2021-2040

System & Resource Outlook

Appendix

DRAFT for 7/26 ESPWG

Appendix A: Glossary

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

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

New York State Bulk Power Transmission Facility (BPTF): Facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to the Northeast Power Coordinating Council by the NYISO pursuant to Northeast Power Coordinating Council requirements. See NYISO OATT

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

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

CARIS: The now expired Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y. (As defined in the NYISO OATT.) The study is replaced by System & Resource Outlook and Economic Transmission Project Evaluation.

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

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

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

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

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

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

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

Day Ahead Market (DAM): A NYISO-administered wholesale electricity market in which Capacity, Energy, and/or Ancillary Services are scheduled and sold Day-Ahead consisting of the Day-Ahead scheduling process, price calculations, and Settlements. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM. (As defined in the NYISO Tariffs)

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

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

Dispatchable Emission Free Resource (DEFR): A proxy generator type assumed for generation expansion in the Policy Case to represent a yet unavailable future technology that would be dispatchable and produces emissions-free energy (*e.g.*, hydrogen, RNG, nuclear, other long-term season storage, etc.).

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

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

Economic Transmission Project Evaluation (ETPE): The evaluation of a Regulated Transmission Project by the NYISO. Under this process a Developer can propose a RETP to address constraint(s) on the BPTFs identified in the Economic Planning Process for purposes of potential cost allocation and cost recovery. The process is further described in Sections 31.3.2, 31.5.1, 31.5.4, and 31.5.6 (As defined in the OATT.)

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

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

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

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

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

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

Gold Book: Annual NYISO publication, also known as the Load and Capacity Data Report. See Library/Reports at NYISO.com

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Multi-Area Production Simulation (MAPS) Software: An analytic tool for market simulation and asset performance evaluations.

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

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

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

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

New York State Department of Public Service (NYDPS): The New York State agency that supports the New York State Public Service Commission. See DPS.NY.gov

New York State Energy Research and Development Authority (NYSERDA): The New York State public authority charged with conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs, including administering the state System Benefits Charge, Renewable Portfolio Standard, energy efficiency programs, the Clean Energy Fund, and the NY-Sun Initiative. See NYSERDA.NY.gov

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

New York State Public Service Commission (NYSPSC): The decision-making body of the New York State Department of Public Service, which regulates the state's electric, gas, team, telecommunications, and water utilities, oversees the cable industry, has the responsibility for setting rates and overseeing that safe and adequate service is provided by New York's utilities, and exercises jurisdiction over the siting of major gas and electric transmission facilities.

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

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

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

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

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

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

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

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

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

PLEXOS Software: An analytic tool used for purposes of capacity expansion optimization in this study.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface. (As defined in the NYISO Tariffs.)

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

Queue Position: The order, in the NYISO's Interconnection Queue, of a valid Interconnection Request, Study Request, or Transmission Interconnection Application relative to all other pending Requests. See NYISO OATT

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

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

Regulated Economic Transmission Project (RETP): A transmission project or a portfolio of transmission projects proposed by Developer(s) to address constraint(s) on the BPTFs identified in the Economic Planning Process, which transmission project(s) are evaluated in the Economic Transmission Project Evaluation and are eligible for cost allocation and cost recovery under the ISO OATT if approved by a vote of the project's Load Serving Entity beneficiaries pursuant to Section 31.5.4 of this Attachment Y.

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

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

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

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

Requested Economic Planning Study (REPS): The process by which a Market Participant or any other interested party may, at any time, request that the NYISO perform a study separate from and in addition to the System & Resource Outlook at the requesting party's sole expense and solely for informational purposes. The process is further described in Section 31.3.3. (As defined in the OATT.)

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

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

Short-Term Assessment of Reliability (STAR): The NYISO's quarterly assessment, in coordination with the Responsible Transmission Owner(s), of whether a Short-Term Reliability Process Need will result from a generator be coming retired, entering into a Mothball Outage, or being unavailable due to an Installed Capacity Ineligible Forced Outage, or from other changes to the availability of Resources or to the New York State Transmission System. See [NYISO OATT] Attachment FF

Short-Term Reliability Process: The process by which the NYISO evaluates and addresses the reliability impacts resulting from both: (1) Generator Deactivation Reliability Need(s), and/or (2) other Reliability Needs on or affecting the Bulk Power Transmission Facilities that are identified in a Short-Term Assessment of Reliability. The Short-Term Reliability Process evaluates reliability needs in years one through five of the ten-year Study Period, with a focus on needs in years one through three. See [NYISO OATT] Attachment FF

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

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

System & Resource Outlook (formerly "CARIS"): Biennial report produced by the NYISO, through which it summarizes the current assessments, evaluations, and plans in the biennial Comprehensive System Planning Process, produces a twenty-year projection of congestion on the New York State Transmission System, identifies, ranks, and groups congested elements, and assesses the potential benefits of addressing the identified congestion.

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

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

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

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

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

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

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

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

Unforced Capacity (UCAP): The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.

List of Key Acronyms

100x40	New York 100% Carbon Free Electric Sector by 2040 Goal
70x30	New York 70% End Use Renewable Energy by 2030 Goal
BTM-PV	Behind-The-Meter Photovoltaic Generation
CARIS	Congestion Assessment and Resource Integration Study
CC	Combined Cycle Generation
CLCPA	Climate Leadership and Community Protection Act
CO_2	Carbon Dioxide
CT	Combustion Turbine
DEFR	Dispatchable Emission Free Resource
DMNC	Dependable Maximum Net Capacity
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESPWG	Electric System Planning Working Group
ESR	Energy Storage Resource
ETPE	Economic Transmission Project Evaluation
FERC	Federal Energy Regulatory Commission
Gold Book	NYISO's Load and Capacity Data Report "Gold Book"
HRM	Hourly Resource Modifier
HQ	Hydro Quebec
ICAP	Installed Capacity
LBMP	Locational-Based Marginal Pricing
LBW	Land Based Wind
MAPS	Multi Area Production Simulation Software
MARS	Multi-Area Reliability Simulation software
MW	Megawatt
MWh	Megawatt Hour
NOx	Nitrogen Oxide
NREL	National Renewable Energy Laboratory

NYCA	New York Control Area
NYISO	New York Independent System Operator
NYSDPS	New York State Department of Public Service
NYSERDA	New York State Energy Research & Development Authority
OATT	Open Access Transmission Tariff
OSW	Offshore Wind
PV	Photovoltaic or Solar Powered Generation
PSH	Pumped Storage Hydro Generation
RE	Renewable Energy
REC	Renewable Energy Certificates
REPS	Requested Economic Planning Study
RETP	Regulated Economic Transmission Project
RGGI	Regional Greenhouse Gas Initiative
RPP	Reliability Planning Process
TARA	Transmission Adequacy & Reliability Assessment
TCCs	Transmission Congestion Contracts
TPAS	Transmission Planning Advisory Subcommittee
TWh	Terawatt Hour
UCAP	Unforced Capacity
UPNY-SENY	Upstate New York – Southeast New York
UPV	Utility Scale Photovoltaic Solar Generation

Appendix B: Other Economic Planning Studies

In addition to the System & Resource Outlook, the Economic Planning Process allows stakeholders to request two types of studies. The Requested Economic Planning Study ("REPS") and Economic Transmission Project Evaluation ("ETPE") provide mechanisms for stakeholders to leverage NYISO models and expertise to study projects and system conditions that differ from the Outlook study. A REPS is an informational study that can be performed in a confidential manner, while an ETPE is performed publicly to evaluate a specific transmission project proposal seeking cost allocation and cost recovery through the NYISO's tariffs. More details on each study type can be found below.

Requested Economic Planning Study ("REPS")

A Market Participant or any other interested party may, at any time, request that the NYISO perform a study separate from and in addition to the System & Resource Outlook at the requesting party's sole expense and solely for informational purposes. The scope and deliverables for the Requested Economic Planning Study will be agreed upon by the NYISO and the requesting party. The rules governing Requested Economic Planning Studies are established in Section 31.3.3 in Attachment Y to the Open Access Transmission Tariff (OATT). The Requested Economic Planning Study Request Form and the Study Agreement for a Requested Economic Planning Study are located in Sections 31.13 and 31.14 in Attachment Y of the OATT. Additionally, the Requested Economic Planning Study Request Form is posted on the NYISO website[1].

Economic Transmission Project Evaluation ("ETPE")

The purpose of the ETPE is to process specific transmission projects for which Developers are seeking to allocate and recover their projects cost through the NYISO OATT as Regulated Economic Transmission Projects. If a Developer voluntarily proposes a RETP to address constraint(s) on the BPTFs identified in the Economic Planning Process, the NYISO: (i) processes that project proposal in an Economic Transmission Project Evaluation in accordance with the relevant provisions set forth in Sections 31.3.2, 31.5.1, 31.5.4, and 31.5.6 of Attachment Y of the NYISO OATT and the Economic Planning Manual and (ii)

[1] See under *Economic Planning Studies > Study Forms* which is located on the NYISO Comprehensive System Planning Process webpage (https://www.nyiso.com/cspp/).

provides benefit/cost analysis and other analysis of potential generic solutions to the congestion identified. For purposes of the ETPE, the NYISO will use the most recent System & Resource Outlook database and report approved by the NYISO Board of Directors.

To perform the ETPE, the NYISO updates the base case database to be utilized in the production cost modeling and associated evaluation of any proposed Regulated Economic Transmission Projects. The tariff establishes the requirements by which the NYISO will first determine whether a proposed Regulated Economic Transmission Project is eligible for consideration by beneficiaries for cost allocation and recovery under the NYISO OATT. In essence, an Economic Transmission Project is eligible for cost allocation if it costs at least $25 million, the benefit to cost ratio of the project is at least 1.0, and 80 percent or more of the weighted vote of the load serving entities approve the project. The tariff also establishes the requirements for the determination of the load serving entity beneficiaries, the assignment of voting shares to load serving entities, and the procedures by which the beneficiaries vote on whether to approve a proposed Regulated Economic Transmission Project for cost allocation and cost recovery under the NYISO OATT. For an Interregional Transmission Project, the NYISO will jointly evaluate the project proposal with the relevant adjacent transmission planning region(s) in accordance with Section 7.3 of the Interregional Planning Protocol.

More details can be found in the Economic Planning Process Manual[2].

[2] Economic Planning Process Manual: https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/6510ece7-e0a6-7bee-e776-694abf264bae/

Appendix C: Production Cost Assumptions Matrix

Parameter	Reference Case Model		
	Baseline Case	**Contract Case**	**Policy Case**
NYCA System Model			
Assumption Lock Down Date	11/1/2021	12/1/2021	4/1/2022
Peak Load	Based on 2021 Load & Capacity Data Report ("Gold Book") Baseline Forecast of Non-Coincident Peak Demand, including impacts of statewide Energy Efficiency programs.	Based on 2021 Load & Capacity Data Report ("Gold Book") Baseline Forecast of Non-Coincident Peak Demand, including impacts of statewide Energy Efficiency programs.	Peak load forecast consistent with scenario S1 and S2 capacity expansion load forecast model.
Energy Forecast	Energy Forecast based on 2021 Load & Capacity Data Report ("Gold Book") Baseline Forecast of Annual Energy, including impacts of statewide Energy Efficiency programs.	Energy Forecast based on 2021 Load & Capacity Data Report ("Gold Book") Baseline Forecast of Annual Energy, including impacts of statewide Energy Efficiency programs.	Energy forecast consistent with scenario S1 and S2 capacity expansion load forecast model.
Capacity Expansion Load Shape Model	2002 Load Shape	2002 Load Shape	2002 Load Shape and additional modifications for public policy impacts.
Load Uncertainty Model	Only base level forecast utilized; the impact of energy or peak forecasts may be utilized in scenarios.	Only base level forecast utilized; the impact of energy or peak forecasts may be utilized in scenarios.	Only base level forecast utilized; the impact of energy or peak forecasts may be utilized in scenarios.
Generating Unit Capacities	Updated to reflect 2021 Gold Book winter and summer DMNC values.	Updated to reflect 2021 Gold Book winter and summer DMNC values.	Updated to reflect 2021 Gold Book winter and summer DMNC values.

New Resources	Updated as per 2021 Gold Book. (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures)	Updated as per 2021 Gold Book. (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures) Generation projects with financial contracts, including state sponsored programs, included	Updated as per 2021 Gold Book. (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures) Generation projects with financial contracts, including state sponsored programs, included Generation resources to support achievement of state and potential federal policies included per capacity expansion model and consistent with capacity expansion scenario S1 and S2 results
Wind Resource Modeling	Units and capacities updated as per 2021 Gold Book. Existing wind resources are modeled based on unit capacities and actual 2019 shapes. New units modeled based on proximate existing units.	Units and capacities updated as per 2021 Gold Book. Existing wind resources are modeled based on unit capacities and actual 2019 shapes. New units modeled based on proximate existing units or using calculated shapes.	Units and capacities updated as per 2021 Gold Book. Existing wind resources are modeled based on unit capacities and actual 2019 shapes. New units modeled based on proximate existing units or using calculated shapes. For capacity expansion wind resources, zonal to nodal placements done on buses from Interconnection Queue. Resource shapes were obtained based on NREL simulated data at the zonal level.
Solar Resource Modeling	Units and capacities updated as per 2021 Gold Book. Existing solar resources are modeled based on unit capacities and actual 2019 shapes. New units modeled based on proximate existing units.	Units and capacities updated as per 2021 Gold Book. Existing solar resources are modeled based on unit capacities and actual 2019 shapes. New units modeled based on proximate existing units or using calculated shapes.	For capacity expansion solar resources, zonal to nodal placements added based on buses from Interconnection Queue. Resource shapes were obtained based on NREL simulated data at the zonal level.

