitivity effectuates reduced exports from the NYISO to external areas by substantially increasing the export hurdle rate on all ties in the export direction.

Hurdle rates are studied during benchmarking analysis to set inter-regional flows economically to historical averages and remain fixed throughout the Base Case study period. This sensitivity models export hurdle rates at 100 times the Base Case amount to reduce exports to neighboring regions. The results presented in Figure 102 for this sensitivity are intended only to show the directional impacts of increasing export hurdle rates. The NYISO has not optimized or studied hurdle rate values in depth. Instead, the NYISO selected a large value to study the directionality of flows and generation.

Increasing export hurdle rates results in decreased exports (and increased net imports) on all inter-regional interfaces, decreased New York renewable and fossil generation output. Higher hurdle rates also increased curtailments as it becomes more economic to curtail production than to export energy with such a high export cost.

Figure 102: Export Sensitivity Case Annual Energy Results

Energy (GWh)	Base Case	ScenarioLoad Constrained	ScenarioLoad Constrained 100xHurdleRate
Nuclear	27,091	27,433	27,419
Other	2,368	2,110	1,621
Fossil	69,028	28,185	21,434
Hydro	28,832	28,050	25,117
Hydro Imports	11,564	19,775	19,830
LBW	5,038	13,290	10,453
OSW	-	21,625	19,125
UPV	115	12,666	9,074
BTM-PV	4,988	9,266	9,072
Pumped Storage	(447)	(822)	(885)
Storage	-	-	-
IESO Net Imports	(2,862)	(5,817)	71
ISONE Net Imports	(535)	(6,418)	972
PJM Net Imports	12,239	(4,446)	1,616
Renewable Generation	50,537	104,672	92,671
Curtailment	0	10,151	18,985
Non-Renewable Generation	98,488	57,728	50,474
GrossLoad	157,418	144,897	144,921

Key Findings of the 70 by 30 Scenario

As policymakers advance an implementation plan for the CLCPA, this assessment is intended to complement their efforts and provide information about possible challenges. This "first look" at the CLCPA target of 70% renewable energy by 2030, identifies the following key findings:

- The "70x30" scenario builds on the base case to model state-mandated policy goals. Results show that renewable generation pockets are likely to develop throughout the state as the existing transmission grid would be overwhelmed by the significant renewable capacity additions. In each of the five major pockets observed, renewable generation is curtailed due to the lack of sufficient bulk and local transmission capability to deliver the power. The results support the conclusion that additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers.

- The level renewable generation investment necessary to achieve 70% renewable end-use energy by 2030 could vary greatly as energy efficiency and electrification adoption unfolds. Two scenarios with varying energy forecasts and associated renewable build-outs were simulated. Both scenarios resulted in the observation that significant transmission constraints exist when adding the necessary volume of renewable generation to achieve the 70% target.

- Energy efficiency initiatives will have significant implications for the level of renewable resources needed to meet the CLCPA goals. For this assessment, utilizing an illustrative set of various renewable sources, nearly 37,600 MW of renewable resources was modeled to approximate a system potentially capable of achievement of the 70x30 policy goal at the base load level. By comparison, nearly 31,000 MW of renewable resources were added to cases with demand reduced by energy efficiency polices.
- The large amount of renewable energy additions to achieve the CLCPA goals would change the operations of the fossil fuel fleet. Overall, the annual output of the fossil fleet would likely decline. The units that are more flexible would be dispatched more often, while the units that are less so may be dispatched less or not at all. In addition, sensitivity analysis indicates that if the statewide nuclear generation fleet retired, emissions from the fossil fuel fleet would likely increase, making the achievement of longer-term emission reduction policy goals more challenging.
- Sensitivity analysis indicates that energy storage could decrease congestion, and when dispatched effectively, energy storage would help to increase the utilization of the renewable generation, particularly the solar generation tested in this analysis.

The NYISO will continue to monitor and track system changes. Subsequent studies, such as 2020 Reliability Needs Assessment and Climate Change Study Phase II, will build upon the findings of this CARIS scenario. To inform policymakers, investors and other stakeholders as implementation unfolds, these forward-looking studies will provide further assessment of the CLCPA focusing on other aspects such as transmission security and resource adequacy analysis.

8. 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.[40] 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.[41]

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

40 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.

41 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.

Appendix A – Glossary

Ancillary Services: Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. (As defined in the Services Tariff.)

Bid Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). (As defined in the NYISO Tariffs.)

Business Issues Committee (BIC): A NYISO governance committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to Bidding, Settlements and the calculation of market prices. The BIC reviews the CARIS report and makes recommendations regarding review of the report by the Management Committee.

Capacity: The capability to generate or transmit electrical power (in MW), or the ability to reduce demand at the direction of the ISO, measured in MW. (As defined in the NYISO Tariffs.)

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y. (As defined in the NYISO OATT.)

Clean Energy Standard (CES): State initiative for 70% of electricity consumed in New York State to be produced from renewable sources by 2030.

