2021-2040

# System & Resource Outlook

DRAFT for 6/21 ESPWG

# Executive Summary (Preliminary Draft)

Driven by the state's Climate Leadership and Community Protection Act ("CLCPA") and other state clean energy policies, New York's electricity generation and demand landscape is rapidly changing. This shift leads to a re-thinking of how and where the resources evolve, and how to efficiently enable their adoption to achieve energy policy targets.

This System & Resource Outlook ("the Outlook"), conducted by the New York Independent System Operator ("NYISO") in collaboration with stakeholders and state agencies, provides a comprehensive overview of the potential resource development over the next 20 years and the resultant transmission constraints throughout New York, and highlights opportunities for transmission investment driven by economics and public policy. Together with the NYISO's publication of the 2021-2030 Comprehensive Reliability Plan, this 2021-2040 System & Resource Outlook provides a full power system outlook to stakeholders, developers, and policymakers.

The Outlook examines a wide range of potential future system conditions and enables comparisons between possible pathways to an increasingly greener resource mix. By simulating several different possible futures and forecasting the transmission constraints for each, the NYISO has:

- projected possible resource mixes that achieve New York's public policy goals while maintaining grid reliability;
- identified regions of New York where renewable resources may be unable to generate at their full capability due to transmission constraints;
- quantified the extent to which these transmission constraints limit delivery of renewable energy to consumers, and;
- identified potential opportunities for transmission investment that may provide economic, policy, and/or operational benefits.

### Key Findings

There are many potential paths and combinations to achieving the various CLCPA policy targets. As the current power system continues to evolve, evaluating a multitude of expansion scenarios will facilitate identification of common and unique challenges among them, establishing a path for investors and policymakers to a greener and reliable future grid. This Outlook evaluates four possible scenarios to better understand the challenges ahead and provides the following key findings:

- Significant new resource development will be required in order to achieve CLCPA energy targets. The total installed generation capacity to meet policy objectives within New York is projected to range from 111 GW and 124 GW by 2040. Compared to the 51 GW of generation capacity that exists and is contracted today, this represents a significant increase in the amount of capacity needed to satisfy system reliability and policy requirements.
- To achieve an emission-free grid, dispatchable emission-free resources (DEFRs) must be developed and deployed throughout New York to replace the various electrical attributes that are provided today by fossil generation. DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. The capacity contribution of intermittent renewable resources declines as more are added to the system. The limited contribution of incremental resources inhibits the ability of the power system to effectively meet mandatory resource requirements and to serve load in hours in which renewable generation are limited or unavailable. The scale and technology of DEFRs necessary to meet state energy needs will also depend upon the buildout of the transmission and distribution grids.
- Resource buildout alone to meet minimum capacity requirements is not sufficient to efficiently achieve policy goals. If resources are not built in excess of reserve requirements to meet reliability margins, New York will likely import significant amount of external energy that may or may not be renewable. Even with additional imports, there could be significant renewable energy that is not deliverable to customers during peak producing hours.
- Transmission expansion is critical to facilitating efficient CLCPA energy target achievement. The current New York transmission system, at both local and bulk levels, is inadequate to achieve currently required policy objectives. Renewable generation pockets throughout the State become more constrained as an increasing number of intermittent generation resources connect, necessitating transmission upgrades to make the renewable energy deliverable. Bulk and local transmission constraints on today's grid will limit the effective delivery of renewable energy to consumers throughout the State. A significant portion of projected renewable generation will be built in upstate New York areas, which are geographically and electrically distant from the major consumer hubs in downstate New York. Without significant transmission investment to provide access to renewable energy resource rich areas, the renewable energy cannot efficiently traverse New York State and be delivered to consumers.

- When dispatched effectively, energy storage would help to increase the utilization of the renewable generation, but energy storage alone cannot completely resolve the transmission limitations in the pockets analyzed.
- Peak load management should be integrated as a measure to facilitate CLCPA energy target achievement. By lowering the peak load and avoiding system buildout to serve the highest demand hour, less DEFR buildout will be needed, and during the transition fossil fuel-fired plants can be utilized less to meet lower peaks.
- Electrification from other sectors, such as building and transportation, into the power sector should be monitored and managed closely. Electrification is one of the largest factors driving peak and annual energy demand. While other sectors, such as transportation, currently account for a larger share of greenhouse gas emissions, unmitigated electrification of the energy sector could lead to higher energy costs and reduced reliability.
- Co-optimization of renewable energy additions and fossil fuel plant operation during the transition could facilitate a more efficient and cost-effective buildout of the future renewable generation portfolio. High natural gas prices, high $CO_2$ prices, or lower capital costs for renewable generation, could all lead to a relatively larger buildout of renewable energy resources. However, the large amount of renewable energy additions to achieve the CLCPA goals will impact the operations of the fossil fuel fleet in the 20-year transition to an emission-free grid. Overall, the annual output of the fossil generation will decline. The units that are more flexible will be dispatched more often, while the units that are less so may be dispatched less or not at all. Balancing the need to retain fossil resources that are necessary in the transition for the continued reliability of the grid with the goals of achieving a zero-emissions grid will be the central challenge to the industry in the coming decades.

### Grid in Transition: Implementation of Contracted Renewables

Through an annual request for proposals, NYSERDA solicits bids from eligible new large-scale renewable resources and procures Renewable Energy Credits ("RECs") from these facilities. The "Contract Case" evaluated in this Outlook adds approximately 9,500 MW of new contracted renewable resources, including 4,262 MW of solar, 899 MW of land-based wind, and 4,316 MW of offshore wind. The addition of these resources to the Baseline system representation provides insights regarding their impact on system performance in the future.

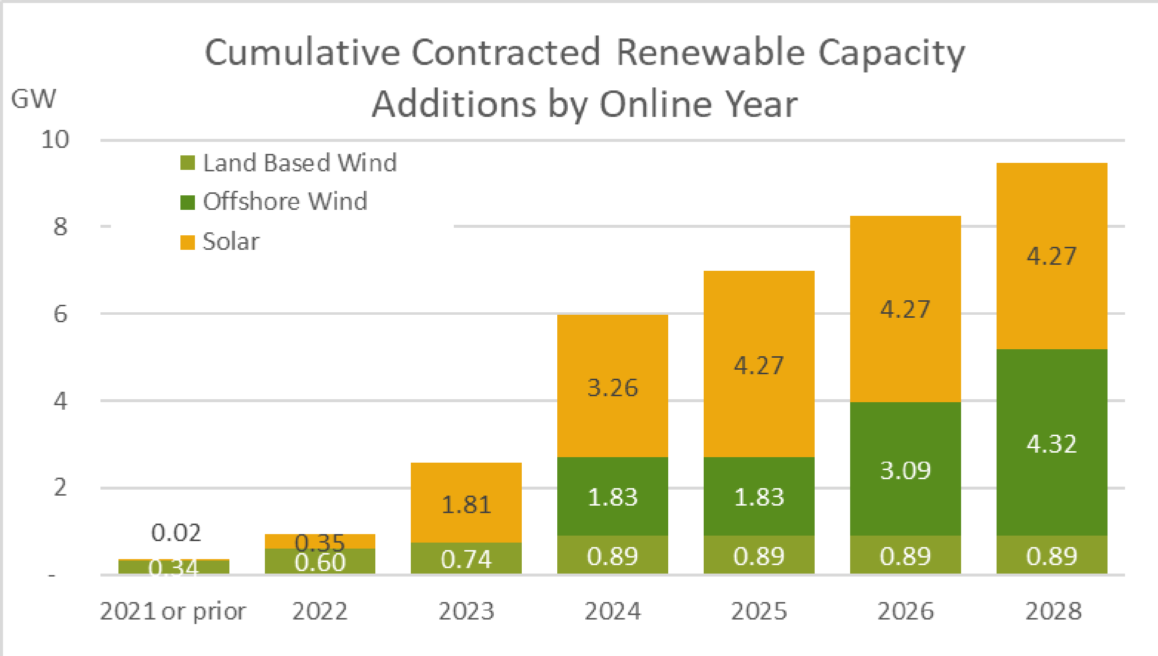
The analysis performed on the Baseline and Contract Cases focuses on transmission congestion and how patterns change through time and as New York State contracted renewable projects are added to the system. It is important to note that neither the Baseline nor Contract Case models generation additions or retirements beyond what was included in the 2021-2030 Comprehensive Reliability Plan or what has been contracted by the State.

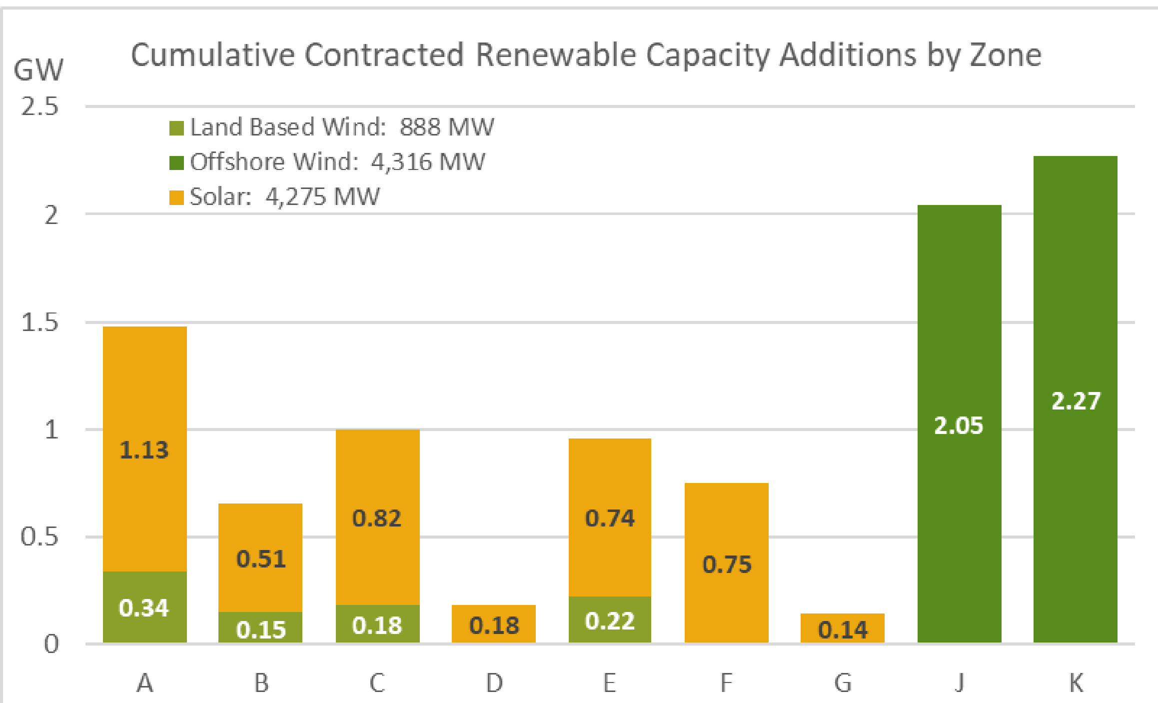
**The contracted renewable project portfolio will exacerbate existing transmission congestion and will encounter new local transmission constraints throughout New York State.** Working from the Baseline Case, the Contract Case was formulated by adding approximately 9,500 MW (9.5 GW) of future renewable generation projects, including land-based wind, solar, and offshore wind generation. The charts below show the geographic dispersion of renewable project procurements through time added in the Contract Case. Most of the renewable projects are upstate solar or downstate offshore wind projects scheduled for installation prior to 2026.[1]

The additional contracted projects represent a nearly five-fold increase in utility scale renewables compared to what exists on the system today. Without any major transmission upgrades planned to specifically address this large influx of contracted renewables, transmission congestion increases. When the contracted renewable projects are added, several additional constraints appear, causing a 23% increase in congestion statewide by 2030.

A major impact of the transmission constraints is that larger amounts of renewable generation experience curtailment. Renewable generators average approximately 5 GWh of annual curtailment in the Baseline Case, whereas curtailments increase to an annual average of 163 GWh in the Contract Case. Most of the curtailments are experienced by offshore wind projects connected to Long Island due to inadequate transmission capacity.

**Contract Case Renewable Capacity Additions**



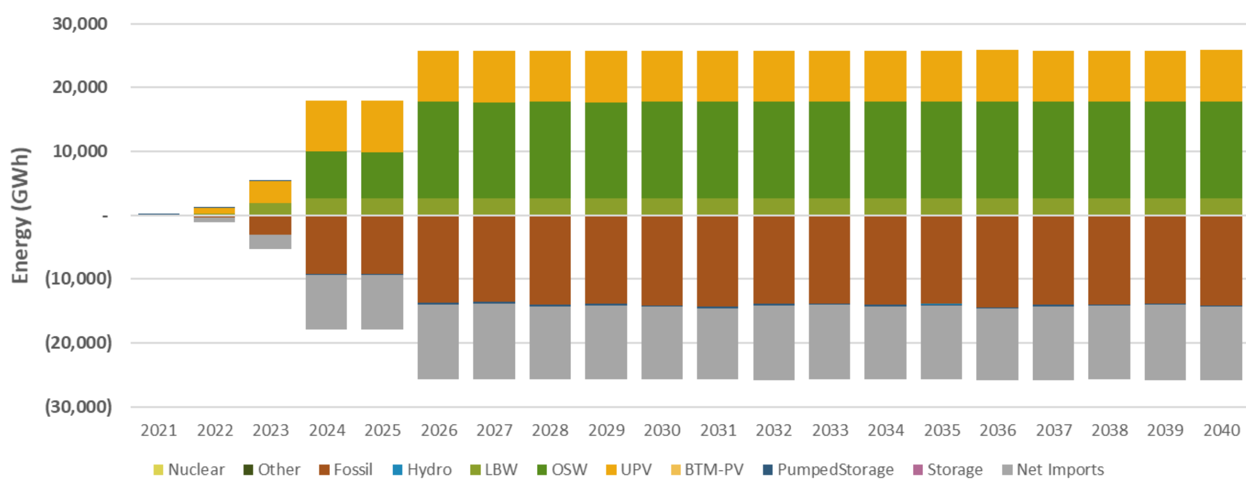



**AC Transmission Public Policy projects and Ontario nuclear retirements greatly reduce current Central East interface congestion.** With the planned completion of the NYISO AC Transmission Public Policy Projects in 2024, which represent substantial upgrades to the electric grid in the Mohawk and Hudson Valleys, transmission congestion on the Central East/Total East interface is nearly eliminated. However, the potential addition of more renewable generation upstream of the Central East interface may results in greater future congestion, as demonstrated in the Policy Case.

A secondary contributing factor to reducing Central East congestion is nuclear retirements and refurbishments planned by the Ontario Independent Electric System Operator ("IESO"). Between 2021 and 2025 over 10,000 MW of nuclear plant capacity is planned for either retirement or long-term refurbishment. This represents over 25% of the generation capacity in Ontario, which typically enables economic energy exports to the NYISO, nearly all of which traverses the Central East interface. Without inexpensive excess capacity in Ontario for export, the NYISO experiences reductions in Ontario imports and a decrease in congestion on the Central East interface.

**Energy production from contracted renewable projects is projected to displace both New York fossil generation and energy imports from external systems.** The energy produced by the 9,500 MW of additional renewable generation projects tends to displace equivalent amounts of in-state fossil generation as well imported generation from neighboring systems. The chart below shows the increase (positive values) in renewable energy as well as the decrease (negative values) in fossil and imported energy in the Contract Case relative to the Baseline Case. The displacement from renewable energy would be even greater if curtailments are eliminated through transmission investment.

**Annual Energy Change due to Contracted Resources**



The displacement of in-state fossil generation is focused in the Capital and New York City zones while the reduction in imported energy is primarily from PJM with a similar reduction in exports to ISO-NE.

### Road to 2040: Resources to Achieve Policy Targets

Building upon the known contracted resources, the NYISO developed postulated scenarios that reflect full achievement of the CLCPA targets. The scenarios are collectively referred to as the "Policy Case". Examples of policies modeled in this case include the "70 x 30" renewable mandate and the 100% carbon-free by 2040 directive. These system representations involve many assumptions and unknowns but provide an informed view of the future to enable sound decision-making by policymakers and stakeholders. The Policy Case will also be utilized as part of the Public Policy Process, including evaluation of the Long Island Offshore Wind Export Public Policy Transmission Need.

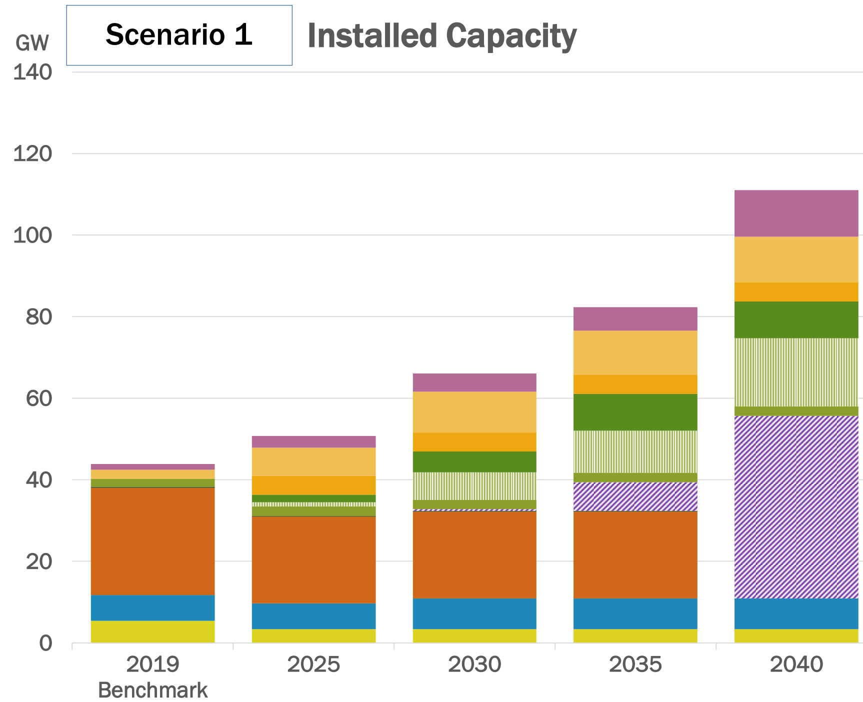
Dozens of preliminary scenarios were evaluated. Key factors such as capital cost and demand forecast were adjusted to investigate the key drivers for resource addition and possible pathways to policy achievement. Among all factors tested, demand forecast demonstrated the largest impact on the resulting capacity expansion.

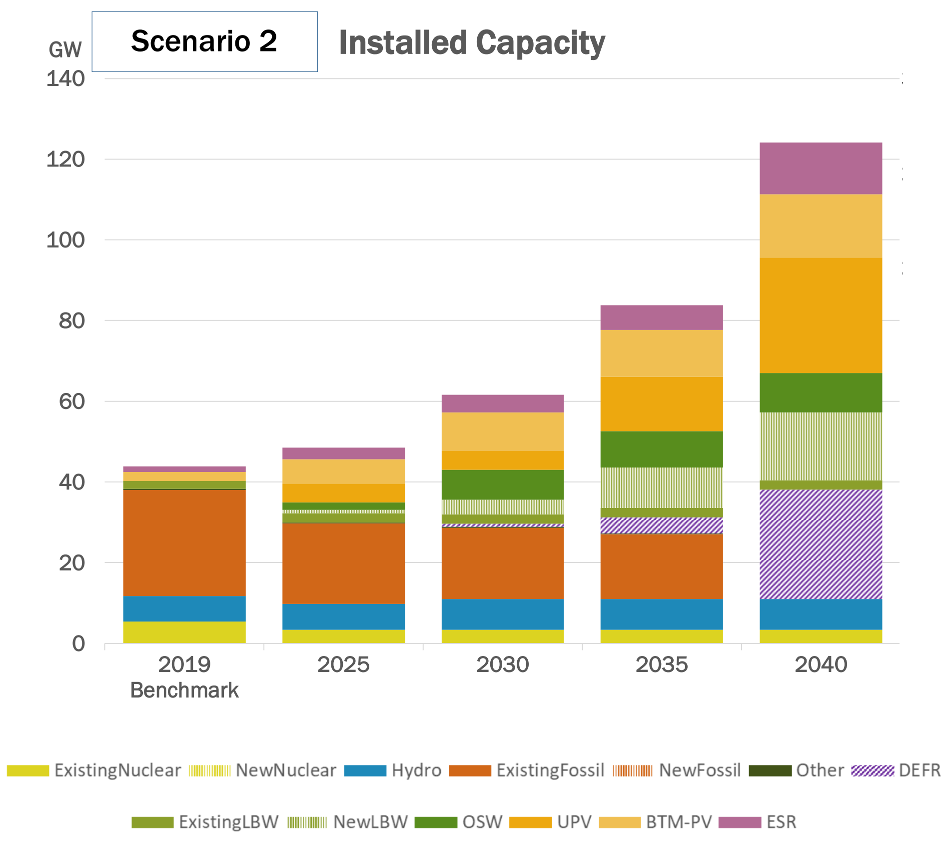
After discussions with stakeholders, including state agencies (DPS and NYSERDA), two distinct scenarios were selected for evaluation as Policy Cases:

- Scenario 1 ("S1") utilizes industry data and NYISO load forecasts, representing a future with high demand (57,144 MW winter peak and 208,679 GWh energy demand in 2040) and assumes less restrictions in renewable generation buildout options.
- Scenario 2 ("S2") utilizes various assumptions consistent with the Climate Action Council Integration Analysis and represents a future with a moderate peak but a higher overall energy demand (42,301 MW winter peak and 235,731 GWh energy demand in 2040).

As shown in the following charts, both scenarios result a blend of land-based wind ("LBW"), offshore wind ("OSW"), utility-scale solar ("UPV"), behind-the-meter solar ("BTM-PV") and energy storage ("ESR") to meet the CLCPA policy targets through 2035. By 2040, all existing fossil generators are forced to retire to achieve the CLCPA target for a zero-emission grid, and the model selects DEFRs as a replacement technology.

**Policy Case Scenario 1 and Scenario 2 Generation Capacity by Type**



Scenario 1 favors land-based wind technologies to meet emission-free targets while Scenario 2 favors a blend of land-based wind and solar. By 2040, Scenario 1 builds approximately 45 GW of DEFR generation capacity while Scenario 2 builds 27 GW. For reference, today's New York fossil fleet totals approximately 26 GW.

The large amount of DEFR capacity in Scenario 1 is a direct result of having a 35% higher peak load forecast than Scenario 2 despite having a 13% lower annual energy demand in 2040. The operational needs of dispatchable generation on the system will become more demanding as the State progresses towards policy goals. The number of dispatchable generator starts/stops, daily ramping, operational range, and other flexibility attributes will increase to meet a more dynamic net-load.

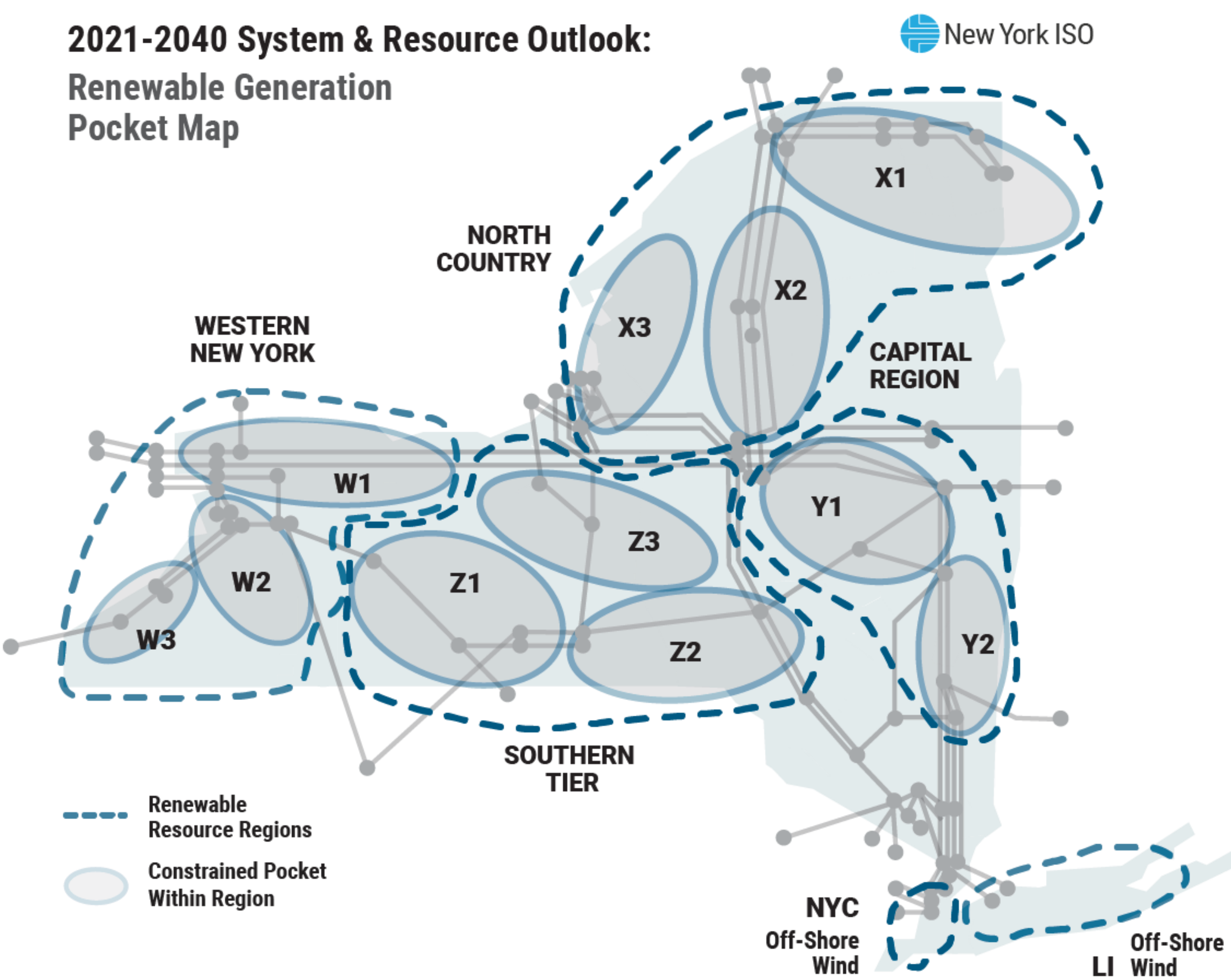
Related to demand forecasts, a secondary but significant driver to both the quantity and type of generation selected by the capacity expansion model are capacity reserve margins. Wind, solar, and energy storage capacity are modeled using declining capacity value curves related to the amount of each technology added to the system. These declining capacity values reflect the limited effectiveness of wind, solar, and storage to meeting the estimated future reserve margin requirements as more of each resource type is added. The reduced values necessitate the addition of DEFR technologies to meet these minimum statewide and locational resource requirements because of their relatively high capacity valuation assumed.

Separately the NYISO analyzed the impact to the resource mix if investments are not made in research, development, and commercialization of dispatchable emission-free resources (DEFRs, such as hydrogen, renewable natural gas, nuclear, etc.). The exclusion of DEFRs as a new technology option, while enforcing the retirement of fossil generators via the zero-emission by 2040 policy, exhausts the amount of land-based wind built and results in the replacement of 45 GW of DEFR capacity in S1 with 30 GW of offshore wind and 40 GW of energy storage. Note that this capacity replacement estimate is not realistic and should only be considered as a directional proxy for information, which is not a substitute for all the attributes provided by either today's fossil fuel-fired fleet or future DEFRs. Further reliability concerns, such as voltage support and dynamic stability, may require other extensive system reinforcements.

### Renewable Generation Pockets: Transmission Challenges and Opportunities

Due to the significant resource additions, new transmission constraints appear across the system as CLCPA achievement approaches in 2040. To better understand the impacts from these new constraints, generation pockets are identified based on their geographical locations. Each pocket depicts a geographic grouping of renewable generators, and transmission constraints in a local area are further highlighted in a sub-pocket. The renewable generation pocket concept originated with the "70 x 30" scenario in the 2019 economic planning study, and a similar framework was used for this Outlook with the addition of the new energy deliverability metric.

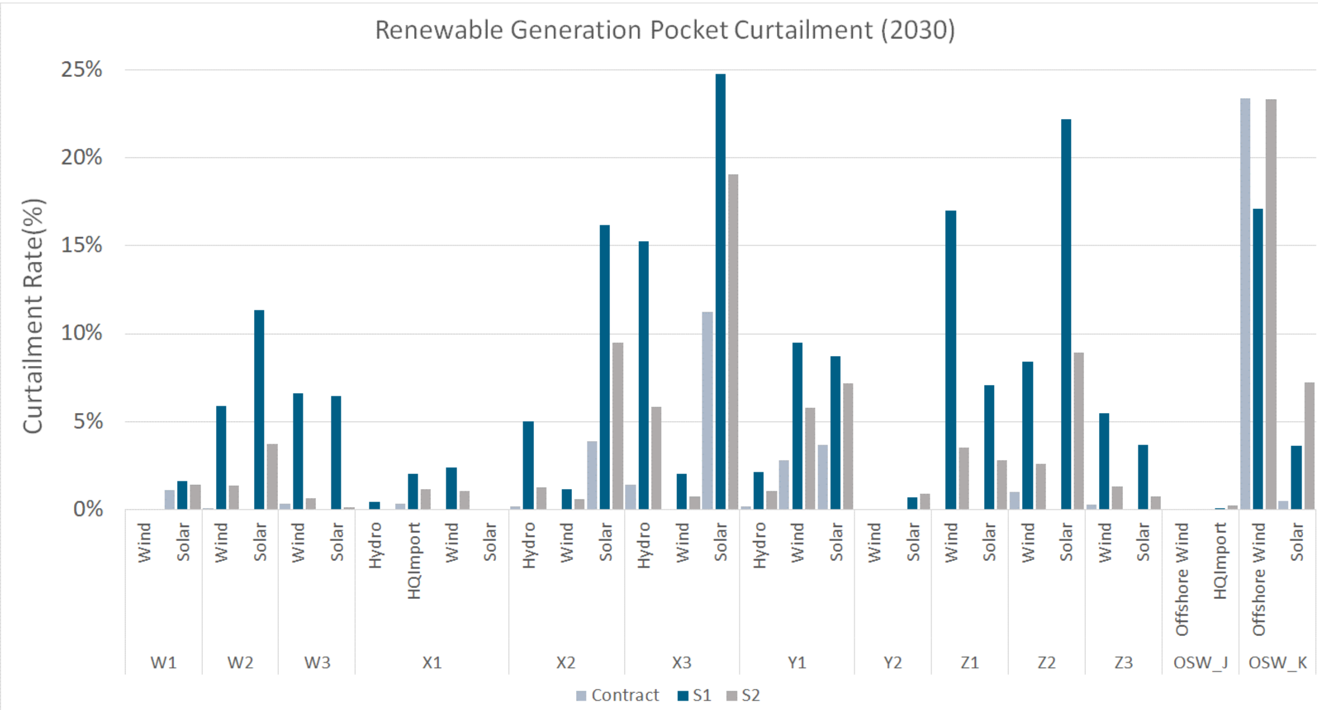
The renewable generation pocket map below was created using renewable energy deliverability results and transmission congestion results from the Contract and Policy cases. The naming conventions and geographic areas for the renewable generation pockets are consistent with those originally identified in 2019, but the transmission constraints and new generation differ.



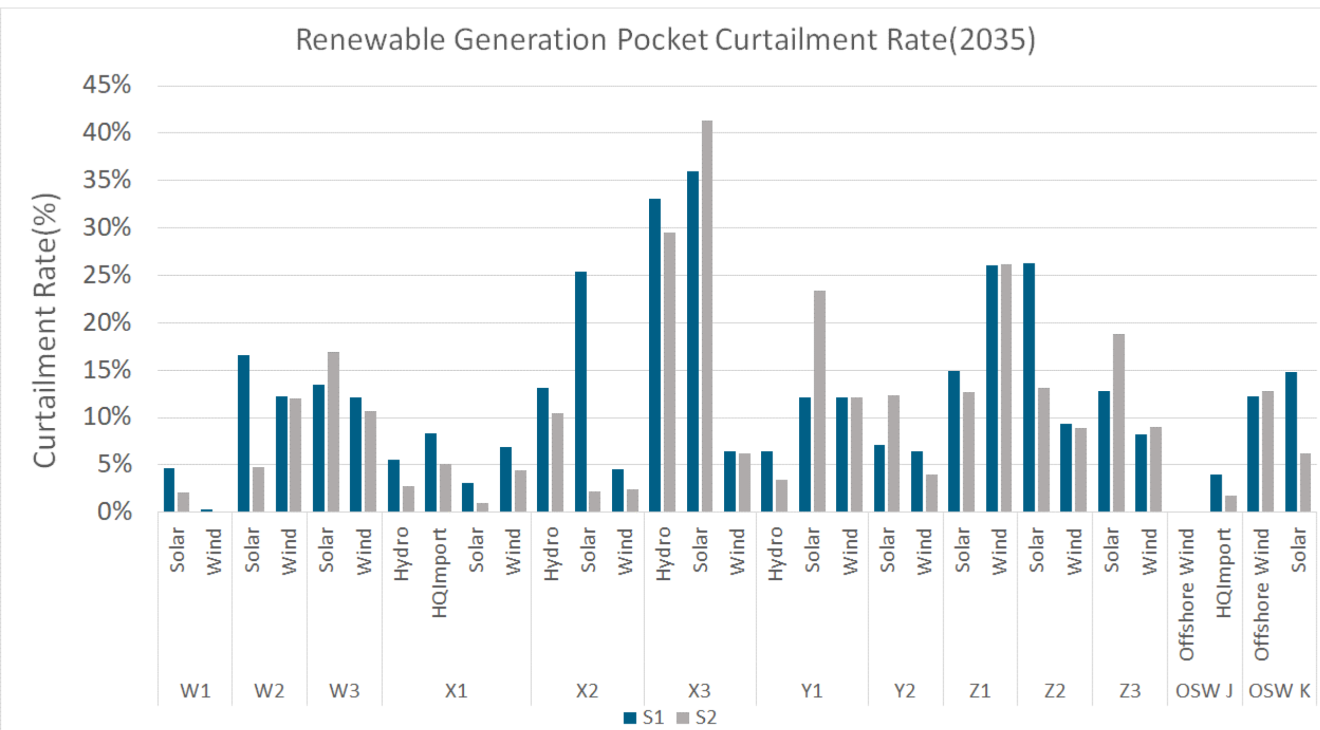

For each renewable generation pocket, the energy deliverability metric was calculated. Energy deliverability represents the ability of renewable generation (wind, solar, and hydro) to inject energy into the grid without curtailment. The following charts highlight the energy deliverability findings in 2030 and

2035. Generally, energy deliverability is reduced as more renewable capacity is added to the system, driven by transmission constraints across the system. The greater the renewable generation curtailment in a given pocket, the greater the opportunity for transmission investment. High curtailment pockets represent transmission needs that must be addressed in order to achieve the public policy targets of the CLCPA.

Curtailment of renewable generation occurs when a transmission line would become overloaded if renewable generation were not dispatched to a lower output level. The decision to curtail a specific renewable generator is dependent upon both electrical location and energy market bids. A second form of renewable generation re-dispatch, termed "spillage," can also occur. Spillage of renewable energy can occur when all relevant dispatchable resources have been set to minimum levels and energy export limits have been reached, which would necessitate a reduction in renewable generation output to balance the system. Spillage conditions are projected to occur as early as 2030 and would be most prevalent during the spring season when electricity demand is low and renewable generator production is high.