Offshore Wind Resource Modeling	n/a	The hourly shapes for OSW generators are based on NREL data; contracted projects are based on clustered site level data and candidates for generation expansion are based on zonal data.	The hourly shapes for OSW generators are based on NREL data; contracted projects are based on clustered site level data and candidates for generation expansion are based on zonal data.
Non-NYPA Hydro Capacity Modeling	Updated as per 2021 Gold Book; unit output is modeled consistent with historic levels.	Updated as per 2021 Gold Book; unit output is modeled consistent with historic levels.	Updated as per 2021 Gold Book; unit output is modeled consistent with historic levels.
Special Case Resources	Not utilized in MAPS production cost modeling; may be incorporated in ICAP Metric calculation.	Not utilized in MAPS production cost modeling; may be incorporated in ICAP Metric calculation.	Not utilized in MAPS production cost modeling; may be incorporated in ICAP Metric calculation.
EDRP Resources	N/A for production cost modeling.	N/A for production cost modeling.	N/A for production cost modeling.
External Capacity – Purchases and Wheel-Through	Flows across schedulable and non-schedulable transmission lines are based on economics.	Flows across schedulable and non-schedulable transmission lines are based on economics.	Flows across schedulable and non-schedulable transmission lines are based on economics.
Facility Deactivation and Retirements	Updated as per 2021 Gold Book. (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures)	Updated as per 2021 Gold Book.. (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures)	Updated as per 2021 Gold Book (Application of inclusion rules identified in Reliability Planning Process Manual, Section 3.2 and NYISO procedures) S1- Deactivations as per capacity expansion scenario S1 outputs S2- Deactivations as per capacity expansion scenario S2 outputs, age-based fossil retirements for applicable units assumed per Climate Action Council Appendix D (ST at 62 years and GT at 47 years of age)
Generator Outages	Scheduled to levelize reserves, as per the maintenance schedules in long term adequacy studies.	Scheduled to levelize reserves, as per the maintenance schedules in long term adequacy studies.	Scheduled to levelize reserves, as per the maintenance schedules in long term adequacy studies.
Gas Turbines Ambient Derate	Modeling utilizes summer and winter DMNC ratings for all units.	Modeling utilizes summer and winter DMNC ratings for all units.	Modeling utilizes summer and winter DMNC ratings for all units.

Environmental Modeling and Emission Allowance Price Forecasts	Allowance costs based on projected RGGI costs and New York Department of Environmental Conservation guidance. SO_2 and NOx Allowance Prices reflect CSAPR markets.	Allowance costs based on projected RGGI costs and New York Department of Environmental Conservation guidance. SO_2 and NOx Allowance Prices reflect CSAPR markets.	Allowance costs based on projected RGGI costs and New York Department of Environmental Conservation guidance. SO_2 and NOx Allowance Prices reflect CSAPR markets. Additional policy-based environmental programs may be modeled.
Commitment and Dispatch Options **Operating Reserves**	Each Balancing Authority commits separately. Hurdle Rates are employed for commitment and dispatch. Operating Reserves as per NYCA requirements.	Each Balancing Authority commits separately. Hurdle Rates are employed for commitment and dispatch. Operating Reserves as per NYCA requirements.	Each Balancing Authority commits separately. Hurdle Rates are employed for commitment and dispatch. Operating Reserves as per NYCA requirements.
Fuel Price Forecast	Annual base prices updated to more heavily weight recent trends. Seasonality and spikes based on five-year history (2016-2020). Calculated natural price forecasts based on blends of hub price forecasts for four hubs (A-E, F-I, J and K). Utilized unit capacities and reported pricing hubs to weight price forecasts. Fuel oil and coal price forecasts are developed utilizing the EIA's annual forecast of national delivered prices. Regional bases are derived using EIA Form 923 data.	Annual base prices updated to more heavily weight recent trends. Seasonality and spikes based on five-year history (2016-2020). Calculated natural price forecasts based on blends of hub price forecasts for four hubs (A-E, F-I, J and K). Utilized unit capacities and reported pricing hubs to weight price forecasts. Fuel oil and coal price forecasts are developed utilizing the EIA's annual forecast of national delivered prices. Regional bases are derived using EIA Form 923 data. .	Annual base prices updated to more heavily weight recent trends. Seasonality and spikes based on five-year history (2016-2020). Calculated natural price forecasts based on blends of hub price forecasts for four hubs (A-E, F-I, J and K). Utilized unit capacities and reported pricing hubs to weight price forecasts. Fuel oil and coal price forecasts are developed utilizing the EIA's annual forecast of national delivered prices. Regional bases are derived using EIA Form 923 data.

Cost Curve Development (including heat rates and emission rates)	Unit heat rates (and emission rates) developed from vendor supplied data, USEPA CAMD fuel input and emissions data matched with NYISO production data for NYCA and USEIA production data for non NYCA units.	Unit heat rates (and emission rates) developed from vendor supplied data, USEPA CAMD fuel input and emissions data matched with NYISO production data for NYCA and USEIA production data for non NYCA units.	Unit heat rates (and emission rates) developed from vendor supplied data, USEPA CAMD fuel input and emissions data matched with NYISO production data for NYCA and USEIA production data for non NYCA units. New technology heat and emission rates developed based upon vendor or publicly available data.
Local Reliability Rules	List and develop appropriate nomograms. Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits.	List and develop appropriate nomograms. Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits.	List and develop appropriate nomograms. Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits. Must-run generation requirements were not replaced as affected generators were retired.
Energy Storage **Gilboa PSH** **Lewiston PSH**	Battery energy storage resources dispatched optimally using zonal load on a daily basis. Gilboa and Lewiston scheduled against NYCA load profile.	Battery energy storage resources dispatched optimally using zonal net load on a daily basis. Gilboa and Lewiston scheduled against NYCA load profile.	Battery energy storage resources dispatched optimally using zonal net load on a daily basis. Gilboa and Lewiston scheduled against NYCA load profile. For capacity expansion storage resources, capacity is based on results from capacity expansion S1 and S2. The resources are dispatched optimally against upstate and downstate zonal load profiles depending on where the resources are located.

Renewable Energy Certificates (REC) Bid Modelling	Existing and contracted land-based wind, offshore wind, and solar projects per NYSERDA large scale renewables database specified REC contract price. Index RECs adjusted by premium to equivalent fixed REC.	Existing and contracted land-based wind, offshore wind, and solar projects per NYSERDA large scale renewables database specified REC contract price. Index RECs adjusted by premium to equivalent fixed REC.	Existing and contracted land-based wind, offshore wind, and solar projects per NYSERDA large scale renewables database specified REC contract price. Index RECs adjusted by premium to equivalent fixed REC. Capacity expansion units: Solar - $20/MWh Land Based Wind - $22/MWh Offshore Wind - $49/MWh
Transmission System Model			
Power Flow Cases	As per RPP or STRP.	As per RPP or STRP	As per RPP or STRP

Interface Limits **Monitored - Contingency Pairs** **Nomograms** **Joint, Grouping** **Unit Sensitive Voltage**	Internal NYCA line, interface and contingency limits updated consistent with Reliability Planning Process and market and grid operation practices. Contingency pairs are expanded to include monitored constraints and contingency pairs either observed in historical market operation or identified in planning and operation studies. Coordinate with the Transmission Owners to incorporate the Transmission Owners' Local Transmission Owner Plans and model the non-BPTF portion of the New York State Transmission System. Interface voltage limits modeled as per latest Benchmark model. Data from the results of external planning studies, vendor-supplied data, operational voltage studies, operational limits, transfer limit analysis for critical interfaces utilized to update transmission model for external regions as required.	Internal NYCA line, interface and contingency limits updated consistent with Reliability Planning Process and market and grid operation practices. Contingency pairs are expanded to include monitored constraints and contingency pairs either observed in historical market operation or identified in planning and operation studies. Coordinate with the Transmission Owners to incorporate the Transmission Owners' Local Transmission Owner Plans and model the non-BPTF portion of the New York State Transmission System. Data from the results of external planning studies, vendor-supplied data, operational voltage studies, operational limits, transfer limit analysis for critical interfaces utilized to update transmission model for external regions as required. Contracted resources and transmission impact captured.	Internal NYCA line, interface and contingency limits updated consistent with Reliability Planning Process and market and grid operation practices. Contingency pairs are expanded to include monitored constraints and contingency pairs either observed in historical market operation or identified in planning and operation studies. Coordinate with the Transmission Owners to incorporate the Transmission Owners' Local Transmission Owner Plans and model the non-BPTF portion of the New York State Transmission System. Data from the results of external planning studies, vendor-supplied data, operational voltage studies, operational limits, transfer limit analysis for critical interfaces utilized to update transmission model for external regions as required. Impacts captured from resources and transmission under contracts as well as driven by policy.

New Transmission Capability	Updated as per 2021 Gold Book and latest Reliability Planning Process. (Application of Baseline Case inclusion rules)	Updated as per 2021 Gold Book. (Application of Baseline Case inclusion rules)	Updated as per 2021 Gold Book. (Application of Baseline Case inclusion rules) New policy-based transmission projects included: NYPA Northern New York Priority Transmission Project (-0MW, +1000MW on Moses South Interface) in 2025 Champlain Hudson Power Express (-0MW, 1250MW) – modeled as fixed profile in Zone J in 2025 Clean Path New York Clean Path New York HVDC (-0MW, +1300MW) in 2027
Internal Controllable Lines (PARs, HVDC, VFT)	Optimized in simulation consistent with operating protocols and agreements, as appropriate.	Optimized in simulation consistent with operating protocols and agreements, as appropriate.	Optimized in simulation consistent with operating protocols and agreements, as appropriate.
External System Model			
External Area Models **Fuel Forecast**	Power flow data from RPP and/or STRP, "production" data developed by NYISO with vendor and neighbor input. Linked with NYCA forecast.	Power flow data from RPP and/or STRP, "production" data developed by NYISO with vendor and neighbor input. Linked with NYCA forecast.	Power flow data from RPP and/or STRP, "production" data developed by NYISO with vendor and neighbor input. Linked with NYCA forecast.
External Capacity **Demand Forecast**	Neighboring systems updated in August 2021. PJM generation fleet updated based on PJM New Services Queue. ISO-NE generation fleet updated based on Capacity, Energy, Loads, and Transmission (CELT) Report filings. IESO generation fleet based on publicly available reports.	Neighboring systems updated in August 2021. PJM generation fleet updated based on PJM New Services Queue. ISO-NE generation fleet updated based on CELT filings. IESO generation fleet based on publicly available reports.	Neighboring systems updated in August 2021. PJM generation fleet updated based on PJM New Services Queue. ISO-NE generation fleet updated based on CELT filings. IESO generation fleet based on publicly available reports.

System Representation	HQ modeled as fixed hourly schedule, synchronized with all other external injections. Full Representation/Participation: NYISO ISONE IESO PJM Classic & AP, AEP, CE, DLCO, DAY, VP, EKPC Proxy Bus Injection: HQ-NYISO, HQ-NE-ISO, NB-NEISO, HQ – IESO Transmission Only/Zeroed Out: MECS, FE, SPP, MAR, NIPS, OVEC, TVA, FRCC, SERC, ERCOT, WECC	HQ modeled as fixed hourly schedule, synchronized with all other external injections. Full Representation/Participation: NYISO ISONE IESO PJM Classic & AP, AEP, CE, DLCO, DAY, VP, EKPC Proxy Bus Injection: HQ-NYISO, HQ-NE-ISO, NB-NEISO, HQ – IESO Transmission Only/Zeroed Out: MECS, FE, SPP, MAR, NIPS, OVEC, TVA, FRCC, SERC, ERCOT, WECC	HQ modeled as fixed hourly schedule, synchronized with all other external injections. Full Representation/Participation: NYISO ISONE IESO PJM Classic & AP, AEP, CE, DLCO, DAY, VP, EKPC Proxy Bus Injection: HQ-NYISO, HQ-NE-ISO, NB-NEISO, HQ – IESO Transmission Only/Zeroed Out: MECS, FE, SPP, MAR, NIPS, OVEC, TVA, FRCC, SERC, ERCOT, WECC

External Controllable Lines (PARs, HVDC, VFT, Radial lines)	B and C modeled as out of service. Current JOA modeled under these outage conditions. Western ties to carry 46% of PJM-NYISO AC Interchange + 20% of RECO Load 5018 line to carry 32% of PJM-NYISO AC Interchange + 80% of RECO Load PAR A to carry 7% of PJM-NYISO AC Interchange PAR J-K to carry 15% of PJM-NYISO AC Interchange Norwalk (-200MW, +200MW) L33,34 (-300MW, +300MW) PV20 (0MW, +150MW) Neptune (0MW, +660MW) CSC (0MW, +330MW) CSC and Neptune optimized subject to "cost of use" HTP (0, 660) Linden VFT (-315,315)	B and C modeled as out of service. Current JOA modeled under these outage conditions. Western ties to carry 46% of PJM-NYISO AC Interchange + 20% of RECO Load 5018 line to carry 32% of PJM-NYISO AC Interchange + 80% of RECO Load PAR A to carry 7% of PJM-NYISO AC Interchange PAR J-K to carry 15% of PJM-NYISO AC Interchange Norwalk (-200MW, +200MW) L33,34 (-300MW, +300MW) PV20 (0MW, +150MW) Neptune (0MW, +660MW) CSC (0MW, +330MW) CSC and Neptune optimized subject to "cost of use" HTP (0, 660) Linden VFT (-315,315)	B and C modeled as out of service. Current JOA modeled under these outage conditions. Western ties to carry 46% of PJM-NYISO AC Interchange + 20% of RECO Load 5018 line to carry 32% of PJM-NYISO AC Interchange + 80% of RECO Load PAR A to carry 7% of PJM-NYISO AC Interchange PAR J-K to carry 15% of PJM-NYISO AC Interchange Norwalk (-200MW, +200MW) L33,34 (-300MW, +300MW) PV20 (0MW, +150MW) Neptune (0MW, +660MW) CSC (0MW, +330MW) CSC and Neptune optimized subject to "cost of use" HTP (0, 660) Linden VFT (-315,315)

Appendix D: Capacity Expansion Assumptions Matrix

	Scenario #1 (S1)	Scenario #2 (S2)
Scenario Description	*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.*	*S2 utilizes various assumptions more closely aligned 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).*
Existing Generation	Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.	Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.
Existing Generation FOM Costs	Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources.	Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources.
Existing Generation Properties	Firm capacity (*i.e.*, UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.	Firm capacity (*i.e.*, UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.
Chronological Representation	Each year is represented by 17 load blocks. For each year, 16 of the load blocks are represented by slicing hours of the year by season (Spring, Summer, Fall, Winter) and time of day (overnight, morning, afternoon, evening) and one load block per year represents a period of peak load hours. The seasonal/time of day blocks are based on 2018 NREL ReEDS documentation and the peak load hours are based on the input hourly load data.	Each year is represented by 17 load blocks. For each year, 16 of the load blocks are represented by slicing hours of the year by season (Spring, Summer, Fall, Winter) and time of day (overnight, morning, afternoon, evening) and one load block per year represents a period of peak load hours. The seasonal/time of day blocks are based on 2018 NREL ReEDS documentation and the peak load hours are based on the input hourly load data.