Climate Leadership and Community Protection Act (CLCPA): State statute enacted in 2019 to address and mitigate the effects of climate change. Among other requirements, the law mandates that; (i) 70% of energy consumed in New York State be sourced from renewable resources by 2030, (ii) greenhouse gas emissions must be reduced by 40% by 2030, (iii) the electric generation sector must be zero greenhouse gas emissions by 2040, and (iv) greenhouse gas emissions across all sectors of the economy must be reduced by 85% by 2050.

Comprehensive Reliability Plan (CRP): A biennial study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point.

Comprehensive System Planning Process (CSPP): The Comprehensive System Planning Process set forth in this [OATT] Attachment Y, and in the Interregional Planning Protocol, which covers the reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and interregional planning process (As defined in the OATT.)

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the Transmission System is unequal. (As defined in the NYISO Tariffs.)

Congestion Rent: The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions. (As defined in the OATT.)

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages. (As defined in the NYISO Tariffs.)

Day Ahead Market (DAM): A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.

DC tie-lines: A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.

Demand Response: A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.

Eastern Interconnection Planning Collaborative (EIPC): A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.

Economic Dispatch of Generation: The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.

Electric System Planning Working Group (ESPWG): A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's CSPP, the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.

Energy Efficiency Portfolio Standard (EEPS): A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.

Exports: A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. (As defined in the NYISO Tariffs.)

External Areas: Neighboring Control Areas including Hydro Quebec, ISO-New England, PJM Interconnection, and IESO.

Federal Energy Regulatory Commission (FERC): The federal energy regulatory agency within the U.S. Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.

FERC Form 715: An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.

FERC Order No. 890: Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 added provisions establishing competition in transmission planning, transparency and planning in wholesale electricity markets and transmission grid operations, and strengthened the OATT with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – to have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.

Grandfathered Rights: The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert them to Grandfathered TCCs. (As defined in the OATT.)

Grandfathered TCCs: The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. (As defined in the OATT.)

Heat Rate: A measurement used to calculate how efficiently a generator uses thermal energy. It is expressed as the number of BTUs of thermal energy required to produce a kilowatt-hour of electric energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel. When thermal energy input is compared to the actual electric energy produced by the generator, the resulting figure tells how efficiently the generator converts fuel into electrical energy.

High Voltage Direct Current (HVDC): A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.

Hurdle Rate: The conditions in which economic interchange is transacted between neighboring markets/control areas. The rate represents a minimum savings level, in $/MWh, that needs to be achieved before energy will flow across the interface.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area. (As defined in the NYISO Tariffs.)

Independent System Operator (ISO): An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single U.S. State, but sometimes encompassing multiple states.

Installed Capacity (ICAP): A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules. (As defined in the OATT.)

Installed Reserve Margin (IRM): The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet the NYSRC resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.

ISO Market Administration and Control Area Services Tariff (Services Tariff): Sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets ("Market Services") and the ISO's provision of Control Area Services ("Control Area Services"), including services related to ensuring the reliable operation of the NYS Power System. (As defined in the Services Tariff.)

ISO Open Access Transmission Tariff (OATT): Every [FERC]-approved ISO or RTO must have on file with [FERC] an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. (As defined in the Code of Federal Regulations.)

Load: A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. (As defined in the NYISO Tariffs.)

Locational Capacity Requirement (LCR): Specifies the minimum amount of installed capacity that must be procured from resources situated specifically within a locality (Zone K and Zone J). It considers resources within the locality as well as the transmission import capability to the locality in order to meet the resource adequacy reliability criteria of the NYSRC and the NPCC.

Load Serving Entity (LSE): Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. (As defined in the Services Tariff.)

Load Zones: The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.

Local Transmission Planning Process (LTPP): The first step in the CSPP, under which stakeholders in New York's electricity markets participate in local transmission planning.

Locational Based Marginal Pricing (LBMP): The price of Energy at each location in the NYS Transmission System.

Management Committee: NYISO governance committee that reviews the CARIS report following review by the Business Issues Committee and makes recommendations regarding approval to the NYISO's Board of Directors.

Market Analysis and Portfolio Simulation (MAPS) Software: An analytic tool for market simulation and asset performance evaluations.

Multi-Area Reliability Simulation (MARS) Software: An analytic tool for market simulation to assess the reliability of a generation system comprised of any number of interconnected areas.

Market Based Solution: Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response programs. .

Market Participant: An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO tariffs, power exchanges, TOs, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.

New York Control Area (NYCA): The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 Load Zones.

New York Independent System Operator (NYISO): Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a more than 11,000-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.

New York State Reliability Council (NYSRC): A not-for-profit entity the mission of which is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator (NYISO) and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.

New York State Bulk Power Transmission Facilities (BPTFs): The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to the NPCC by the ISO pursuant to NPCC requirements. (As defined in the OATT.) The BPTFs include (i) all NYCA transmission facilities 230 kV and above, (ii) all NYCA facilities identified by the NYISO to be part of the Bulk Power System, as defined by the NPCC and the NYSRC, and (iii) select 115 kV and 138 kV facilities that are considered to be bulk power transmission in accordance with the 2004 FERC Order.