Renewable Generation Pocket Curtailment (2030)
Curtailment Rate(%)
25%
20%
15%
10%
5%
0%
Wind
Solar
Hydro
HQImport
Offshore Wind
W1
W2
W3
X1
X2
X3
Y1
Y2
Z1
Z2
Z3
OSW_J
OSW_K
Contract
S1
S2

Renewable Generation Pocket Curtailment Rate(2035)
Curtailment Rate(%)
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
Solar
Wind
Hydro
HQImport
Offshore Wind
W1
W2
W3
X1
X2
X3
Y1
Y2
Z1
Z2
Z3
OSW J
OSW K
S1
S2

### Next Steps

The Outlook has, for the first time, built upon the data, modelling, and studies developed within the NYISO's System & Resource Planning Department and will serve as another building block for continued analyses and study work both within and outside of the NYISO. The data and findings provided by the Outlook can be used by policymakers, investors, and other stakeholders to identify the challenges and opportunities associated with achieving state policies in an economic and reliable manner.

The 2022 Reliability Needs Assessment will leverage data from the Outlook to identify commitment and dispatch trends as policy goals are approached. The 2022 Grid in Transition study being performed by the NYISO Market Structures Department will leverage data from the Outlook to continue analysis surrounding potential market needs and designs for the future grid.

### Recommendations

The important findings identified in the 2021-2040 System & Resource Outlook bring forth several recommendations to face the challenges investigated in the study. The recommendations are:

- This Outlook identifies many transmission needs expected to arise over the next 20 years driven by public policy requirements. The 2022-2023 Public Policy Transmission Planning cycle kicks off on August 1, at which time the NYISO will provide an opportunity for any stakeholders or interested parties to submit comments regarding proposed transmission needs that may be driven by public policy requirements and for which transmission solutions should be requested and evaluated. Interested parties should consider the key findings from the Outlook when submitting comments for consideration by the New York State Public Service Commission.
- The Transmission Owners should continue to consider the transmission and distribution constraints identified in the Outlook when planning for local system expansion in their respective transmission districts.
- Future uncertainty is the only thing certain about the electric power industry. From policy advancements to new dispatchable emissions-free resource technology development, the system is set to change at a rapid pace. Situational awareness of system changes and continuous assessment are critical to ensure a reliable and lower-emissions grid for New York. The Economic Planning databases and models will be continually updated with new information and the Outlook study will be improved and performed on a biennial basis.

* The challenges identified in the Outlook cannot be solved by any single entity. Communication and collaboration between stakeholders are essential to making progress towards achieving policy objectives while maintaining an efficient power market and reliable power grid.

# State of NYISO System & Resource Planning

The System & Resource Outlook ("The Outlook") represents the primary economic planning report and database developed by the NYISO. The Outlook provides a comprehensive overview of the potential system resource development and transmission constraints throughout New York, and highlights opportunities for transmission investment driven by economics and public policy. The Outlook is developed through the Economic Planning Process, which is part of the NYISO's Comprehensive System Planning Process ("CSPP"). Through the CSPP, numerous assessments, evaluations, and plans are developed and relied upon by the NYISO to conduct transmission system planning processes, including the following: demand forecast & analysis, Short-Term Reliability Process, Reliability Planning Process, Public Policy Transmission Planning Process, interregional planning, and Interconnection Studies.

## Demand Forecast & Analysis

The NYISO published the *2022 Load & Capacity Data Report ("Gold Book")*[2] on April 28, 2022. This report presents the NYISO load and capacity data for 2022 and future years, including historic and future energy and peak forecasts through 2052, existing and proposed generating capacity projected through 2032, and existing and proposed transmission facilities. Three load forecasts are produced, specifically the baseline forecast, the high load scenario, and the low load scenario. The two scenarios differ from the baseline forecast in assumptions on adoption of electric vehicles, building electrification, behind-the-meter solar (BTM-PV), and energy efficiency programs. Over a 30-year horizon, the NYCA baseline energy and summer peak demand forecast growth rates both increased compared to 2021, as shown in the following table:

**Figure 1: Gold Book Average Annual NYCA Baseline Energy and Summer Peak Demand Growth Rates**

| | Average Annual Growth Rates | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Baseline Energy Usage | | | | Baseline Summer Peak Demand | | | |
| | Years 1-30 | Years 1-10 | Years 11-20 | Years 21-30 | Years 1-30 | Years 1-10 | Years 11-20 | Years 21-30 |
| 2021 Gold Book (2021-51) | 0.96% | -0.28% | 1.15% | 1.88% | 0.20% | -0.24% | 0.44% | 0.39% |
| 2022 Gold Book (2022-52) | 1.04% | 0.22% | 2.25% | 0.49% | 0.39% | 0.14% | 0.68% | 0.32% |

Peak load and energy demand remains stable over the first decade of the forecast, as energy efficiency

[2] https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/

and BTM-PV installations offset expected econometric load growth. Demand increases in the latter decades as increased adoption of electrification end uses in the building and transportation sector more than offset continued load reductions from energy efficiency and BTM-PV. Due to these forecasted changes, the NYCA system is expected to transition from a summer to a winter peaking system, driven principally by electrification of space heating, in the mid-2030s. The actual loads experienced by the electric system will depend on assumptions related to load flexibility and adoption rates of electrification across scenarios. **Figure 1**

Total generation resource capability in NYCA for the summer of 2022 is projected to be 41,060 MW, which is a decrease of 11 MW compared to the information provided for summer 2021 in the 2021 *Gold Book*. This total includes 37,431 MW of NYCA generating capability, 1,164 MW of Special Case Resource ("SCR"), and 2,465 MW of net long-term purchases and sales with neighboring control areas. The NYCA generating capability includes 6,470 MW of renewable resources, including 4,274 MW of hydro, 1,818 MW of wind, 52 MW of large-scale solar PV, and 326 MW of other renewable resources. Since the publication of the 2021 *Gold Book* in April 2021, there has been a reduction of 1,091 megawatts (MW) of summer capability that has been deactivated. Over the same period, there has been an increase of 33 MW in summer capability due to new additions and uprates, and a decrease of 92 MW of summer capability due to ratings changes. As a result, net summer capability as of March 15, 2022 is 37,520 MW, a decrease of 1,150 MW. The NYCA generating capability for summer 2022 is projected to be 359 MW lower than the capability reported for summer 2021 in the 2021 *Gold Book*. Additionally, the *Gold Book* reports on proposed generation, which includes 10,158 MW of wind, 7,109 MW of grid-connected solar, 4,302 MW of energy storage, and 3,262 MW of natural gas or dual-fuel projects.

### Transmission Additions.

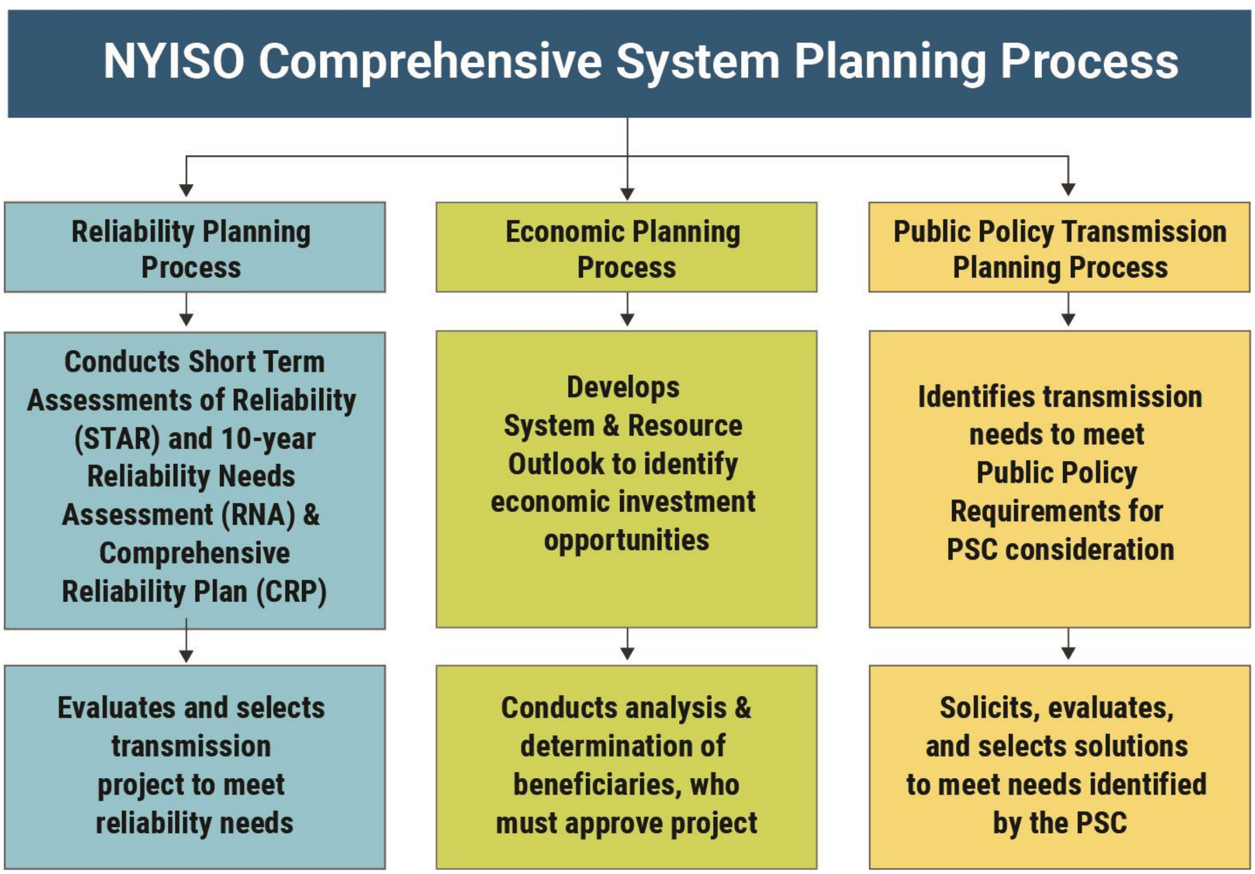
The 2022 *Gold Book* also reports on proposed transmission facilities. Transmission additions include the Smart Path Connect Project, a priority transmission project approved by the New York Public Service Commission ("NYPSC") under New York's Accelerated Renewable Energy Growth and Community Benefit Act. Three public policy transmission projects have been added, as selected by the NYISO Board of Directors: Western New York (Empire State Line by NextEra Energy Transmission New York, Inc.), AC Transmission Segment A (Segment A Double Circuit by LS Power Grid New York, LLC and NYPA), and AC Transmission Segment B (Segment B Knickerbocker-PV by National Grid and New York Transco). The selected developers have received siting approval of their transmission facilities from the NYPSC under Article VII of the Public Service Law, and all selected projects have commenced construction.

## Comprehensive System Planning Process

Understanding the impacts to the generation, transmission, and load components of the bulk electric system is critical to understanding the challenges to reliable electric service in the coming years. The NYISO is evolving its CSPP to match the pace of change on the grid while continuing to find needs and opportunities for investment to promote reliable and efficient operations.

The CSPP establishes the rules by which the NYISO solicits, evaluates, and selects the more efficient or cost-effective solutions to address reliability, economic, and public policy-driven transmission needs in New York. The NYISO's CSPP has four components—the Local Transmission Planning Process, the Reliability Planning Process/Short-Term Reliability Process, the Economic Planning Process, and the Public Policy Transmission Planning Process. In concert with these four components, interregional planning is conducted with the NYISO's neighboring control areas in the United States and Canada under the Northeastern ISO/RTO Planning Coordination Protocol.

**Figure 2: NYISO Comprehensive System Planning Process**




**Reliability Planning Process**

The Reliability Planning Process is composed of four components:

1. Each transmission owner conducts a public Local Transmission Planning Process for its transmission district that feeds into statewide planning;
2. The quarterly Short-Term Assessments of Reliability (STARs) address near-term needs, with a focus on needs arising in the next three years. The Short-Term Reliability Process includes assessing the potential for reliability needs arising from proposed generator deactivations;
3. The Reliability Needs Assessment (RNA) focuses on longer-term reliability needs for years four through ten of a ten-year, forward looking study period; and
4. The Comprehensive Reliability Plan (CRP) integrates all of the planning studies into a ten-year reliability for New York.

Together, these processes enable the NYISO to nimbly identify reliability needs ranging from localized needs to broader statewide needs arising over the next decade.

The 2021-2030 Comprehensive Reliability Plan (CRP)[3] completed the NYISO's 2020-2021 cycle of the Reliability Planning Process. The 2020 Reliability Needs Assessment (RNA)[4], approved by the NYISO Board of Directors in November 2020, was the first step of the NYISO's 2020-2021 Reliability Planning Process. The CRP followed the 2020 RNA and post-RNA updates and incorporates findings and solutions from the quarterly Short-Term Reliability Process. The study concluded that the New York State Bulk Power Transmission Facilities as planned will meet all currently applicable reliability criteria from 2021 through 2030 for forecasted system demand in normal weather. Some risk factors to system reliability are noted, namely tightening reserve margins due to additional loss of generation, any delays in planned transmission projects, and extreme weather events such as heatwaves or storms.

The CRP also notes that the mandates in New York's Climate Leadership and Community Protection Act ("CLCPA") of 70% of electricity from renewable resources by 2030 and zero-emissions electricity by 2040 marks significant changes to the electric system, and that understanding the impacts of these mandates is critical to understanding the challenges of maintaining system reliability. Transmission will play a key role in moving energy from the renewable resources to the load centers. Several transmission projects have been approved across upstate to accommodate delivery of renewable energy from northern New York. The NYISO is currently evaluating transmission solutions to address the NYSPSC-identified

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[3] https://www.nyiso.com/documents/20142/2248481/2021-2030-Comprehensive-Reliability-Plan.pdf/

[4] https://www.nyiso.com/documents/20142/2248793/2020-RNAReport-Nov2020.pdf

need for facilities to deliver power from offshore wind. Even with the potential benefits provided by these bulk system projects, several renewable generation pockets across the state are projected to persist, which could constrain output from renewable resources, including production from offshore wind. As the level of renewable resource generation increases, the grid will need sufficient flexible and dispatchable resources to balance variations in wind and solar output. The integration of batteries will help store energy for later use on the grid, which will aid with the short duration and daily cycles of reduced renewable resource output.

Looking ahead to 2040, the policy for a zero-emissions electric system will also require the development of new technologies to maintain the supply demand balance. Substantial dispatchable emission-free resources (DEFR) will be required to fully replace fossil fuel-fired generation, which currently serves as the primary balancing resource. Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the objectives of the CLCPA. Resources with this combination of attributes are not commercially available at this time but will be critical to future grid reliability.

#### Public Policy Transmission Planning Process

The Public Policy Transmission Planning Process (PPTPP) is a two-year process performed in parallel with the RNA and the CRP. It occurs in two phases: Phase I, Identify Needs and Assess Solutions; and Phase II, Transmission Evaluation and Selection. In Phase I, the NYISO solicits transmission needs driven by Public Policy Requirements, and the NYSPSC identifies transmission needs and defines additional evaluation criteria. The NYISO then holds a Technical Conference and solicits solutions to address the identified needs. Lastly, the NYISO performs the Viability and Sufficiency Assessment (VSA) on those solutions. In Phase II, the NYISO evaluates the viable and sufficient transmission solutions and recommends the more efficient or cost-effective solution. Thereafter, the NYISO Board may select a transmission solution for purposes of cost allocation and recovery under the NYISO Tariff.

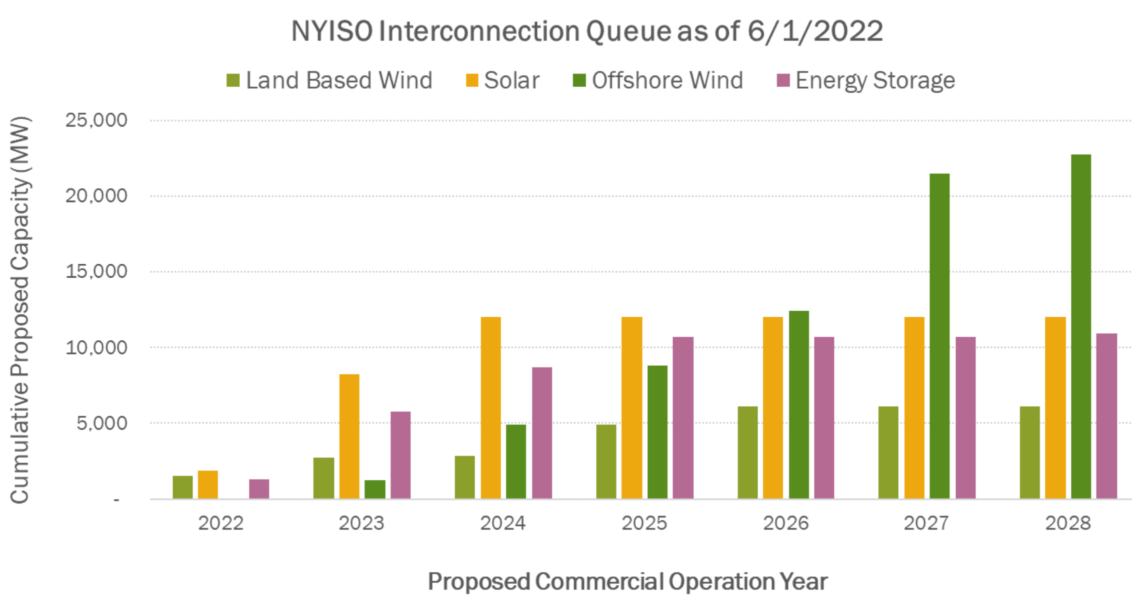
In August 2020, the NYISO solicited transmission needs and received 15 proposals for transmission needs driven by Public Policy Requirements, including the CLCPA and the Accelerated Renewable Growth and Community Benefit Act, and submitted those proposals to the NYSPSC. Eleven of those proposals, associated with the development of transmission in support of offshore wind generation, were also submitted to the Long Island Power Authority for consideration. In its comments to the NYSPSC, the NYISO expressed its support for declaration of Public Policy Transmission Needs to deliver renewable energy to consumers from upstate generation pockets, offshore wind facilities connected to Long Island, and offshore wind facilities connected to New York City.

In March 2021, the NYSPSC issued an order declaring that offshore wind goals are driving the need for additional transmission facilities to deliver that renewable power from Long Island to the rest of New York State. The NYSPSC referred the identified need to the NYISO to solicit potential solutions. Nineteen projects were proposed by four developers, sixteen of which were found to be Viable and Sufficient. The Evaluation and Selection phase for these projects is ongoing.

### Interconnection Studies

The NYISO's Interconnection processes[5] are crucial to facilitating the development and interconnection of proposed generation, transmission, and load facilities to the NYCA system. The interconnection planning process supports grid reliability in that it identifies potential adverse impacts due to proposed interconnection projects, and requires coordination between the NYISO, developers, and associated transmission owners throughout the process. These ongoing processes are necessary to accommodate the significant portfolio of new projects that developers are proposing to interconnect to the grid in response to state policies. Of note, a significant portion of the new projects are renewable energy and energy storage resources, as shown below in Figure 3 to help address these policies.

**Figure 3: Proposed Renewable Energy Capacity in the NYISO Interconnection Queue**




Similar to other NYISO Planning Studies, the NYISO's Interconnection planning process is key to the

5 https://www.nyiso.com/interconnections

generation and load assumptions in the 2021-2040 System and Resource Outlook study. As it pertains to the Outlook study, the NYISO's Interconnection Queue was used as a reference in each of the three cases, Baseline, Contract, and Policy Cases, for purposes of generation placement in the NYCA. The Baseline and Contract Cases include proposed generation and load projects based on the NYISO's Interconnection Queue, as determined using inclusion rules for each case. Specific to the Policy Case, projects proposed in the Interconnection Queue were informative in guiding the process of translating the generation expansion results from the capacity expansion model at a zonal level into discrete generators at the nodal level in production cost modeling. Additional information on the generator placement process for the Policy Case is included in [section placeholder].

## System & Resource Outlook Overview

In 2020, the NYISO undertook a comprehensive review of its Economic Planning Process to determine how the studies, tools, and metrics in that process could be enhanced. The impetus for the review arose, in part, from the rapidly shifting resource landscape toward renewable resources driven by the CLCPA and other state clean energy policies. This changing landscape led the NYISO to engage stakeholders to examine how the NYISO's Economic Planning studies could be enhanced to identify the most economic and efficient locations for the construction of renewable resources, the transmission needed to deliver energy to consumers from onshore and offshore renewable resources, and the impact of the renewable resources on the transmission system. The enhancements developed extend the study outlook to 20 years and broaden the benefits considered in evaluating potential projects to address congestion, such as the deliverability of energy output from new renewable resources and capacity cost savings associated with transmission expansion. These enhancements were approved by stakeholders and were accepted by FERC in April 2021.

For the first time, the NYISO has compiled this 20-year System & Resource Outlook. The Outlook provides a comprehensive overview of system resources and transmission constraints throughout New York, highlighting opportunities for transmission investment driven by economics and public policy. Together, the Comprehensive Reliability Plan and the System & Resource Outlook provide a full power system outlook to stakeholders, developers, and policymakers.

The Outlook provides a wide range of potential future system conditions and enables comparisons between possible pathways to an increasingly lower emissions resource mix. By forecasting transmission congestion, the NYISO will:

- Identify regions of New York where renewable generation may be heavily curtailed due to transmission constraints;
- Quantify the extent to which these constraints limit delivery of renewable energy to consumers; and identify potential transmission opportunities that may provide economic and/or operational benefits.

This new Outlook process provides transmission developers and resources the ability to request their own studies using the NYISO tools to identify the most economic opportunities for investment. Moreover, if a developer proposes a regulated transmission project to address constraints identified in the Economic Planning Process, the NYISO will perform an evaluation of the proposed project. Load serving entities ("LSEs") identified by the NYISO as the project beneficiaries must approve the selection of a proposed regulated transmission project by a super-majority vote. If a project is approved, it is eligible for cost allocation and recovery through the NYISO tariffs.

In the Outlook, the system is evaluated under various future system conditions and resource buildouts to provide multiple potential future outcomes for analysis. Unlike previous Economic Planning studies, which only evaluated a single base case, the Outlook evaluates three reference cases. The development of each of the reference cases leverages NYISO's expertise in power system data and modeling as well as consistent and meaningful engagement with stakeholders.

The three reference cases are:

**Baseline Case -** The Baseline Case is a "business-as-usual" type scenario that aligns with the Reliability Planning Process to define the demand, generation, and transmission assumptions. Strict inclusion rules limit the amount of new projects that are assumed in this case and generic future generation is added to meet reliability requirements through 2030, if needed. The Baseline utilizes the demand and energy forecasts from the 2021 NYISO Load & Capacity Data Report ("Gold Book").

**Contract Case -** This case builds upon the Baseline Case by adding incremental renewable generation projects that have obtained financial contracts with the state (e.g., NYSERDA Renewable Energy Credit ("REC") contracts) and thus have a higher likelihood of completion, even though they do not yet meet Baseline Case inclusion rules. Incremental projects may include both those within New York and within the neighboring regions.

**Policy Case -** Assumptions in the Policy case reflect the federal, state, and local policies that impact the New York power system. Examples of policies modeled in this case include the "70 by 30" renewable mandate and the 2040 zero-emissions directive. This system representation will also be utilized as part of the Public Policy Process, including evaluation of the Long Island offshore wind export Public Policy Transmission Need.

The suite of analyses in the Outlook provides a wide range of potential future system conditions and afford the ability to compare possible pathways to the future resource mix. Through the projection of future transmission congestion utilizing complex hourly production cost simulations, the NYISO will: (1) identify regions of New York where renewable generation "pockets" are expected to form, (2) quantify the extent to which those pockets limit delivery of renewable energy to consumers, and (3) present information for stakeholders to identify potential transmission opportunities that may provide economic and operational benefits. In addition, the NYISO will utilize the simulations to investigate and assess future system performance including ramping, reserves, and cycling of conventional thermal generators. This will in turn inform reliability studies, including the 2022 Reliability Needs Assessment.

# Baseline Case Findings

### Key Assumptions Review

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 2021 Outlook Study Period aligns with the ten-year planning horizon for the 2021-2030 Comprehensive Reliability Plan with an additional ten years to 2040, and study assumptions are based on any updates that met the NYISO's inclusion rules as of the lock-down date for data inputs into the Outlook. The NYISO chose the August 1, 2021 lock-down date because it aligns with the most recent reliability case lockdown date for the 2021 Comprehensive Reliability Plan.

The Outlook Baseline 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.[6] Appendix placeholder includes a detailed description of the assumptions utilized in the Outlook analysis.

The key assumptions for the Baseline Case are:

- The load and capacity forecasts are updated using the 2021 Load and Capacity Data Report ("Gold Book") Baseline forecast for energy and peak demand by Zone for the 20-year Study Period. New resources and changes in resource capacity ratings were incorporated based on the Reliability Needs Assessment inclusion rules.
- The power flow case uses the 2021 Reliability Planning Process (RPP) case as the starting point and is updated with the latest information from the 2021 Gold Book.
- 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 the 2021 RPP case.
- 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 allowance price forecasts 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 based on a

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

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

**Figure 4: Major Model Inputs and Changes**

| Major Modeling Inputs | |
|---|---|
| **Input Parameter** | **Change from 2019 CARIS 1** |
| **Load Forecast** | comparable |
| | Modeled Large Loads from the 2021 Load and Capacity Data Report |
| **Natural Gas Price Forecast** | higher |
| **$CO_2$ Price Forecast** | higher |
| **$NO_x$ Price Forecast** | Annual $NO_X$ lower, Ozone $NO_X$ high in earlier years and lower in later years |
| **$SO_2$ Price Forecast** | same |
| **Hurdle Rates** | PJM lower, MISO higher |
| **Modeling Changes** | |
| **MAPS Software Upgrades** | GE MAPS Version 14.400.1404 was used for production cost simulation |
| **PJM/NYISO JOA** | same |
| **NY Transmission Upgrades** | LTP Updates on Con Edison 345/138 kV PAR controlled feeder lines in NY city. |
| | STRP solution for addressing 2023 short-term need |
| | SR in-service on following 345 kV cables: 71, 72, M51, M52 |
| | Bypassing the SR on the following 345 kV cables: 41, 42, Y49 |

**Figure 5: Timeline of Major NYCA Modeling Changes**

| Year | Year-to-year Modeling Changes |
|---|---|
| 2021 | Janis Solar, 20 MW, in service 7/1/2021 |
| | Cassadaga Wind, 126.5 MW, in service: 7/6/2021 |
| | Puckett Solar, 20 MW, in service 8/1/2021 |
| | Tayandenega Solar, 20 MW, in service: 9/1/2021 |
| | Albany County 1 Solar, 20 MW, in service: 11/1/2021 |
| | Albany County 2 Solar, 20 MW, in service: 11/1/2021 |
| | Greene County 1 Solar, 20 MW, in service: 11/1/2021 |
| | Greene County 2 Solar, 10 MW, in service: 11/1/2021 |
| | North Country Solar, 15 MW, in service: 11/1/2021 |
| | Pattersonville Solar, 20 MW, in service: 11/1/2021 |
| | Grissom Solar, 20 MW, in service: 12/1/2021 |
| | Darby Solar, 20 MW, in service: 11/1/2021 |
| | Branscomb Solar, 20 MW, in service: 11/1/2021 |
| | ELP Stillwater Solar, 20 MW, in service: 11/1/2021 |
| | Regan Solar, 20 MW, in service: 12/1/2021 |
| | Rock District Solar, 20 MW, in service: 12/1/2021 |
| | Roaring Brook Wind, 79.7 MW, in service: 12/1/2021 |
| 2022 | WNY Stamp Load, in service 1/1/2022 |
| | Greenidge Load, in service 1/1/2022 |
| | Somerset Load, in service 1/1/2022 |
| | Cayuga Load, in service 1/1/2022 |
| | NCDC Load, in service 1/1/2022 |
| | Skyline Solar, 20 MW, in service 3/1/2022 |
| | Dog Corners Solar, 20 MW, in service 5/1/2022 |
| | Sky High Solar, 20 MW, in service 8/1/2022 |
| | Eight Point Wind Energy, 101.8 MW, in service 9/1/2022 |
| | Number 3 Wind Energy, 103.9 MW, in service 9/1/2022 |
| | Martin Solar, 20 MW, in service 10/1/2022 |
| | Bakerstrand Solar, 20 MW, in service 10/1/2022 |
| | Scipio Solar, 18 MW, in service 12/1/2022 |
| | Niagara Solar, 20 MW, in service 12/1/2022 |
| | Ball Hill Wind, 100 MW, in service 12/1/2022 |
| 2023 | Watkins Road Solar, 20 MW, in service 6/1/2023 |
| | Baron Winds, 238.4 MW, in service 7/1/2023 |
| 2024 | Athens SPS retired on 1/2024 |

### Simulation Results

This section presents summary level results for the Outlook Baseline Case. Study results are described in more detail in Appendix placeholder.

#### Generation

**Figure 6: Projected NYCA Generation by Zone**

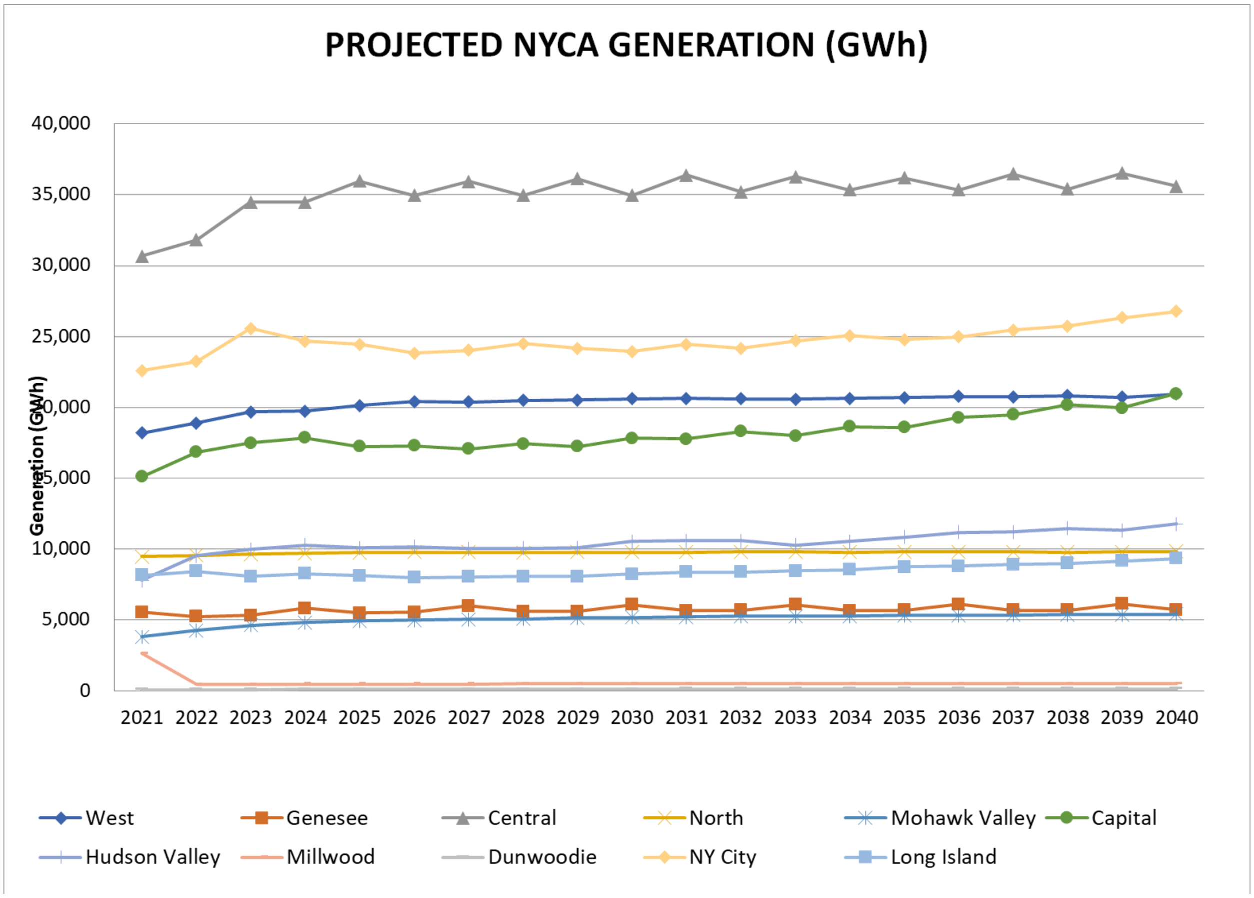
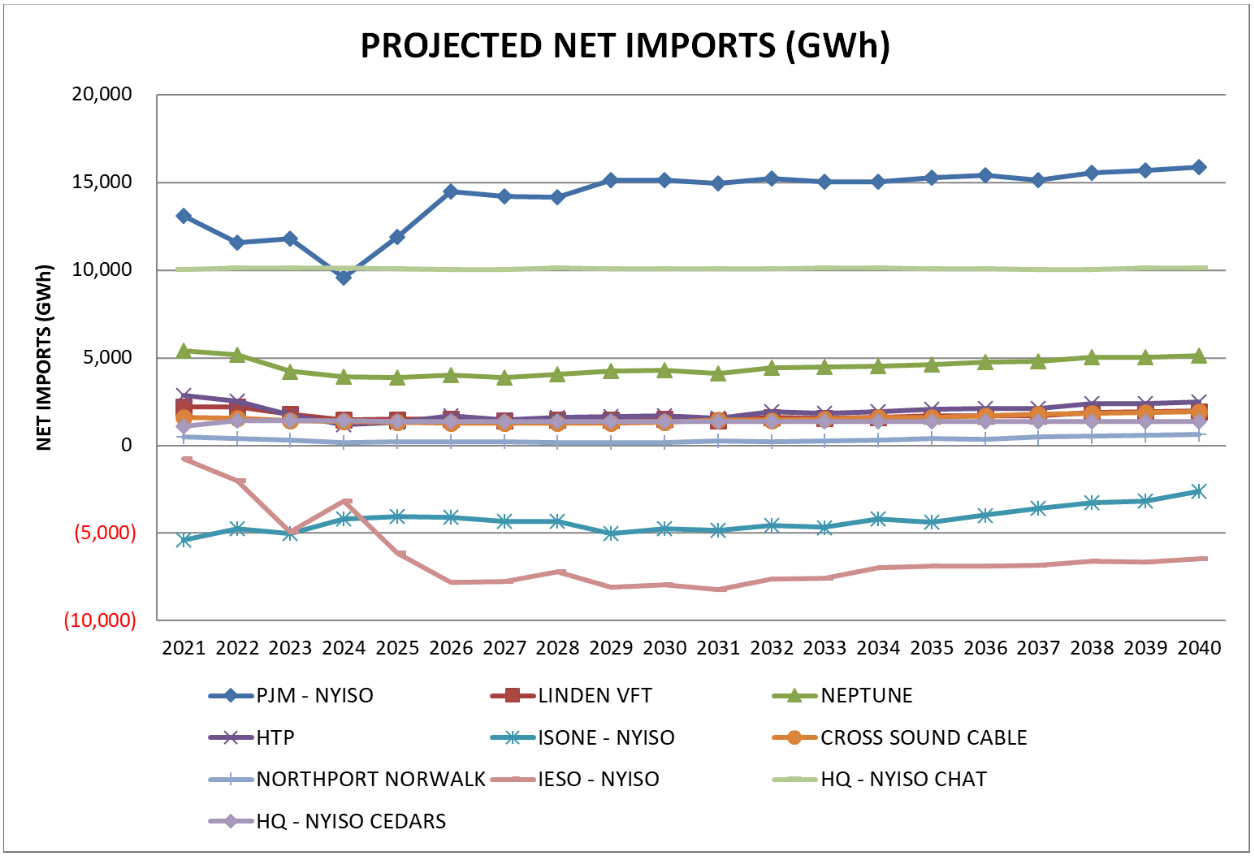



Figure 6 shows the projection of annual generation by NYCA zone over the study period. Generation is largely flat in the Baseline Case, with Millwood (Zone H) generation sharply decreasing after the retirement of Indian Point and Zone C and Zone F generation subsequently increasing. Intra year variations in Central (Zone C) generation can be explained by nuclear unit maintenance scheduled in the MAPS database. New York City (Zone J) generation also declines after 2023 with the addition of AC Transmission.