Energy Demand & Profile

Energy Forecast based on 2021 Load & Capacity Data Report (“Gold Book”) CLCPA Case Forecast of Annual Energy, with modifications to account for the following:

- 10 GW BTM-PV by 2030 CLCPA target,
- Removal of impact from energy storage resources, and
- Smoothed annual electrification forecasts through 2040, maintaining the original forecast for 2040.

Annual Energy in the following table represents net load.

Outlook Scenario S1: Annual Energy Forecast (GWh)

Year	Base Shape	BTM PV	EV	Electrification	Annual Energy
2025	139,863	-7,483	1,922	10,402	144,704
2030	133,856	-11,068	5,488	22,633	150,909
2035	130,775	-11,983	10,322	43,452	172,566
2040	129,178	-12,454	16,361	75,594	208,679

Outlook Scenario S1: Peak Forecasts (MW)

Year	Summer Peak	Winter Peak
2025	31,679	26,491
2030	34,416	31,717
2035	40,033	41,681
2040	48,253	57,144

Outlook Scenario S1: BTM-PV Capacity (MW)

Year	BTM PV
2025	6,834
2030	10,055
2035	10,828
2040	11,198

Energy Forecast based on Appendix G: Annex 2: Key Drivers and Outputs of the Climate Action Council draft scoping plan Strategic Use of Low Carbon Fuels Scenario (“Scenario 2”), with modifications to account for the following:

- Removal of impact from electrolysis loads (*i.e.*, Hydrogen), and
- Adoption of “No End Use Flexibility” sensitivity.

Annual Energy in the following table represents gross load.

Outlook Scenario S2: Annual Energy Forecast (GWh)

Year	BTM PV	Annual Energy
2025	-7,631	150,047
2030	-14,461	164,256
2035	-17,223	204,702
2040	-23,220	235,731

Outlook Scenario S2: Peak Forecasts (MW)

Year	Summer Peak	Winter Peak
2025	29,612	21,758
2030	30,070	25,892
2035	34,402	35,093
2040	38,332	42,301

Outlook Scenario S2: BTM-PV Capacity (MW)

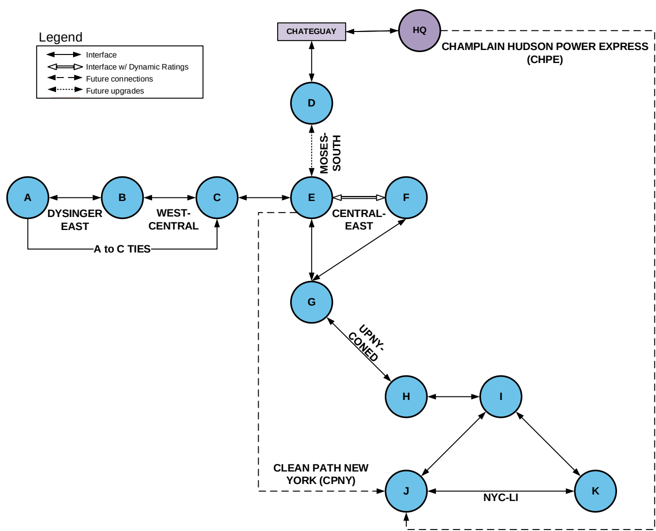
Year	BTM PV
2025	6,000
2030	9,523
2035	11,601
2040	15,764

Existing Transmission

Nodal to zonal reduction performed by PLEXOS to create a pipe-and-bubble equivalent model, where intra-zonal lines are collapsed.

Voltage and stability limited interface limits consistent with Policy Case production cost simulation database. Thermally limited pipe limits set to sum of thermal normal ratings of each interface line (N-0 normal limit).

Applicable N-X contingencies modeled explicitly in production cost simulation.

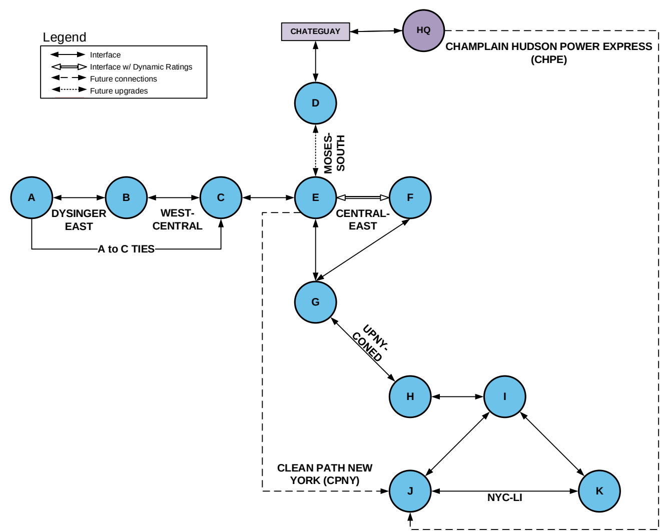


Years	Interface/Interzonal Pipes	+ Limit (MW)	- Limit (MW)	Source
All	DYSINGER EAST	2,700	*	2020 ATR
All	A to C TIES	550	0	2021 CRP limit
All	WEST-CENTRAL	1,475	*	2020 ATR
2021-2024	MOSES-SOUTH	3,050	-1,500	1/2015 Ops study stability limit [1]
2025-2040	MOSES-SOUTH	4,050	-1,500	Tier 4 contract [2]
2021-2023	CENTRAL-EAST (summer)	2,380	-2,380	Operational nomogram [3]
2021-2023	CENTRAL-EAST (winter)	2,615	-2,615	Operational nomogram [3]
2024-2040	CENTRAL-EAST (summer)	3,255	-3,255	Operational nomogram [3]
2024-2040	CENTRAL-EAST (winter)	3,490	-3,490	Operational nomogram [3]
2021-2023	UPNY-CONED	6,150	*	2021 CRP limit
2024-2040	UPNY-CONED	6,525	*	2021 CRP limit
All	DUNWOODI-NYC	*	*	
All	DUNWOODI-LI	*	*	
All	NYC-LI	0	-350	Wheel contract
2027-2040	CLEAN PATH NEW YORK	1,300	0	Tier 4 contracts [4]
2025-2040	CHAMPLAIN HUDSON POWER EXPRESS	1,250	0	Tier 4 contracts [4]

Nodal to zonal reduction performed by PLEXOS to create a pipe-and-bubble equivalent model, where intra-zonal lines are collapsed.

Voltage and stability limited interface limits consistent with Policy Case production cost simulation database. Thermally limited pipe limits set to sum of thermal normal ratings of each interface line (N-0 normal limit).

Applicable N-X contingencies modeled explicitly in production cost simulation.



Years	Interface/Interzonal Pipes	+ Limit (MW)	- Limit (MW)	Source
All	DYSINGER EAST	2,700	*	2020 ATR
All	A to C TIES	550	0	2021 CRP limit
All	WEST-CENTRAL	1,475	*	2020 ATR
2021-2024	MOSES-SOUTH	3,050	-1,500	1/2015 Ops study stability limit [1]
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2024-2040	UPNY-CONED	6,525	*	2021 CRP limit
All	DUNWOODI-NYC	*	*	
All	DUNWOODI-LI	*	*	
All	NYC-LI	0	-350	Wheel contract
2027-2040	CLEAN PATH NEW YORK	1,300	0	Tier 4 contracts [4]
2025-2040	CHAMPLAIN HUDSON POWER EXPRESS	1,250	0	Tier 4 contracts [4]

New Transmission

Transmission expansion not enabled in PLEXOS as a modeling option.

New policy-based transmission projects included:

-NYPA Northern New York Priority Transmission Project

-Champlain Hudson Power Express

-Clean Path New York

Transmission expansion not enabled in PLEXOS as a modeling option.

New policy-based transmission projects included:

-NYPA Northern New York Priority Transmission Project

-Champlain Hudson Power Express

-Clean Path New York

New Generation Types	Updated to include units with financial contracts, including state sponsored programs, per firm builds as noted in large-scale renewable projects reported by NYSERDA. Specific generation added to the Contract Case is assumed as firm builds in the Policy Case. Updated to include units to support achievement of state and federal policies, per 2021 EIA Energy Outlook. Capacity expansion is limited to the NYCA, where each zone assumes one candidate generator per technology. Generation types from 2021 EIA Energy Outlook Table 3 assumed in model: land based wind offshore wind utility PV 4-hour battery storage In addition to the generator types noted above, Dispatchable Emission Free Resource (DEFR) has been added as a candidate technology type for years 2030 and beyond, with additional details below.	Updated to include units with financial contracts, including state sponsored programs, per firm builds as noted in large-scale renewable projects reported by NYSERDA. Specific generation added to the Contract Case is assumed as firm builds in the Policy Case. Updated to include units to support achievement of state and federal policies, per 2021 EIA Energy Outlook. Capacity expansion is limited to the NYCA, where each zone assumes one candidate generator per technology. Generation types from 2021 EIA Energy Outlook Table 3 assumed in model: land based wind offshore wind utility PV 4-hour battery storage In addition to the generator types noted above, Dispatchable Emission Free Resource (DEFR) has been added as a candidate technology type for years 2030 and beyond, with additional details below.

New Generation Costs

Overnight (capital) costs, fixed O&M, and variable O&M costs assumed per 2021 EIA Energy Outlook.

Overnight costs, fixed O&M and variable O&M costs for Dispatchable Emission Free Resource (DEFR) options will represent a range of costs. Assumed costs for the Dispatchable Emission Free Resource (DEFR) options are:

Candidate Capacity Expansion Technology	Capital Cost ($/kW)	Variable O&M Costs ($/MWh)	Fuel Cost ($/mmBtu)	Heat Rate (mmBtu/MWh)
High Operating/Low Capital	1,000	16	40	6.37
Medium Operating/Medium Capital	4,500	9	23	6.37
Low Operating/High Capital	8,000	2	5	6.37

Regional multipliers assumed for candidate generators by zone are based on the 2021 EIA Energy Outlook and the Climate Action Council Integration Analysis Assumptions (Accessed Assumptions at https://climate.ny.gov/Climate-Resources December 10, 2021). Regional multipliers assumed for candidate battery storage units are based on the 2021 EIA Energy Outlook and 2021-2025 Demand Curve Reset.

Candidate Technology	Base Capital	Zonal Multiplier for Capital Costs										
		A	B	C	D	E	F	G	H	I	J	K
Utility PV	1,248	1.05	1.04	1.04	1.01	1.01	1.04	1.20	-	-	-	1.39
Land based wind	1,846	0.98	0.96	1.02	1.06	1.03	1.06	1.14	-	-	-	-
Offshore wind	4,362	-	-	-	-	-	-	-	-	-	1.01	1.01
4-hour battery storage	1,165	1.00	1.00	1.00	1.00	1.00	1.01	1.02	1.02	1.02	1.28	1.10
LcHo DEFR	1,000	1	1	1	1	1	1	1	1	1	1	1
McMo DEFR	4,500	1	1	1	1	1	1	1	1	1	1	1
HcLo DEFR	8,000	1	1	1	1	1	1	1	1	1	1	1

Technological optimism factors applied to capital costs per NREL 2020-ATB-data.

Candidate Technology	Technology Optimism Factors by Year				
	2020	2025	2030	2035	2040
Utility PV	1	0.81	0.62	0.59	0.56
Land based wind	1	0.90	0.79	0.75	0.71
Offshore wind	1	0.81	0.70	0.63	0.59
4-hour battery storage	1	0.69	0.56	0.53	0.49
DEFR	n/a	n/a	1	1	1

Overnight (capital) costs, fixed O&M, and variable O&M costs assumed per 2021 EIA Energy Outlook.

Overnight costs, fixed O&M and variable O&M costs for Dispatchable Emission Free Resource (DEFR) options will represent a range of costs. Assumed costs for the Dispatchable Emission Free Resource (DEFR) options are:

Candidate Capacity Expansion Technology	Capital Cost ($/kW)	Variable O&M Costs ($/MWh)	Fuel Cost ($/mmBtu)	Heat Rate (mmBtu/MWh)
Medium Operating/Medium Capital	4,500	9	23	6.37

Regional multipliers assumed for candidate generators by zone are based on the 2021 EIA Energy Outlook and the Climate Action Council Integration Analysis Assumptions (Accessed Assumptions at https://climate.ny.gov/Climate-Resources December 10, 2021). Regional multipliers assumed for candidate battery storage units are based on the 2021 EIA Energy Outlook and 2021-2025 Demand Curve Reset. Regional multipliers for candidate Dispatchable Emission Free Resource (DEFR) units are based on regional multipliers for the combined cycle technology option in the 2021 EIA Energy Outlook.