Nomogram: Nomograms are system representations used to model electrical relationships between system elements. These can include; voltage or stability related to load level or generator status; two interfaces related to each other; generating units the output of which are related to each other; and operating procedures.

North American Electric Reliability Corporation (NERC): A nonprofit corporation based in Atlanta Georgia to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America. NERC establishes mandatory reliability standards that it enforces and that are enforced by the Northeast Power Coordinating Council.

Northeast Coordinated System Planning Protocol (NCSPP): ISO New England, PJM and the NYISO work together under the NCSPP, to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.

Northeast Power Coordinating Council (NPCC): A not-for-profit corporation in the state of New York responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. The NPCC encompasses Ontario, Quebec, New York and New England, and serves as the Regional Entity overseeing and enforcing the reliability standards of the North American Electric Reliability Corporation.

Operating Reserves: Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. (As defined in the Services Tariff.)

Overnight Costs: Direct permitting, engineering and construction costs with no allowances for financing costs.

Phase Angle Regulator (PAR): Device that controls the flow of electric power in order to increase the efficiency of the transmission system.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy

Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface. (As defined in the NYISO Tariffs.)

Public Policy Transmission Planning Process (PPTPP): The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all solutions on a comparable basis, and selects the more efficient or cost effective transmission solution, if any, for eligibility for cost allocation under the ISO Tariffs. (As defined in the OATT.)

Regional Greenhouse Gas Initiative (RGGI): A cooperative effort by ten Northeast and Mid-Atlantic states to limit carbon dioxide emissions using a market-based cap-and-trade approach.

Regulated Backstop Solution: Proposals required of Responsible TOs to meet Reliability Needs identified in the RNA as outlined in the OATT. Those solutions can include generation, transmission or Demand Response. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap Solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap Solution should be temporary and strive to be compatible with market-based solutions. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.

Regulation Service: The Ancillary Service defined by the FERC as "frequency regulation" and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market. .

Reliability Need: A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (As defined in the OATT.)

Reliability Needs Assessment (RNA): A biennial report that evaluates resource adequacy and transmission system security over years three through ten of a ten-year planning horizon, and that identifies future needs of the New York electric grid. It is the first step in the NYISO's Reliability Planning Process.

Reliability Planning Process (RPP): The process set forth in this [OATT] Attachment Y by which the ISO determines in the RNA whether any Reliability Need(s) on the BPTFs will arise in the Study Period and addresses any identified Reliability Need(s) in the CRP, as the process is further described in Section 31.1.2.2. (As defined in the OATT.)

Security Constrained Unit Commitment (SCUC): A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.

Shadow Price: The incremental economic impact of a constraint on system production cost. Calculated in linear program optimization for economic dispatch.

Short Term Reliability Process (STRP): The process set forth in this [OATT] Attachment FF by which the ISO evaluates and addresses the reliability impacts resulting from both: (i) Generator Deactivation Reliability Need(s), and/or (ii) other Reliability Needs on the BPTFs that are identified in a [Short Term Assessment of Reliability] STAR. The STRP covers years one through five of the Study Period, with a focus on Reliability Needs arising in years one through three.

Special Case Resource (SCR): Demand Side Resources whose Load is capable of being interrupted upon demand at the direction of the ISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System or the distribution system at the direction of the ISO. (As defined in the Services Tariff.).

Stakeholders: A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.

Thermal transfer limit: The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.

Transfer Capability: The amount of electricity that can flow on a transmission line at any given instant, in MW, respecting facility rating and reliability rules.

Transmission Congestion Contract (TCC): The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (As defined in the OATT.)

Transmission Constraint: Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.

Transmission District: The geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (As defined in the NYISO Tariffs.)

Transmission Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Transmission Owner (TO): The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff. (As defined in the NYISO Tariffs.)

Transmission Planning Advisory Subcommittee (TPAS): A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.

List of Key Acronyms

CARIS	Congestion Assessment and Resource Integration Study
CE	Central East
CE+NS-KN	Central East-New Scotland-Knickerbocker
CLCPA	Climate Leadership and Community Protection Act
DMNC	Dependable Maximum Net Capacity
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
Gold Book	2019 Load and Capacity Data Report “Gold Book”
HQ	Hydro Quebec
ICAP	Installed Capacity
LBMP	Locational-Based Marginal Pricing
MAPS software	Multi Area Production Simulation Software
MARS software	Multi-Area Reliability Simulation software
MUST	Managing and Utilizing System Transmission
MW	megawatt
MWh	megawatt hour
NYCA	New York Control Area
NYISO	New York Independent System Operator
RGGI	Regional Greenhouse Gas Initiative
SCUC software	Security Constrained Unit Commitment software
TARA	Transmission Adequacy & Reliability Assessment
TCCs	Transmission Congestion Contracts
TWh	terawatt hour
UPNY-SENY	Upstate New York – Southeast New York
VS	Volney - Scriba