### Net Imports

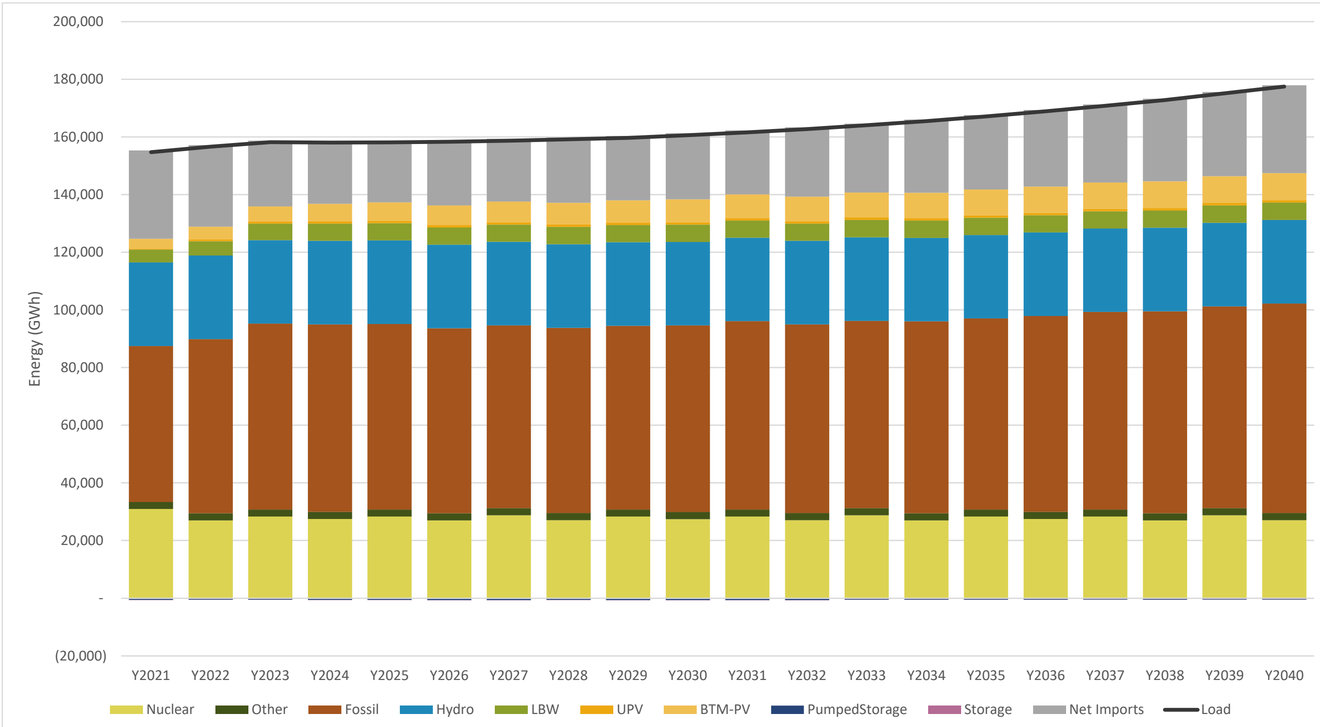
**Figure 7: Projected Net Imports by Interface**




7 shows the projection of net imports on each interface for the Baseline Case. Net imports from Ontario decline with the retirement of the Pickering nuclear power plant in 2024 and 2025 and the refurbishment of the Darlington and Bruce nuclear power plants throughout the study period. Net imports from PJM increase in response to this refurbishment schedule. Across the other interfaces, net imports are largely flat through the study period.

Figure 8 shows the annual projection of generation by unit type, along with the forecast of net imports and load.

**Figure 8: Baseline Case NYCA Generation and Net Imports (GWh)**




### Congestion Assessment

The Outlook includes the development of a twenty-year projection of future Demand$ Congestion costs. This projection is combined with the past five years of historic congestion to identify 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, New York. 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 are based on actual market operation and have been conducted at the NYISO since 2005 with metrics and procedures developed in consultation with stakeholders. 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 in 2018, followed by Tariff changes in Appendix A of Attachment Y to the OATT, only the following historic Day-Ahead Market congestion-related data were 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 the Outlook as "demand$ congestion" by constraint). The results of the historic congestion analyses are posted on the NYISO website.[7]

Historic congestion costs by Zone, expressed as Demand$ Congestion, are presented in Figure 9, indicating that the highest congestion occurred in New York City and Long Island.

**Figure 9: Historic Demand$ Congestion by Zone 2016-2020 (nominal $M)**[8]

| Zone | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| **West** | $116 | $63 | $65 | $88 | $49 |
| **Genesee** | $7 | $12 | $10 | $2 | $5 |
| **Central** | $29 | $40 | $37 | $24 | $17 |
| **North** | $7 | $6 | $15 | $6 | $10 |
| **Mohawk Valley** | $7 | $10 | $7 | $5 | $3 |
| **Capital** | $95 | $90 | $80 | $70 | $55 |
| **Hudson Valley** | $64 | $66 | $50 | $44 | $33 |
| **Millwood** | $19 | $21 | $16 | $13 | $11 |
| **Dunwoodie** | $41 | $44 | $34 | $30 | $21 |
| **New York City** | $378 | $443 | $405 | $320 | $200 |
| **Long Island** | $339 | $287 | $303 | $220 | $242 |
| **NYCA Total** | **$1,102** | **$1,082** | **$1,024** | **$823** | **$644** |

Figure 10 below ranks historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2016 to 2020. The top congested paths are shown below.

7 For more information on the historical results below see: https://www.nyiso.com/ny-power-system-information-outlook

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

**Figure 10: Historic Demand$ Congestion by Constrained Paths 2016-2020 (nominal $M)**

| Demand Congestion (Nominal $M) | Historic | | | | | Total |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | |
| CENTRAL EAST | 641 | 598 | 540 | 516 | 402 | 2,696 |
| DUNWOODIE TO LONG ISLAND | 164 | 88 | 133 | 82 | 98 | 565 |
| EDIC MARCY | 32 | 125 | 107 | 4 | 2 | 270 |
| LEEDS PLEASANT VALLEY | 63 | 101 | 9 | 20 | 1 | 195 |
| GREENWOOD | 31 | 18 | 62 | 25 | 22 | 159 |
| PACKARD HUNTLEY | 54 | 30 | 41 | 9 | 3 | 136 |
| DUNWOODIE MOTTHAVEN | 2 | 30 | 65 | 28 | 4 | 129 |
| CHESTR-SHOEMAKR_138 | - | - | - | 19 | 10 | 30 |
| UPNY-ConEd | - | 4 | - | 0 | 3 | 8 |
| VOLNEY SCRIBA | 0 | 1 | 1 | 3 | 1 | 6 |

#### Projected Future Congestion

Future congestion for the Baseline Case study period was determined from a MAPS software simulation. As reported in the "Historic Congestion" section above, congestion is reported as Demand$ Congestion. MAPS software simulations are highly dependent upon many long-term assumptions, each of which affects the study results. The MAPS software utilizes the input assumptions listed in Appendix placeholder.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant assumptions not included in projected congestion costs using MAPS software including: (a) virtual bidding; (b) transmission outages; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments; (f) co-optimization with ancillary services, and (g) real-time events and forecast uncertainty. As in prior Economic Planning Process cycles, the projected congestion is less severe than historic levels due to the factors cited.

Figure 11 presents the projected congestion from 2021 through 2040 by load zone. Year-to-year changes in congestion reflect changes in the model, which are discussed in the "Baseline System Assumptions" section above.

**Figure 11: Projection of Future Demand$ Congestion 2021-2040 by Zone for Baseline Case (nominal $M)**

| Demand Congestion ($M) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| West | $33 | $14 | $6 | $3 | $3 | $6 | $6 | $10 | $13 | $15 |
| Genesee | $16 | $8 | $3 | $2 | $2 | $3 | $3 | $5 | $6 | $6 |
| Central | $51 | $42 | $26 | $25 | $32 | $42 | $40 | $45 | $48 | $47 |
| North | $3 | $2 | $0 | $0 | $1 | $0 | $1 | $1 | $1 | $1 |
| Mohawk Valley | $12 | $6 | $2 | $0 | $1 | $1 | $1 | $1 | $1 | $0 |
| Capital | $96 | $45 | $19 | $13 | $4 | $2 | $2 | $3 | $1 | $1 |
| Hudson Valley | $51 | $22 | $11 | $0 | $4 | $7 | $6 | $7 | $8 | $9 |
| Millwood | $16 | $7 | $3 | $1 | $1 | $2 | $2 | $2 | $2 | $2 |
| Dunwoodie | $30 | $14 | $7 | $2 | $2 | $3 | $3 | $3 | $4 | $4 |
| NY City | $266 | $129 | $66 | $21 | $9 | $20 | $19 | $20 | $25 | $26 |
| Long Island | $246 | $153 | $94 | $58 | $44 | $37 | $36 | $34 | $39 | $45 |
| NYCA Total | $819 | $442 | $238 | $125 | $103 | $122 | $119 | $130 | $148 | $157 |

| Demand Congestion ($M) | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|
| West | $17 | $20 | $21 | $21 | $24 | $32 | $32 | $39 | $39 | $42 |
| Genesee | $7 | $8 | $9 | $9 | $10 | $13 | $14 | $16 | $17 | $19 |
| Central | $49 | $48 | $51 | $49 | $51 | $55 | $62 | $63 | $69 | $74 |
| North | $0 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $3 |
| Mohawk Valley | $2 | $3 | $1 | $1 | $1 | $2 | $3 | $3 | $3 | $3 |
| Capital | $1 | $0 | $3 | $6 | $2 | $1 | $4 | $2 | $2 | $1 |
| Hudson Valley | $8 | $10 | $10 | $9 | $10 | $13 | $14 | $15 | $16 | $19 |
| Millwood | $2 | $3 | $3 | $2 | $2 | $3 | $3 | $3 | $3 | $3 |
| Dunwoodie | $4 | $5 | $5 | $4 | $5 | $7 | $5 | $6 | $7 | $7 |
| NY City | $22 | $30 | $32 | $25 | $26 | $40 | $24 | $39 | $42 | $24 |
| Long Island | $58 | $58 | $71 | $82 | $100 | $89 | $109 | $119 | $141 | $150 |
| NYCA Total | $172 | $188 | $209 | $209 | $234 | $256 | $270 | $308 | $341 | $345 |

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 12.

**Figure 12: Projection of Future Demand$ Congestion 2021-2040 by Constrained Path for Baseline Case (nominal $M)**

| Demand Congestion ($M) | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|
| CENTRAL EAST | $609 | $286 | $122 | $25 | $4 | $1 | $1 | $4 | $1 | $2 |
| DUNWOODIE TO LONG ISLAND | $56 | $40 | $29 | $26 | $27 | $27 | $29 | $27 | $30 | $32 |
| N.WAV-E.SAYR_115 | $25 | $29 | $18 | $12 | $15 | $17 | $18 | $18 | $20 | $20 |
| ELWOOD-PULASKI_69 | $24 | $24 | $14 | $8 | $5 | $4 | $1 | $1 | $6 | $8 |
| VOLNEY SCRIBA | $6 | $6 | $7 | $6 | $7 | $8 | $6 | $8 | $9 | $9 |
| UPNY-ConEd | $0 | $0 | $0 | $2 | $2 | $2 | $1 | $3 | $6 | $5 |
| CHESTR-SHOEMAKR_138 | $31 | $27 | $26 | $2 | $1 | $1 | $1 | $2 | $3 | $2 |
| NEW SCOTLAND KNCKRBOC | $0 | $0 | $0 | $20 | $8 | $3 | $5 | $13 | $7 | $8 |
| SGRLF-RAMAPO_138 | $0 | $0 | $0 | $8 | $5 | $4 | $5 | $5 | $5 | $4 |
| NORTHPORT PILGRIM | $7 | $8 | $5 | $4 | $2 | $2 | $1 | $1 | $3 | $4 |
| GREENBSH-STEPHTWN_115 | $0 | $0 | $0 | $5 | $5 | $5 | $4 | $5 | $5 | $5 |
| INGHAMS CD-INGHAMS E_115 | $0 | $0 | $0 | $11 | $2 | $2 | $2 | $4 | $2 | $1 |
| ALCOA-NM - ALCOA N_115 | $0 | $1 | $1 | $2 | $2 | $3 | $3 | $4 | $4 | $4 |
| DUNWOODIE MOTTHAVEN | $3 | $3 | $0 | $1 | $1 | $3 | $3 | $1 | $2 | $2 |
| OWENSCRN-SABICO_115 | $0 | $0 | $0 | $3 | $3 | $3 | $3 | $2 | $3 | $3 |
| FERND-W.WDB_115 | $13 | $6 | $8 | $2 | $2 | $1 | $0 | $0 | $2 | $1 |

| Demand Congestion ($M) | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|
| CENTRAL EAST | $1 | $1 | $2 | $6 | $3 | $5 | $6 | $7 | $2 | $1 |
| DUNWOODIE TO LONG ISLAND | $38 | $39 | $47 | $46 | $58 | $53 | $57 | $62 | $72 | $75 |
| N.WAV-E.SAYR_115 | $21 | $21 | $23 | $21 | $23 | $26 | $29 | $30 | $34 | $36 |
| ELWOOD-PULASKI_69 | $9 | $12 | $13 | $15 | $18 | $21 | $26 | $27 | $31 | $37 |
| VOLNEY SCRIBA | $10 | $10 | $12 | $11 | $15 | $12 | $15 | $15 | $17 | $18 |
| UPNY-ConEd | $5 | $4 | $4 | $5 | $4 | $6 | $19 | $19 | $27 | $42 |
| CHESTR-SHOEMAKR_138 | $1 | $1 | $4 | $2 | $5 | $4 | $3 | $4 | $4 | $6 |
| NEW SCOTLAND KNCKRBOC | $9 | $8 | $7 | $12 | $11 | $4 | $4 | $3 | $3 | $1 |
| SGRLF-RAMAPO_138 | $6 | $7 | $6 | $7 | $10 | $7 | $16 | $14 | $9 | $7 |
| NORTHPORT PILGRIM | $4 | $4 | $4 | $4 | $6 | $7 | $7 | $8 | $9 | $11 |
| GREENBSH-STEPHTWN_115 | $5 | $5 | $6 | $6 | $7 | $7 | $8 | $8 | $9 | $9 |
| INGHAMS CD-INGHAMS E_115 | $2 | $3 | $5 | $10 | $4 | $7 | $11 | $9 | $11 | $10 |
| ALCOA-NM - ALCOA N_115 | $4 | $5 | $5 | $5 | $5 | $6 | $5 | $6 | $6 | $7 |
| DUNWOODIE MOTTHAVEN | $3 | $5 | $4 | $2 | $3 | $5 | $6 | $5 | $3 | $19 |
| OWENSCRN-SABICO_115 | $3 | $4 | $4 | $5 | $5 | $5 | $5 | $7 | $7 | $8 |
| FERND-W.WDB_115 | $2 | $2 | $2 | $3 | $1 | $3 | $4 | $4 | $3 | $1 |

#### Ranking of Congested Elements

The identified congested elements from the twenty-year projected congestion are appended to the past five years of identified historic congested elements to develop twenty-five years of Demand$ Congestion statistics for each initially identified top constraint. The twenty-five years of statistics are analyzed to identify recurring congestion. Ranking the identified constraints is initially based on the highest present value of congestion over the twenty-five year period with five years of historic and twenty years of projected congestion.

Figure 13 lists the ranked elements based on the highest present value of congestion over the twenty-five years of the study, including both positive and negative congestion.

**Figure 13: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the 25 Yr Aggregate (Baseline Case)**

| Demand Congestion (2021 $M) | Hist. Total | Proj. Total | 25Y Total |
|---|---|---|---|
| CENTRAL EAST | 3,487 | 1,061 | 4,548 |
| DUNWOODIE TO LONG ISLAND | 733 | 467 | 1,200 |
| EDIC MARCY | 359 | 0 | 359 |
| LEEDS PLEASANT VALLEY | 266 | 5 | 271 |
| N.WAV-E.SAYR_115 | - | 251 | 251 |
| GREENWOOD | 203 | 22 | 225 |
| DUNWOODIE MOTTHAVEN | 164 | 35 | 199 |
| PACKARD HUNTLEY | 184 | - | 184 |
| ELWOOD-PULASKI_69 | - | 161 | 161 |
| CHESTR-SHOEMAKR_138 | 34 | 101 | 135 |
| VOLNEY SCRIBA | 7 | 107 | 114 |
| NEW SCOTLAND KNCKRBOC | - | 73 | 73 |
| UPNY-ConEd | 10 | 58 | 67 |
| SGRLF-RAMAPO_138 | - | 59 | 59 |
| NORTHPORT PILGRIM | - | 55 | 55 |
| GREENBSH-STEPHTWN_115 | - | 49 | 49 |

The frequency of historic and projected congestion is shown in Figure 14 and Figure 15. The figures present the historic number of congested hours by constraint, from 2016 through 2020, and projected hours of congestion, from 2021 through 2040. Historic congested elements which are not congested, or congestion is limited to few hours in the projected years are replaced with new constraints in Figure 15 which are congested for greater number of hours.

**Figure 14: Historical Number of Congested Hours by Constraint (Baseline Case)**

| Congested Hours | Historic | | | | |
|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 |
| CENTRAL EAST | 4,636 | 5,062 | 4,031 | 5,308 | 4,482 |
| DUNWOODIE TO LONG ISLAND | 6,085 | 8,212 | 8,624 | 6,645 | 6,902 |
| EDIC MARCY | 164 | 307 | 312 | 17 | 26 |
| LEEDS PLEASANT VALLEY | 623 | 982 | 83 | 159 | 51 |
| GREENWOOD | 7,347 | 7,573 | 7,310 | 3,996 | 3,120 |
| DUNWOODIE MOTTHAVEN | 134 | 1,281 | 2,743 | 1,317 | 674 |
| PACKARD HUNTLEY | 1,425 | 821 | 818 | 355 | 29 |
| CHESTR-SHOEMAKR_138 | - | - | - | 228 | 234 |
| VOLNEY SCRIBA | 46 | 324 | 254 | 1,093 | 112 |
| UPNY-ConEd | - | 22 | - | 9 | 59 |

**Figure 15: Projected Number of Congested Hours by Constraint (Baseline Case)**

| Congested Hours | Projected | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
| ALCOA-NM - ALCOA N_115 | 207 | 315 | 577 | 656 | 818 | 985 | 988 | 957 | 999 | 995 |
| CENTRAL EAST | 3649 | 2548 | 1582 | 448 | 97 | 22 | 25 | 67 | 14 | 35 |
| CHESTR-SHOEMAKR_138 | 276 | 341 | 295 | 20 | 11 | 8 | 7 | 17 | 20 | 20 |
| DUNWOODIE MOTTHAVEN | 1199 | 1081 | 348 | 509 | 476 | 498 | 545 | 520 | 527 | 514 |
| DUNWOODIE TO LONG ISLAND | 7253 | 7172 | 7520 | 7894 | 7693 | 7297 | 7450 | 7507 | 7416 | 7588 |
| ELWOOD-PULASKI_69 | 318 | 302 | 243 | 240 | 208 | 161 | 142 | 159 | 183 | 214 |
| GREENBSH-STEPHTWN_115 | 2 | 1 | 1 | 93 | 88 | 82 | 78 | 78 | 78 | 81 |
| INGHAMS CD-INGHAMS E_115 | 0 | 0 | 0 | 291 | 82 | 52 | 44 | 97 | 37 | 36 |
| N.WAV-E.SAYR_115 | 5586 | 7678 | 5924 | 5533 | 6302 | 6444 | 6120 | 5914 | 5961 | 5413 |
| NEW SCOTLAND KNCKRBOC | 0 | 0 | 0 | 215 | 93 | 43 | 74 | 103 | 76 | 68 |
| NORTHPORT PILGRIM | 0 | 0 | 5600 | 4708 | 5989 | 7437 | 7561 | 6945 | 7739 | 7576 |
| North Tie: OH-NY | 316 | 375 | 314 | 334 | 283 | 234 | 206 | 187 | 156 | 214 |
| OWENSCRN-SABICO_115 | 3 | 96 | 64 | 1740 | 1372 | 1364 | 1166 | 1035 | 1167 | 1212 |
| SGRLF-RAMAPO_138 | 0 | 0 | 0 | 214 | 149 | 91 | 115 | 83 | 79 | 96 |
| UPNY-ConEd | 0 | 0 | 19 | 12 | 19 | 17 | 11 | 17 | 45 | 37 |
| VOLNEY SCRIBA | 1845 | 1982 | 2348 | 2156 | 2636 | 2594 | 2362 | 2293 | 2634 | 2407 |

| Congested Hours | Projected | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 |
| ALCOA-NM - ALCOA N_115 | 986 | 1052 | 974 | 958 | 973 | 1120 | 1003 | 1021 | 964 | 1009 |
| CENTRAL EAST | 16 | 31 | 26 | 82 | 38 | 76 | 66 | 69 | 42 | 27 |
| CHESTR-SHOEMAKR_138 | 13 | 11 | 22 | 16 | 23 | 19 | 17 | 18 | 17 | 22 |
| DUNWOODIE MOTTHAVEN | 672 | 726 | 657 | 691 | 809 | 771 | 817 | 860 | 879 | 1043 |
| DUNWOODIE TO LONG ISLAND | 7721 | 7731 | 7865 | 7904 | 7944 | 7941 | 7930 | 7972 | 8041 | 8087 |
| ELWOOD-PULASKI_69 | 222 | 254 | 266 | 243 | 273 | 302 | 327 | 306 | 323 | 400 |
| GREENBSH-STEPHTWN_115 | 85 | 92 | 97 | 107 | 115 | 120 | 128 | 136 | 144 | 148 |
| INGHAMS CD-INGHAMS E_115 | 31 | 55 | 79 | 145 | 49 | 110 | 131 | 104 | 107 | 84 |
| N.WAV-E.SAYR_115 | 5794 | 5322 | 5159 | 5266 | 5440 | 5407 | 5517 | 5454 | 5554 | 5961 |
| NEW SCOTLAND KNCKRBOC | 76 | 66 | 74 | 84 | 110 | 53 | 50 | 42 | 50 | 21 |
| NORTHPORT PILGRIM | 7906 | 7325 | 7252 | 7027 | 7061 | 7209 | 7188 | 7070 | 7205 | 7205 |
| North Tie: OH-NY | 231 | 223 | 230 | 227 | 245 | 275 | 260 | 272 | 286 | 319 |
| OWENSCRN-SABICO_115 | 1204 | 1381 | 1419 | 1491 | 1489 | 1648 | 1466 | 1837 | 1691 | 2169 |
| SGRLF-RAMAPO_138 | 127 | 136 | 129 | 162 | 157 | 131 | 220 | 181 | 114 | 91 |
| UPNY-ConEd | 43 | 36 | 31 | 31 | 29 | 31 | 69 | 53 | 67 | 93 |
| VOLNEY SCRIBA | 2655 | 2347 | 2963 | 2442 | 3154 | 2411 | 2951 | 2489 | 2884 | 2867 |

### Unserved Energy

In the production cost model, unserved energy occurs when the model lacks sufficient resources to serve load in a given hour. Any unserved energy in a load zone is met by a zonal 'dummy' generator in the MAPS program. In the Baseline Case, four hours in Zone J in 2040 experience unserved load, which results in 409 MWh of operation from the dummy generator in Zone J. It is important to note that while the study period of the Baseline Case ends in 2040, no new generation is added to the case past 2023 based on the inclusion rules. A lack of new resources over a period of almost 20 years is unrealistic, and the presence of unserved load in later years should not be interpreted as projected violation of system reliability.

#### Key Findings

- Demand congestion declines sharply in the first five years of the study period across the Central East interface. This decline is largely due to the retirement and refurbishment of nuclear generators in Ontario. The model forecasts NYCA becoming a significant exporter to IESO over the course of the study period. The decline in Central East congestion may also be attributed to the AC Transmission project coming into service as well as the introduction of the large loads located upstream of the interface.
- The large loads located in zones A, C, and D are served primarily by increased output from fossil fuel-fired generation located upstate. As a result, upstate zonal $CO_2$ emissions as well as zonal demand congestion increase through the study period.
- The large non-conforming loads, which do not follow conventional diurnal patterns as conventional loads and mostly have a flat profile, comprise of approximately 20% of Zone A, 6% of Zone C and 23% of Zone D total energy requirement by 2027 when all loads are at their maximum capacities. This increase in upstate load is primarily served by existing upstate fossil fuel-fired resources. This causes congestion on major bulk transmission lines such as Central East to decrease as a result of less power flowing through the interface to serve downstate loads.
- As expected, the CLCPA target of 70 by 30 is not achieved in the Baseline Case. This case uses the most conservative input assumptions of the three Outlook cases and is meant to serve as a reference case for the Contract and Policy cases.

## Contract Case Findings

### Key Assumptions Review

Through an annual request for proposals, NYSERDA solicits bids from eligible new large-scale renewable resources and procures Renewable Energy Credits ("RECs") from these facilities.[9] The Contract Case of the 2021 Outlook builds off the Baseline Case and additionally models the awarded units through NYSERDA's 2020 Solicitation that have not yet met the inclusion rules of the Outlook Baseline Case. Approximately 9,500 MW of new renewable units are added in this case, including 4,262 MW of solar, 899 MW of land-based wind, and 4,316 MW of offshore wind. The zonal breakdown of these additions is shown below. [10] On June 2, 2022 NYSERDA released the results of the 2021 REC Solicitation, announcing contracting with 22 new solar projects totaling 2,408 MW.[11]

**Figure 16: Zonal Renewable Generation Additions in the Contract Case (MW)**

| Zone | | Solar | Land Based Wind | Offshore Wind | Total |
|---|---|---|---|---|---|
| A | West | 290 | 339 | | 629 |
| B | Genesee | 1,330 | 200 | | 1,530 |
| C | Central | 852 | 147 | | 999 |
| D | North | 180 | | | 180 |
| E | Mohawk Valley | 739 | 213 | | 952 |
| F | Capital | 730 | | | 730 |
| G | Hudson Valley | 140 | | | 140 |
| J | New York City | | | 2,046 | 2,046 |
| K | Long Island | | | 2,270 | 2,270 |
| | Total | 4,262 | 899 | 4,316 | 9,476 |

### Simulation Results

This section summarizes study results for the Outlook Contract Case. Detailed results are described in more detail in Appendix placeholder.

#### Annual Generation

[9] https://data.ny.gov/Energy-Environment/Large-scale-Renewable-Projects-Reported-by-NYSERDA/dprp-55ye

[10] A more detailed list of units added to the Contract Case can be found at https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Contract_Case_Renewables.xlsx/

[11] https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2021-Solicitation-Resources

**Figure 17: Projected NYCA Generation by Zone, Delta from Baseline Case**

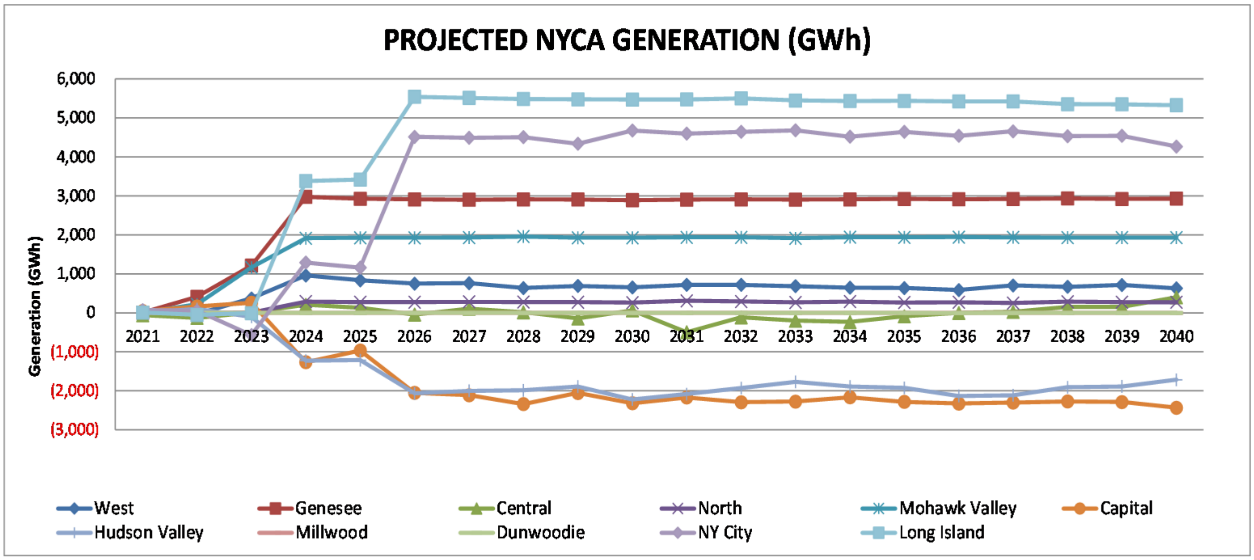



**Figure 18: Projected NYCA Generation by Fuel Type, Delta from Baseline Case**

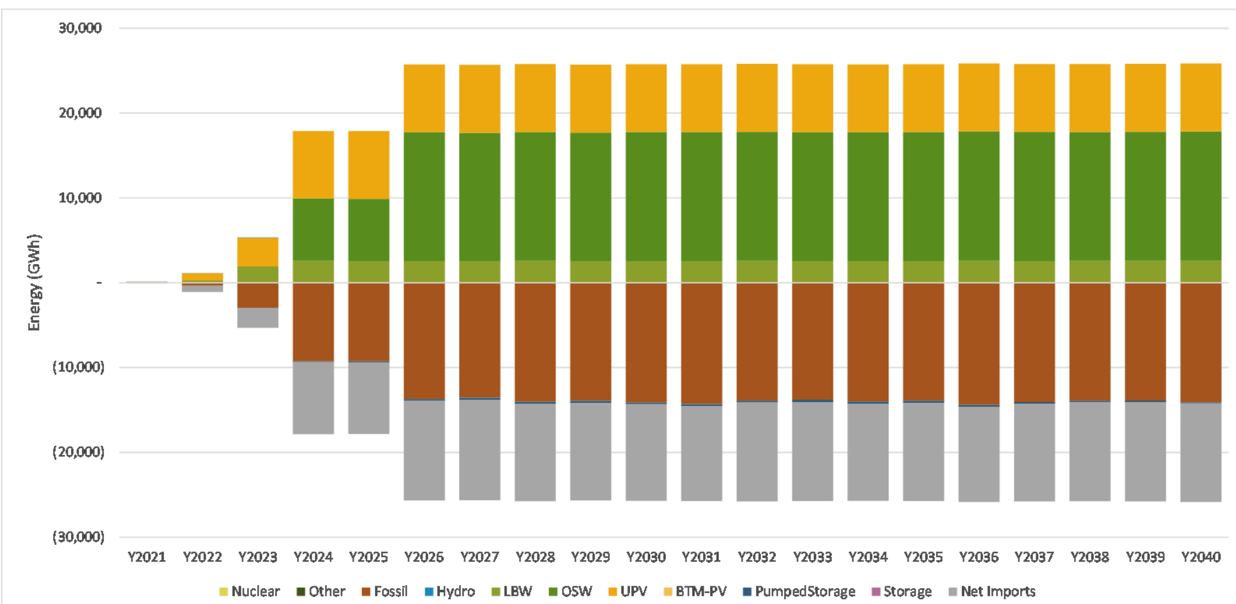
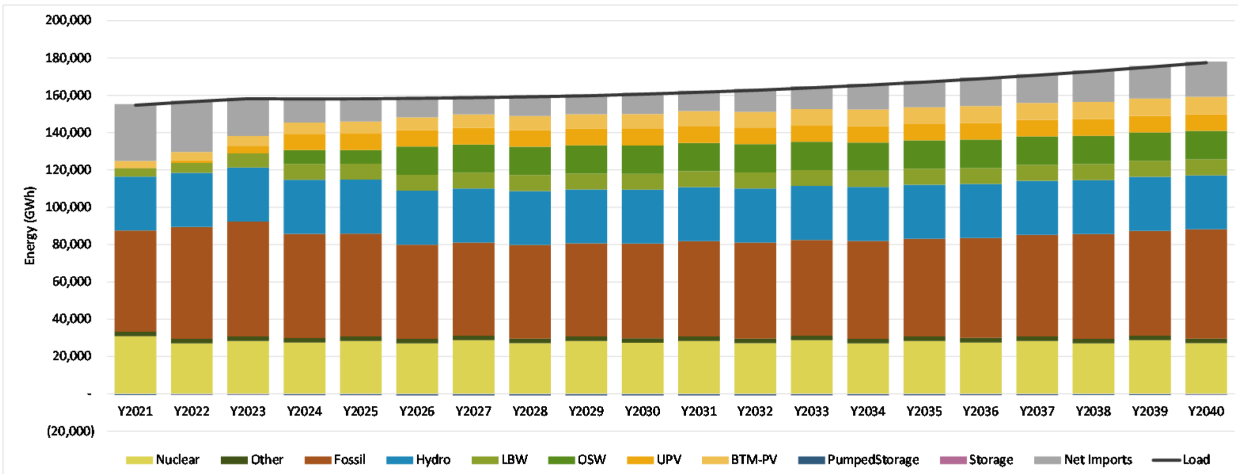



Figure 17 and Figure 18 show the changes in projected NYCA generation from the Baseline Case, both zonally and by fuel type. Generation increases across the upstate zones and in Zones J and K with the increases in available renewable energy. These increases displace primarily fossil fuel-fired energy in the Capital and in the Hudson Valley regions. Figure 18 also shows that the additions of renewable energy displaces net imports through the study period. Figure 19 shows the resulting fuel mix for the Contract Case.

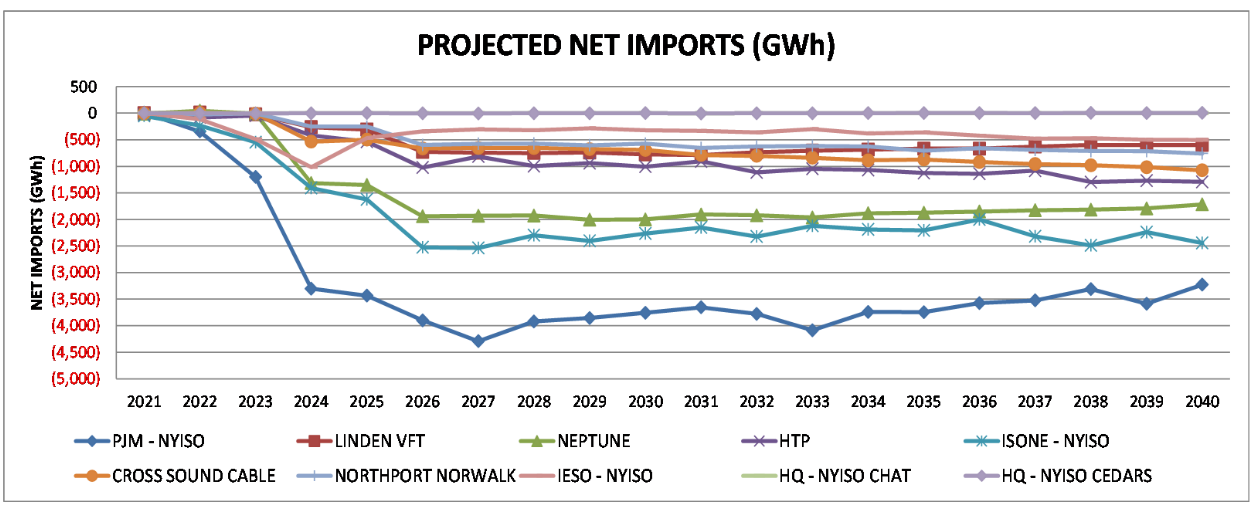
**Figure 19: Projected NYCA Generation by Fuel Type**




### Net Imports

As seen in Figure 18, net imports in the Contract Case are displaced by the added renewable generators in NYCA. Figure 20 shows the change in net imports from the Baseline Case by interface.