Candidate Technology	Base Capital	Zonal Multiplier for Capital Costs										
		A	B	C	D	E	F	G	H	I	J	K
Utility PV	1,248	1.05	1.04	1.04	1.01	1.01	1.04	1.20	-	-	-	1.39
Land based wind	1,846	0.98	0.96	1.02	1.06	1.03	1.06	1.14	-	-	-	-
Offshore wind	4,362	-	-	-	-	-	-	-	-	-	1.01	1.01
4-hour battery storage	1,165	1.00	1.00	1.00	1.00	1.00	1.01	1.02	1.02	1.02	1.28	1.10
McMo DEFR	4,500	1	1	1	1	1	1	1.14	1.14	1.14	1.39	1.30

Technological optimism factors applied to capital costs per NREL 2020-ATB-data.

Candidate Technology	Technology Optimism Factors by Year				
	2020	2025	2030	2035	2040
Utility PV	1	0.81	0.62	0.59	0.56
Land based wind	1	0.90	0.79	0.75	0.71
Offshore wind	1	0.81	0.70	0.63	0.59
4-hour battery storage	1	0.69	0.56	0.53	0.49
DEFR	n/a	n/a	1	1	1

New Generation Properties	Unit heat rates per 2021 EIA Energy Outlook. The heat rates for the Dispatchable Emission Free Resource (DEFR) option are consistent with the combined cycle technology option in the 2021 EIA Energy Outlook. The Dispatchable Emission Free Resource (DEFR) technologies are modeled as flexible resources with parameters consistent with the combined cycle technology option in the 2021 EIA Energy Outlook. Linear capacity expansion by technology-zone. Maximum allowable capacities are enforced for applicable generator types based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. The firm capacity (*i.e.*, UCAP) values for the Dispatchable Emission Free Resource (DEFR) option are consistent with the combined cycle technology option, based on default derating factor value from the NERC GADS database. Firm capacity values for Land based wind, offshore wind, utility PV, and battery storage units are modeled as having a declining capacity value as a function of that generator type's installed capacity. These values are based on the 2020 Grid in Evolution Study.	Unit heat rates per 2021 EIA Energy Outlook. The heat rates for the Dispatchable Emission Free Resource (DEFR) option are consistent with the combined cycle technology option in the 2021 EIA Energy Outlook. The Dispatchable Emission Free Resource (DEFR) technologies are modeled as flexible resources with parameters consistent with the combined cycle technology option in the 2021 EIA Energy Outlook. Linear capacity expansion by technology-zone. Maximum allowable capacities are enforced for applicable generator types based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. For land-based wind, the maximum allowable capacities enforced for model years 2021-2030 are based on 2030 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. The firm capacity (*i.e.*, UCAP) values for the Dispatchable Emission Free Resource (DEFR) option are consistent with the combined cycle technology option, based on default derating factor value from the NERC GADS database. Firm capacity values for Land based wind, offshore wind, utility PV, and battery storage units are modeled as having a declining capacity value as a function of that generator type's installed capacity. These values are based on the 2020 Grid in Evolution Study.
Capacity Reserve Margin	Capacity reserve margins (IRM and LCRs) for 2021-2022 Capability Year translated to UCAP equivalent for model years, per NYISO ICAP to UCAP translation. The minimum capacity reserve margin for the G-J Locality assumes a 10% reduction in its requirement due to future impacts from AC Transmission. The G-J and J Localities assume a 650 MW reduction in LCR requirements due to the Clean Path New York HVDC project. Minimum UCAP requirements by capacity zone are as follows: • NYCA: 110.11% summer, 110.56% winter • Zones G-J: 84.43% summer, 83.69% winter model years 2021-2023, 74.43% summer, 73.69% winter model years 2024-2040 • Zone J: 78.14% summer, 78.31% winter • Zone K: 97.85% summer, 95.48% winter	Capacity reserve margins (IRM and LCRs) for 2021-2022 Capability Year translated to UCAP equivalent for model years, per NYISO ICAP to UCAP translation. The minimum capacity reserve margin for the G-J Locality assumes a 10% reduction in its requirement due to future impacts from AC Transmission. The G-J and J Localities assume a 650 MW reduction in LCR requirements due to the Clean Path New York HVDC project. Minimum UCAP requirements by capacity zone are as follows: • NYCA: 110.11% summer, 110.56% winter • Zones G-J: 84.43% summer, 83.69% winter model years 2021-2023, 74.43% summer, 73.69% winter model years 2024-2040 • Zone J: 78.14% summer, 78.31% winter • Zone K: 97.85% summer, 95.48% winter

<table>
<tr>
<td>Policy Targets and Other Model Constraints</td>
<td>CLCPA targets and other state policy mandates modeled include:
6 GW BTM-PV by 2025
70% renewable energy by 2030
3 GW energy storage by 2030
10 GW BTM-PV by 2030
9 GW offshore wind by 2035
100% emission free grid by 2040
As noted above, maximum allowable capacities are enforced for applicable generator types by zone based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan.</td>
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10 GW BTM-PV by 2030
9 GW offshore wind by 2035
100% emission free grid by 2040
As noted above, maximum allowable capacities are enforced for applicable generator types by zone based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. For land-based wind, the maximum allowable capacities enforced for model years 2021-2030 are based on 2030 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan.</td>
</tr>
</table>

Appendix E: Study Assumptions and Methodology

This appendix describes model preparation, framework, and assumptions that makeup the Baseline, Contract, and Policy Cases. Many of the assumptions in the Baseline Case also apply to the Contract Case. Similarly, the Policy Case is based off the Contract Case, including additional assumptions pertaining to the application of state policies. These sections go through the assumptions in each case.

Appendix E.1: Baseline Case Assumptions

As described in Section 31.3.1 of Attachment Y, the System & Resource Outlook will align with the Reliability Planning Process, and the ten-year Study Period covered by the most recently approved CRP shall be the first ten years of the System & Resource Outlook Study Period.

The data utilized in the Baseline Case simulations for the System & Resource Outlook is largely derived from the 2021-2030 CRP, 2021 Gold Book, and the Outlook Assumptions Matrix (Appendix C: Production Cost Assumptions Matrix). Major components of the data include base load flow data, unit heat rates, unit capacities, load forecasts, load shape, fuel and emissions allowance price forecasts, transmission constraint modeling, both simulated and actual and scheduled interchange values, and operation and maintenance (O&M) cost.

Figure 1: 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

E.1.1. Baseline Case Load and Capacity Forecast

The load and capacity forecast used in the Baseline Case was based on the 2021 Gold Book and accounts for the impact of programs such as energy efficiency, electrification, and the Peaker Rule[3]. Baseline Case load forecasts are presented in Figure 2 and Figure 3. Figure 2 presents the Annual Zonal Energy in gigawatt-hours (GWh) and Figure 3 presents summer non-coincident peak demand in megawatts (MW). Figure 4 presents the timeline of generation changes made in NYCA, and Figure 5 presents annual NYCA capacity for the Baseline Case.

Figure 2: Annual Zonal Energy (GWh)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2021	14,866	10,013	15,911	5,571	8,110	12,367	9,588	2,916	5,824	48,647	20,708	154,521
2022	15,774	10,062	16,096	6,696	8,153	12,441	9,513	2,927	5,841	48,491	20,511	156,502
2023	16,948	10,053	16,485	7,303	8,180	12,445	9,465	2,934	5,849	48,021	20,213	157,896
2024	17,130	10,049	16,658	7,478	8,197	12,448	9,428	2,937	5,810	47,656	20,025	157,816
2025	17,362	9,952	16,776	7,657	8,240	12,364	9,440	2,939	5,771	47,477	19,817	157,796
2026	17,597	9,901	16,797	7,815	8,283	12,346	9,441	2,950	5,755	47,383	19,601	157,868
2027	17,729	9,850	16,787	7,967	8,312	12,354	9,459	2,961	5,765	47,442	19,566	158,192
2028	17,724	9,833	16,770	7,969	8,334	12,440	9,482	2,974	5,784	47,627	19,708	158,644
2029	17,743	9,830	16,740	7,968	8,347	12,503	9,489	2,981	5,809	47,879	19,912	159,200
2030	17,818	9,840	16,730	7,973	8,378	12,570	9,548	2,992	5,838	48,174	20,189	160,050
2031	17,872	9,875	16,685	7,982	8,408	12,679	9,594	3,006	5,882	48,573	20,454	161,009
2032	17,935	9,910	16,660	7,990	8,441	12,784	9,648	3,022	5,931	49,025	20,715	162,061
2033	18,026	9,956	16,662	8,000	8,473	12,899	9,725	3,044	5,993	49,570	20,986	163,335
2034	18,137	10,006	16,688	8,011	8,518	13,002	9,803	3,071	6,058	50,153	21,265	164,713
2035	18,263	10,069	16,747	8,025	8,563	13,110	9,898	3,100	6,134	50,812	21,579	166,299
2036	18,389	10,133	16,836	8,039	8,610	13,224	10,001	3,134	6,217	51,535	21,893	168,013
2037	18,515	10,207	16,950	8,055	8,658	13,339	10,113	3,172	6,306	52,330	22,222	169,866
2038	18,651	10,283	17,085	8,070	8,713	13,468	10,239	3,217	6,402	53,168	22,553	171,849
2039	18,798	10,373	17,238	8,091	8,775	13,609	10,398	3,260	6,511	54,125	22,904	174,083
2040	18,963	10,484	17,425	8,112	8,852	13,757	10,569	3,310	6,622	55,071	23,271	176,435

Figure 3: Summer Non-Coincident Peak Demand by Zone (MW)

[3] The NYS Department of Environmental Conservation "Peaker Rule", 6 NYCRR Subpart 227-3, which phases in ozone season compliance obligations between 2023 and 2025, will impact simple cycle combustion turbines located mainly in the lower Hudson Valley, New York City, and Long Island.

Year	A	B	C	D	E	F	G	H	I	J	K
2021	2,934	2,127	3,003	845	1,552	2,620	2,447	663	1,444	11,298	5,512
2022	3,037	2,072	3,113	953	1,650	2,718	2,465	668	1,425	11,422	5,455
2023	3,194	2,077	3,210	1,038	1,733	2,758	2,477	670	1,424	11,407	5,365
2024	3,257	2,092	3,278	1,077	1,799	2,802	2,493	671	1,419	11,405	5,294
2025	3,226	2,160	3,234	1,080	1,791	2,811	2,489	668	1,442	11,384	5,213
2026	3,266	2,164	3,260	1,104	1,823	2,839	2,494	669	1,441	11,399	5,155
2027	3,283	2,172	3,280	1,127	1,851	2,867	2,500	673	1,445	11,464	5,127
2028	3,369	2,117	3,390	1,161	1,930	2,910	2,527	682	1,428	11,548	5,145
2029	3,371	2,124	3,400	1,167	1,950	2,935	2,539	686	1,437	11,638	5,178
2030	3,378	2,127	3,406	1,173	1,969	2,960	2,556	691	1,446	11,724	5,236
2031	3,287	2,186	3,313	1,147	1,931	2,972	2,554	693	1,483	11,808	5,277
2032	3,294	2,189	3,313	1,153	1,946	2,997	2,567	697	1,495	11,885	5,350
2033	3,398	2,133	3,408	1,191	2,017	3,039	2,603	709	1,480	11,955	5,451
2034	3,410	2,135	3,411	1,198	2,031	3,063	2,617	713	1,490	12,023	5,527
2035	3,421	2,140	3,413	1,204	2,044	3,085	2,634	718	1,500	12,088	5,603
2036	3,431	2,143	3,414	1,211	2,054	3,106	2,650	725	1,510	12,149	5,672
2037	3,336	2,202	3,327	1,180	2,012	3,109	2,639	721	1,546	12,218	5,718
2038	3,343	2,202	3,333	1,188	2,021	3,121	2,654	725	1,552	12,274	5,777
2039	3,458	2,156	3,422	1,231	2,083	3,149	2,693	735	1,530	12,307	5,850
2040	3,469	2,164	3,427	1,237	2,090	3,163	2,711	737	1,536	12,354	5,899

Figure 4: 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

Figure 5: NYCA Capacity (MW)

Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2021	3,497	771	6,650	2,056	1,223	4,734	4,704	1,088	-	9,618	5,167	39,508
2022	3,570	791	6,810	2,075	1,347	4,734	4,704	52	-	9,602	5,154	38,839
2023	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,075	5,043	38,421
2024	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,075	5,043	38,421
2025	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2026	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2027	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2028	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2029	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2030	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2031	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2032	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2033	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2034	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2035	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2036	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2037	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2038	3,637	791	7,048	2,056	1,367	4,734	4,666	52	-	9,047	5,043	38,441
2039	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393
2040	3,570	791	7,048	2,075	1,367	4,734	4,666	52	-	9,047	5,043	38,393

E.1.2. Transmission Model

The Outlook production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which includes the power system in the United States and Canadian Provinces East of the Rocky Mountains, excluding the Western Electricity Coordinating Council and Texas. The Outlook model includes an active and detailed representation for the power systems and electricity markets of the NYISO, ISO-New England, IESO, and PJM Interconnection Control Areas. The transmission representation of the three neighboring control areas is derived from the most recent CRP case and include changes expected to significantly impact NYCA congestion.