**Figure 20: Projected Net Imports by Interface, Delta from Baseline Case**




### Emissions

**Figure 21: Projected Zonal CO2 Emissions, Delta from Baseline Case**

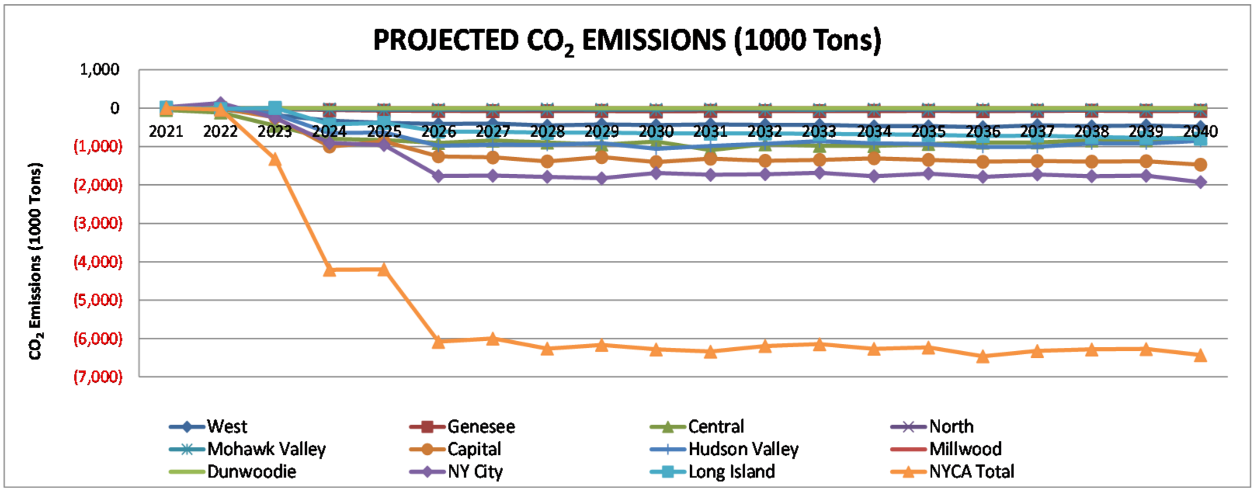



Figure 21 shows the projected change from the Baseline Case in zonal and NYCA $CO_2$ emissions. New York City and Capital see the largest reductions, and NYCA sees an annual reduction of approximately 6 million tons over most of the study period.

### Congestion

**Figure 22: Projected Demand Congestion by Zone, Delta from Baseline Case**

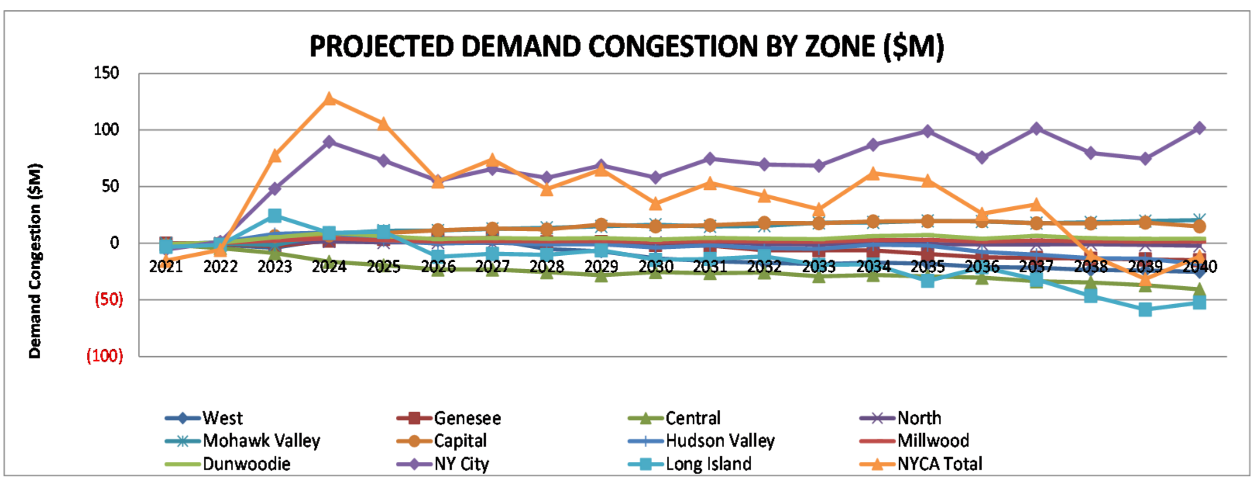


**Figure 23: Demand Congestion by Constraint, Delta from Baseline Case**

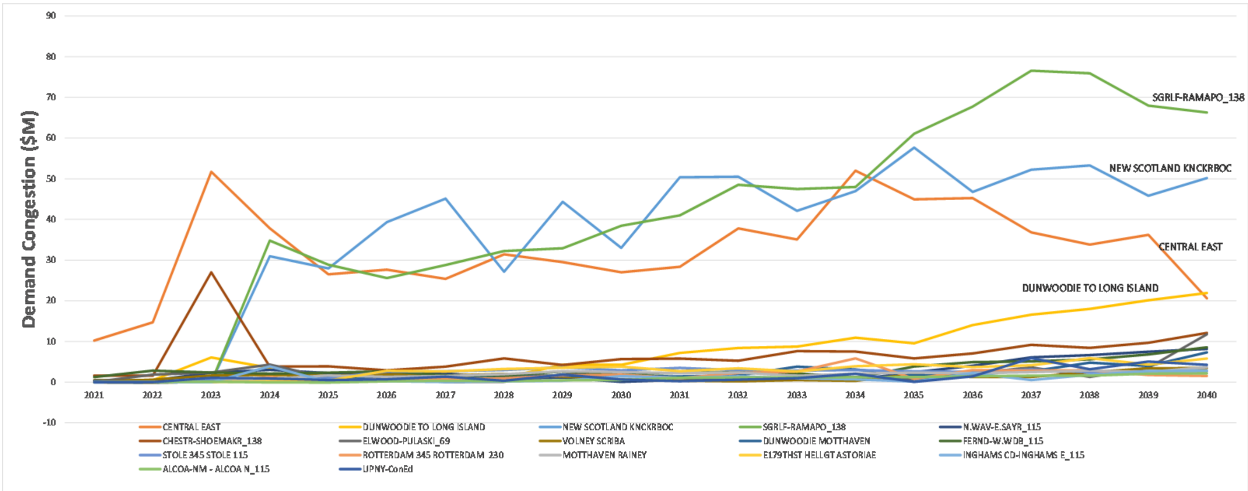
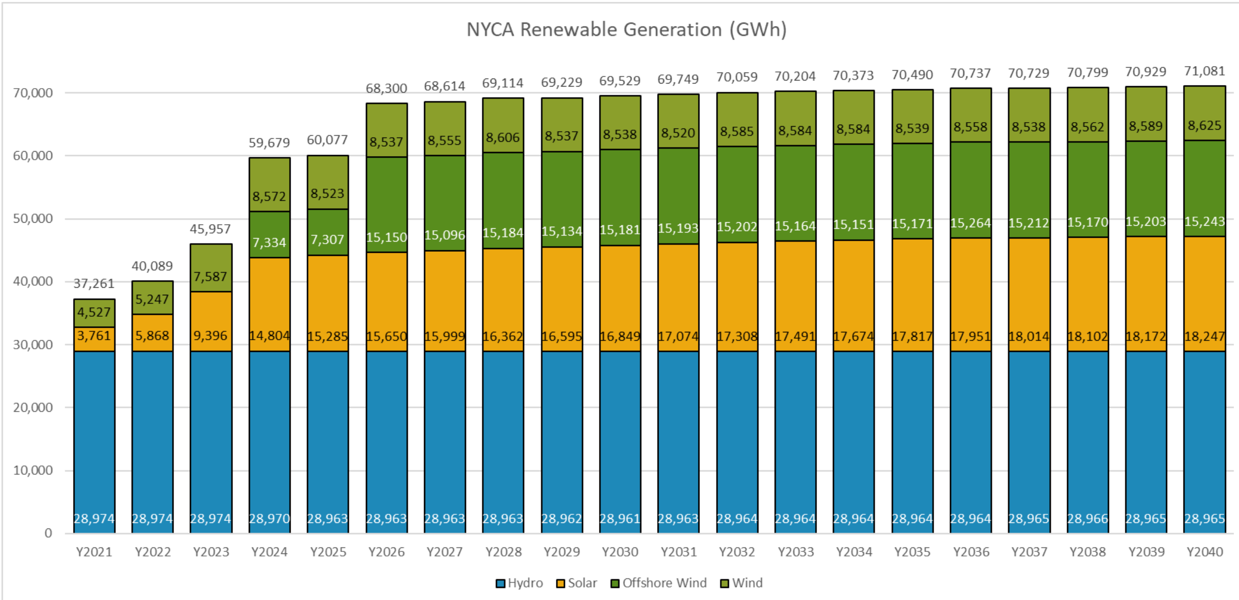



Figure 22 and Figure 23 show the changes from the Baseline Case in demand congestion both zonally and by constraint. Zone J sees the most significant increase in demand congestion while Central and Long Island see decreases in demand congestion. The constraints with the most prominent increases in demand congestion are Sugarloaf to Ramapo, New Scotland to Knickerbocker, Central East, and Dunwoodie to Long Island.

#### Renewable generation and curtailment

The Contract Case generator additions include renewable energy projects under contracts with NYSERDA that have procured REC contracts to serve energy in New York. The following chart shows renewable energy generation by type in each zone for the 20 years studied in the Contract Case.

**Figure 24: Annual Generation by Unit Type and Zone**




REC prices for each project are modeled as a negative bid adder in production cost simulation to represent impact from out of market payments. This price sets the priority order for economic dispatch and curtailment of resources due to transmission congestion.

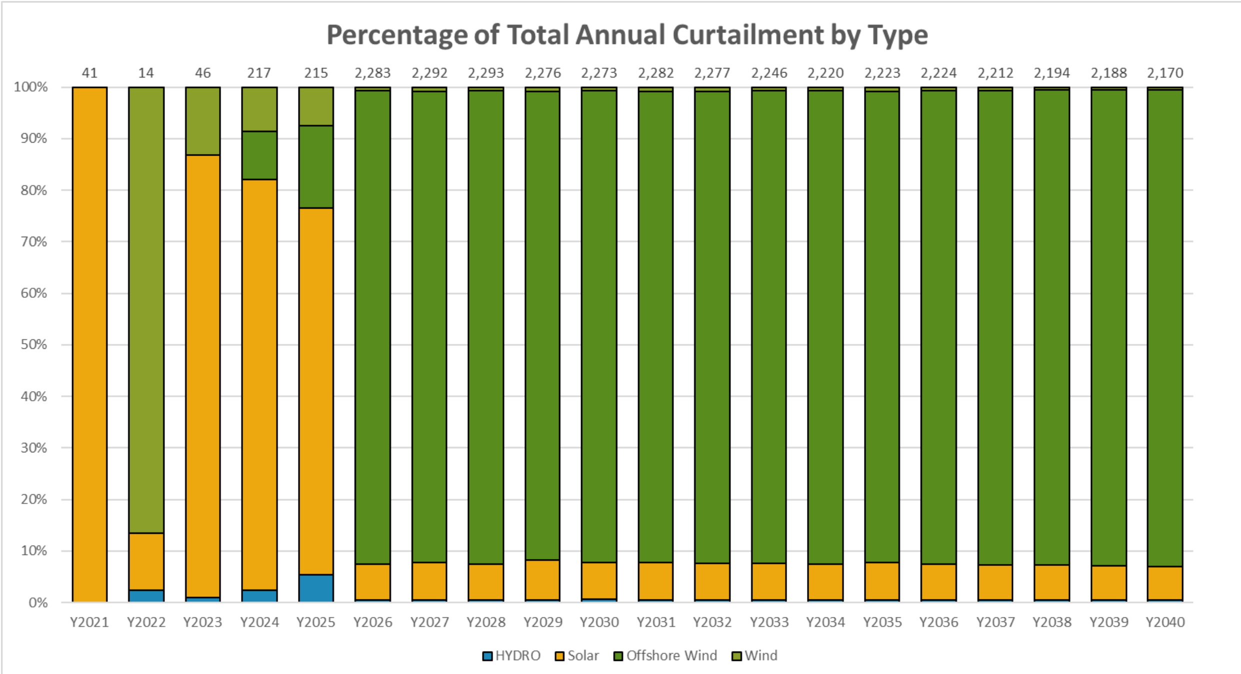
The aggregate premium of Index REC Strike price to Fixed RECs is used as a proxy to represent a negative bid adder for Index RECs. Index RECs are difficult to model in production cost simulations and therefore the following bid values were used for fixed and index REC prices:

*Modeled Fixed REC bid = - REC price*

*Modeled Indexed REC bid = - (Index Strike Price – Average Index Premium)*

For each generator with Index RECs, the bids are offset by the average index premium by generator type. For example, if the average wind fixed REC is $21, the average wind index REC is $55, and hypothetical Wind Plant X’s index REC is $60, modeled REC bid = -($60-($55-$21)) = -$26.

**Figure 25: Annual Curtailment by Unit Type**




As shown in the chart above, curtailment levels are low in the Contract Case in the early years of the study period and can be attributed mostly to solar units in upstate New York. The NYISO also observed an amount of hydro and land-based wind resource curtailment. Starting in 2026, a significant increase in offshore wind curtailment can be observed. The Contract Case includes offshore wind projects which have received ORECs from NYSERDA. The offshore wind curtailment can mostly be attributed to local constraints at the point of interconnection in Zone K. Specific upgrades related to the interconnection of each project were not modeled as part of the production cost modeling.

#### Unserved energy

Periods of unserved energy in production cost simulations occur when there are not enough dispatchable resources available to serve load in an area. This is typically caused by transmission congestion in a localized zone which does not allow load to be served within that pocket or zone. To ameliorate this condition, the NYISO's production cost database has 'DD' units, which are hypothetical, high operating cost thermal units designed to come online and serve load in situations where capacity is deficient or dispatchable resources in the system are unable to serve load due to congestion. The output from these units is distributed to each load bus in a zone proportional to the load factor of the bus. Activation of any zone's DD unit for any number of hours indicates that there exists a capacity deficiency in that particular hour or there are significant amounts of congestion in and around the load such that energy cannot be delivered. The Contract Case observed three hours in 2040 when DD units operate in

New York City.

### Renewable generation pockets and map

The 2019 CARIS 1 70x30 scenario ("2019 70x30 Scenario") examined the congestion and constraint results from sensitivity cases to form renewable generation pockets within NYCA. These pockets illustrated transmission constraints that could prevent full utilization of renewable resources within the area. A similar analysis was performed here for the Contract Case for the year 2030 and two Policy Case scenarios for years 2030 and 2035.

The 2019 70x30 Scenario pocket definitions were taken as the starting point to identify constraints and generators within the pockets in the Contract Case as well as the Policy cases. Pocket names and geographic locations of the pockets were kept consistent with the 2019 70x30 scenario. It should be noted that since the assumptions and generation mix in the Contract and Policy cases are different in the Outlook than the 2019 70x30 Scenario, some pockets might not form as a result of constraints that are non-binding within the pocket definition.

The renewable curtailment in the cases studied could result from a combination of drivers, including: (i) resource siting location, (ii) size of renewable buildout, (iii) the congestion pattern of transmission constraints, (iv) existing thermal unit operations, and (v) zonal load level and shape. 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.

Bulk level constraints which are historically binding remain among the most congested elements in the Contract Case. Some constraints could be more congested and new constraints might appear due to resource shifts in the system. Generation from fossil fuel-fired plants is replaced with that from land-based wind and solar renewable energy resources additions located upstate and away from load centers in Southeast New York.

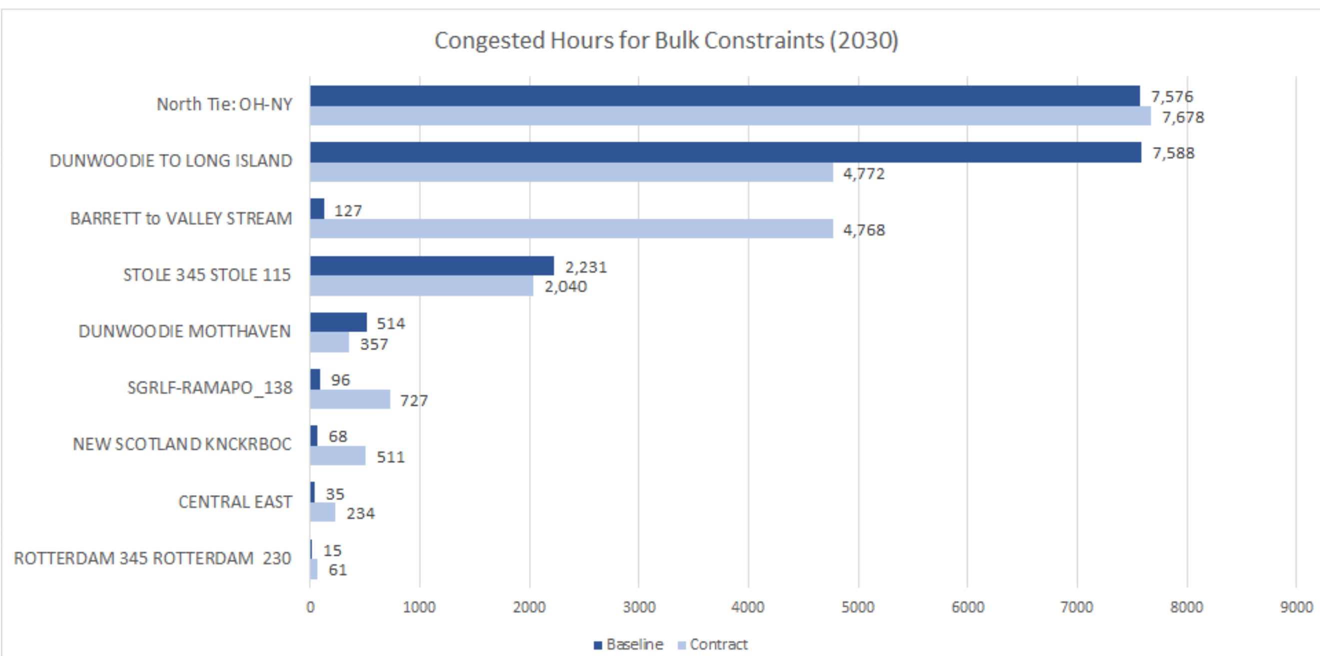
It is important to note that the Contract Case does not have the same amount of renewable capacity buildout as the 2019 70x30 Scenario. A comparison between the capacity builds in the two cases shows that the contract case has less renewable capacity built through 2030 compared to the 70x30 case, which was designed to meet the mandate of 70% renewable generation by 2030.

**Figure 26: Comparison of Renewable Capacity from 2019 CARIS 1 70x30 Scenario to Contract Case**

| Resource Type | 2019 CARIS 1 70x30 Scenario Load Case (MW) | 2021 System and Resource Outlook Contract Case (MW) |
|---|---|---|
| HYDRO | 4,467 | 4,489 |
| UPV | 10,831 | 4,804 |
| OSW | 6,098 | 4,316 |
| LBW | 6,476 | 3,670 |
| **Total** | **27,872** | **17,279** |

The decrease in congestion for land-based wind and solar resources from the 2019 70x30 Scenario to the Contract Case is driven primarily by a decrease in capacity and different load assumptions. Despite decreases in congestion and curtailment in the Contract Case, this study identifies the same pockets as in the 2019 70x30 Scenario. The pocket analysis indicates potential areas of generator curtailment for new renewable resources due to nearby transmission constraints. As such, these pockets identified in the 2019 70x30 Scenario continue to exist in the system modeled in the Contract Case, which contains probable future renewable generation locations for wind and solar and also persistent patterns of congestion that could lead to curtailment of such resources.

**Figure 27: Number of Congested Hours by Constraint, Baseline and Contract Cases**



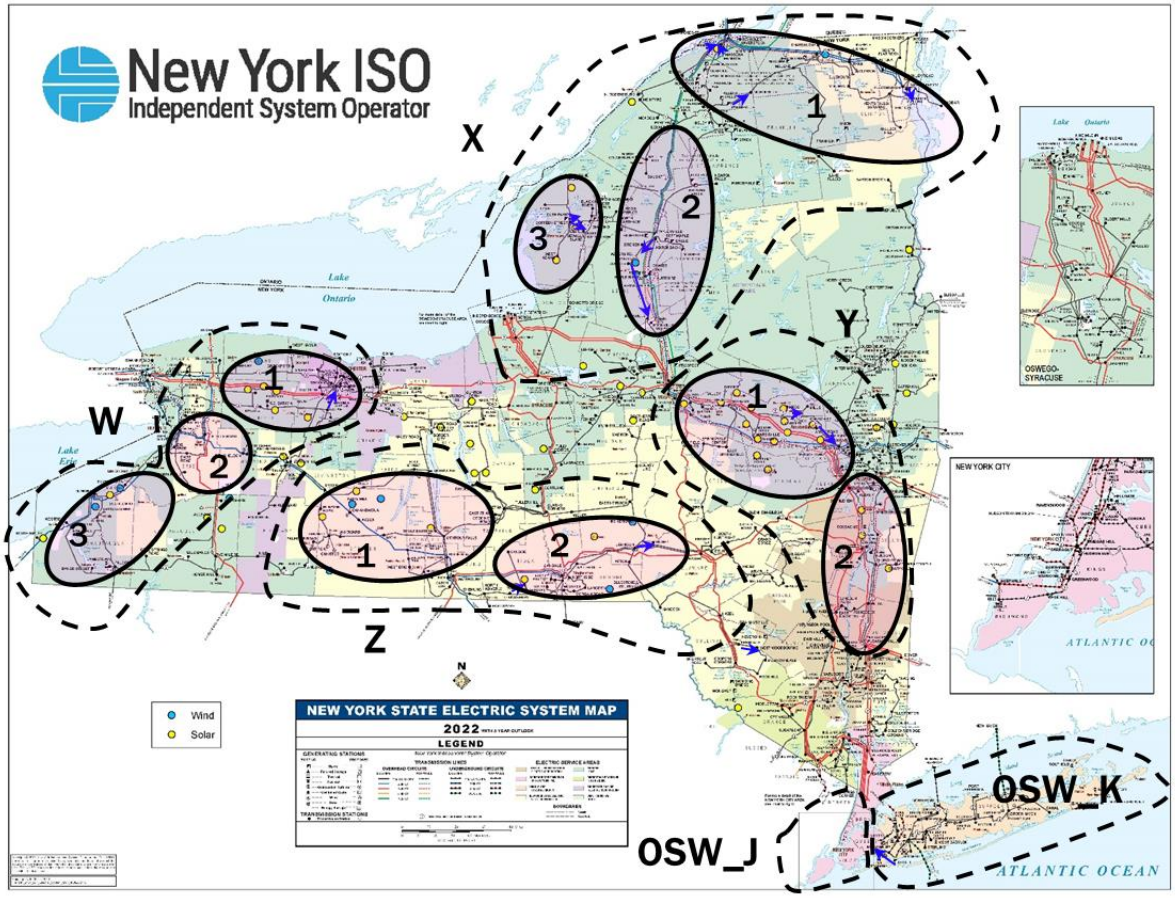

The above figure shows the number of hours bulk level constraints are congested in the year 2030.

Since most of the contracted resources are scheduled to be in-service by this time, using 2030 as the reference year for comparison between the Baseline and Contract cases is particularly meaningful. Congested hours is the primary metric used to identify congested elements in the pocket analysis for the contract and policy cases. It indicates the amount of time the flow on a particular element is at its limit or exceeds its limit in a specific year.

Historically congested paths such as *Central East* show very low numbers of congested hours in the Baseline Case as well as the Contract Case. This can be attributed to the following major factors: 1) AC transmission projects being in-service, 2) lower imports from IESO due to nuclear refurbishment and retirements, and 3) higher load overall in upstate New York (due to addition of large non-conforming loads) compared to prior study cycles. The *Dunwoodie to Long Island* interface, which is highly congested in the Baseline Case, is congested for fewer hours in the Contract Case as a result of offshore wind resources in Zone K injecting into Long Island and pushing back some of the flow coming into the island through the Y49 and Y50 lines. The *North Tie: OH-NY interface,* which is comprised of the L33 and L34 PARs on the New York to Ontario border, remains highly congested in both cases.

The two parallel 138 kV lines from Barrett to Valley Stream are one of the most congested elements in the system in the Contract Case. Congestion on these lines results from the injection of offshore wind energy interconnected to the Barrett substation. This study does not model system interconnection upgrades for contracted resources which are yet to be determined in the NYISO Interconnection Process. Therefore, the impact on congestion of any upgrades required for a particular project to interconnect at a substation were not captured as part of this study.

**Figure 28: 2030 Contract Case Pocket Map**




Consistent with the methodology developed in the 2019 70x30 Scenario, the generation pocket assignments are defined by two main considerations: renewable generation buildout location, and the constraint congestion results from the contract case. Each pocket (W, X, Y and Z), along with corresponding sub-pockets (W1, X2, Y1, etc.), depicts a geographic grouping of renewable generation and the transmission constraints in a local area. Blue and yellow colored circles show approximate locations of new contracted renewables (wind and solar generation respectively) that are not included in the Baseline Case. Blue arrows overlayed on transmission paths indicate the direction of congested elements within a pocket.

These constrained paths, which are generally on the lower kV network, are electrically close to new contracted generators added in the Contract Case. Congestion on lines within the pocket could cause curtailment of generators within the pocket if alternate paths are not available or there are limited opportunities for redispatch in a given hour. There could also be higher kV bulk level constraints which limit the flow of energy from upstate to downstate, but usually lower kV constraints, which have lower line ratings, would become congested first, limiting the amount of energy that can flow out of the generation pocket and onto the bulk system.

It should be noted that not all renewable energy pockets were identified for the Contract Case compared to the 2019 70x30 Scenario as the buildout of renewable resources is different. Therefore, not all areas observe enough congestion or resources added to be studied as a pocket in the Contract Case.

The following pockets are studied in the Contract and Policy Cases:

- **Western NY (Pocket W)**: Western NY constraints, mainly 115 kV in Buffalo and Rochester areas:

1) **W1**: 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)

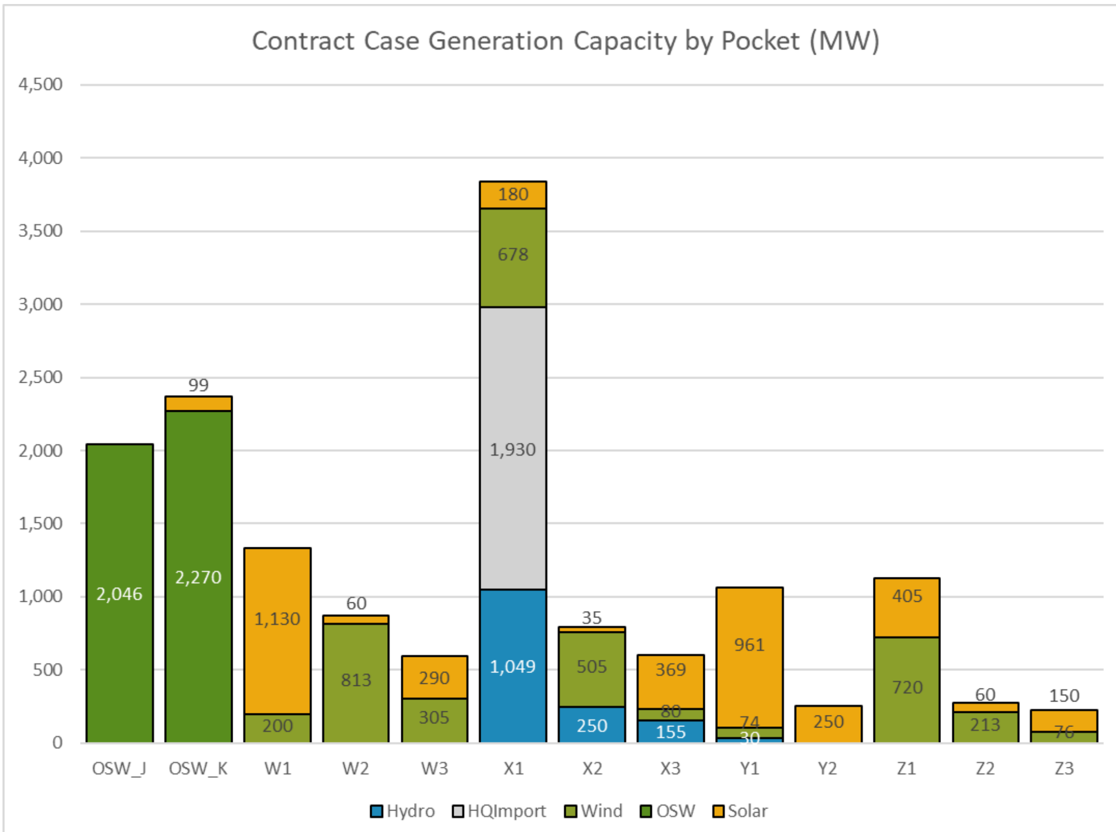
- **Southern Tier (Pocket Z)**: Southern Tier constraints, mainly the 115 kV constraints in the Finger Lakes area:

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)

Renewable energy generation capacity by generation pockets is shown below in **Figure 29** for the Contract Case. Offshore wind makes up the majority of renewable generation added in Zones J and K. Upstate renewable generation is a mix of utility scale solar and land-based wind resources. The existing HQ imports into Zone D are considered qualifying renewable generation injecting into the X1 pocket.

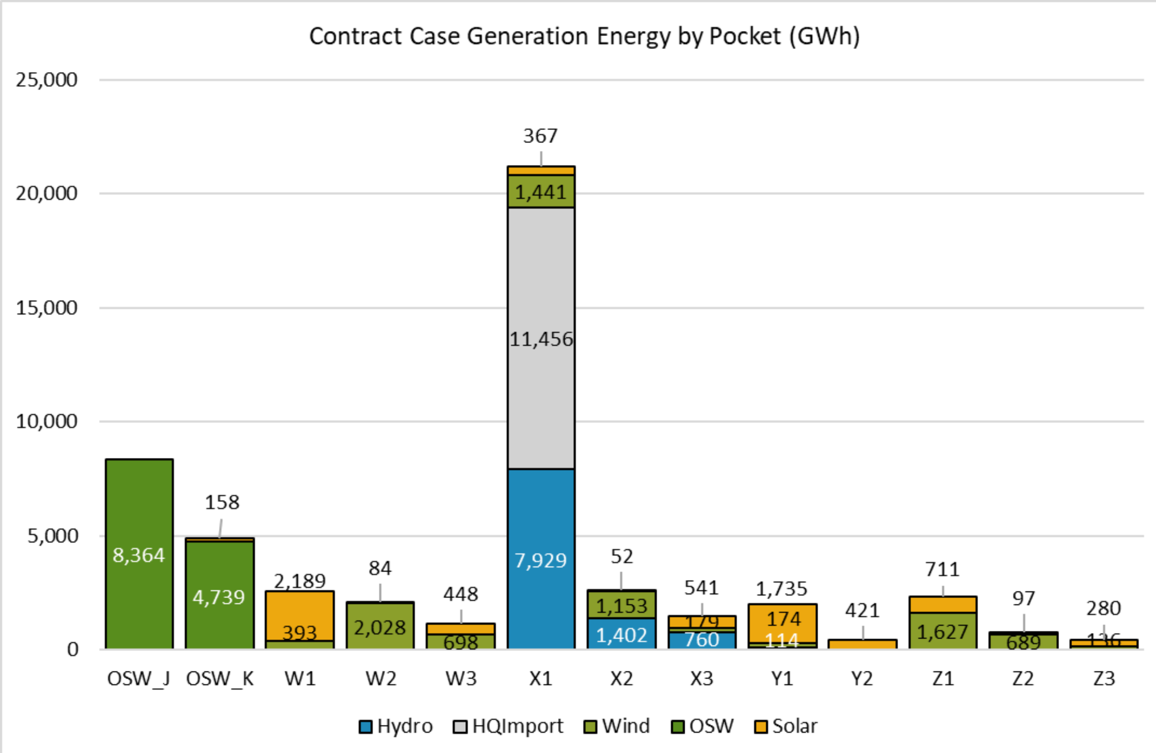
**Figure 29: Contract Case Generation Capacity by Pocket (MW)**




Each renewable generator is associated with an hourly generation profile for modeling purposes in the production cost simulation program. Owing to load, renewable scheduled generation, local transmission topology, and system conditions, a portion of potential renewable generator output may be curtailed. Curtailment of scheduled generation is usually caused when a generator is located upstream of a transmission bottleneck or in localized pockets with limited export capabilities.

As defined in above section, the pockets identified in this study are based on the combination of renewable generation and transmission system modeling assumptions. The aggregate amount of renewable energy curtailments within the pockets defined in this study accounts for 99% of all NYCA renewable energy curtailments in the Contract Case.

**Figure 30: Contract Case Generation Energy by Pocket (GWh)**




#### Energy deliverability calculations

Energy deliverability for a pocket is defined as the total energy utilized to serve load from a group of resources in a pocket. It is calculated by dividing the energy dispatched in a year for each resource type by the total scheduled energy for that resource.

$$Energy\ Deliverability = \frac{Total\ Dispatched\ Energy}{Total\ Scheduled\ Energy}$$

The energy deliverability metric gives an idea about how much of the total energy was utilized and how much was curtailed. The table below shows the Energy Deliverability metric by pocket and resource type.

**Figure 31: Contract Case Energy Deliverability by Pocket and Resource Type**

| Pocket | Type | Capacity (MW) | Scheduled Energy (GWh) | Dispatched Energy (GWh) | Curtailment (GWh) | Energy Deliverability (%) |
|---|---|---|---|---|---|---|
| W1 | Wind | 200 | 393 | 393 | 0 | 100.0% |
| | Solar | 1,130 | 2,214 | 2,189 | 25 | 98.9% |
| W2 | Wind | 813 | 2,029 | 2,028 | 2 | 99.9% |
| | Solar | 60 | 84 | 84 | 0 | 100.0% |
| W3 | Wind | 305 | 700 | 698 | 2 | 99.6% |
| | Solar | 290 | 448 | 448 | 0 | 100.0% |
| X1 | Hydro | 1,049 | 7,929 | 7,929 | 0 | 100.0% |
| | HQImport | 1,930 | 11,498 | 11,456 | 41 | 99.6% |
| | Wind | 678 | 1,441 | 1,441 | 0 | 100.0% |
| | Solar | 180 | 367 | 367 | 0 | 100.0% |
| X2 | Hydro | 250 | 1,405 | 1,402 | 3 | 99.8% |
| | Wind | 505 | 1,154 | 1,153 | 0 | 100.0% |
| | Solar | 35 | 54 | 52 | 2 | 96.2% |
| X3 | Hydro | 155 | 771 | 760 | 11 | 98.6% |
| | Wind | 80 | 179 | 179 | 0 | 100.0% |
| | Solar | 369 | 609 | 541 | 69 | 89.9% |
| Y1 | Hydro | 30 | 114 | 114 | 0 | 99.8% |
| | Wind | 74 | 179 | 174 | 5 | 97.3% |
| | Solar | 961 | 1,801 | 1,735 | 66 | 96.5% |
| Y2 | Wind | - | - | - | - | - |
| | Solar | 250 | 421 | 421 | 0 | 100.0% |
| Z1 | Wind | 720 | 1,628 | 1,627 | 0 | 100.0% |
| | Solar | 405 | 711 | 711 | 0 | 100.0% |
| Z2 | Wind | 213 | 696 | 689 | 7 | 99.0% |
| | Solar | 60 | 97 | 97 | 0 | 100.0% |
| Z3 | Wind | 76 | 136 | 136 | 0 | 99.7% |
| | Solar | 150 | 280 | 280 | 0 | 100.0% |
| OSW_J | Offshore Wind | 2,046 | 8,366 | 8,364 | 2 | 100.0% |
| | HQImport | - | - | - | - | - |
| OSW_K | Offshore Wind | 2,270 | 8,891 | 6,815 | 2,076 | 76.7% |
| | Solar | 99 | 159 | 158 | 1 | 99.5% |

The majority of curtailment is limited to Long Island from offshore wind injection. This results in a low energy deliverability percentage compared to other pockets and resource types. Some solar curtailment is seen in upstate New York in pockets X2, X3, and Y1, which have increasing amounts of solar projects proposed in the Interconnection Queue. These curtailments are generally due to a lack of a strongly interconnected network to deliver power, at both bulk and local system levels.

Detailed analysis of each pocket identified in the Contract and Policy Cases are included in Appendix

XX of this report.

#### Key Findings

- Resource additions in the Contract Case were not designed to fulfill any policy requirements. Renewable capacity is less than what was built for 2019 70x30 Scenario, which results in different congestion patterns and levels of curtailment.
- Local and bulk level constraints in the system (existing or new ones) may lead to renewable resources not being able to deliver all the scheduled energy at a given hour. Curtailment of resources within a localized area is studied by grouping together generators and constraints inside renewable generation pockets.
- Congestion patterns on the constraints inside the pockets show that the elements are more congested as additional resources are added to the area. More pockets may develop in the system where the geographic location might be suitable for renewable energy development, but existing transmission paths may not be adequate to transmit power out of the region.
- Curtailment of resources and congestion patterns are highly dependent on where the resources are located in the system, the transmission system topology, and capability of available transmission lines to deliver power to loads.
- Overall, the majority of the curtailments seen in the contract case can be attributed to offshore wind resources in Zone K. Injecting large amounts of power into a transmission system not designed to handle such levels causes the curtailment.

## Policy Case Findings

The Climate Leadership and Community Protection Act ("CLCPA") establishes several policy requirements to materially change the resource mix and system demand of the New York electric grid. Over the next twenty years, the CLCPA mandates that New York be served by 70% renewable energy by 2030 ("70 x 30"), includes specific technology-based targets for distributed solar (six GW by 2025, additional four GW by 2030), storage (three GW by 2030), and offshore wind (nine GW by 2035) and ultimately establishes that the electric sector will be carbon free by 2040. These policies will likely result in the acceleration of conventional generation retirements well in advance of the 2040 target year. As part of the Outlook, the NYISO is assessing a range of future scenarios to understand the breadth of challenges and potential system risks.

The dramatic transformation of New York State's energy industry aimed at mitigating the effects of climate change is primarily driven by public policies and is being undertaken by branches of the New York State government. The electric sector climate change related policies are being implemented through many initiatives, including the development of renewable generation and storage, reductions in $CO_2$ emissions, and specific technology-based targets. Each goal or target drives project procurement decisions made by NYSERDA.

The Contract Case includes projects with existing contracts implemented through the 2020 REC Solicitation. That case represents the current outlook of the system with contracts in hand at the time assumptions were locked down on December 1, 2021. Recognizing that the Contract Case does not aim to achieve the State policies, the NYISO has established a Policy Case to evaluate future scenarios that expand renewable resource capacity meet those policy objectives.

Given the significant uncertainty that exists surrounding the path to achieving policy objectives, the NYISO has introduced a capacity expansion model to the Economic Planning Process to evaluate many alternative paths. The capacity expansion model optimizes future generation buildout to minimize capital and operating costs while also achieving each specific policy modeled (e.g., 70 x 30 and zero-emissions by 2040 targets). Two specific generation buildout scenarios were selected from the multitude of capacity expansion simulations performed to formulate a detailed nodal production cost simulation model. While the capacity expansion model indicates optimal generation buildouts, the production cost model shows how a selected buildout operates on an hourly basis within a networked transmission system. Higher resolution production cost models enable a deeper evaluation of the transmission and operational challenges related to adopting high levels of intermittent renewable generation.

## Key Assumptions Review

### Policy Case Methodology Overview

In addition to the assumptions in the Contract Case for this study, the Policy Case includes additional assumptions specific to accommodating state policies, including the CLCPA targets, updated load forecasts and shapes, and contracted NYSERDA Tier 4 HVDC transmission projects. For use in the 2021-2040 System & Resource Outlook's Policy Case, a capacity expansion model was developed using PLEXOS software to simulate generation expansion and retirements to study achievement of these state policy mandates. The capacity expansion model incorporates assumptions from the Baseline and Contract Case databases as a starting point and includes additional assumptions as applicable in the Policy Case to simulate optimal capacity mix over the study period. Specifics of these assumptions are included in

Appendix XX.

In this inaugural System & Resource Outlook study, the capacity expansion model was developed, tested, and validated through the NYISO stakeholder process. Through scenarios, various assumption changes were examined to assess their impact on the capacity expansion model results. Ultimately, two of the capacity expansion scenarios were selected to represent capacity expansion cases for the detailed nodal production cost model for further analysis; these cases will be referred to as Scenario 1 (“S1”) and Scenario 2 (“S2”) for purposes of this report.

Owing to the uncertainty of the pathway to the future system in the Policy Case, simulations for the capacity expansion and production cost models are limited to five-year increments within the study period (i.e., 2025, 2030, 2035, and 2040 study years).

#### Capacity Expansion Assumptions Review

As noted above, two capacity expansion scenarios, S1 and S2, were selected as representative capacity expansion cases to run through production cost simulation. Several key assumptions for the Policy Case scenarios S1 and S2 are highlighted below. A detailed list of all modelling assumptions is included Appendix C.2.

- System representation is limited to the NYCA system only, inclusive of qualifying (renewable hydropower) imports from Hydro Quebec.
- Load and capacity forecasts for S1 and S2 are based on the 2021 *Gold Book* CLCPA Case Forecast and Climate Action Council draft scoping plan, respectively.
- Generation assumptions build off the Contract Case, and allows for generation expansion of the following generator types at the zonal level:
    - Offshore wind (OSW)
    - Land based wind (LBW)
    - Utility PV (UPV)
    - 4-hour battery storage
    - Dispatchable Emission Free Resource (DEFR), which represent a yet unavailable future technology that would be dispatchable and produces emissions-free energy (e.g., hydrogen, RNG, nuclear, other long-term seasonal storage, etc.).
- The transmission model assumed in S1 and S2 uses the Baseline Case database and is

represented by a pipe-and-bubble equivalent model of the NYCA region in the PLEXOS capacity expansion model. In addition to the assumptions from the Baseline Case, the Policy Case assumes three new transmission projects included as firm projects to accommodate public policy initiatives.

- Each year of the capacity expansion model is represented by 17 time slices, representative of season and time of day. Consistent with the Baseline and Contract Cases, the production cost model assumes hourly granularity for the Policy Case.
- CLCPA targets and state policy mandates are included as constraints in the capacity expansion model, such that the model must satisfy each constraint in its optimization.
- Resource adequacy constraints, such as statewide reserve margin and locational capacity requirements, are enforced for the NYCA and Localities in the capacity expansion model for each year of the model horizon.

Using the assumptions for the capacity expansion model, the model provides a projection as to how the resource mix could evolve. The capacity expansion results in this study are not an endorsement of outcomes under any specific set of assumptions; rather, results are intended to inform policymakers, investors, and other stakeholders of potential generation buildouts under a multitude of scenarios.

#### Capacity Expansion Scenario Key Assumptions Review

As described above, a number of additional scenarios, beyond S1 and S2, were tested in the capacity expansion model as part of this first System & Resource Outlook study. Prior to selecting the two capacity expansion scenarios for the Policy Case, various assumption changes were examined in the capacity expansion model to assess their impact on the model results. In addition to other input assumptions, key factors such as generator capital cost and load forecast were adjusted to investigate the key drivers for resource additions and impacts on the projections of resource growth in New York. A comprehensive list of the capacity expansion scenarios examined during this Outlook study are included in Appendix XX.

### Capacity Expansion Simulation Results

Results of the capacity expansion model represent the optimization outcome for minimization of total operational and fixed costs including capital costs over the entire 20-year study period. The system representation model of the NYCA included splitting each year into 17 time slices and 11 zones while satisfying policy and other constraints. Given that the global optimization results would differ if performed on a full nodal system representation with hourly resolution, as will occur in production cost modeling in a single year, these results should not be viewed as buildouts that would fully achieve the CLCPA targets even as the capacity expansion model 'solved' to them. Rather, these results represent potential future scenarios that can meet policy objectives absent the detailed technical constraints that are evaluated later in the production cost model.

#### Capacity Expansion S1 & S2 Results

For purposes of this Outlook study, two capacity expansion scenarios were selected, S1 and S2, and were run through production cost simulations for further analysis in the Policy Case. The intention of these two scenarios is to show a range of potential future capacity buildouts resulting from two sets of differing input assumptions. This Outlook study does not endorse one scenario over the other, and these scenarios should be viewed as possible outcomes given the large uncertainty of the future system.

For certain types of generation, the results were similar for S1 and S2, as these outcomes were likely driven by policy constraints or build limits modeled in both scenarios. Results for other types of generation, whether in terms of installed capacity and/or generation mix, differed between the two scenarios, as these results were driven by the assumptions specific to each scenario. Overall, results for S2 showed a higher level of renewable penetration than S1, most notably in UPV capacity builds, and had different projection of the capacity expansion throughout the study period as compared to S1 for all generator types. The main factors for these differences are the assumptions for load forecasts and differences in constraints modeled between the two scenarios.

Results that are similar between the two cases are noted below, and results that are specific to each scenario are described in detail in the S1 or S2 section below respectively.

##### a. Existing Generation

For purposes of this section, existing generation in the capacity expansion model is limited to qualifying generation in the NYCA consistent with the Baseline Case as well as scheduled generation builds in service consistent with the assumptions in the Contract Case of this Outlook study. The generator types assumed as existing generation as of the 2021 start year include: fossil fuel-fired, nuclear, hydro (including qualifying imports from Hydro Quebec), LBW, UPV, storage (including pumped storage hydro and battery storage), and Other (i.e., landfill gas, refuse, and biomass fired generators).

Due to the CLCPA requirement of a zero emissions grid by 2040, the NYISO required all fossil fuel-fired to retire by the modeling horizon year since these $CO_2$ emitting generators cannot operate in 2040. Existing zero-emitting generation, such as nuclear, hydro, LBW, and UPV generation, remains operational in the system through 2040.

### b. Generation Expansion

In both S1 and S2, a significant amount of capacity from renewable generation and DEFRs was installed by 2040. The results show a total of approximately 111 GW of installed capacity for S1 and 124 GW of installed capacity for S2, inclusive of NYCA generators and qualifying imports from Hydro Quebec only. This level of total installed capacity would be needed in 2040 to satisfy the state policy, energy, and resource adequacy constraints for S1 and S2, respectively. Of this total amount of installed capacity, approximately 75 GW and 84 GW is attributed to generation expansion for S1 and S2, respectively, beyond what is planned through state contracts. For comparison, the Baseline and Contract Cases have approximately 42 GW and 51 GW, respectively, of installed capacity by 2040. For comparison, total installed capacity was approximately 43 GW in the 2019 Benchmark simulation.

In both Policy Case scenarios, a significant amount of LBW capacity was built by 2040. As compared to the other renewable technologies available to the model, LBW was preferred due to its assumed capital cost, generation profile (i.e., HRM shape's implied capacity factor), and unforced capacity ("UCAP") ratings. In both scenarios, LBW adds to the assumed capacity build limits imposed (~16 GW).

Additionally, a significant amount of DEFR capacity was installed by 2040 in both scenarios S1 and S2, however, the types of DEFRs built in each case differed. Additional detail on the generation expansion and operations from DEFRs is discussed below.

Lastly, more than 10 GW and 11 GW of battery storage capacity was built in S1 and S2, respectively. Approximately 1 GW of additional battery storage capacity was built in S2 to help satisfy the capacity reserve margins, due to its assumed UCAP rating and relatively low capital cost, as compared to the other generator types available for expansion in S2.

#### i. Results Specific to S1

The results show that a significant amount of DEFR capacity is needed to support the higher loads and renewable penetration built by 2040. The High Capital/ Low Operating cost DEFR option generates a significant amount of energy in 2040; this DEFR option essentially operates as a baseload generator in the capacity expansion model. The Low Capital/High Operating cost DEFR option generates very little energy in the capacity expansion model in 2040 and is primarily selected to help satisfy the capacity reserve margins at the statewide and Locality levels due to its high assumed UCAP rating and low capital cost, as compared to the other generator types available. While an option, the Medium Capital/ Medium Operating cost DEFR option is not built in S1.

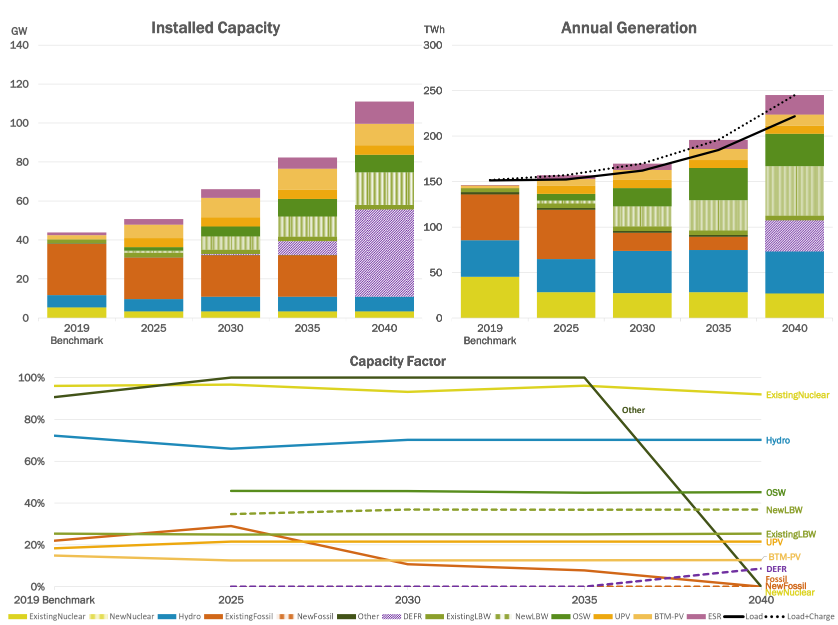
In the S1 case, UPV capacity does not build beyond what is planned through state contracts (included in the Contract Case). The lower energy contribution, especially in the overnight load blocks, in addition to its comparatively low UCAP rating, are the primary reasons that UPV does not build economically in S1. The transition to a winter peaking system, when solar irradiance levels are the lowest, also impacted the ability of UPV to assist in meeting capacity and energy needs.

Additionally, OSW capacity does not exceed its 9 GW minimum requirement per the CLCPA. Of the candidate generator types eligible for capacity expansion, OSW is assumed to have the highest capital cost, excluding the High Capital/Low Operating cost DEFR option. The high capital cost and relatively lower UCAP rating of OSW, after 9GW are selected, are the primary reasons that OSW capacity does not exceed the capacity required by its respective CLCPA target in S1.

Results specific to S1 are included in the figure below. The figure displays 2019 Benchmark capacity (GW) and generation (TWh) alongside the capacity expansion model outputs provided in five-year intervals. Results on the NYCA level are broken out by generation type in both graphical and tabular form. The generation table includes calculation of total, renewable, and zero-emissions generation relative to the load in units of energy and percentage and show that the CLCPA 70% renewable generation by 2030 and 100% zero-emissions by 2040 policy constraints were satisfied. The resultant $CO_2$ emissions reductions and capacity factor trajectories are also included in the figure. A more detailed figure can be found in Appendix XX.

**Figure 32: S1 Capacity and Generation Results**

## Capacity Expansion Model Results: S1




| Installed Capacity (MW) | | | | | |
|---|---|---|---|---|---|
| | 2019 | 2025 | 2030 | 2035 | 2040 |
| Nuclear | 5,400 | 3,346 | 3,364 | 3,364 | 3,364 |
| Fossil | 26,262 | 21,310 | 21,232 | 21,234 | - |
| DEFR - HcLo | - | - | - | - | 3,812 |
| DEFR - McMo | - | - | - | - | - |
| DEFR - LcHo | - | - | 420 | 7,053 | 40,938 |
| Hydro | 6,331 | 6,302 | 7,537 | 7,540 | 7,540 |
| LBW | 1,985 | 3,335 | 9,086 | 12,612 | 19,087 |
| OSW | - | 1,826 | 5,036 | 9,000 | 9,000 |
| UPV | 32 | 4,676 | 4,676 | 4,676 | 4,676 |
| BTM-PV | 2,116 | 6,834 | 10,055 | 10,828 | 11,198 |
| Storage | 1,405 | 2,910 | 4,410 | 5,793 | 11,450 |
| Total | 43,838 | 50,763 | 66,460 | 89,376 | 111,066 |

| Generation (GWh) | | | | | |
|---|---|---|---|---|---|
| | 2019 | 2025 | 2030 | 2035 | 2040 |
| Nuclear | 45,429 | 28,338 | 27,444 | 28,338 | 27,092 |
| Fossil | 50,520 | 54,174 | 19,987 | 14,516 | - |
| DEFR - HcLo | - | - | - | - | 33,482 |
| DEFR - McMo | - | - | - | - | - |
| DEFR - LcHo | - | - | - | - | 523 |
| Hydro | 40,034 | 36,418 | 46,342 | 46,392 | 46,391 |
| LBW | 4,416 | 8,189 | 26,971 | 38,297 | 59,362 |
| OSW | - | 7,331 | 20,186 | 35,460 | 35,647 |
| UPV | 51 | 8,817 | 8,816 | 8,817 | 8,819 |
| BTM-PV | 2,761 | 7,483 | 11,068 | 11,983 | 12,454 |
| Storage | 612 | 4,347 | 7,004 | 10,084 | 21,339 |
| Total Generation | 146,262 | 157,088 | 169,810 | 195,879 | 245,109 |
| RE Generation | 47,261 | 68,238 | 113,383 | 140,949 | 162,672 |
| ZE Generation | 93,301 | 100,922 | 147,831 | 179,371 | 245,109 |
| Load | 151,386 | 152,336 | 162,122 | 184,836 | 221,828 |
| Load+Charge | 151,773 | 157,089 | 169,811 | 195,879 | 245,109 |
| % RE [RE/Load] | 31% | 45% | 70% | 76% | 73% |
| % ZE [ZE/(Load+Charge)] | 61% | 64% | 87% | 92% | 100% |

| Emissions (million tons) | | | | | |
|---|---|---|---|---|---|
| | 2019 | 2025 | 2030 | 2035 | 2040 |
| $CO_2$ Emissions | 22.24 | 23.53 | 8.50 | 6.22 | - |

* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo)

#### i. Results Specific to S2

The results of S2 show that less DEFR capacity is needed to support the lower peak load levels and high renewable penetration built by 2040 relative to S1. For comparison, the total amount of DEFR capacity built by 2040 was comparable to the total NYCA fossil fuel-fired capacity installed as of the 2019 benchmark analysis. S2 assumes that the Medium Capital/Medium Operating cost DEFR is the only capacity expansion DEFR generator option. The Medium Capital/Medium Operating cost DEFR produces a different operational profile in the capacity expansion model as compared to the High Capital/Low Operating and Low Capital/High Operating cost DEFR generators. See [section placeholder] for further information on these results.

Of note, S2 assumed lower maximum capacity limitations for LBW generators through model year 2030, while maintaining the same maximum capacity limitations for LBW for model years 2031-2040.[12] Due to the lower build limit, less LBW was built by 2030 as compared to S1. However, like S1, LBW builds to the maximum allowable capacity in all zones by 2040, as imposed by its respective constraints.

As compared to S1, which did not observe economic builds from UPV, a significant amount of UPV capacity is built in S2 later in the model horizon to help address the system's energy needs, most notably in the upstate zones. This is primarily driven by the load forecast and DEFR options allowed for generation expansion in S2. Of note, LBW and OSW are the preferential build options in the capacity expansion model as compared to UPV due to their assumed costs, generation profiles, and UCAP ratings. Whereas LBW and OSW see a significant portion of their total capacity built prior to 2030, UPV capacity is not built until after 2030; with the majority of UPV capacity built between years 2035 and 2040. UPV capacity is built in Zones A-G and K as a lower cost energy option as compared to the Medium Capital/Medium Operating cost DEFR.

In S2, the candidate generators in Zones J & K are limited to the Medium Capital/ Medium Operating DEFR option, UPV, and OSW. Due to the limited candidate generation types available for Zones J & K in S2, OSW capacity is built beyond the minimum required by the 9 GW CLCPA target to help satisfy the energy needs in these zones because it is comparably the more economic choice. Additionally, the amount of OSW capacity built by 2030 was higher in S2 as compared to S1 to help satisfy the 70% renewable generation by 2030 CLCPA target. Ultimately, more OSW was built earlier on because less LBW capacity was allowed

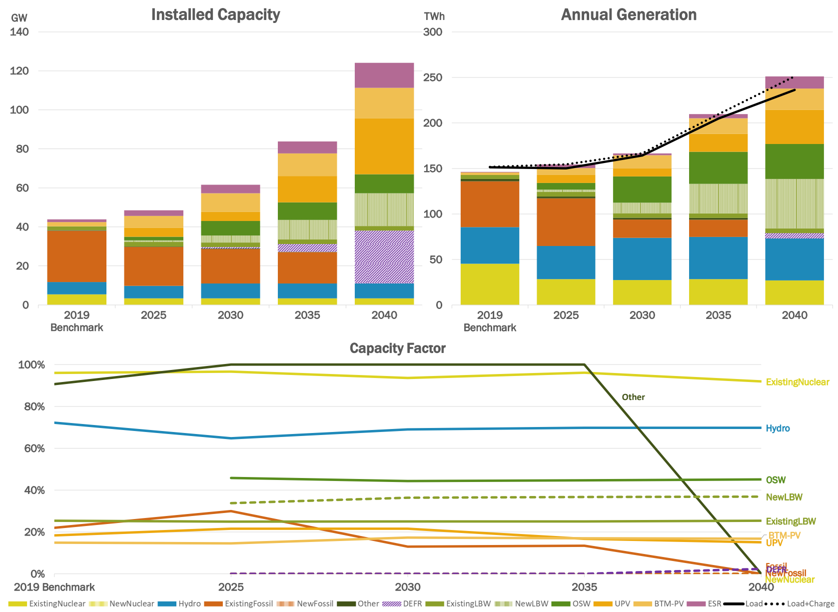
[12] Zonal capacity limitations are assumed for candidate LBW, OSW, and UPV generators and are based on the 2040 limitations for the applicable generator type, per https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.ashx, excluding LBW in S2. For LBW in S2, the maximum allowable capacities for model years 2021-2030 are based on the 2030 limitations for LBW and model years 2031-2040 are based on the 2040 limitations.

to build by 2030 due to the assumed build constraints for LBW in S2.

Results specific to S2 are included in the figure below.

**Figure 33: S2 Capacity and Generation Results**

## Capacity Expansion Model Results: S2




| Installed Capacity (MW) | 2019 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| Nuclear | 5,400 | 3,346 | 3,346 | 3,364 | 3,364 |
| Fossil | 26,262 | 19,988 | 17,650 | 16,071 | - |
| DEFR - HcLo | - | - | - | - | - |
| DEFR - McMo | - | - | 819 | 3,990 | 27,200 |
| DEFR - LcHo | - | - | - | - | - |
| Hydro | 6,331 | 6,415 | 7,660 | 7,584 | 7,584 |
| LBW | 1,985 | 3,138 | 5,890 | 12,366 | 19,087 |
| OSW | - | 1,826 | 7,436 | 9,000 | 9,720 |
| UPV | 32 | 4,676 | 4,676 | 13,448 | 28,606 |
| BTM-PV | 2,116 | 6,000 | 9,523 | 11,601 | 15,764 |
| Storage | 1,405 | 2,910 | 4,410 | 6,147 | 12,810 |
| Total | 43,838 | 48,523 | 62,454 | 87,787 | 124,135 |

| Generation (GWh) | 2019 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| Nuclear | 45,429 | 28,338 | 27,444 | 28,338 | 27,092 |
| Fossil | 50,520 | 52,437 | 20,066 | 18,908 | - |
| DEFR - HcLo | - | - | - | - | - |
| DEFR - McMo | - | - | - | - | 5,584 |
| DEFR - LcHo | - | - | - | - | - |
| Hydro | 40,034 | 36,418 | 46,342 | 46,392 | 46,391 |
| LBW | 4,416 | 7,518 | 16,494 | 37,460 | 59,362 |
| OSW | - | 7,331 | 28,865 | 35,247 | 38,388 |
| UPV | 51 | 8,817 | 8,816 | 19,661 | 37,705 |
| BTM-PV | 2,761 | 7,631 | 14,461 | 17,223 | 23,220 |
| Storage | 612 | 4,007 | 2,086 | 4,492 | 13,414 |
| Total Generation | 146,262 | 154,488 | 166,567 | 209,714 | 251,155 |
| RE Generation | 47,261 | 67,715 | 114,979 | 155,984 | 205,065 |
| ZE Generation | 93,301 | 100,059 | 144,509 | 188,814 | 251,155 |
| Load | 151,386 | 150,047 | 164,255 | 204,764 | 236,334 |
| Load+Charge | 151,773 | 154,488 | 166,567 | 209,715 | 251,155 |
| % RE [RE/Load] | 31% | 45% | 70% | 76% | 87% |
| % ZE [ZE/(Load+Charge)] | 61% | 65% | 87% | 90% | 100% |

| Emissions (million tons) | 2019 | 2025 | 2030 | 2035 | 2040 |
|---|---|---|---|---|---|
| $CO_2$ Emissions | 22.24 | 22.87 | 8.98 | 8.50 | - |

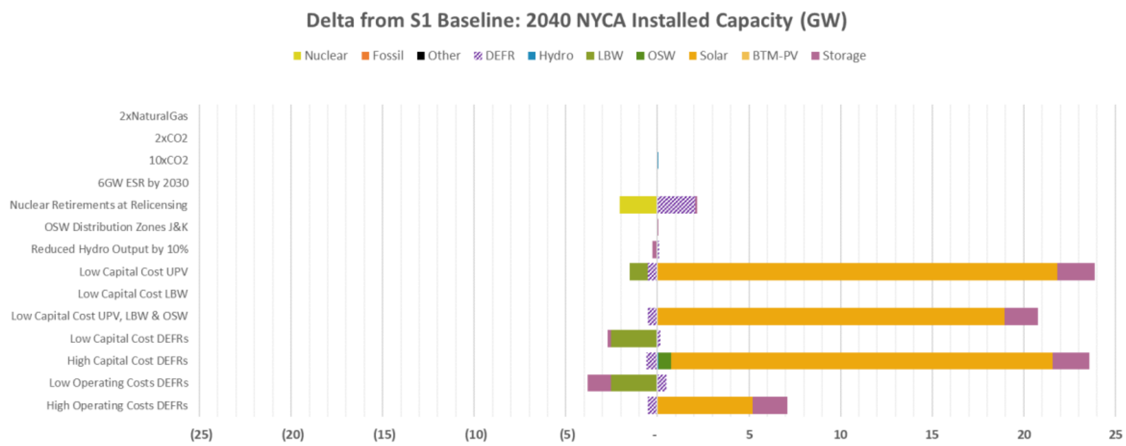
* Storage includes Pumped Storage Hydro and Batteries
* Utility solar (UPV) includes existing (77 MW) and new UPV
* Hydro includes hydro imports from Hydro Quebec
* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo)

### Capacity Expansion Scenario Results

In addition to the insights from Policy Cases S1 and S2, results of the scenario testing in the capacity expansion model are informative in showing which assumptions drive changes in the capacity expansion model results, and the scale to which these changes may occur. The scenarios provide insight on which assumptions drive certain results and the degree to which the capacity and/or generation mix are impacted. For example, results of scenario testing highlight the impact(s) that generator capital costs have on the timing of generator capacity builds as well as the total amount built by generator type.

The following charts provide a comparison of the capacity expansion results for each of the scenarios examined as part of this Outlook study. For both S1 and S2, there is a comparison of the 2040 Installed Capacity (GW) and 2040 Generation (TWh) for the range of scenarios. Detailed results pertaining to the capacity expansion scenarios tested are included in the Appendix.

**Figure 34: Scenario Capacity (GW) Deltas from S1 and S2**



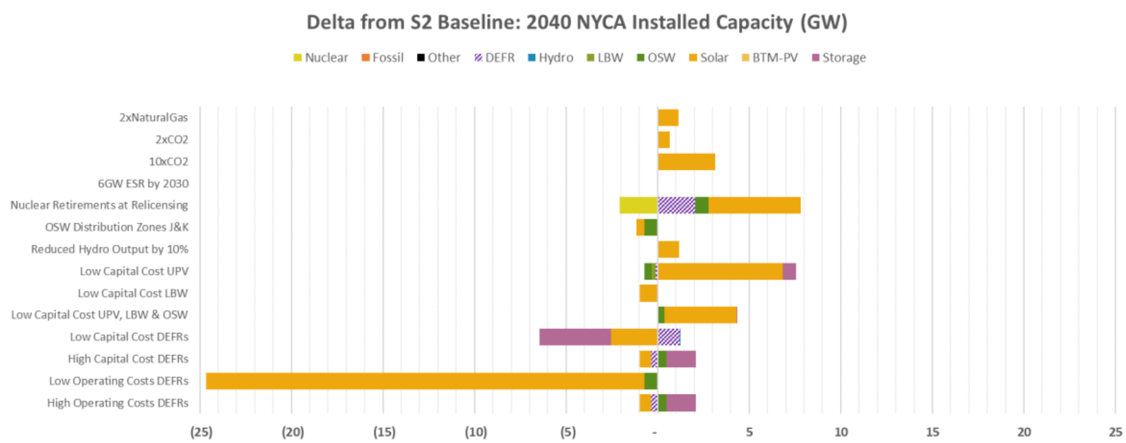
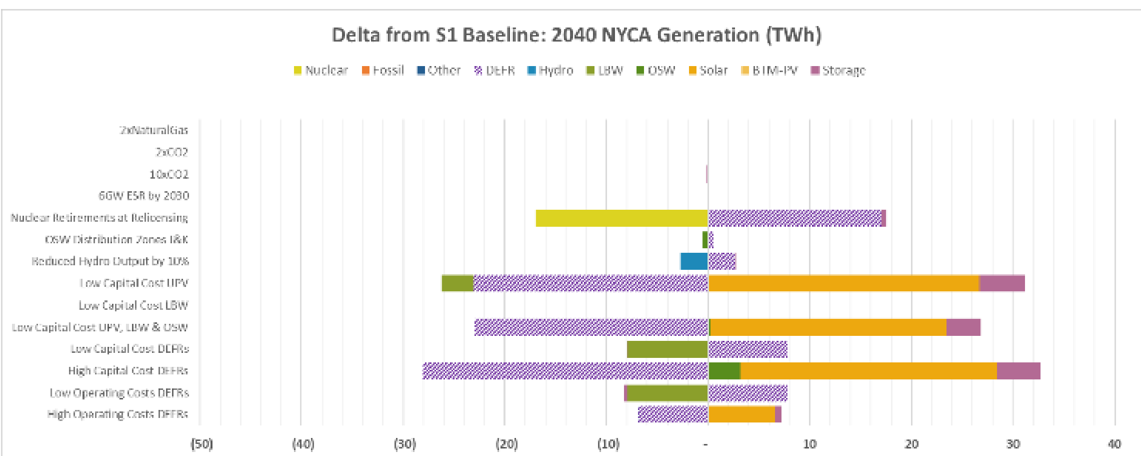
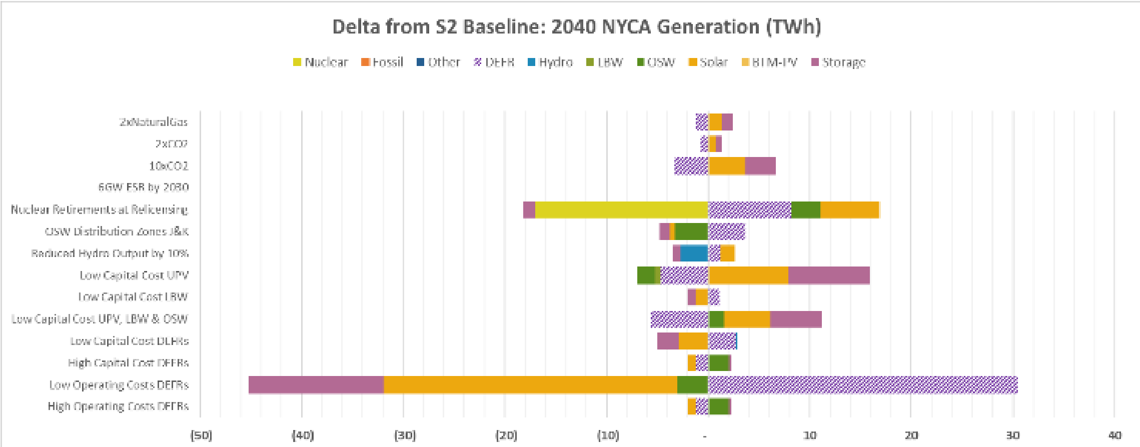




**Figure 35: Scenario Generation (TWh) Deltas from S1 and S2**






A test scenario was evaluated in the analysis to test the model's selection of renewable technologies in the absence of DEFR technologies. There are many technical limitations to the validity of the scenario, but it provides information surrounding the marginal technology that will increase or decrease as more or less DEFRs are selected. The test scenarios found that the exclusion of DEFRs as a new technology option, while enforcing the retirement of fossil generators via the 100% emission-free by 2040 policy, exhausts the amount of land-based wind built and results in the replacement of 45 GW or 27 GW of DEFR capacity, for S1 and S2 respectively, with 30 GW of offshore wind and 40 GW of energy storage, and a significant reduction in UPV capacity in S2. Note that this capacity replacement estimate is not realistic and should only be considered as a directional proxy for information, which is not a substitute for all the attributes provided by either today's fossil-fueled fleet or future DEFRs. Further reliability concerns, such as voltage support and dynamic stability, may require other extensive system reinforcements.

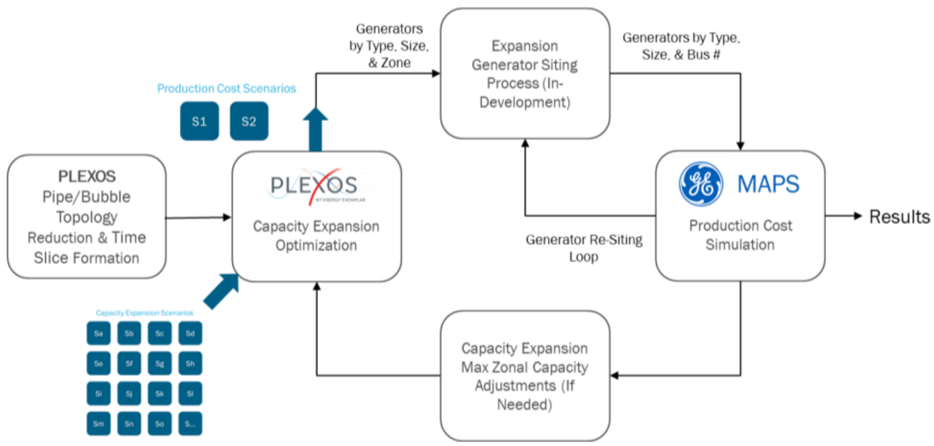
## Production Cost Simulation for Policy Cases

Production cost simulations allow a detailed view of the interconnected operation of transmission and generation across a large footprint with a high temporal resolution. While the assumptions across the capacity expansion and production cost models are aligned, generally the production cost model will provide more detailed insights into the specific economic and operational challenges that will occur under the capacity futures selected by the capacity expansion model. The focus of production cost modelling is to utilize the detailed transmission topology constraints identified to characterize renewable generation pockets that form as increasing amounts of resources locate in the same area. These pockets are associated with a disproportionally large share of the curtailments observed.