E.1.3. New York Control Area Transfer Limits

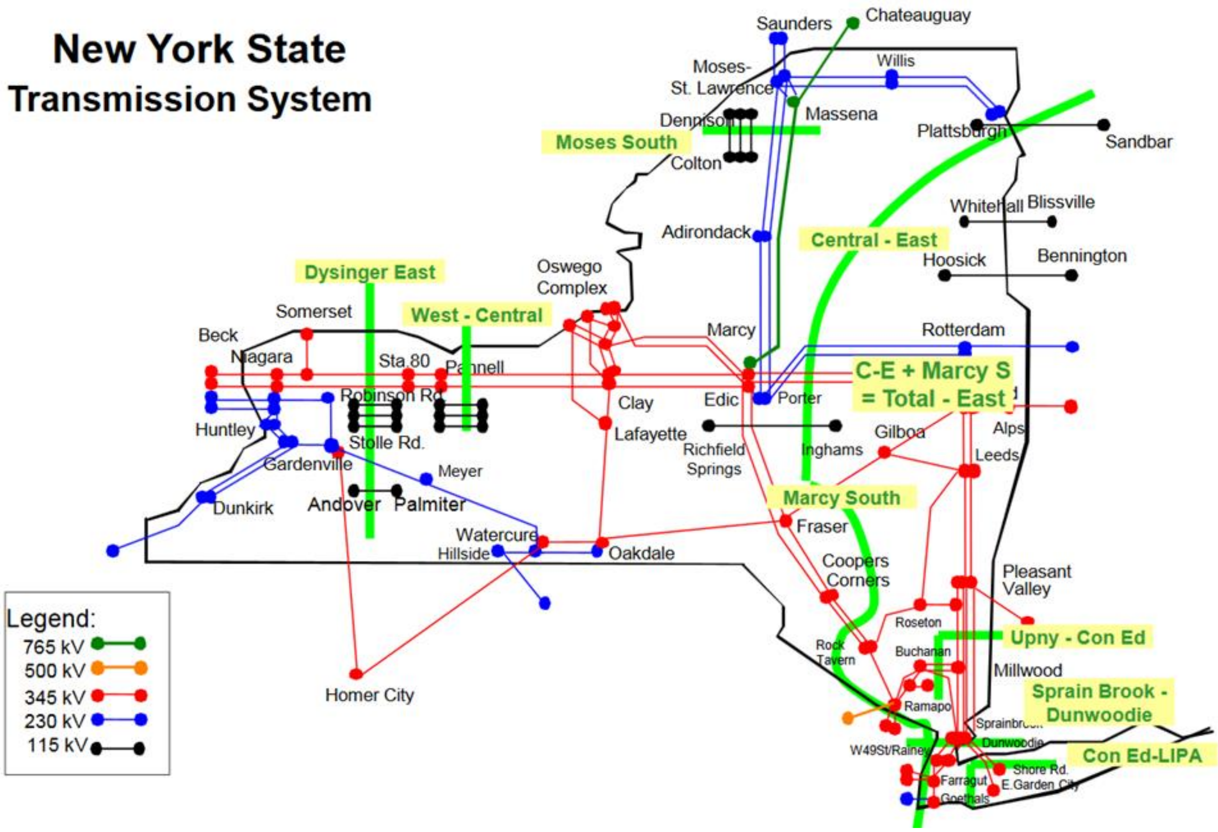
The Outlook utilizes normal transfer criteria for MAPS software simulations to determine system production costs. Normal thermal interface transfer limits for the Outlook report are not directly utilized from the thermal transfer analysis performed using TARA software.[4] Instead, the Outlook uses the most severe limiting monitored lines and contingency sets identified from analysis using TARA software and from historical binding constraints. More details on the round-trip analysis used to develop contingency sets can be found in Appendix E.2.2.

For voltage and stability-based limits, the normal and emergency limits are assumed to be the same.

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

For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[5] The Central East interface was modeled with a unit sensitive nomogram reflecting the algorithm utilized by NYISO Operations.[6] Adjustments were made to this nomogram to accommodate new transmission projects that impact the interface limit.

Figure 6: NYISO 115 kV and Above Transmission Map



New York Control Area System Changes, Upgrades and Resource Additions

System changes modeled for 2019 and beyond are as follows:

a) Conforming the modeling of the PJM/NYISO interface to the current NYISO-PJM Joint Operating Agreement

[5] https://www.nyiso.com/documents/20142/3691079/NYISO_InterfaceLimtsandOperatingStudies.pdf/

[6] https://www.nyiso.com/documents/20142/3692791/CE_VoltageandStability_Limit_ReportFinalOCApproved3-17-2016.pdf

b) Seasonal (winter) by-pass of the Marcy South Series Compensation (MSSC)

c) Erie – South Ripley series reactor in-service (2019)

d) Rainey – Corona PAR in-service (2019)

e) Leeds Hurley SDU in-service (2021)

f) Cedar Rapids Transmission Upgrade (2021)

g) LTP updates on Con Edison 345/138 kV PAR controlled feeder lines in New York City (2021)

h) Empire State Line/Western NY Public Policy Transmission project modeled in-service (2022)

i) STRP solution for addressing 2023 short-term need – Series Reactor (SR) status changes, starting 2023, through 2030

j) Placing in service the SR on the following 345 kV cables: 71, 72, M51, M52

k) Bypassing the SR on the following 345 kV cables: 41, 42, Y49

l) Selected AC Public Policy Transmission projects (segments A and B) modeled in-service (2024)

E.1.4. Fuel Forecasts

The fuel price forecasts for the Outlook[7] are based on the U.S. Energy Information Administration's ("EIA")[8] current national long-term forecast of delivered fuel prices, which is released each spring as part of its Annual Energy Outlook. The figures in this forecast are in nominal dollars. The same fuel forecast is utilized for all study cases.

New York Fuel Forecast

In developing the New York fuel forecast, regional adjustments were made to the EIA fuel forecast to reflect fuel prices in New York. Key sources to estimate the relative differences for fuel-oil prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[9] The regional adjustments for natural gas prices are based on a comparative analysis of monthly national delivered prices published in EIA's Short Term Energy Outlook and spot prices at the selected trading hubs. The base annual forecast series from the Annual

[7] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Fuel_Forecast.xlsx

[8] www.eia.doe.gov

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

Energy Outlook are adjusted to reflect the New York prices relative to the national delivered prices as described below.

Natural Gas

For the 2021 Outlook, the New York Control Area is divided into four (4) gas regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

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

- Zones A to E – Dominion South (91%), Tetco M3 (7%), & Columbia (2%);
- Zones F to I – Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%), and Tetco M3 (3%);
- Zone J – Transco Zone 6 (100%);
- Zone K – Iroquois Zone 2 (51%) & Transco Zone 6 (49%)

The forecasted regional adjustment, which reflects the differential between the blended regional price and the national average, is calculated as the three-year weighted-average of the ratio between the regional price and the national average delivered price from the Short-Term Energy Outlook.[10] Forecasted fuel prices for the gas regions are shown in

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

Figure 7 through Figure 10.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see Annual Energy Outlook 2021, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional adjustments were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil #2) and Residual (Fuel Oil #6) prices. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in

Figure **7** through Figure 10.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted regional delivered price adjustment for coal. (The published figures do not make a distinction between the different varieties of coal; *i.e.,* bituminous, sub-bituminous, and lignite). No coal plants are modeled in service in New York past 2020, and this coal price forecast applies only to units in external areas.

Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, the NYISO estimated seasonal factors using standard statistical methods.[11] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the 2021 seasonal factors are as follows:

- Natural Gas: Raw daily prices from S&P Global/Platts for the various trading hubs incorporated in the regional price blends.
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. The Outlook assumes the same seasonality for both types of fuel oil.
- The seasonalized time-series represents the forecasted trend of average monthly prices. Because the Outlook uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 53 weekly prices for a given year. Furthermore, price "spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as five-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they sum to zero.

[11] This is a two-step process: First, deviations around a centered 12-month moving average are calculated over the 2016-2020 period; second, the average values of these deviations are normalized to estimate monthly/seasonal factors.

Figure 7: Forecasted Fuel Prices for Zones A-E (Nominal $)

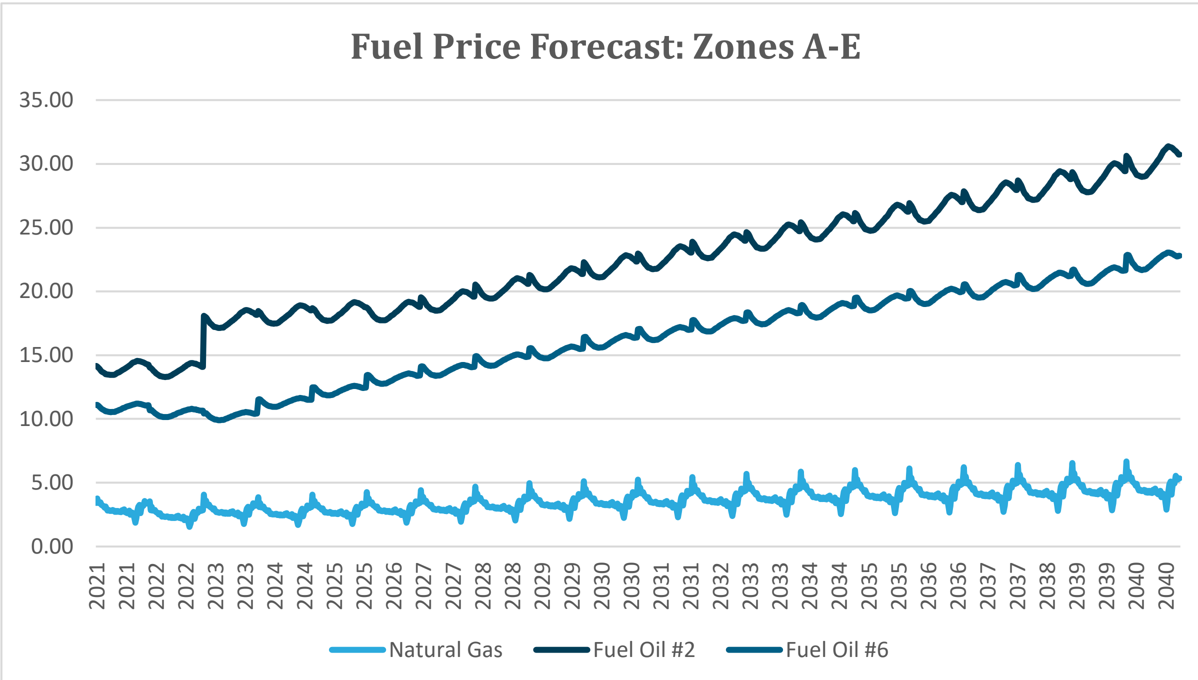


Figure 8: Forecasted Fuel Prices for Zones F-I (Nominal $)

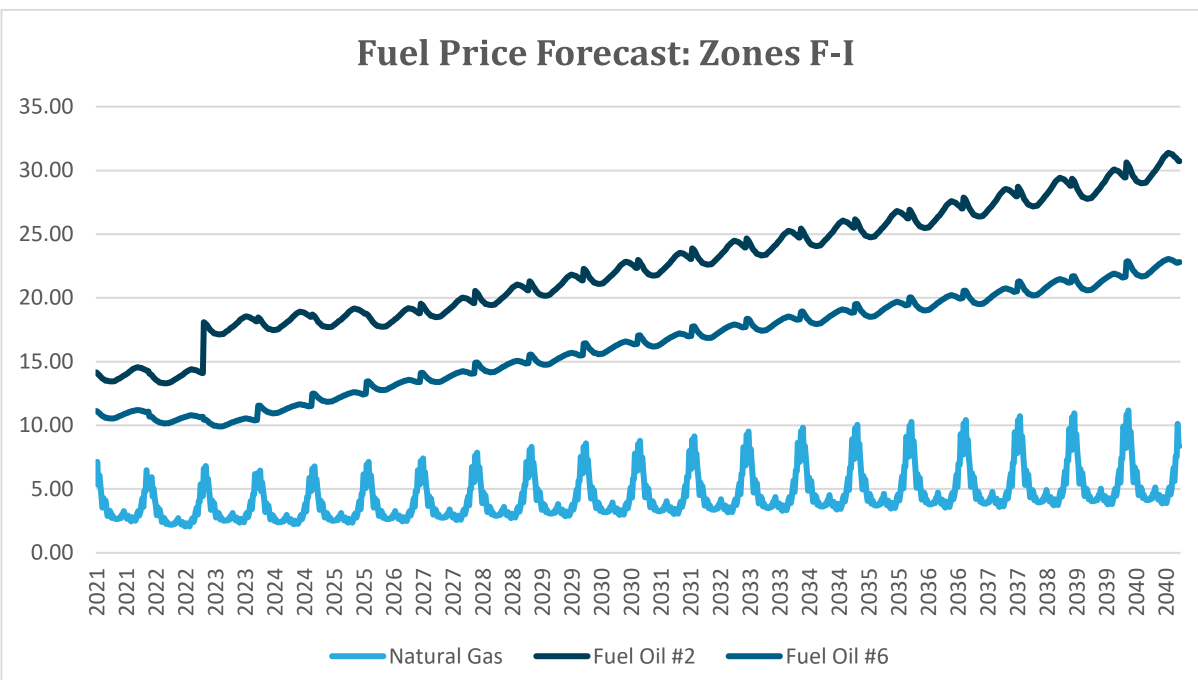


Figure 9: Forecasted Fuel Prices for Zone J (Nominal $)