### Capacity Expansion to Production Cost Model Translation

Production cost simulations for Policy Case scenarios S1 and S2 are based on the generator addition and retirement decisions from the capacity expansion model results, which are translated from a zonal to nodal attribution. This higher granularity allows for deeper insights into how the system performs in an hourly basis under a high renewable penetration scenario.  The model data-flow diagram in 36 below highlights the process used in translating the capacity expansion model to the production cost model.

**Figure 36: Policy Case Modelling Process Diagram**




### a. Generator assumptions in Production Cost Simulation

New renewable generator additions from capacity expansion simulations for S1 and S2 were modeled in the production cost model as hourly fixed shapes for each year of the simulation. The shapes utilized for a specific generator type is consistent with that used in the capacity expansion model assumptions. Since capacity expansion produces zonal level aggregate generator addition capacities for each type (UPV, LBW, etc.), these values have to be allocated to buses in the production cost model to simulate actual injections at individual nodes.

The existing interconnection queue was leveraged as a starting point to identify probable points of interconnection for new resource additions. The proposed project capacity from the interconnection queue was taken as reference to calculate the proportion of total zonal capacity (from capacity expansion results for S1 and S2) to be added to the project location. This allowed the NYISO to examine system performance under conditions where most of the proposed projects in the interconnection queue would be in-service at varying capacities. DEFR units were placed in available buses vacated by retired fossil fuel-fired units. Energy storage was scheduled by MAPS production cost software and was distributed zonally to all load buses proportional to the nodal load factor, consistent with the process for distributing BTM-PV.

Generator retirements/deactivations and derates were kept consistent with assumptions and results for S1 and S2. Any must-run or operational nomograms associated with fossil units assumed to retire were removed from the production cost model. These nomograms were not updated with replacement units in the Policy Cases.

#### b. Transmission System Assumptions in Production Cost Simulation

The Baseline Case transmission topology was assumed as the starting point for the Policy Cases. The following projects were added to the underlying powerflow for both S1 and S2 cases:

- **December 2025:** NYPA Northern New York Priority Transmission Project, the NYPA "Smart Path", modeled as a 1,000 MW upgrade to existing transmission lines;
- **December 2025:** Champlain Hudson Power Express (CHPE), modeled as 1,250 MW additional imports from Hydro Quebec into Zone J; and
- **June 2027:** Clean Path New York (CPNY), modeled as 1,300 MW, connecting Zone E and Zone J.

The Champlain Hudson Power Express project is modeled as a fixed hourly injection directly into New York City as the Hydro Quebec system is not explicitly modelled. Elective upgrade facilities at the interconnection point were modeled as part of the project.

#### Production Cost Simulation Results

Capacity expansion results were ported to the production cost model and the hourly simulations were performed. Policy Cases were simulated in five-year intervals from 2025 to 2040. Generation capacity remains consistent between the capacity expansion and production cost simulations, but the operation of the fleet can differ due to a more detailed nodal network, higher temporal resolution, and full modelling of neighboring systems in the latter. The differing results between the models provides important insights into the challenges that may occur when procuring a significant amount of renewable generation capacity to meet policy objective(s). The more detailed results also help to identify specific needs that may arise for the future scenarios evaluated (e.g., ramping characteristics).

#### Process Feedback Loops

As depicted in 36 above, there are several modelling feedback loops that are embedded into the Policy Case process in order to integrate the models being used. The "round-trip" feedback loop is fully described in Appendix XX and more information can be found there. The production cost siting and capacity expansion feedback loops were both tested in this Outlook cycle but were not ultimately used. The information gleaned from testing each was very informative on system behavior but ultimately did not necessitate model changes. The NYISO found that:

- The generation placement feedback loop was tested by relocating renewable generators with greater than 20% curtailment to adjacent bulk system locations. This was done until generators had less than the 20% curtailment threshold. It was found that the total system curtailment changed minimally during this process as the transmission congestion causing curtailment simply moved to different circuits.
- The NYISO tested the capacity expansion feedback loop, which was designed to capture model resolution discrepancies between the capacity expansion and production cost model. In this test, the maximum zonal capacity of specific resource types was adjusted in the capacity expansion model for NYISO zones with high levels of curtailment of a specific type. The results showed that as limits in LBW, UPV, and/or OSW were reduced, more DEFR capacity was added to make up for the capacity and/or energy attributes.

#### Modeling 2040

During the development process for the production cost simulations, the NYISO found that the 2040 simulation year contained a meaningful number of unsolved hours in the simulation. Approximately 8% of the 8784 hours simulated were infeasible in the security constrained commitment and dispatch optimization. It was found that a major contributing factor of optimization non-convergence was the number of constraints encountered as the amount of generation capacity on the system grew by 36-45% and demand energy by 15-20% between 2035 and 2040 while the transmission system remained constant. A majority of the constraints encountered were at the 115kV and 138kV voltage levels. To enable a solution for 2040, a simplifying assumption of monitoring but NOT securing the 115kV and 138kV constraints was made. With this in mind, the 2040 results provide a reasonable indicator of the bulk transmission constraints that would exist if local transmission constraints were resolved. It also represents a system that is vastly different than the system of today. By 2040, it was assumed that the system will be enhanced to accommodate renewable resources, at least at the local level, to achieve policy goals. The 2040 case is designed to highlight the system congestion on higher kV elements under a policy buildout.

#### Unserved Energy

Unserved energy represented by operation of Dispatchable Demand ("DD") units in MAPS represents the load energy not met by installed generators in the system or area due to transmission constraints. The retirement of existing fossil fuel generation and the addition of intermittent resources in the Policy Case scenarios resulted in periods of unserved energy that are greater in number than those compared to the Baseline and Contract Cases. In 2040, there was a total of 969 combined hours representing 319 GWh of energy in S1 and 444 combined hours representing 109 GWh of energy in S2 supplied by DD units. In both scenarios, Capital (Zone F) had the greatest number of hours of DD operation. With significant amounts of fossil fuel units retiring, high amounts of congestion directly upstream of Central East and limited build of new resources might be some of the causes for DD units turning on to serve load in the Capital region.

The charts in Figure 37 through Figure 42show the system and zonal capacity, energy production, and curtailment results for both scenarios simulated (S1 and S2).

**Figure 37: Scenario 1 Production Cost Capacity by Type by Zone**

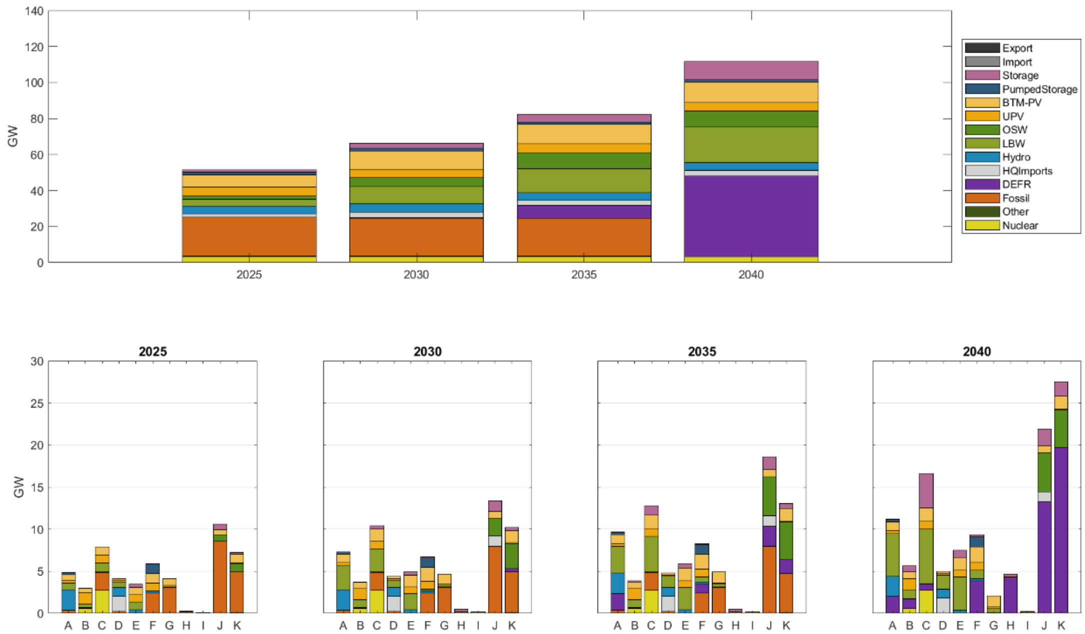



**Figure 38: Scenario 2 Production Cost Capacity by Type by Zone**

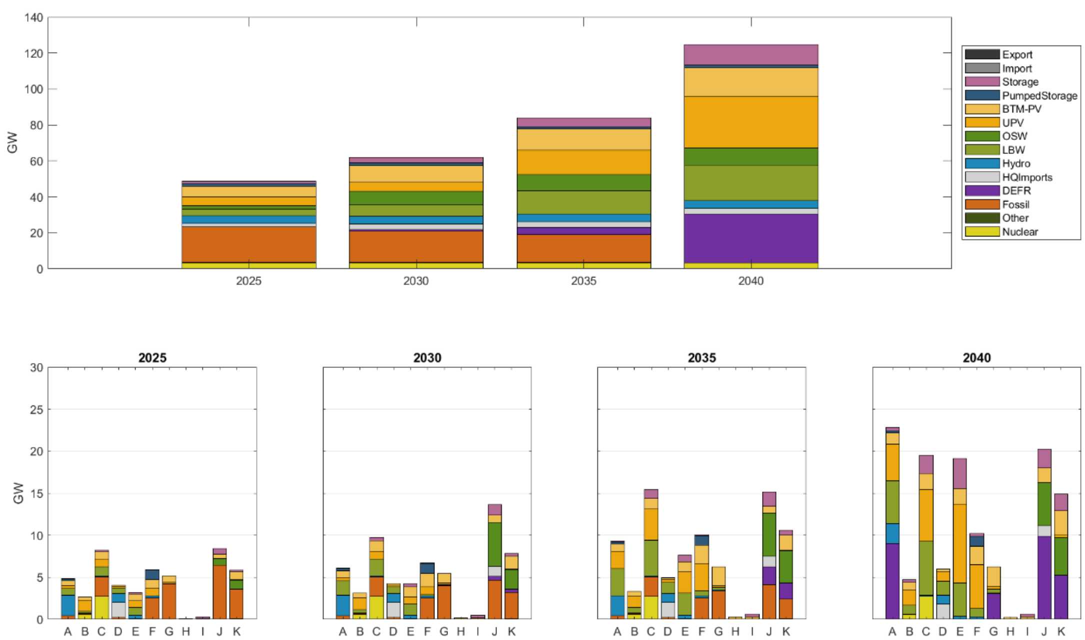


**Figure 39: Scenario 1 Production Cost Energy by Type by Zone**

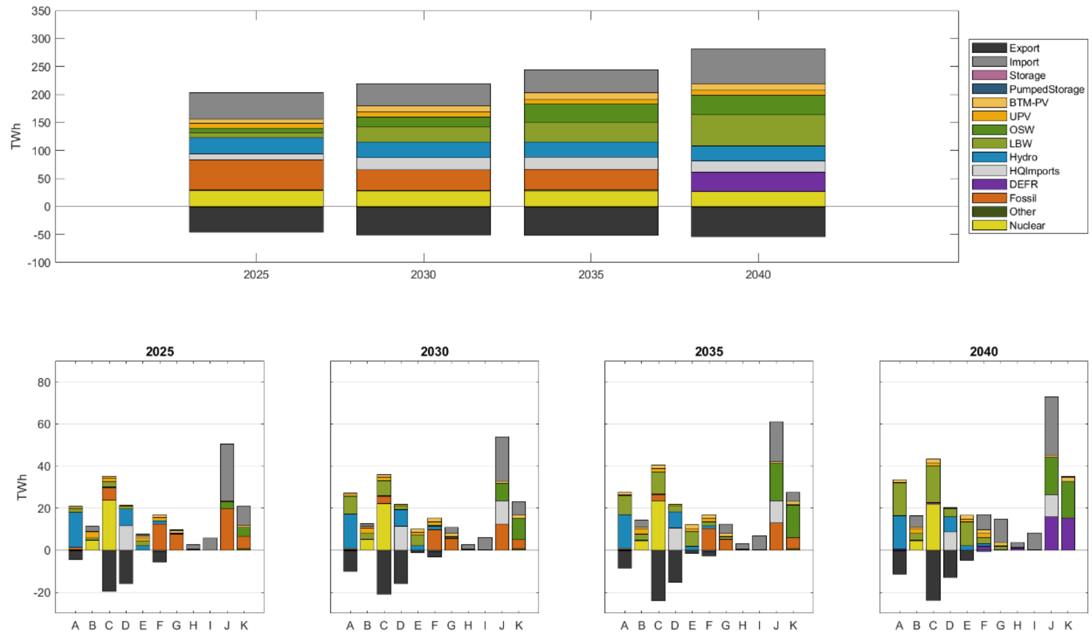



**Figure 40: Scenario 2 Production Cost Energy by Type by Zone**

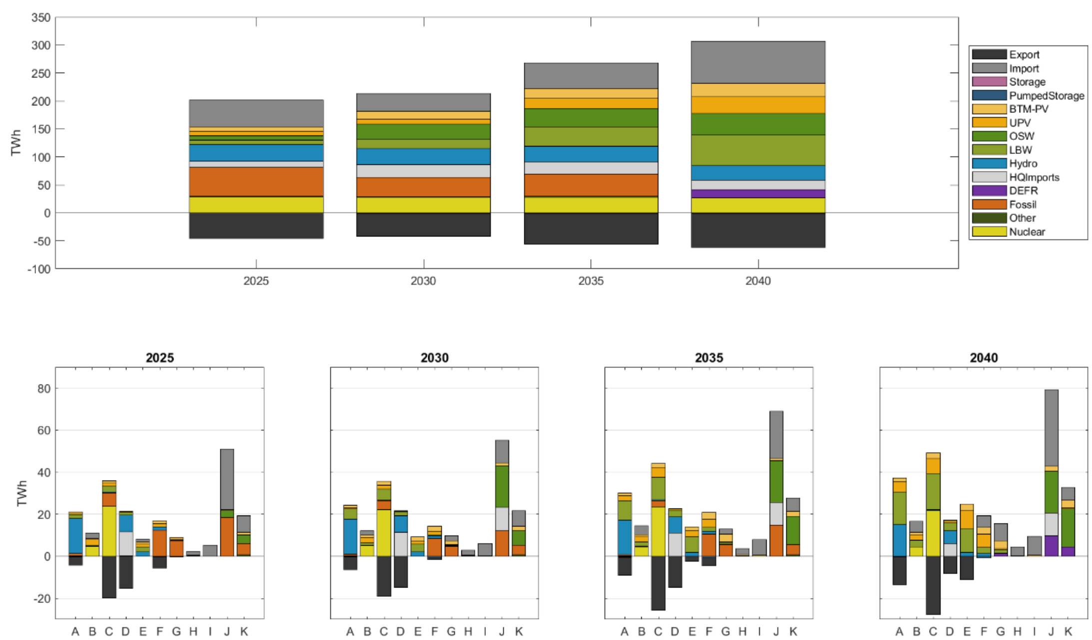


**Figure 41: Scenario 1 Production Cost Curtailment by Type by Zone**

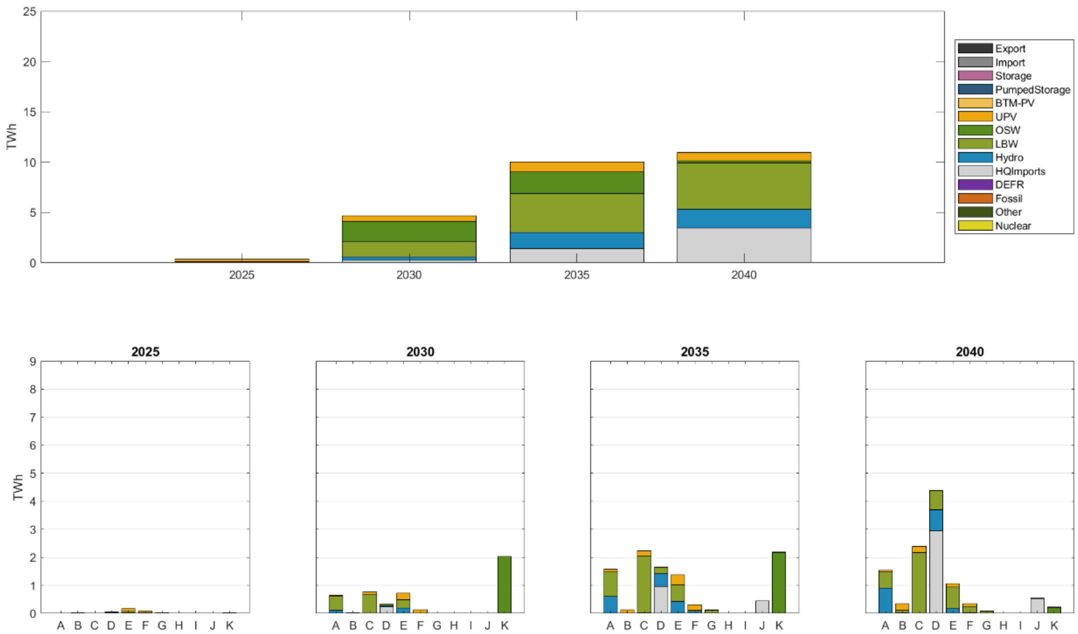
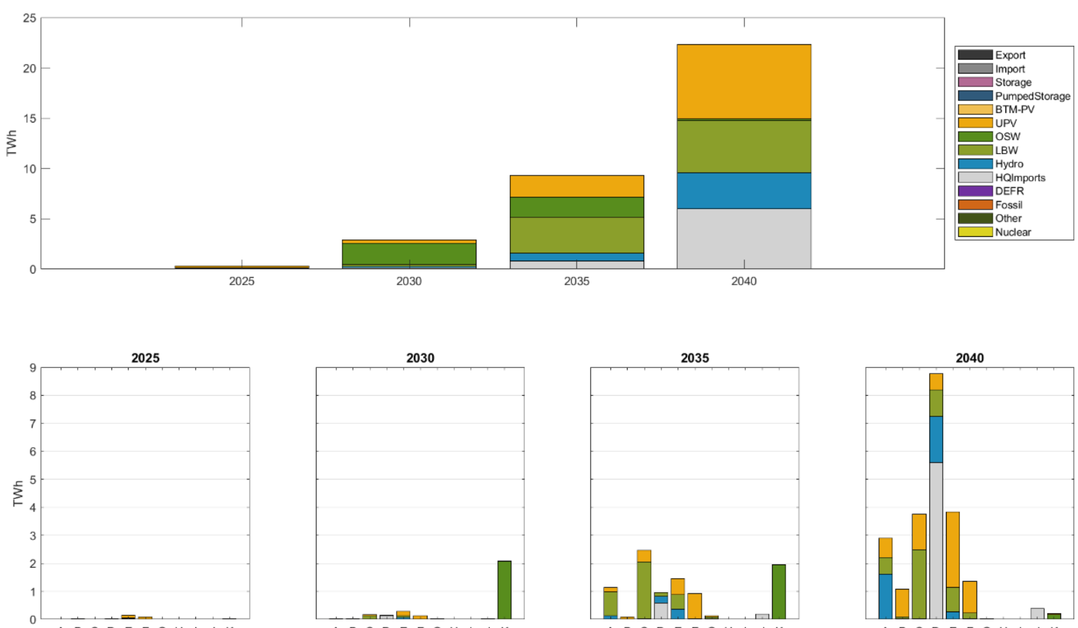



**Figure 42: Scenario 2 Production Cost Curtailment by Type by Zone**



#### Policy Case Renewable Generation Pockets

The Policy Case pocket analysis, similar to the Contract Case, is based on the grouping of congested lines and generators which are likely to be curtailed within a localized area. The pocket definitions and locations are kept consistent with those in the Contract Case. With the addition of new Policy Case resources resulting from capacity expansion simulations for scenarios S1 and S2, there exists a greater number (and higher capacity) of renewable energy resources in the system compared to the Baseline and Contract Cases.

The two figures below depict the approximate locations of new resources added to the Policy Case scenarios S1 and S2 in years 2030 and 2035, respectively.

**Figure 43: 2030 Policy Case Pocket Map**

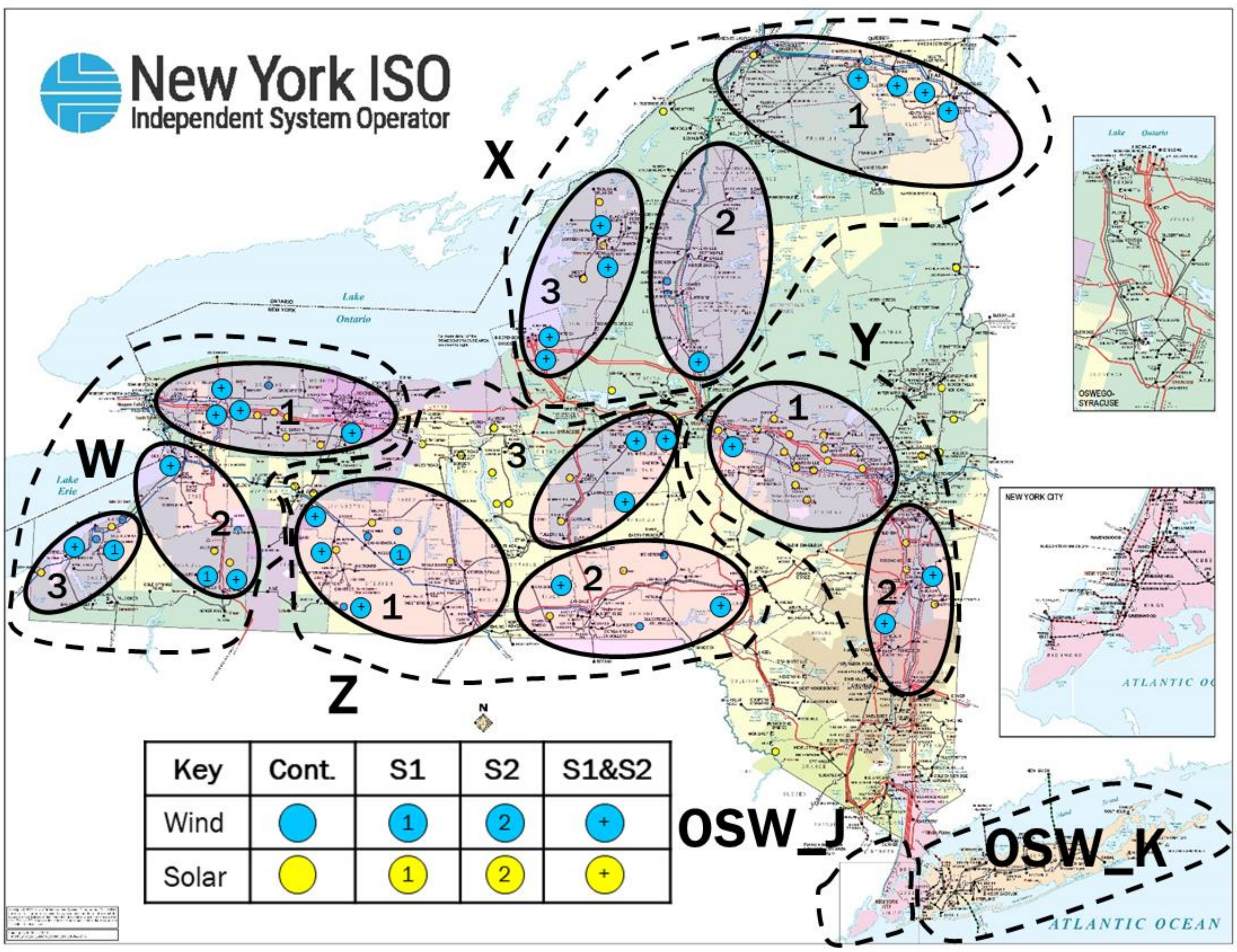
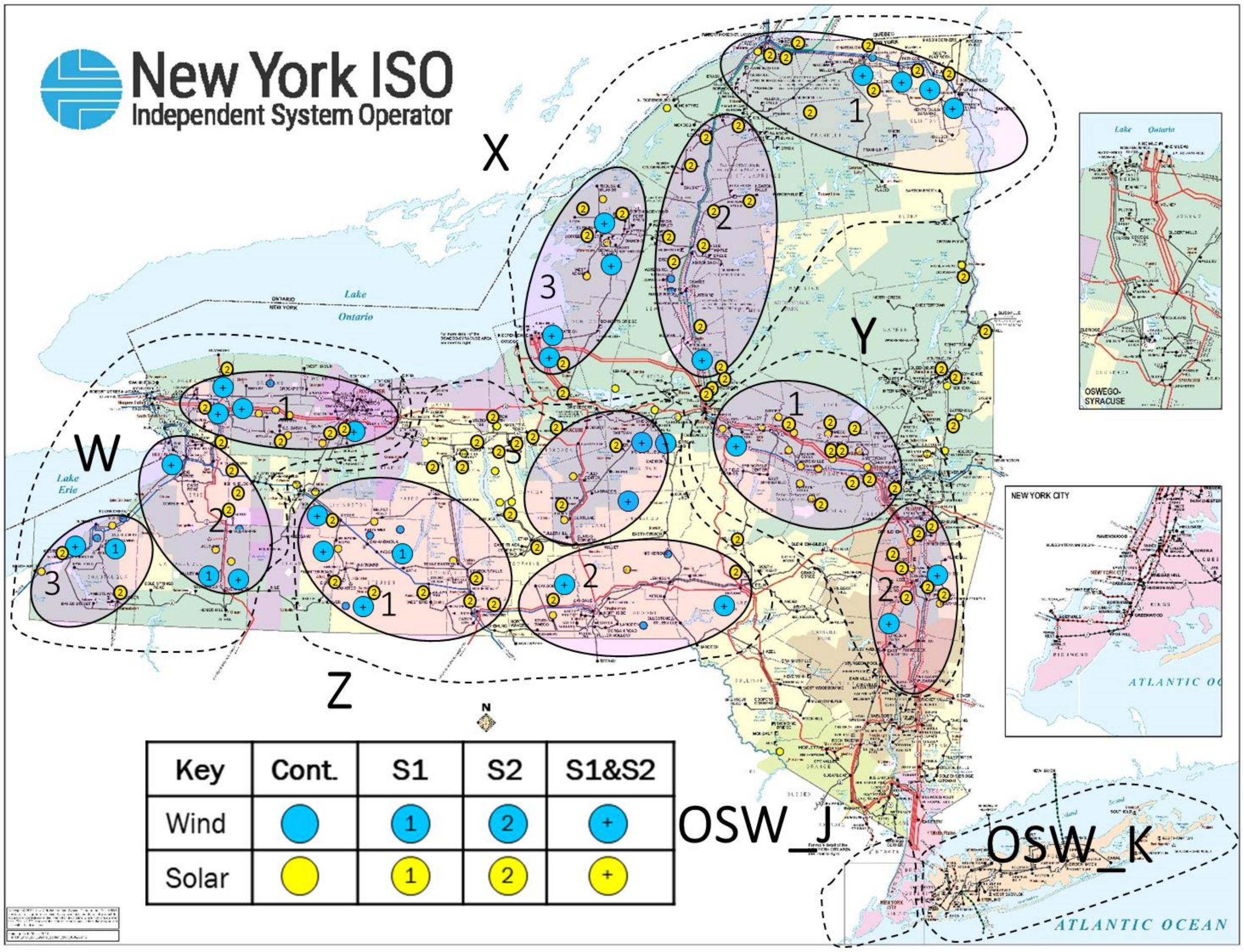


**Figure 44: 2035 Policy Case Pocket Map**



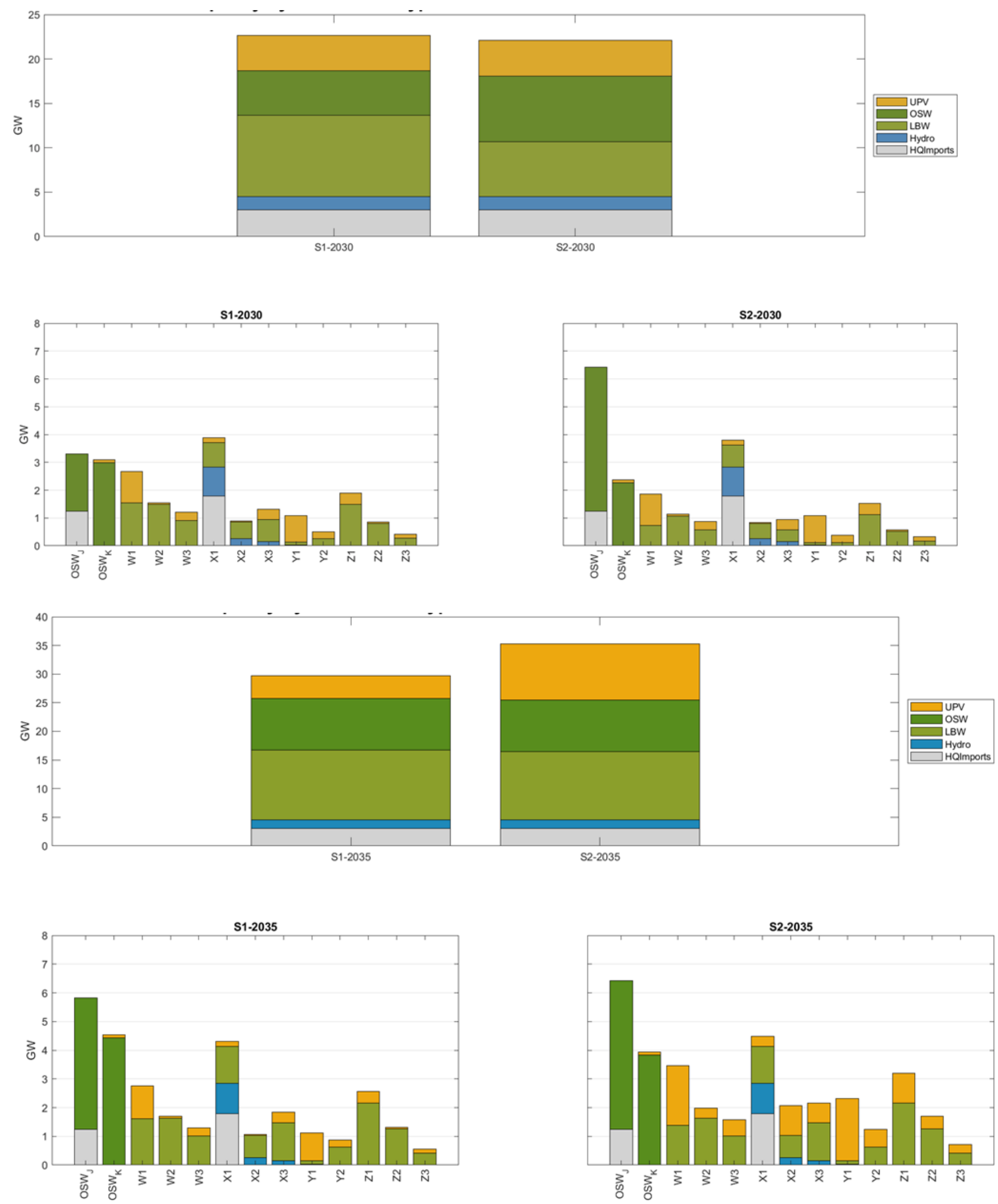

The new resource additions from the capacity expansion simulations were placed at available buses identified in the Interconnection Queue for new wind (land-based and offshore) and solar units. These locations represent the probable sites for new resource additions and provide likely interconnection points on the existing system. Most of the resources added in S1 and S2 are located inside the general pocket locations identified in the Contract Case. This is intuitive since the pockets represent locations where future generators are most likely to interconnect. A study of local congestion within these pockets provides a look ahead at expected obstacles in the transmission system to transmit power out of the pockets to serve loads elsewhere. A detailed look at each individual pocket and associated metrics is provided in Appendix J of this report.

#### Policy Case pocket level results

The chart below shows the summer capacity in the pockets by generator type for S1 and S2 in years

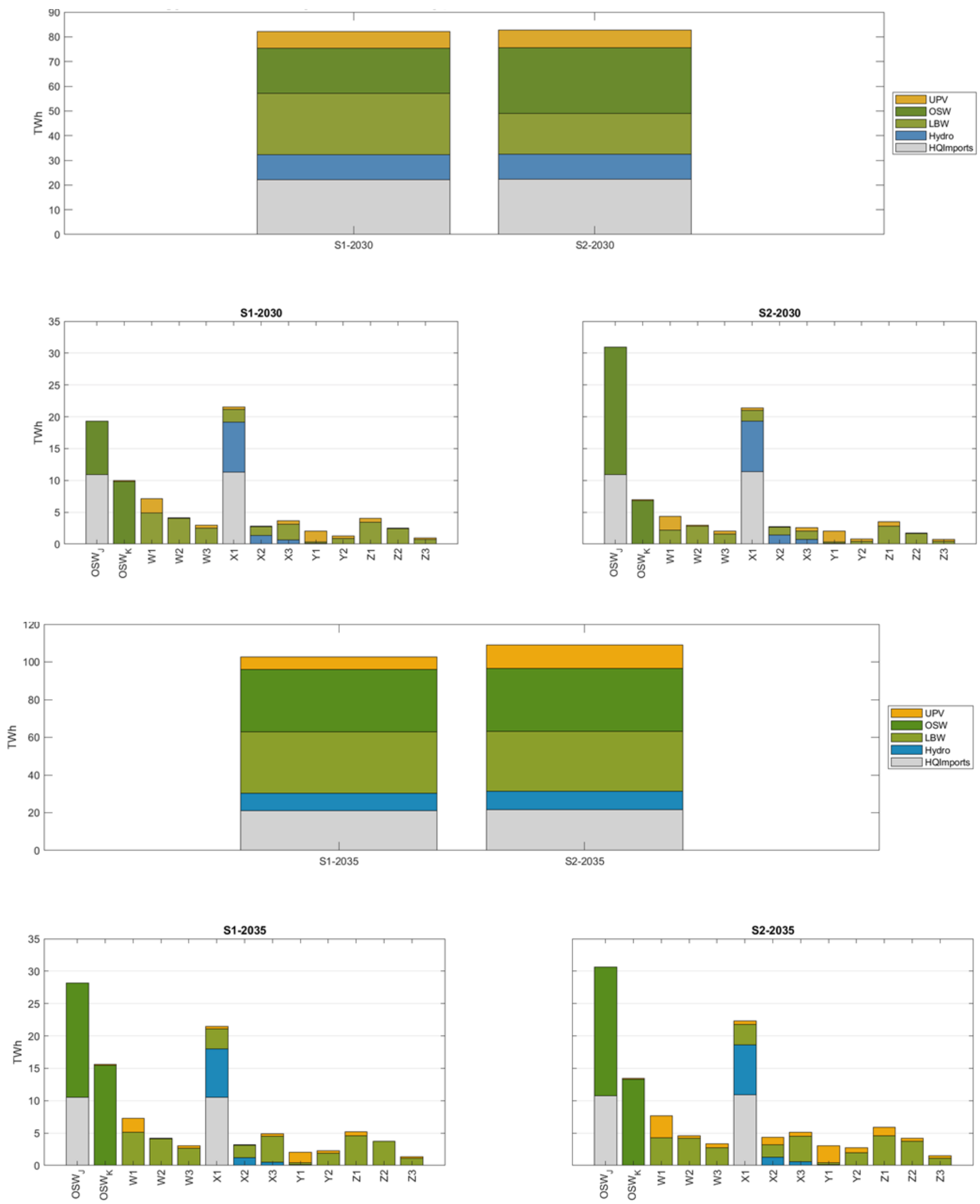
2030 and 2035 based on the additions from capacity expansion simulations for each scenario and existing Baseline and Contract Case resources. These charts illustrate the differences in buildout between S1 and S2 across resource types. Major differences between S1 and S2 are higher offshore wind capacity in S2 in 2030, higher overall land-based wind capacity in S1 in 2030, and notably higher solar capacity in S2 in 2035.

**Figure 45: Summer Capacity by Generation Type Across Identified Pockets**



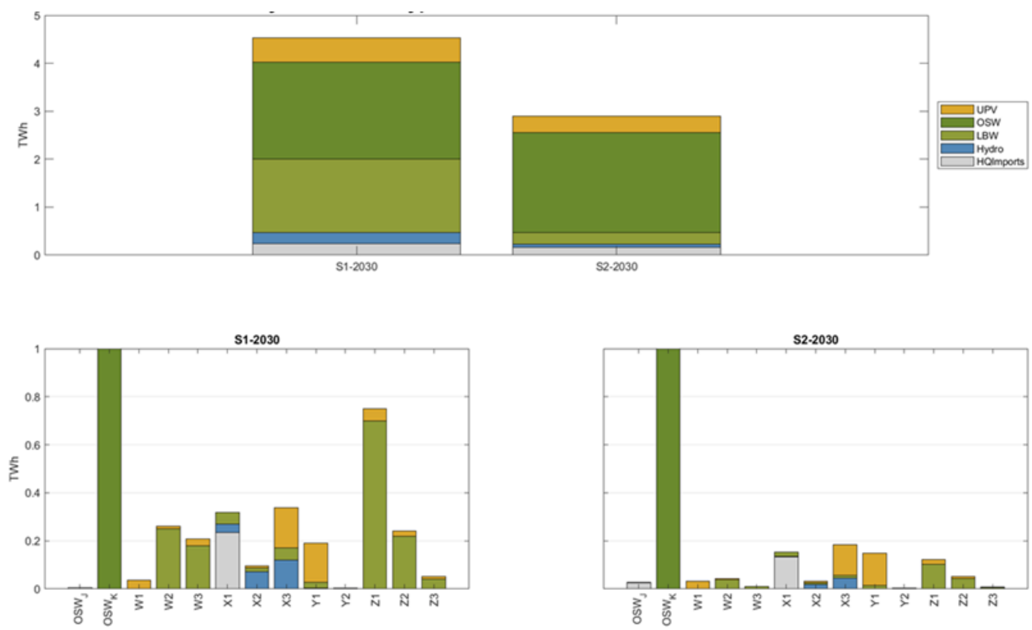
The energy production from generators within the pockets in 2030 is approximately the same on aggregate for S1 and S2. However, the distribution of energy between land-based wind and offshore wind is different, owing to the differences in installed capacity between the two scenarios. S2 has slightly higher generation due to higher solar buildout in 2035 and retirements of existing fossil resources.

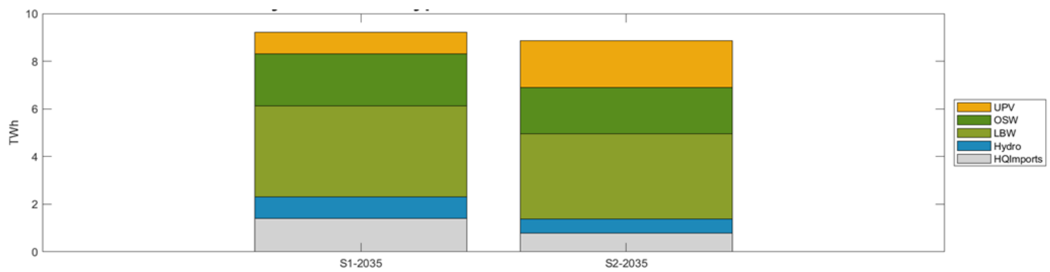
**Figure 46: Energy Production by Generator Type Across Identified Pockets**

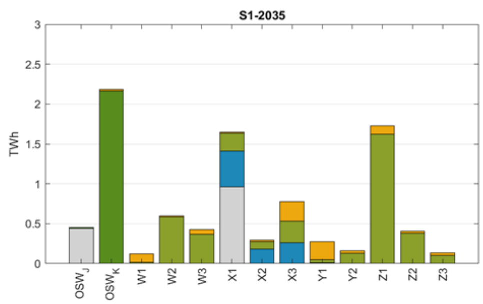


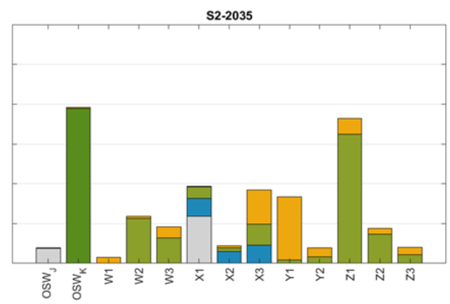

Due to large amounts of renewable resources added in the Policy Cases, the level of curtailment is high compared to the Baseline and Contract Cases. Offshore wind curtailment continues to stand out as the largest curtailment by generator type in 2030 for both Policy Cases. Local congestion at the point of interconnection and surrounding constraints causes high levels of curtailment for this resource, which would need to be resolved in a separate process. Curtailment of resources is also highly dependent on retirements of existing fossil fuel resources. S2 has more capacity retiring in 2030 compared to S1, driven by differing assumptions between the two scenarios. Some fossil fuel units (especially in Zones J and K) have must-run reliability rule requirements that require them to be online or generate in most hours of the year. Retiring such units allows for more flexible resources to generate or intermittent resources to dispatch when available to a greater extent.

**Figure 47: Curtailment by Generation Type Across the Identified Generation Pockets**






**Policy Case Bulk Transmission Congestion**

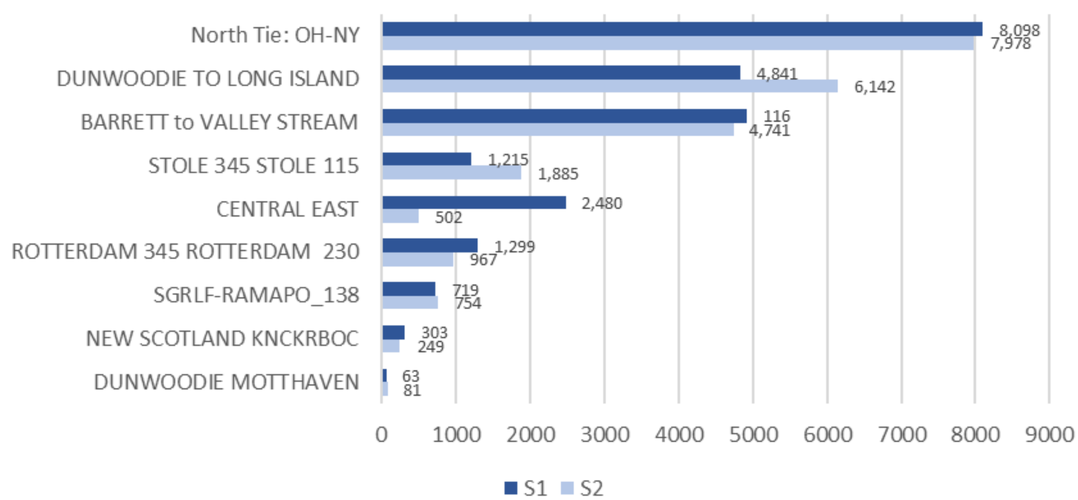
Bulk level lines and interfaces in the Policy Cases remain some of the most congested elements in the system, owing to their high transfer capabilities to move power from areas of high renewable resource injection to load centers. Some historically congested interfaces such as *Central East* might have different congestion patterns depending on resource buildouts and load levels on either side of the interface. Another interface that is highly dependent on resource buildout is *Dunwoodie* to *Long Island*, which usually transfers power from upstate to Long Island (Zone K). Due to high amounts of Offshore Wind resources built in the Policy Case, congestion on this interface drops as more resource capacity is added. Overall, the congestion increases on the system as more resources are added and no upgrades are made on the existing transmission system.

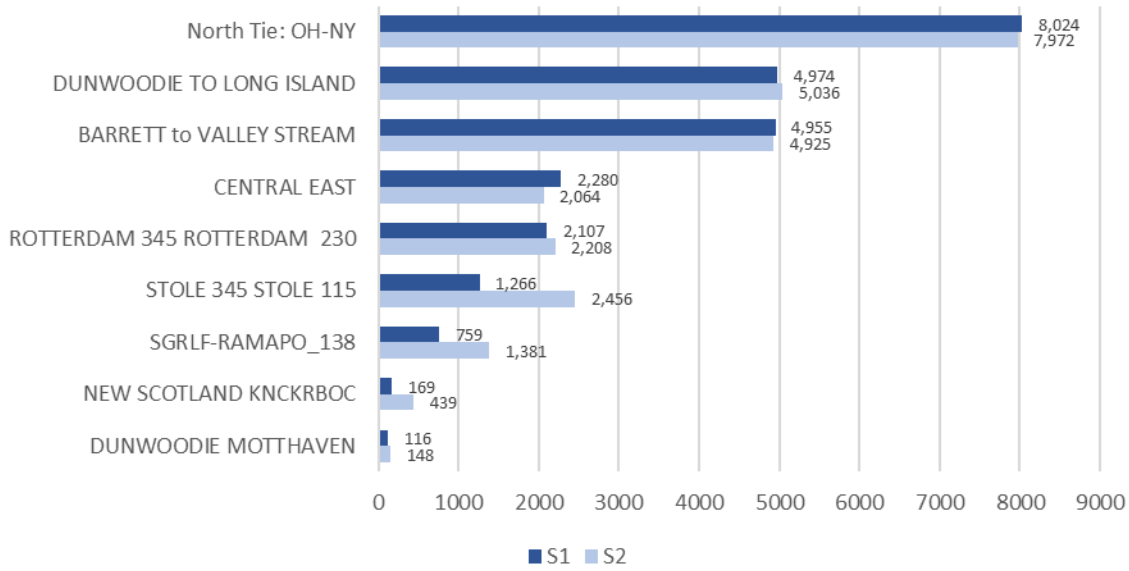
**Figure 48: Percentage of Hours Congested, Years 2030 and 2035**

| % of Year Congested (2030) | S1 | S2 |
|---|---|---|
| North Tie: OH-NY | 92% | 91% |
| DUNWOODIE TO LONG ISLAND | 55% | 70% |
| BARRETT to VALLEY STREAM | 56% | 54% |
| STOLE 345 STOLE 115 | 14% | 22% |
| CENTRAL EAST | 28% | 6% |
| ROTTERDAM 345 ROTTERDAM 230 | 15% | 11% |
| SGRLF-RAMAPO_138 | 8% | 9% |
| NEW SCOTLAND KNCKRBOC | 3% | 3% |
| DUNWOODIE MOTTHAVEN | 1% | 1% |

| % of Year Congested (2035) | S1 | S2 |
|---|---|---|
| North Tie: OH-NY | 92% | 91% |
| DUNWOODIE TO LONG ISLAND | 57% | 57% |
| BARRETT to VALLEY STREAM | 57% | 56% |
| CENTRAL EAST | 26% | 24% |
| ROTTERDAM 345 ROTTERDAM 230 | 24% | 25% |
| STOLE 345 STOLE 115 | 14% | 28% |
| SGRLF-RAMAPO_138 | 9% | 16% |
| NEW SCOTLAND KNCKRBOC | 2% | 5% |
| DUNWOODIE MOTTHAVEN | 1% | 2% |

**Figure 49: Number of Congested Hours for Bulk Constraints, Years 2030 and 2035**





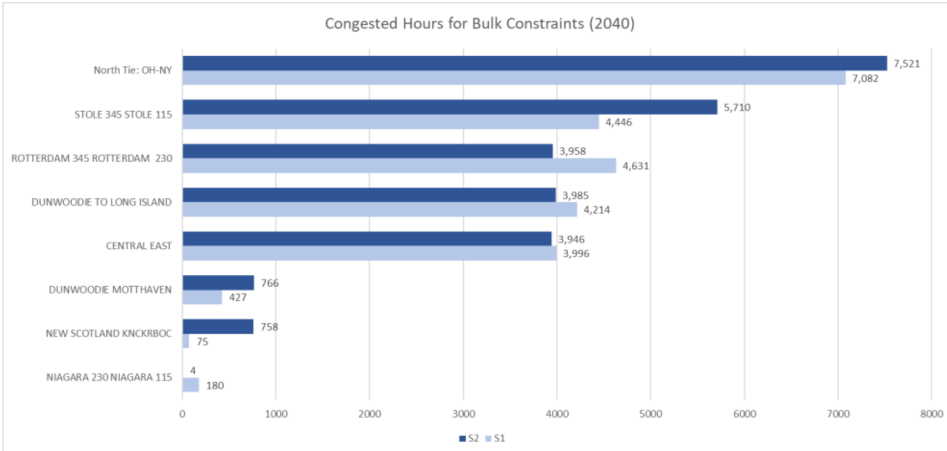

In the 2040 simulation year, all lower kV constraints (<200 kV) in NYCA were relaxed to enable a simulation solution. With the limits on these lines removed, the flows and congestion on the bulk system under a high renewable penetration scenario at full CLCPA achievement can be effectively evaluated. Removing limits on lower kV lines where most of the renewable resources interconnect allows for additional energy to reach to the bulk level, which moves power over greater distances across the state into load centers.

The chart below shows the congested hours for the same list of bulk level transmission elements as those mentioned above for 2030 and 2035. The congested hours chart below shows that the congestion on bulk system mostly increases with additional resources added and lower voltage system relaxed. Some interfaces also can have lower congestion due to congestion on lines further upstream at the bulk level.

**Figure 50: Percentage of Hours Congested, Year 2040**

| Constraint | S1 | S2 |
|---|---|---|
| North Tie: OH-NY | 81% | 86% |
| STOLE 345 STOLE 115 | 51% | 65% |
| ROTTERDAM 345 ROTTERDAM 230 | 53% | 45% |
| DUNWOODIE TO LONG ISLAND | 48% | 45% |
| CENTRAL EAST | 45% | 45% |
| DUNWOODIE MOTTHAVEN | 5% | 9% |
| NEW SCOTLAND KNCKRBOC | 1% | 9% |
| NIAGARA 230 NIAGARA 115 | 2% | 0% |

**Figure 51: Number of Congested Hours for Bulk Constraints, Year 2040**

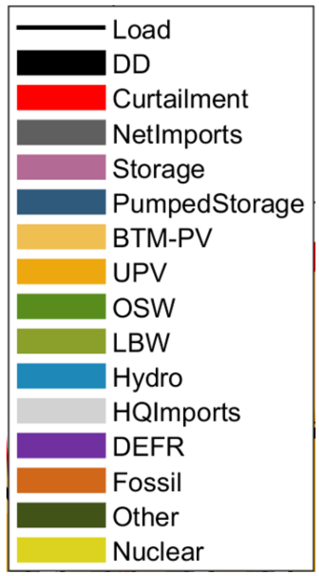



The 2040 case with lower kV lines relaxed highlights the need for additional transmission capability on the bulk system assuming all lower kV level congestion is resolved. This shows that building large scale renewable resources in areas where they are feasible also requires upgrades to the existing bulk level transmission system to fully utilize energy generated by these resources.

**Policy Case Seasonal Hourly Analysis**

Leveraging the hourly results from production simulation, an hourly generation analysis for each scenario across years and seasons was performed. A diagram summarizing each scenario is provided with Figure 52 and Figure 53below. Each chart is also provided in greater detail in Appendix XX. Below is information to assist in effectively viewing information presented in the series of hourly charts:

- All charts are presented with a data range between -20GW and 70GW
- Each of the 3 seasons presented represent a single month of hourly simulation results with the following dates represented by each:
  - Spring: April 1 – April 30
  - Summer: July 1 – July 31
  - Winter: January 1 – January 31
- The Fall season is very similar to the Spring season and was therefore not presented for simplicity purposes.
- Chart Key:



Load
DD
Curtailment
NetImports
Storage
PumpedStorage
BTM-PV
UPV
OSW
LBW
Hydro
HQImports
DEFR
Fossil
Other
Nuclear

**Figure 52: Scenario 1 Seasonal Hourly Generation by Type**

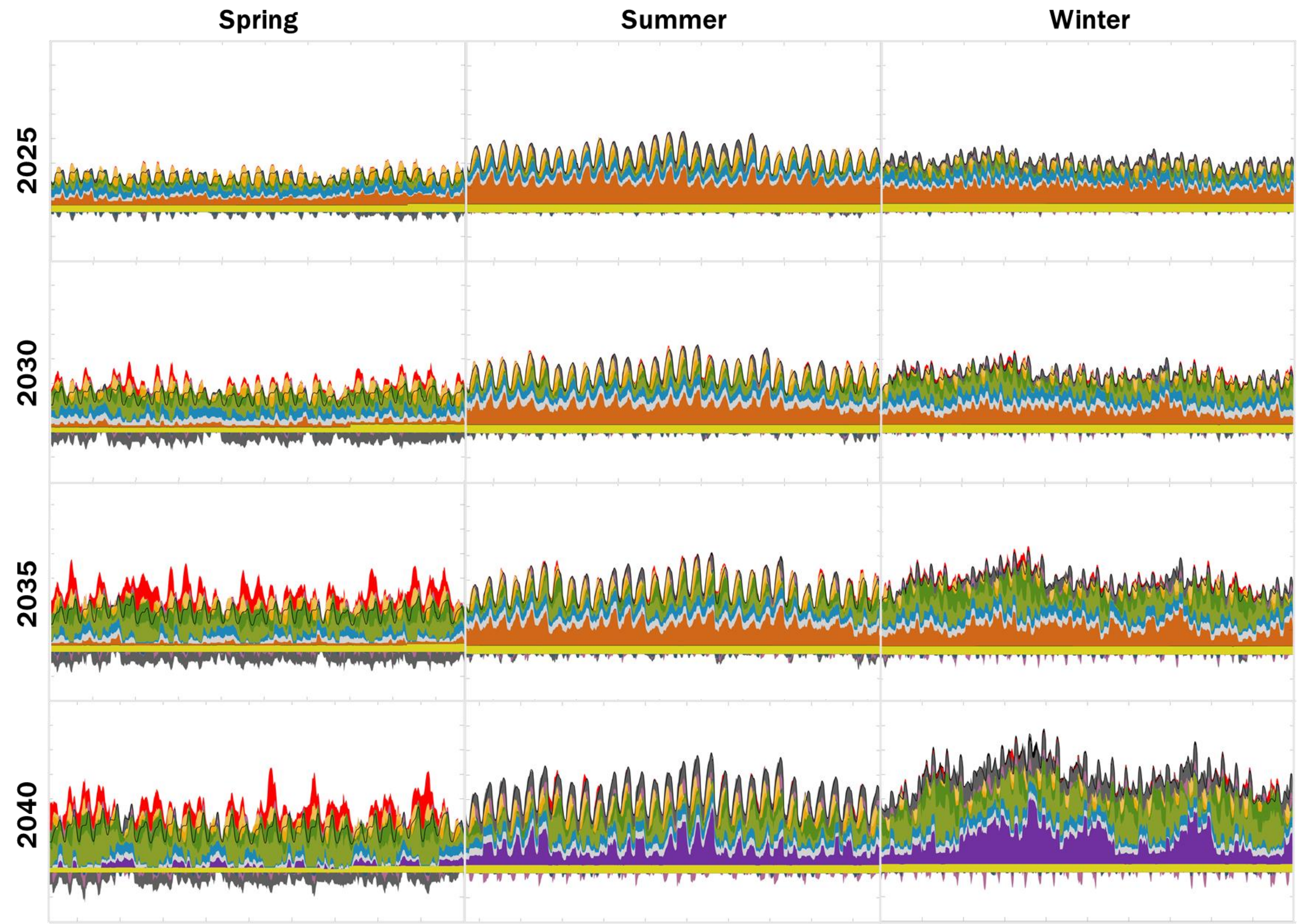
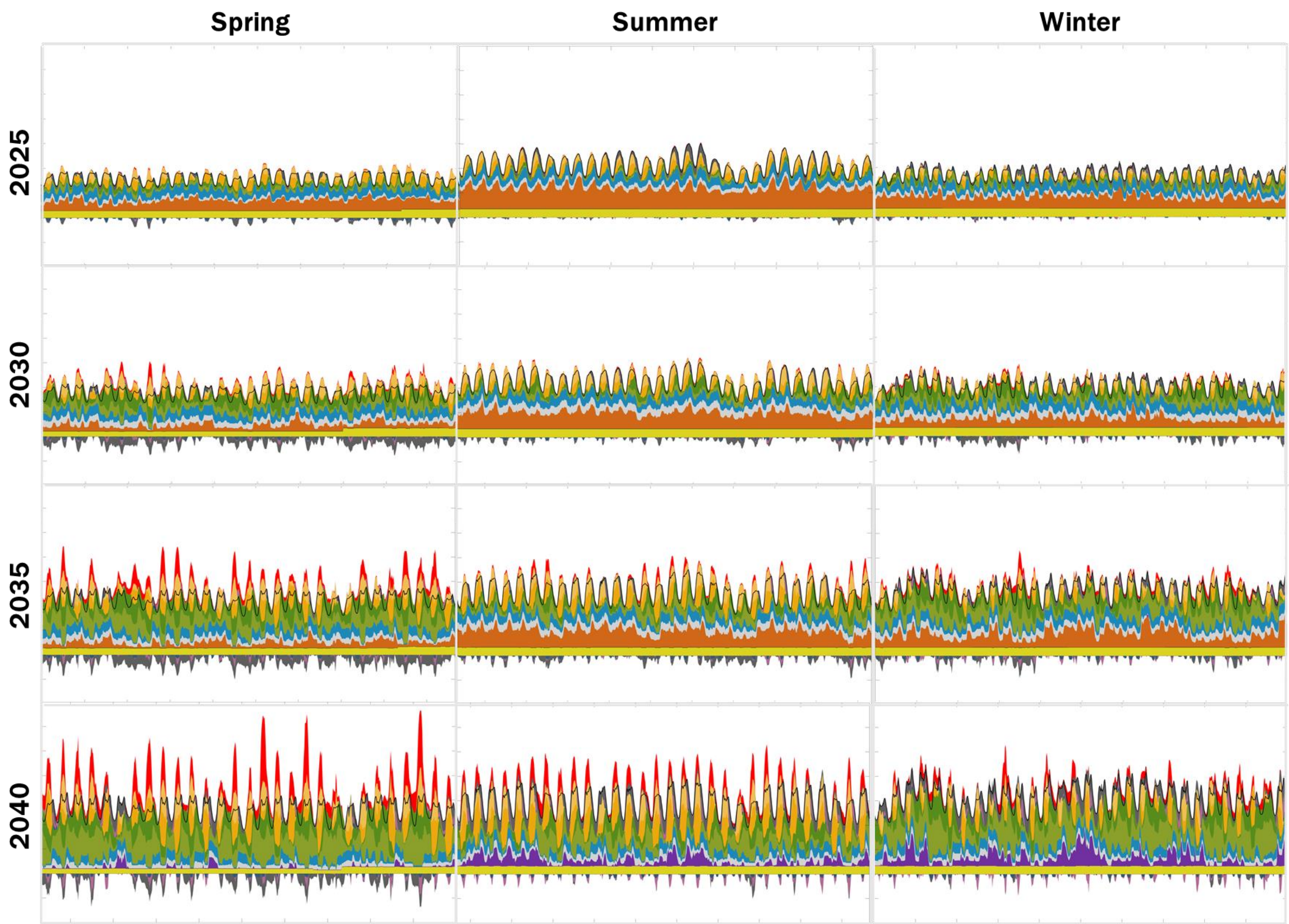


**Figure 53: Scenario 2 Seasonal Hourly Generation by Type**



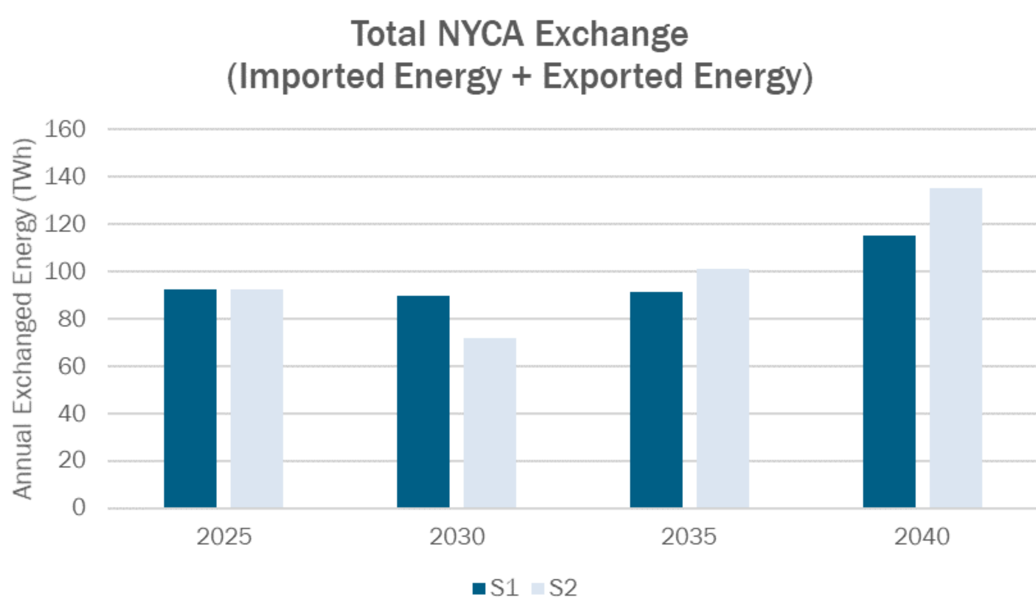
Some observations obtained from evaluating the seasonal and five-year trends from each scenario follow:

- In both S1 and S2, the Spring season experiences the most curtailment of wind, solar, and hydro generation. Spring in New York can be characterized as having lower energy demand (less heating and cooling required because of more moderate temperatures), higher wind generation profiles, moderately high solar irradiance, and high water flows due to snow-melt runoff. These weather characteristics result in a power system condition where significant renewable generation energy is available while electric demand is low, which ultimately leads to high levels of curtailment of resources as they are not needed.
- Fossil fleet operation is at a minimum during the Spring and a maximum during the Summer season. Fossil generation online during many Spring days has been committed for reliability purposes and represents the minimum potential fossil dispatch.
- As time progresses through the study period and increased economic or age-based retirements occur an increasing amount of renewable capacity has to be built to replace the capacity and energy provided by the retired generators. S2 includes an increased number of age-based retirements compared to S1 (~9 GW scheduled fossil retirements). This results in a larger amount of renewable generation capacity built by 2035 being primarily solar in S2. Comparing the 2035 Summer period between S2 and S1, one can observe a large amount of solar induced curtailment during peak hours as a result of the increased solar capacity on the system, which is attributable to the additional age-based retirements assumed in S2.
- The production cost model includes nodal representations of three (3) of New York's neighboring systems. Like today's energy market operations, the economic exchange of energy occurs between markets through imports and exports with each neighbor. In both S1 and S2, the reliance on imported and exported energy to meet system demands changes by season. In Spring and Fall, New York exports the excess of renewable energy produced that cannot be consumed with lower load levels and minimal dispatchable generation available. Energy interchanged differs between S1 and S2 during Summer as S1 exhibits a diurnal pattern of imports during daytime net-peak load and overnight exports, which increase through time. S2 exhibits a differing pattern where energy is imported in 2025 and 2030 to assist in meeting peak load until significant amounts of solar capacity is built by 2035 when the system tends to export the excess solar during peak periods. The Winter season interchange patterns are more

variable in both scenarios and tends to change day-to-day depending on the net load pattern. Low levels of solar production and higher levels of wind production has the effect of aligning interchange more closely with wind production patterns, especially as more land-based and offshore wind capacity is built through time.

- The magnitude of interchange, both imports and exports, increase through time in both scenarios as more variable renewable resources are added to the system. Figure 54 below shows the total magnitude of interchange. S1 and S2 increase energy exchange by 24% and 47% by 2040 with S2 having a higher value due to having a much larger energy demand and greater variability in net-load.

**Figure 54: Total Annual Interchanged Energy with ISO-NE, PJM, and IESO**




- Most of the renewable downward dispatch observed is a result of "curtailment" caused by transmission congestion as opposed to "spillage" caused by net-load exceeding dispatchable generation + exports. While neighboring systems were included in the model, any new policy-based generation capacity was not included in those systems. Excess renewable energy generated within NYCA would likely flow into neighboring regions provided the flow does not encounter any congestion. Any curtailment observed for resources in NYCA is likely due to congestion of transmission paths within the four-pool model. If neighboring regions were to be modeled with policy goals like New York, limitations on exports to neighboring regions would likely result in spillage of unused energy.

- Storage is modeled using the production cost model's internal scheduling function and represented on a zonal basis in a distributed fashion in the same way BTM-PV is distributed to buses within a zone. Storage discharge shapes target cost minimization using initial unit commitments around net load to reduce overall system costs, charging when net loads are low (and prices are low) and discharging during peak net loads (and prices are higher). The price spread must be sufficient to overcome storage losses to reduce cost on the modeled system.
- In both cases, the dispatchable fleet transitions from requiring maximal operation during the summer peak to during a winter peak in the mid-2030s. This transition continues into 2040 as DEFRs operate at higher levels during winter. Ramping behavior of the dispatchable fleet increased due to larger diurnal load swings driven by electrification and the increasing level of weather dependent intermittent renewable resources added. New resources with increased ramping capabilities will be needed to balance load with supply across the system and during multiple timescales.

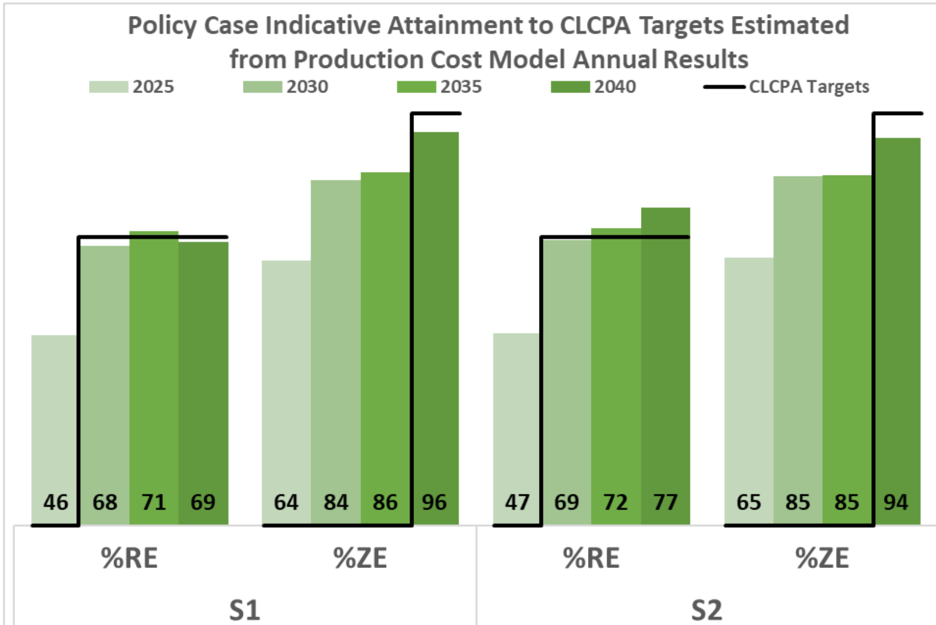
### Policy Attainment

The official renewable generation accounting towards CLCPA policy attainment will be based on programs to be developed by the NYSPSC. In this analysis, a simplified representative calculation of the renewable and zero-emissions percentages are provided for informational purposes. These output metrics are distinct from the actual computations performed by NYSERDA/NYSPSC to calculate the state's fuel mix and progress towards achieving the CLCPA targets, e.g., imports and exports were not considered as part of this simplified calculation.

In the production cost model, the generation placement is based on the results of capacity expansion analysis, and no further attempt was made to achieve full attainment of CLCPA requirements as the Outlook is focused on identifying the challenges to the system along the way to, rather than the exact solutions to, achieving policy goals.

The CLCPA Targets include 70% renewable generation in 2030 and (100%) zero-emissions in 2040. Indicative CLCPA annual renewable energy (%RE) and zero-emissions (%ZE) metrics were calculated and compared against the targets as show in the figure below.

**Figure 55: Policy Case CLCPA Target Attainment Estimate**




The specific calculations for renewable energy and zero-emission energy were as follows:

*RE = LBW + OSW + UPV + BTM-PV + Hydro + HQ Imports*

*ZE = RE + Nuclear + DEFR*

*%RE = RE/Gross Load*

*%ZE = (ZE + Storage Discharge)/(Gross Load + Storage Charge)*

Storage includes Pumped Storage and Batteries. The percentage of ZE computed in all years includes impact of Storage Discharge and Storage Charge even though not all storage charging will be from ZE: supply before 2040.

### Operational Analysis

#### Existing Thermal Fleet Impact

The existing fossil fleet currently operates to maintain the supply and demand balance in response to changes in net load, forecast uncertainty, reliability rules, and real-time events. Net load is defined here as the system load minus the output of intermittent resources such as wind and solar generators. In addition, fossil fuel-fired generators may be called on to provide reserves, regulation, and/or other products that help maintain the reliability of the grid. As increasing levels of intermittent generation are added to the system, this dispatchable fleet is expected to operate more flexibly and less frequently overall across an increasing number of starts. This occurs because many renewable generators will be selected to run in the

NYISO's markets due to low operating and zero fuel costs.

Examination of the operational patterns of the dispatchable fleet in the Policy Cases reveals trends associated with the future fleet operations. The fossil fleet is called upon to start more often to compensate for the variability of the intermittent renewable energy generation. In 2035, when both fossil and DEFR generators are available, the fossil fleet provides nearly all the flexible operations. By 2040, as the DEFR generators become the only dispatchable option they tend to fill the role which was previously filled by the fossil fleet's operations. Overall, the total number of starts in 2035 are the highest of the model years at approximately 10,000 starts per year.  The number of DEFR starts decrease in 2040.

The figures below show cumulative capacity curves for several operational parameters across different segments of the fossil fleets. Each point along a curve represents a single generator's operational performance over the course of the model years in the S1 and S2 cases.

Operations of the combined cycle (CC) fleet are most sensitive to increasing penetration of renewable generators as they currently operate most frequently and flexibly among the fossil fuel-fired generation fleet. Results indicate reductions in CC capacity factors and an increase in the number of starts for these generators moving from 2025 to 2030 and 2035. Meanwhile, the simple cycle combustion turbine (CT) fleet, which typically operates less frequently, sees an increase in both annual capacity factor and number of starts as these generators are used more often to fill in shorter intervals in the net load requirements. The steam turbine (ST) fleet has a more muted response, due to the less flexible nature of these generators, where both an increase and decrease in capacity factor and starts are observed across the fleet. Before 2040, while some DEFR are available, so too are fossil fuel-fired generators which continue to operate such that the DEFR fleet is rarely, if ever, called upon. In 2040, as all fossil fuel-fired generators are retired the DEFR fleet serves the role of meeting net load. Generally, the DEFR fleet operates at capacity factors below 20% (similar to ST units) but has a larger number of starts (similar to CC units), indicating generally lower runtimes per start than either the ST or CC fleets.