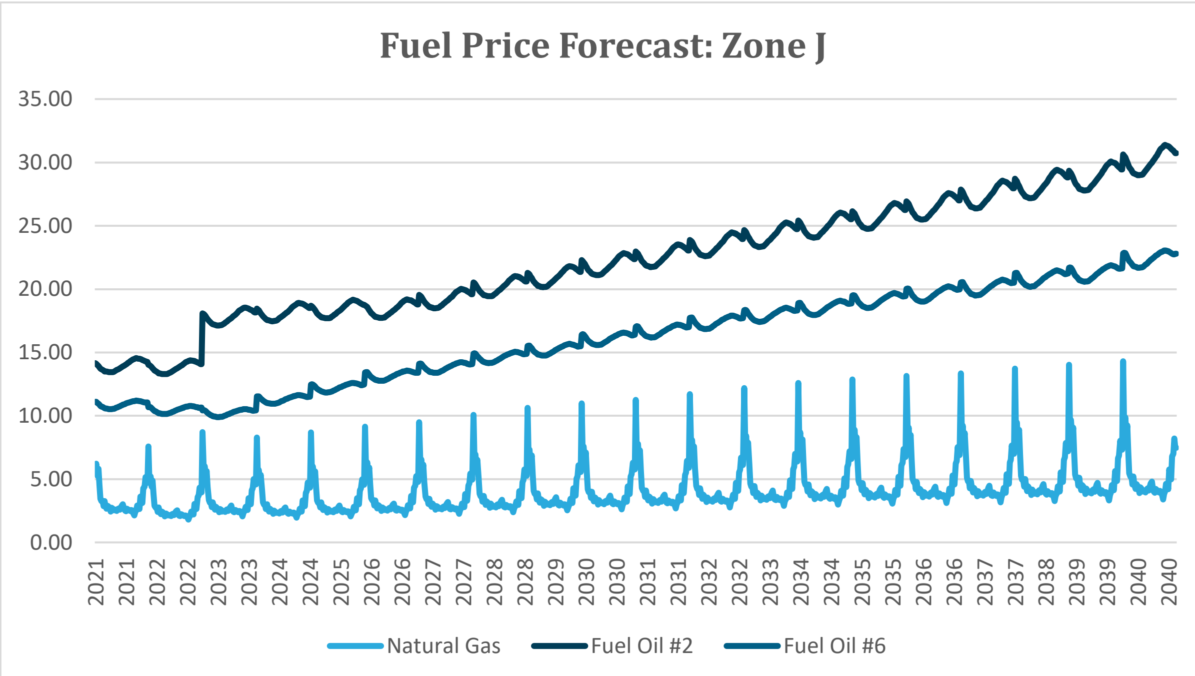
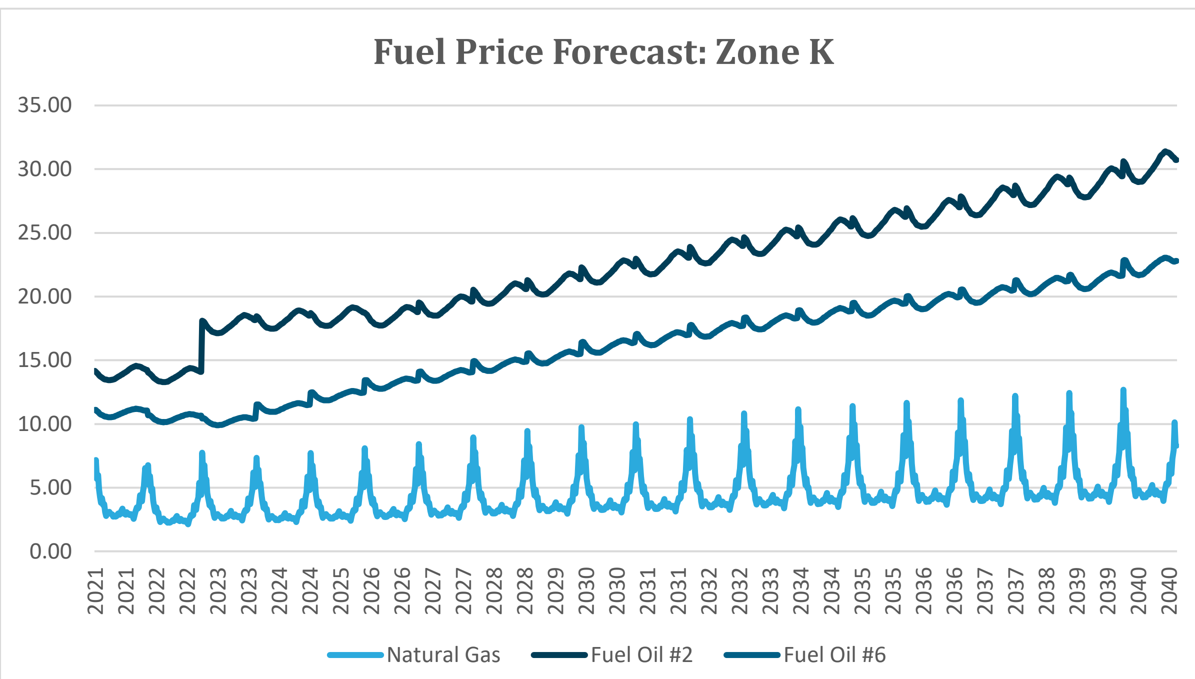


Figure 10: Forecasted Fuel Prices for Zone K (Nominal $)



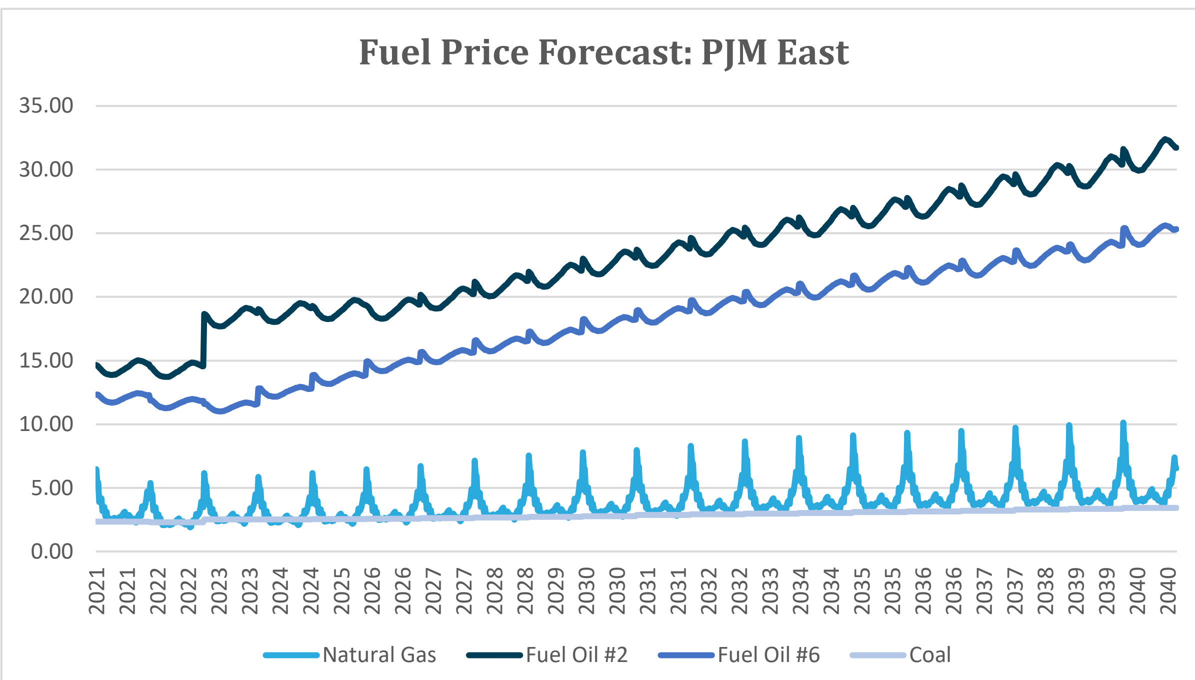
External Areas Fuel Forecast

Fuel forecasts for the three external Control Areas, ISO-New England, PJM Interconnection and IESO Ontario, were also developed. For each of the fuels, the ISO-New England North, ISO-New England South, PJM-East and PJM-West forecasts are based on the EIA data obtained from the same sources as those used for New York. With respect to the IESO Ontario control area, the relative price of natural gas is based on spot-market data for the Dawn hub obtained from SNL Energy.[12] The Outlook does not model any IESO Ontario generation as being fueled by either oil or coal.

Figure 11: External Areas Fuel Forecast Regional Multiplier

Fuel	PJM-East	PJM-West	ISONE-North	ISONE-South	IESO
Fuel Oil #2	0.970	1.080	1.050	1.050	1.125
Fuel Oil #6	1.000	1.100	0.975	0.975	1.075
Natural Gas	0.858	0.821	1.040	1.012	0.898
Coal	1.250	0.950	2.000	2.000	1.300

Figure 12: Forecasted Fuel Prices for PJM East (Nominal $)



12 Copyright © 2021, SNL Financial LLC

Figure 13: Forecasted Fuel Prices for PJM West (Nominal $)

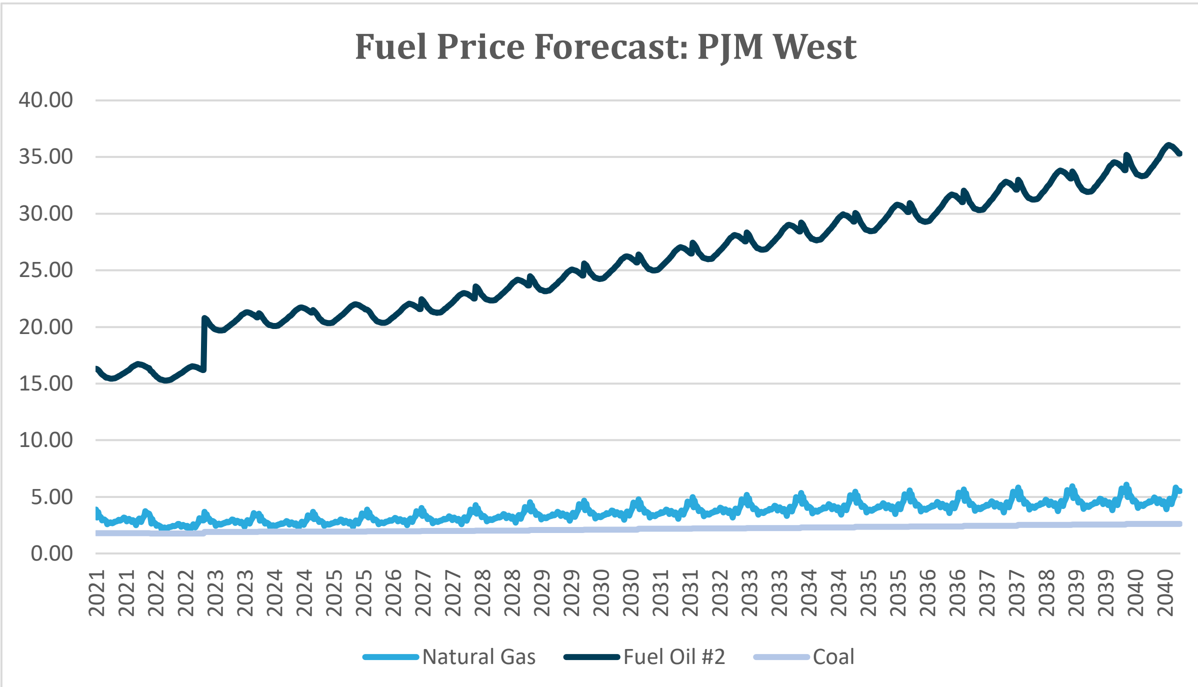


Figure 14: Forecasted Fuel Prices for ISO-NE (Nominal $)

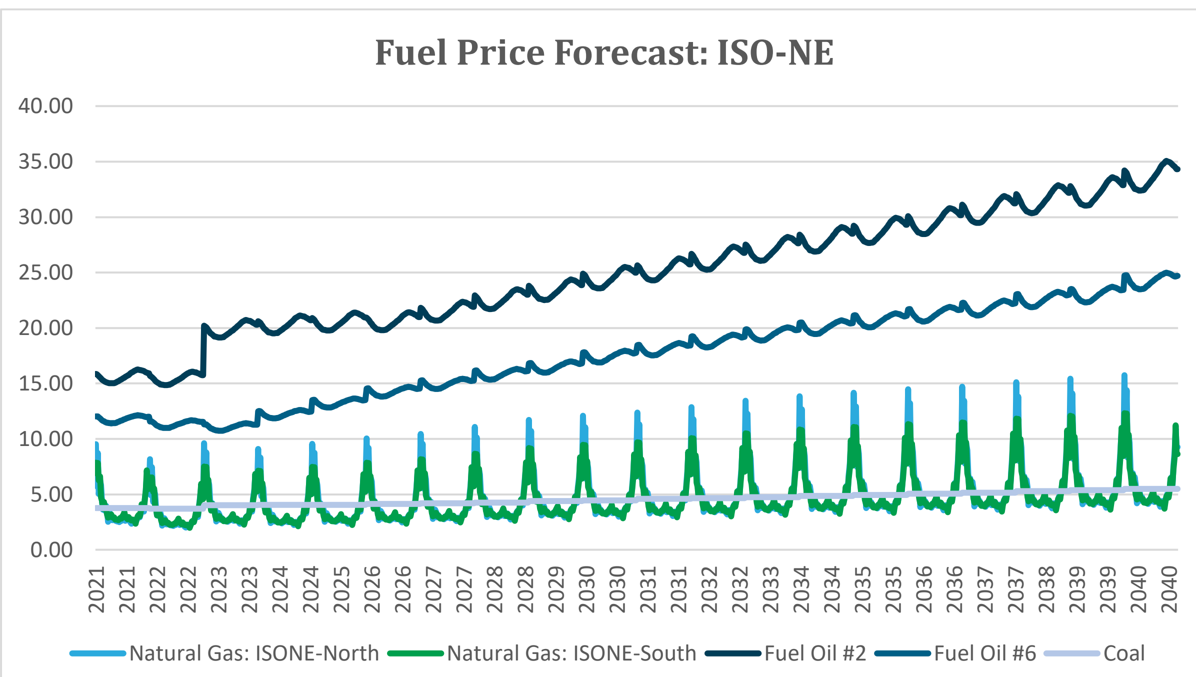
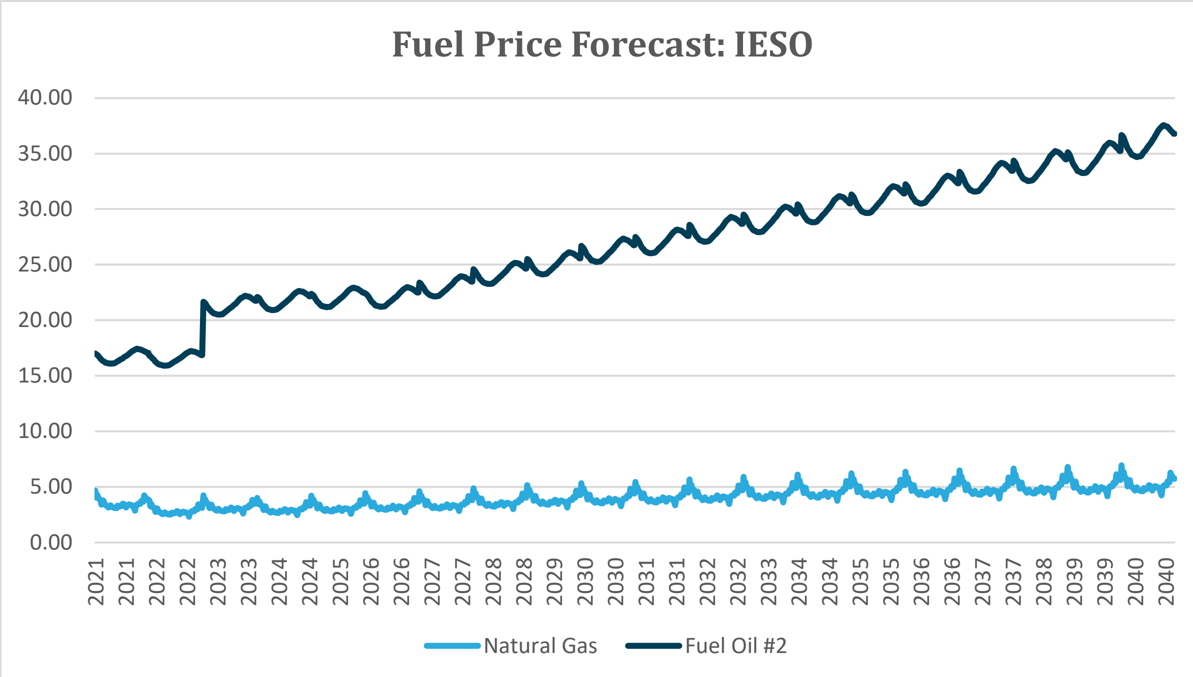