**Figure 56: Fossil Fleet Cumulative Capacity Curve: Unit Level Capacity Factors**

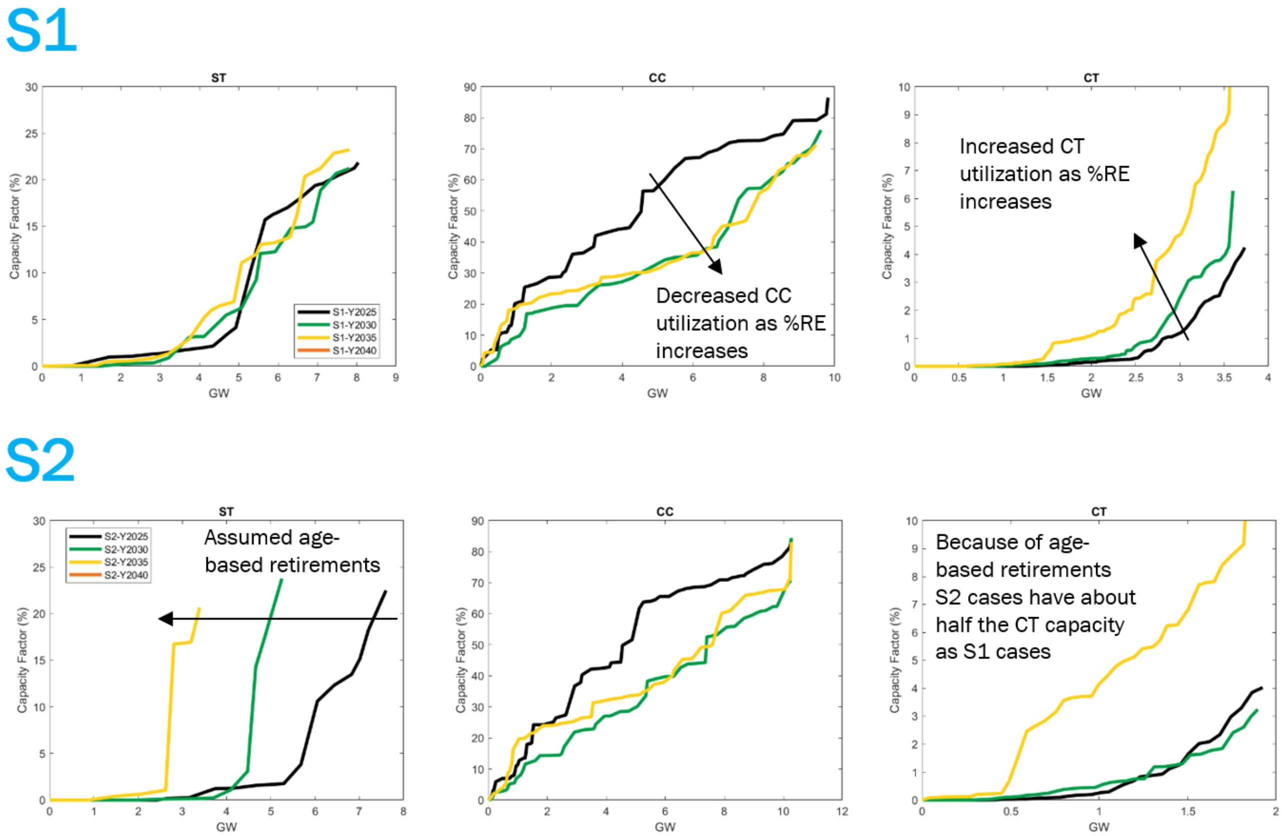



**Figure 57: Fossil Fleet Cumulative Capacity Curve: Unit Level Number of Starts**

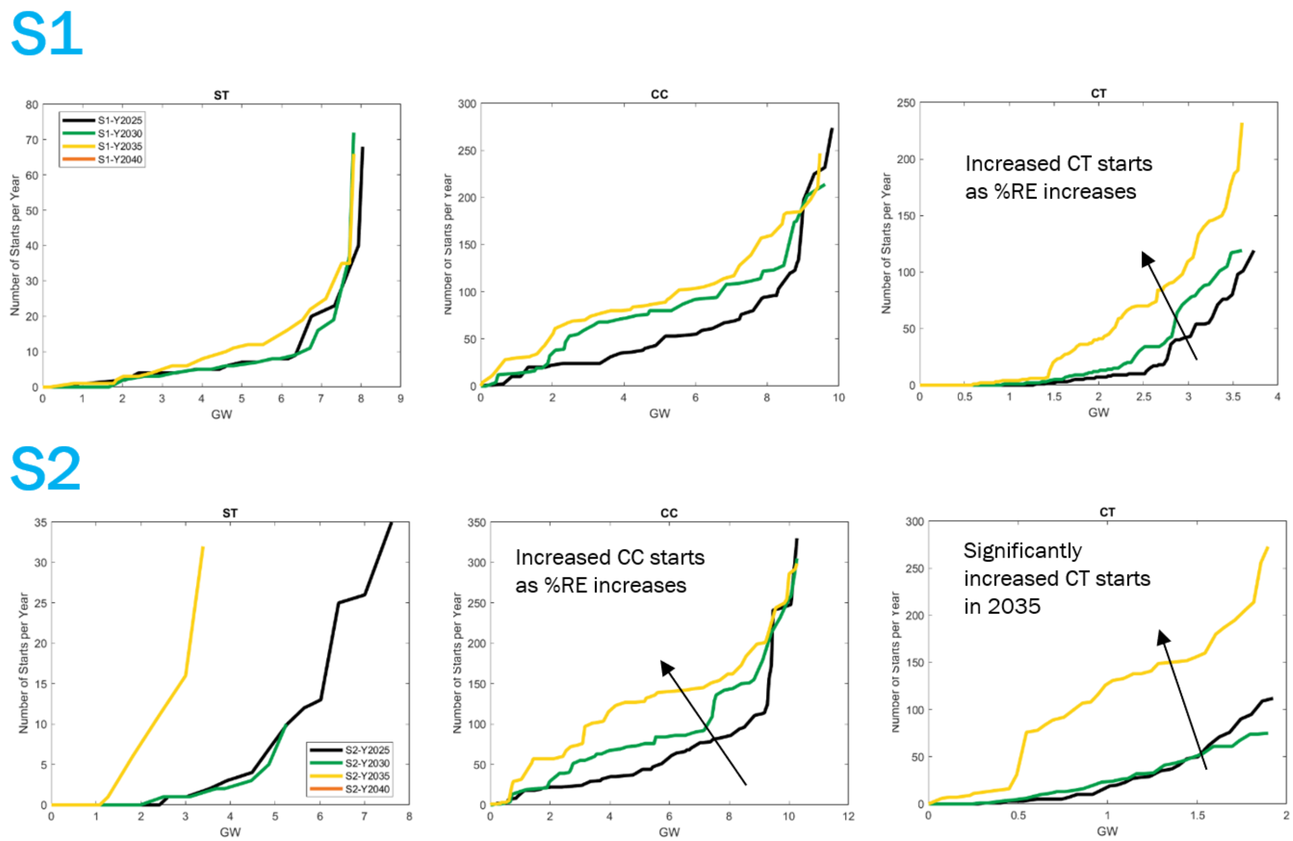
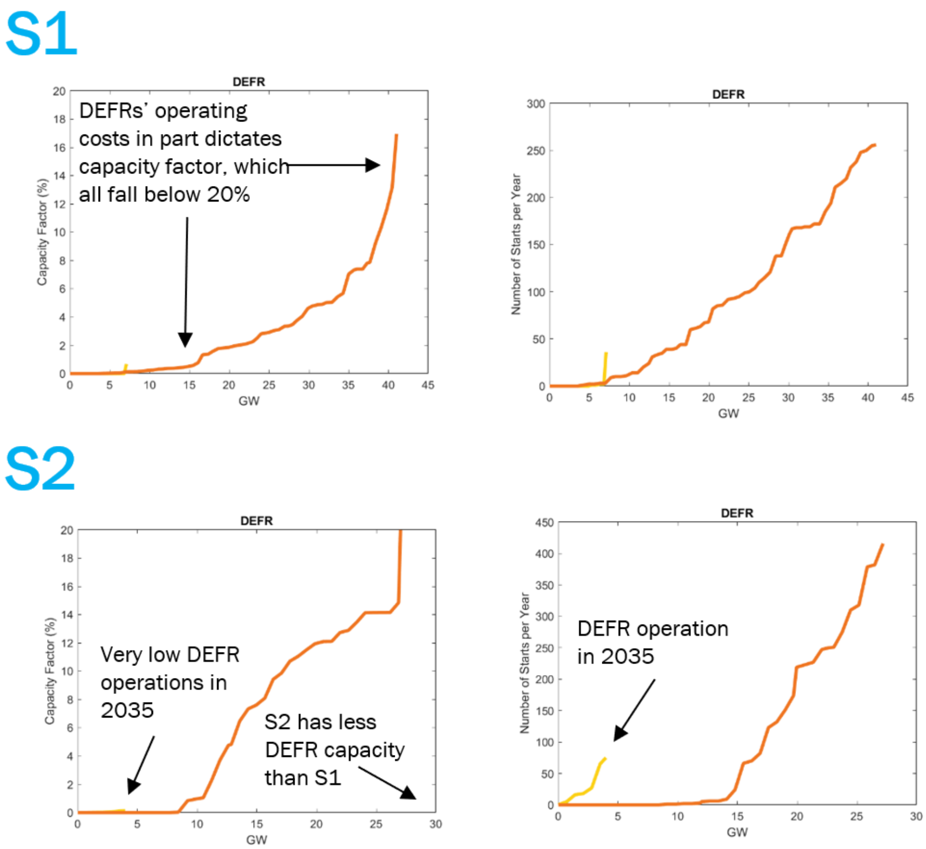



**Figure 58: DEFR Cumulative Capacity Curve: Unit Level Capacity Factors and Number of Starts**




Hourly ramp rates of the fossil fleet in 2030 allows the flexibility of these generators to be examined.. Figures showing hourly operation by fuel type in both cases are displayed in Appendix X. The figures below display the NYCA fossil fleet maximum up (increasing output) and down (decreasing output) ramp, in MW/hour which occurred during each month and hour and signify the highest increase or decrease in fossil fleet output called upon in the model in each hour of each month. Generally maximum up-ramps increase throughout the study period and display consistent ramp-demand patterns in both S1 and S2. High up-ramp requirement periods generally align with the traditional morning load pickup as well as the late afternoon net-load increase caused by the sharp decrease in solar production as loads rise past sunset.

Fossil fleet maximum up-ramp occurred during the morning and afternoon load ramp events across the year, while down-ramp primarily occurred in the late overnight intervals. High down-ramp needs are concentrated around the midnight hour as load decreases towards its minimum value each day.

**Figure 59: Maximum Fossil Fleet Up-Ramp by Month and Hour**

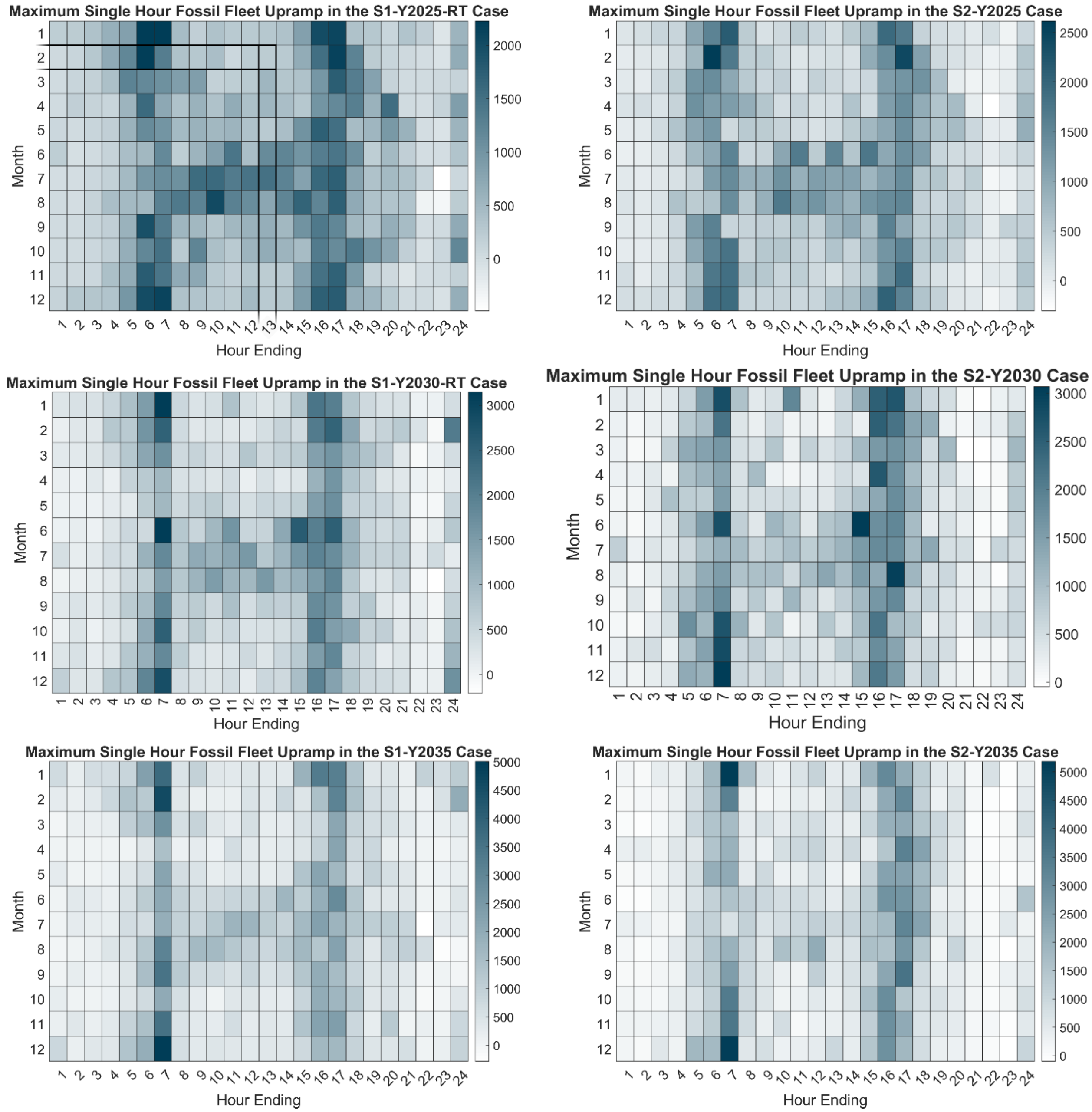
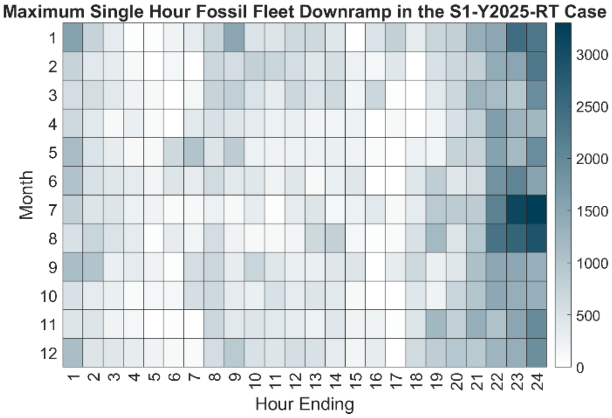
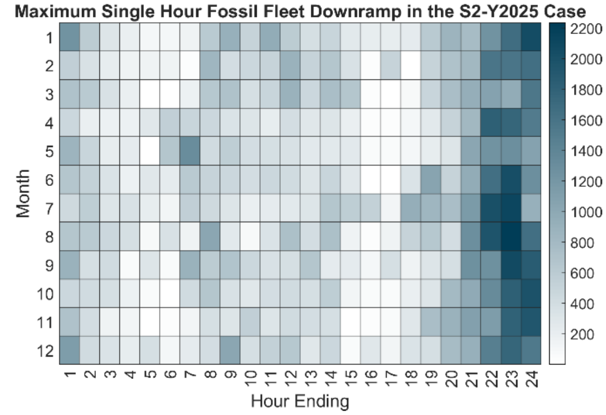



**Figure 60: Maximum Fossil Fleet Down-Ramp by Month and Hour**

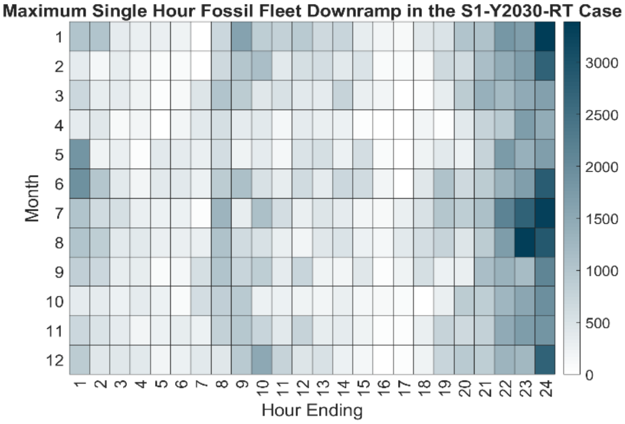
Maximum Single Hour Fossil Fleet Downramp in the S1-Y2025-RT Case



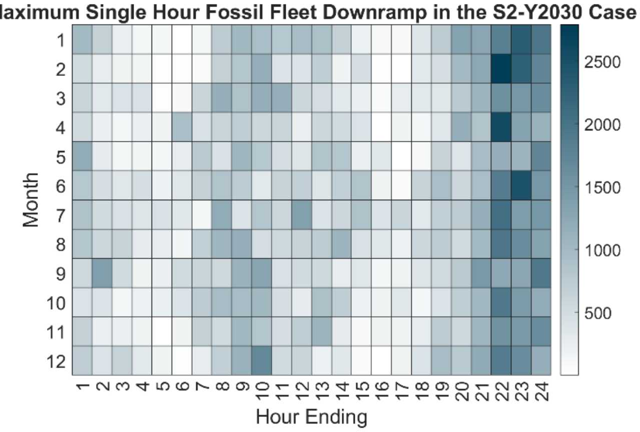

Maximum Single Hour Fossil Fleet Downramp in the S2-Y2025 Case



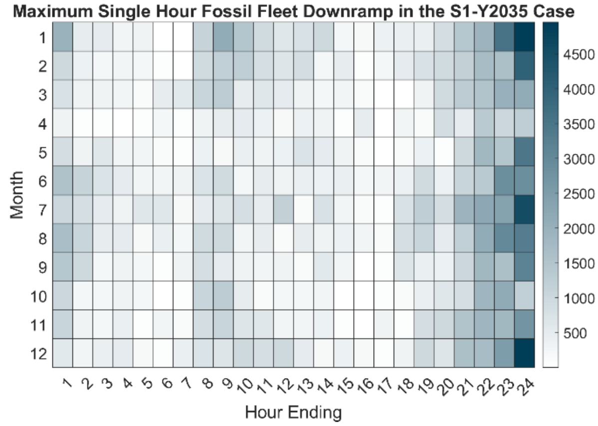

Maximum Single Hour Fossil Fleet Downramp in the S1-Y2030-RT Case



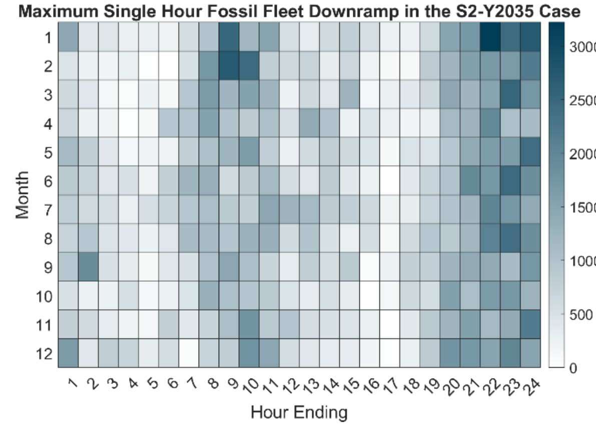

Maximum Single Hour Fossil Fleet Downramp in the S2-Y2030 Case




Maximum Single Hour Fossil Fleet Downramp in the S1-Y2035 Case




Maximum Single Hour Fossil Fleet Downramp in the S2-Y2035 Case

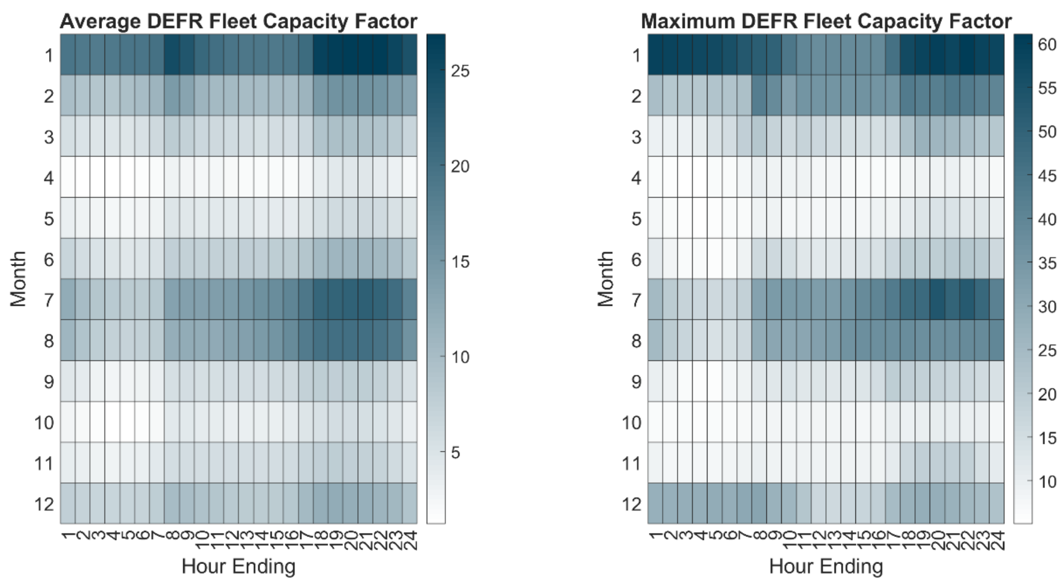


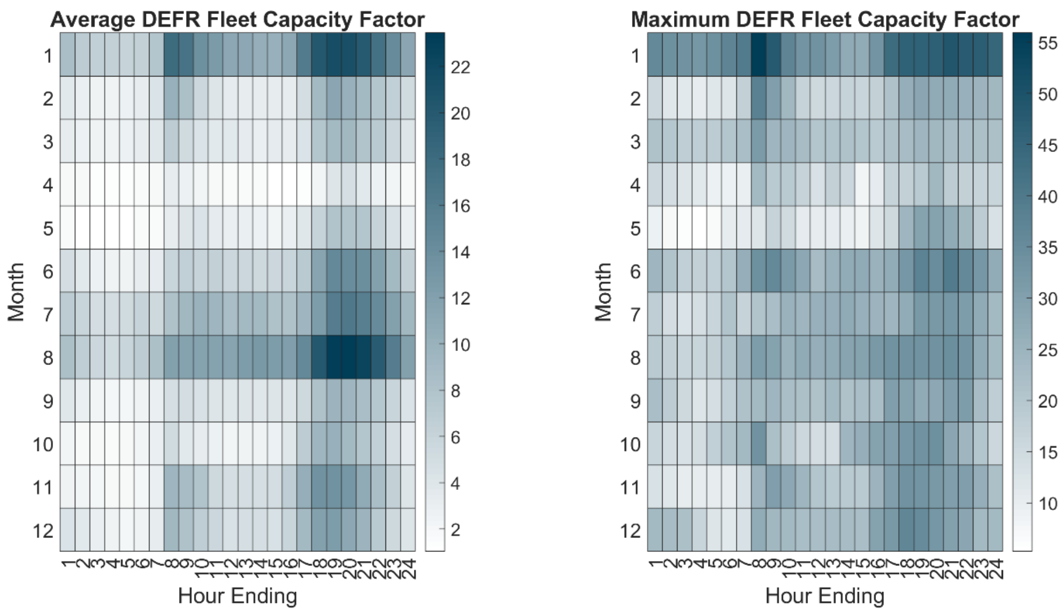

**DEFR Operation & Implications**

While not currently commercially available, the DEFRs will be expected to balance load and supply on a zero-emissions grid. Although DEFRs operate at some level in all years included in the simulations, they do not operate significantly until 2040, when the NYCA has no fossil generators available.

The figure displays, in a month-hour binning, the average and maximum capacity factors of the entire DEFR fleets in 2040 for both scenario cases, S1(top) and S2 (bottom). DEFR output increases in the summer and winter months and is reduced during the shoulder spring and fall seasons with lower loads and higher renewable generation. In both cases, capacity factors appear to increase throughout the day. Similarities in operation across S1 and S2 would be expected because the same renewable profiles were used in both cases (but the buildout capacities were different). As different load shapes were used in the two scenario cases the net load contained some similar characteristics. The monthly-hourly pattern is similar to the pattern of maximal capacity factors in S1. However, in S2 the pattern of maximal DEFR fleet utilization becomes slightly more dispersed across more hours with a different structure.

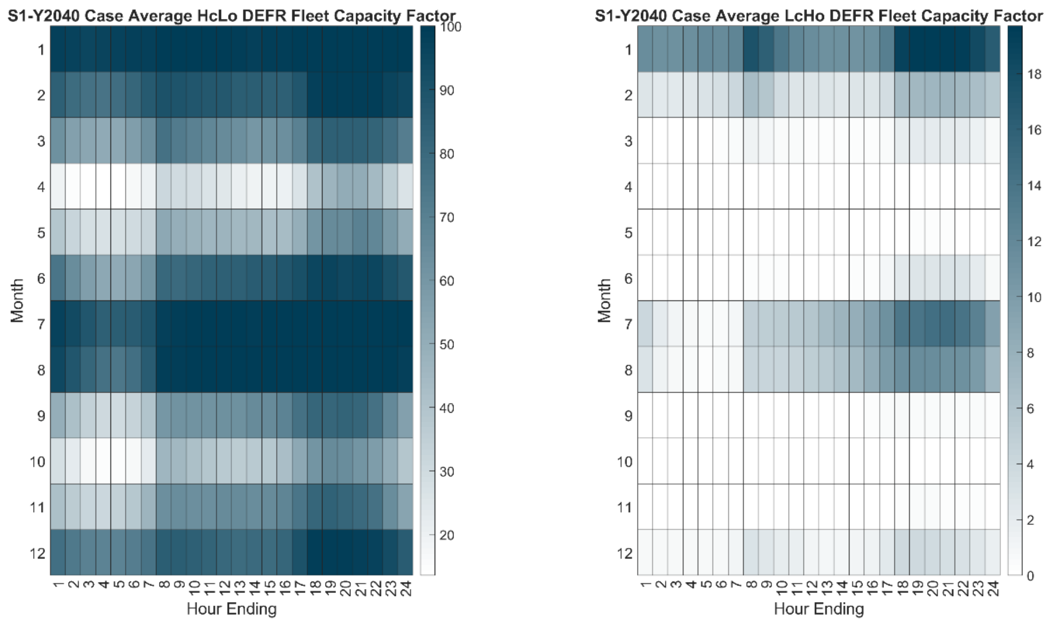
**Figure 61: Average and Maximum DEFR Fleet Capacity Factors by Month and Hour: 2040 S1 and S2**






In S1, two types of DEFRs were modeled in production cost while in S2 a single intermediate DEFR option was included. **Figure 62** shows the split operations of the High Capital Low Operating (HcLo) and Low Capital High Operating (LcHo) cost DEFR options in 2040 for Policy Case S1. The pattern of operations is similar, however, utilization of the low operating cost option (HcLo) was strongly preferred, as expected. The highest output of the high operating cost option (LcHo) occurs around the winter overnight peak in January 2040.

**Figure 62: Average DEFR Fleet Capacity Factor by Type by Month and Hour: 2040 S1**




Overall, the DEFR fleet operations mirrored those of the fossil fleet but with higher costs leading to overall lower operations. Comparison of the DEFR up-ramp and down-ramp pattern in the following figures show them to be similar but muted compared to the similar fossil fleet figures above. Significantly, the scale of the maximal hourly ramps increases across the DEFR fleet in comparison to the fossil fleets, indicating the impacts from increased electrification and as well as new requirements on the dispatchable fleet caused by increased renewable penetration.

**Figure 63: Maximum DEFR Fleet Upramp by Month and Hour: 2040 S1 and S2**

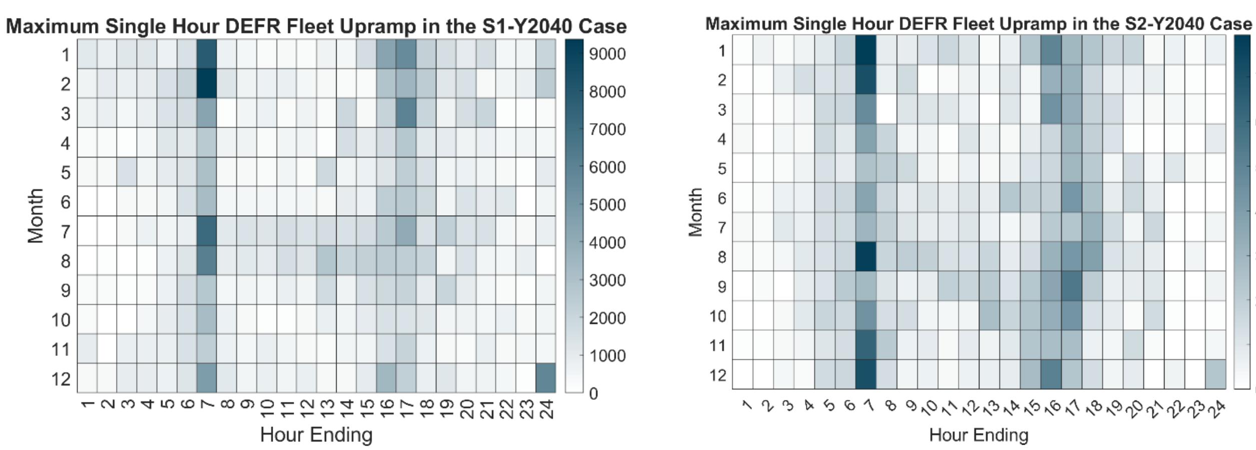
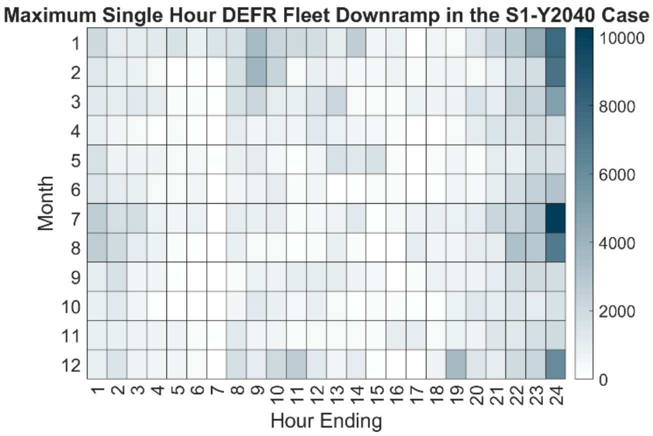
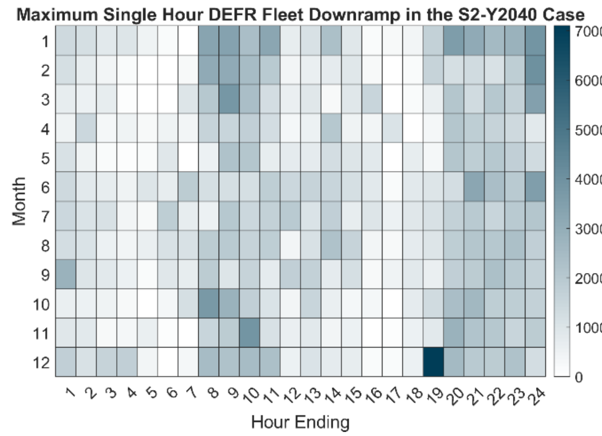



**Figure 64: Maximum DEFR Fleet Upramp by Month and Hour: 2040 S1 and S2**




The hourly model does not capture sub-hourly variations, day-ahead to real-time market arbitrage, forecast uncertainty, transmission outages and other unplanned events. These real-world considerations could tend to increase flexibility demand of DEFR generators. As stated in the assumptions section, as fossil generators were removed, additional reliability constraints were not imposed on the replacement DEFRs. Should additional reliability rules or programs be imposed, higher capacity factors and different operations would be expected to occur. The careful progression from an operating fossil fleet to one supplying similar services by an as-yet undefined set of technologies requires further study, including how reliability constraints may need to evolve as the system advances towards decarbonization.

### Key Findings

The simulations performed in the Policy Case provide insight into the challenges that New York power system will face as renewable and $CO_2$ free policy objectives are progressed. The NYISO has identified several important insights during the analysis of Policy Case simulations and data, which include:

- Dispatchable emission free resource (DEFR) technologies must be developed and deployed to meet policy objectives, reliability margins, and local capacity requirements.
- There are multiple potential paths to achieving policy targets. As the current system continues to evolve, evaluating a multitude of expansion scenarios will facilitate identification of common and unique challenges amongst them, which could lead to a greener and reliable future grid.
- Significant new resource construction will be required to achieve CLCPA energy targets. The total installed generation capacity to meet policy objectives within the NYCA is projected to be between 111 GW and 124 GW by 2040. For comparison, the Baseline and Contract Cases assume

approximately 42 GW and 51 GW installed capacity. This is a very significant increase in the amount of capacity needed to satisfy system and policy requirements.

- Resource buildout for meeting minimum capacity requirements is not sufficient, and building additional resources may be necessary to meet policy goals. When only sufficient resources are built to meet installed reserve and state/Locality capacity requirement, energy requirement will not be economically met while achieving CLCPA policy targets. If resources are not built in excess of minimum capacity requirements, NYCA will likely import significant amount of external energy that may or may not be renewable resources, but then there could be significant energy that is not deliverable during renewable energy peak producing hours.
- Transmission expansion, at both local and bulk levels, is critical to facilitate efficient CLCPA energy target achievement as transmission constraints will limit the effective transfer of renewable energy throughout the State.
- When dispatched effectively, energy storage would help to increase the utilization of the renewable generation, but energy storage likely cannot by itself completely resolve the transmission limitations in the pockets analyzed.
- Peak load management should be integrated as a measure to facilitate CLCPA energy target achievement. Comparing the two scenario cases tested in the Policy Case, by lowering the peak and avoiding buildout to serve the highest load hour, less DEFR buildout will be needed, and during the transition fossil fuel-fired plants would need to be utilized.
- Electrification from other sectors, such as building and transportation, into the power sector must be monitored and managed closely. Electrification is one of the largest factors driving peak and annual energy demand, which can lead to higher energy costs and reduced reliability.
- Existing local and bulk transmission networks will inhibit the ability to meet CLCPA Policy objectives. The Policy Case capacity expansion model produced two scenarios that each inherently meet policy objectives. When these generation capacity buildouts were modeled in the production cost simulation, which reflects a more detailed operation and limitations of the power system, significant curtailment was occurred. Curtailed energy directly impedes progress towards policy goals.
- As more intermittent renewable generation capacity of a single type is added to the system the contribution of adding more renewable resources towards meeting net-peak load is reduced. The

declining capacity value behavior of renewable capacity additions reduces their ability to meet reliability criteria as policy goals are approached.

- Capacity reserve margins were a major contributing factor to types of generation and quantities selected by the capacity expansion model.

## Conclusions and Recommended Actions

[In Progress]