Figure 15: Forecasted Fuel Prices for IESO (Nominal $)



E.1.5. Emission Cost Forecast

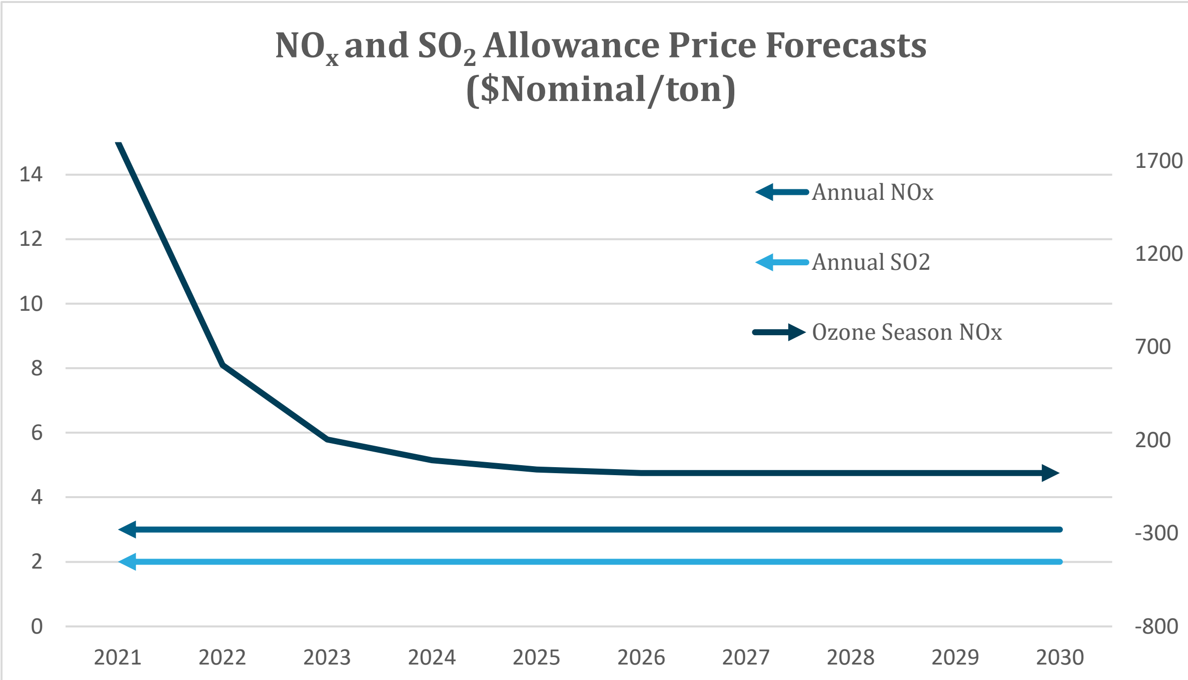
The costs of emission allowances are an increasing portion of generator production costs. Currently, all New York fossil fuel-fired generators greater than 25 MW and most generators in many surrounding states are required to procure allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

Baseline Case allowance price forecasts[13] for annual and seasonal NO_X and SO_2 emissions are developed using representative prices at the time the assumptions are finalized. The Cross-State Air Pollution Rule ("CSAPR") NO_X and SO_2 allowances prices reflect persistent oversupply of annual programs, and the expectation that stricter seasonal limitations in the Cross-State Air Pollution Rule Update will continue to be manageable program-wide, leading to price declines as market participants adjust to new operational limits. Figure 16 shows the assumed NO_X and SO_2 allowance price forecasts used in this study.[14]

Figure 16: NO_X and SO_2 Emission Allowance Price Forecasts

[13] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Emissions_Price_Forecast.xlsx

[14] Annual NO_X allowance prices are used October through April; ozone season NO_X allowance prices in addition to Annual NO_X allowance prices are used in May through September.



The Regional Greenhouse Gas Initiative (RGGI) program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, Delaware, New Jersey, and Virginia. Historically, the RGGI market has been oversupplied and prices have remained near the floor. In January 2012, the RGGI States chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in an effort to reduce the market oversupply. During the program review that was completed in 2017, the nine RGGI states agreed to an emissions cap reduction from 78 million tons in 2020 to 55 million tons in 2030. New Jersey reentered the program in 2020 with a budget of 20 million tons and Virginia entered in 2021 with a budget of approximately 27 million tons. Both states have committed to commensurate reductions to the other RGGI states. Starting in 2021, an Emission Containment Reserve provides price support by holding back allowances from auction if prices do not exceed predefined threshold levels. Additionally, the states have agreed to adjust banked allowances by reducing the budgets in 2021-2025 by approximately 19 million tons per year. New York began regulating most generators of 15 MW or more in 2021 under RGGI. The 2021 program review is currently underway and is expected to be completed in 2023. For the purposes of this Outlook, Pennsylvania is assumed to join RGGI in 2023.

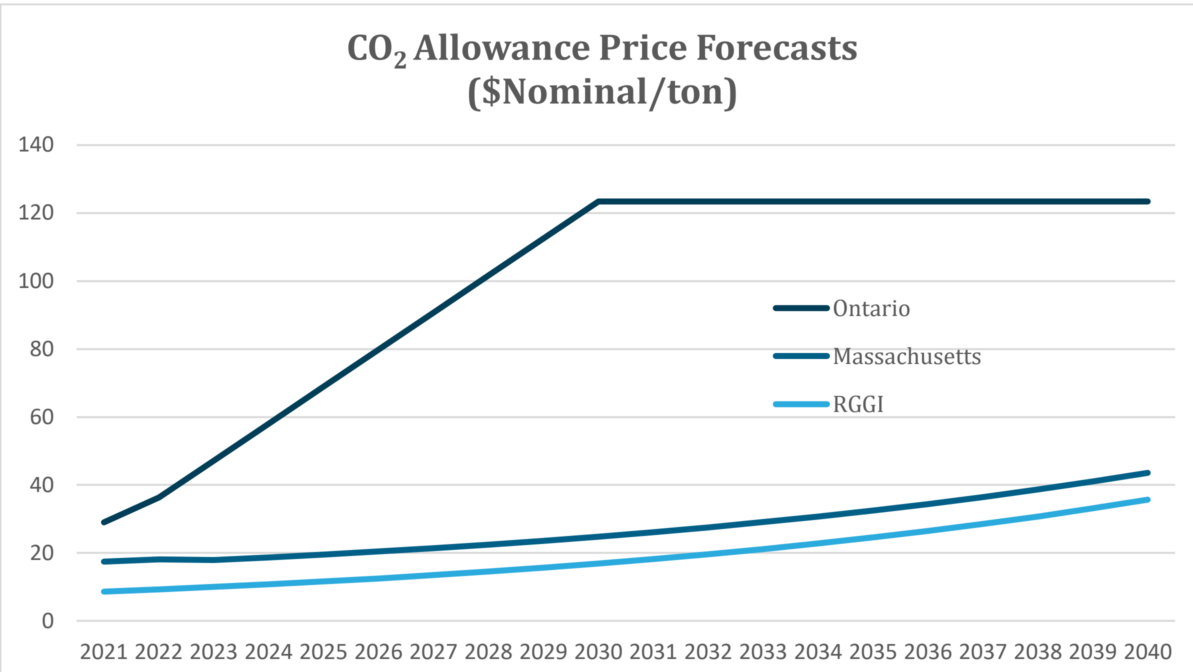
Massachusetts began implementing its own single state cap-and-trade program in 2018, which is similar to RGGI but with more restrictive caps applicable to generators located in Massachusetts.[15]

[15] https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

Massachusetts allowance prices assumed in this study are incremental to RGGI allowance prices imposed upon Massachusetts's emitting generators. The study also assumes a distinct CO_2 allowance price forecast applicable to IESO (Ontario) generation based upon CO_2 prices in *Canada's A Healthy Environment and a Healthy Economy*.[16]

Figure 17 below shows the CO_2 emission allowance price forecasts by year in $/ton

Figure 17: CO_2 Emission Allowance Price Forecast



E.1.6. External Area Model

ISO-NE, IESO, and PJM are actively modeled in the production cost simulation. The HQ system is not explicitly modeled since it is asynchronously tied to the New York bulk system. Proxy buses representing the direct ties from HQ to NYISO, HQ to IESO and HQ to ISO-NE are modeled. Figure 18 through

[16] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/climate-plan-overview/healthy-environment-healthy-economy.html

Figure **20** list the additions, retirements and rerates for the external control areas by fuel source by year as reported by the external control areas in their respective planning documents.

Figure **21** presents the aggregate capacities by unit type.

Figure 18: PJM Unit Additions and Retirements (MW)

Year	Source	Additions	Retirements
2021	Coal		1,010
	Fossil Fuel	2,453	215
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	751	
	Wind	560	
2022	Coal		1,199
	Fossil Fuel	3,988	44
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	660	
	Wind		
2023	Coal		1,006
	Fossil Fuel	1,200	80
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		

Figure 19: IESO Unit Additions and Retirements (MW)

Year	Source	Additions	Retirements
2021	Coal		
	Fossil Fuel	224	
	Hydro		
	Landfill Gas/Bio		38
	Nuclear		
	Solar		
	Wind	100	
2022	Coal		
	Fossil Fuel		38
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2023	Coal		
	Fossil Fuel	896	
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2024	Coal		
	Fossil Fuel		
	Hydro		
	Landfill Gas/Bio		
	Nuclear		1,030
	Solar		
	Wind		
2025	Coal		
	Fossil Fuel	1,568	
	Hydro		
	Landfill Gas/Bio		
	Nuclear		2,064
	Solar		
	Wind		

Figure 20: ISO-NE Unit Additions and Retirements (MW)

Year	Source	Additions	Retirements
2021	Coal		383
	Fossil Fuel		
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	227	
	Wind		
2022	Coal		
	Fossil Fuel	679	662
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar		
	Wind		
2023	Coal		
	Fossil Fuel		272
	Hydro		
	Landfill Gas/Bio		
	Nuclear		
	Solar	100	
	Wind		
2024	Coal		
	Fossil Fuel		1,607
	Hydro		
	Landfill Gas/Bio		8
	Nuclear		
	Solar		
	Wind		

Figure 21: Control Area Capacity Values

SUMMER CAP (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IESO	**35,646**	**35,650**	**36,732**	**36,732**	**37,228**	**35,164**	**35,164**	**35,206**	**35,206**	**35,206**
Combined Cycle	6,923	6,923	6,885	6,885	6,885	6,885	6,885	6,885	6,885	6,885
Combustion Turbine	716	716	1,836	1,836	3,404	3,404	3,404	3,404	3,404	3,404
Conventional Hydro	7,121	7,163	7,163	7,163	7,121	7,121	7,121	7,163	7,163	7,163
Other Steam Turbines	332	294	294	294	294	294	294	294	294	294
Pumped Storage Hydro	175	175	175	175	175	175	175	175	175	175
Solar	478	478	478	478	478	478	478	478	478	478
Steam Turbine (Nuclear)	12,959	12,959	12,959	12,959	11,929	9,865	9,865	9,865	9,865	9,865
Steam Turbine (Oil and Gas)	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018
Wind	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924
NYISO	**39,507**	**38,837**	**38,421**	**38,421**	**38,441**	**38,441**	**38,441**	**38,393**	**38,393**	**38,393**
Combined Cycle	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
Combustion Turbine	4,482	4,453	3,778	3,778	3,750	3,750	3,750	3,750	3,750	3,750
Conventional Hydro	4,489	4,441	4,441	4,441	4,489	4,489	4,489	4,441	4,441	4,441
Internal Combustion Engine	22	22	22	22	22	22	22	22	22	22
Landfill Gas	106	106	106	106	106	106	106	106	106	106
Other Steam Turbines	209	209	209	209	209	209	209	209	209	209
Pumped Storage Hydro	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
Solar	384	522	542	542	542	542	542	542	542	542
Steam Turbine (Nuclear)	4,378	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Steam Turbine (Oil and Gas)	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634	10,634
Wind	2,192	2,497	2,736	2,736	2,736	2,736	2,736	2,736	2,736	2,736
PJM	**202,357**	**205,746**	**205,703**	**204,617**	**204,652**	**204,652**	**204,652**	**204,617**	**204,617**	**204,617**
Combined Cycle	53,770	57,646	58,846	58,846	58,846	58,846	58,846	58,846	58,846	58,846
Combustion Turbine	29,655	29,655	29,611	29,531	29,531	29,531	29,531	29,531	29,531	29,531
Conventional Hydro	2,928	2,893	2,893	2,893	2,928	2,928	2,928	2,893	2,893	2,893
Internal Combustion Engine	683	683	683	683	683	683	683	683	683	683
Landfill Gas	521	521	521	521	521	521	521	521	521	521
Other Steam Turbines	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338	3,338
Pumped Storage Hydro	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182	5,182
Solar	4,265	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925	4,925
Steam Turbine (Coal)	49,716	48,706	47,507	46,501	46,501	46,501	46,501	46,501	46,501	46,501
Steam Turbine (Nuclear)	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418	33,418
Steam Turbine (Oil and Gas)	7,168	7,066	7,066	7,066	7,066	7,066	7,066	7,066	7,066	7,066
Wind	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713	11,713
ISO-NE	**32,177**	**32,883**	**32,321**	**32,049**	**30,416**	**30,416**	**30,416**	**30,443**	**30,443**	**30,443**
Combined Cycle	13,988	14,512	14,449	14,449	13,012	13,012	13,012	13,012	13,012	13,012
Combustion Turbine	3,401	3,556	3,540	3,391	3,373	3,373	3,373	3,373	3,373	3,373
Conventional Hydro	1,961	1,988	1,988	1,988	1,961	1,961	1,961	1,988	1,988	1,988
Internal Combustion Engine	185	185	180	160	144	144	144	144	144	144
Landfill Gas	74	74	74	74	66	66	66	66	66	66
Other Steam Turbines	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Pumped Storage Hydro	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860	1,860
Solar	287	287	387	387	387	387	387	387	387	387
Steam Turbine (Nuclear)	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380	3,380
Steam Turbine (Oil and Gas)	4,751	4,751	4,173	4,070	3,943	3,943	3,943	3,943	3,943	3,943
Wind	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238	1,238
Grand Total	**309,687**	**313,116**	**313,177**	**311,819**	**310,737**	**308,673**	**308,673**	**308,659**	**308,659**	**308,659**

E.1.7. Hurdle Rates and Interchange Models

Hurdle rates set the conditions under which economic interchange occurs between neighboring markets/control areas in the model. They represent a minimum savings level that needs to be achieved before energy will transact across the interface. Hurdle rates help ensure that the production-cost simulation is reasonably consistent with the historical pattern of internal NYCA generation and imports. Hurdle rates are used to reflect actual inter-regional energy market transaction costs. A hurdle rate tuning process is used during the benchmarking stage of modelling to align the base model imports and exports with historic performance.

Two independent hurdle rates are used in the Outlook, one for the commitment of generation and a separate one for the dispatch of generation. Both commitment and dispatch hurdle rates are held constant throughout the 2021-2040 study period. The hurdle rate values produce results consistent with NYCA historic total import levels.

During the tuning process, the flow on the Cross Sound Cable (CSC) was modeled to allow up to 330 MW from ISO-NE to Long Island. The flow on the Linden VFT was modeled to allow up to 315 MW in both directions. The Neptune and HTP flows were modeled to allow up to 660 MW of flow from PJM into Long Island and New York City, respectively.

The hourly interchange flow for each interface connecting the NYISO with neighboring control areas was priced at the LBMP of its corresponding proxy bus for purposes of calculating the import and export cost component of NYCA Wide production cost. The summation of all 8,760 hours determined the annual cost of the energy for each interface. Figure 22 lists the proxy bus location for each interface.

Figure 22: Interchange LBMP Proxy Bus Area

Interface	Proxy Bus
PJM	Keystone
Ontario	Bruce
Quebec	Chateauguay and Cedars
Neptune	Raritan River
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor
HTP	Bergen
VFT	Linden 138 kV
Northport Norwalk Cable	Norwalk Harbor

E.1.8. Production Cost Model

Production cost models require input data to develop cost curves for the resources that the model will commit and dispatch to serve the load, subject to the constraints given in the model. This section discusses how production cost input data is developed. The incremental cost of generation is the product of the incremental heat rate multiplied by the sum of fuel cost, emissions cost, and variable operation and maintenance expenses.

Heat Rates

Fuel costs typically represent the largest variable expense for fossil fuel-fired generating units. Cost curves are the product of fuel prices and incremental heat rates. Individual unit heat rates are commercially sensitive confidential information and thus are not widely available from generator owners. Unit heat rate input data is based on the U.S. Environmental Protection Agency's (EPA) Clean Air Market Data[17] and, where available, unit production data from the U.S. Energy Information Administration (EIA).

Outlook simulation models employ power points which represent minimum, intermediate, and maximum power production levels where generating units can be simulated to operate on a sustained basis. Each power point is tied to a point on the heat rate curve allowing incremental heat rates to be determined for each unit. The power points and incremental heat rates are developed on a Summer/Winter Capability Period basis and differentiate between fuels where applicable.

Fuel Switching

Fuel switching capability is widespread within the NYCA. According to data from the 2021 Gold Book[18], 50% of the 2021 generating capacity in the NYCA – 19,315 MW of generation – has the ability to burn either oil or gas. For such units, the production-cost simulation model selects the economic fuel based on weekly production costs for units with dual-fuel capability.

The New York State Reliability Council (NYSRC) establishes rules for the reliable operation of the New York Bulk Power System. Two of those rules guard against the loss of electric load because of the loss of gas supply. The loss of a gas facility may lead to the loss of some generating units. This loss becomes critical because it may result in voltage collapse when load levels are high enough. Therefore, criteria are established whereby certain units that are capable of doing so are required to switch to minimum oil burn levels so that in the event of the worst single gas system contingency these units stay on-line at minimum generation levels and support system voltage.

Rule I-R3 states that "The New York State bulk power system shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone." Rule I-R5 similarly states "The New York State bulk power system shall be operated so that the loss of a single gas facility will not result in the uncontrolled loss of electricity within the Long Island zone."

To satisfy the I-R3 and I-R5 criteria, annual studies are performed by the TOs that update the configurations of the electricity and gas systems and simulate the loss of critical gas supply facilities.

[17] https://ampd.epa.gov/ampd/

[18] Taken from Table V-2a https://www.nyiso.com/documents/20142/2226333/2021-Gold-Book-Final-Public.pdf/

Some new combined cycle gas turbine units in the New York City and Long Island Zones have the ability to "auto-swap" from gas-burn to oil-burn with a limited loss of output that can be quickly recovered. As the generator fleets in these zones have experienced a shift to increased use of combined cycle units with auto-swap capability, the amount of oil used in steam units to satisfy minimum oil burn criteria has decreased.

Minimum oil burn rules have not been explicitly modeled in the production cost simulations for the Outlook. Minimum oil burn units are committed and dispatched in the NYISO markets using the cost of the most economic fuel. Any cost incurred from firing oil when it is not economic to do so is recovered outside the market. Consequently, the minimum oil burn program does not affect LBMPs or any derivative metric (Demand Congestion, Load, Payment, *etc.*) and is more appropriately accounted for outside the GE-MAPS simulation.

Generation Maintenance

NYCA generation maintenance modeling was updated for the Outlook utilizing the latest planned and random outage rates from the 2021-2030 CRP process. External control areas (IESO, ISO-NE, and PJM) generation planned and forced outage were developed using NERC class average outage data.

Hourly Resource Modifiers (HRMs)

Several types of generation technologies, such as non-pondage hydro, wind, and solar were represented using MAPS hourly modifier models. This approach uses a fixed 8,760 hourly input schedule that represents the hourly generation dispatch for each unit. The shape applied to the HRM inputs for each generator type is based on historical data. Capacity and energy capabilities are adjusted for individual generator parameters.

Hourly modifier output matches the input schedule with the one exception of energy curtailment, mostly due to transmission constraints. In MAPS, curtailment occurs when the LBMP at a generator node drops below the modeled dispatch cost of the hourly modifier, which is an indication of local transmission congestion caused by renewable generation injection. The amount of energy curtailed represents the amount necessary to limit LBMP at or above the dispatch cost of the generator, to the extent that a generator has energy to curtail.

The dispatch costs modeled for hydro, wind, and solar in the Outlook database were based on historical observations and published Renewable Energy Certificates ("REC") values where available. The dispatch cost determines the curtailment order of resources in the event of a tie. Units with higher REC prices modeled will be curtailed after units with lower REC prices at the same location.

Generally, as hydro, wind, and solar units are not co-located they experience different nodal LBMP impacts of transmission congestion and losses. In the analyses performed in the Outlook, a majority of the curtailments observed were a direct result of local transmission congestion.

Hydro Model

Hydro units in the GE-MAPS production cost model leverage the internal pondage logic, which assumes pondage capability even though not all hydro units in New York are capable. The pondage model schedules resources using a fixed monthly energy targets based on historical operation. The software optimizes hydro operation to minimize production cost of the entire system and meet the monthly energy targets for each unit. In doing so, the pondage capability of some units, such as run-of-the-river hydro, may be overestimated as the software can re-distribute unused energy to other hours within a month when available. This way of scheduling hydro resources to operate in a flexible manner may not reflect actual operation of units that have limited pondage capability, and thus would likely under report the amount of curtailed energy from such resources.

Additionally, Zone D imports from the hydro dominant HQ region leverage the GE-MAPS fixed-injection model, which has no flexibility in scheduling. Hydro generation electrically close to the HQ imports in Zone D, such as St. Lawrence Hydro (a run-of-the-river hydro modeled as pondage,) will compete to deliver energy to the network. Depending on the dispatch cost of Zone D HQ imports and the nearby hydro, considering transmission constraints, it's likely that curtailed energy is biased towards the fixed-injection model over the pondage model. This model interaction will be evaluated further in future Outlook studies.

Appendix E.2: Contract Case

The principle change in the Contract Case is the inclusion of REC contracted generators through the 2020 NYSERDA REC Solicitation.[19] Figure 23 and Figure 24 break out the nearly 9,500 MW of renewable capacity additions included in the Contract Case that were not modeled in the Baseline Case by online year and zone.[20] Some projects with state contracts are in-service or advanced in development and therefore already included in the Baseline Case either as existing or as new if they have met the inclusion rules.

Figure 23: Contract Case Renewable Capacity Additions by Online Year

[19] https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2020-Solicitation-Resources#

[20] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Contract_Case_Renewables.xlsx

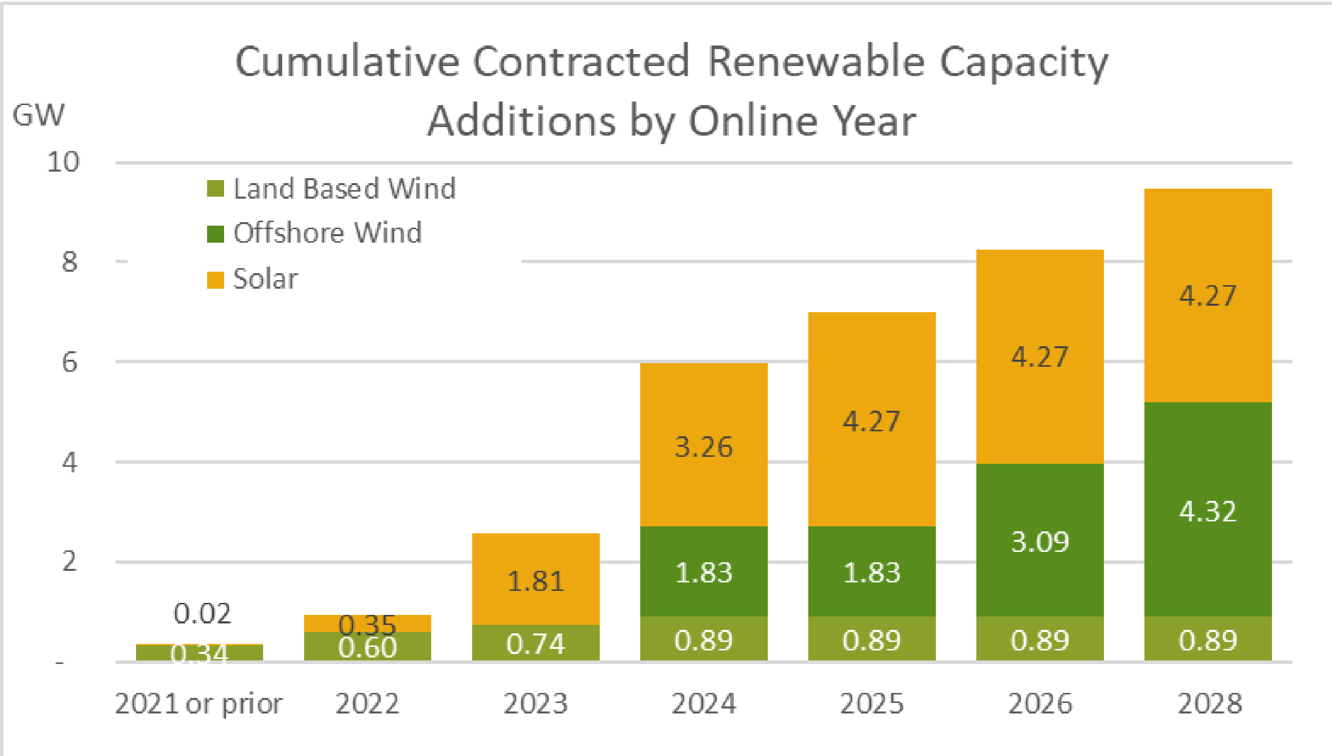
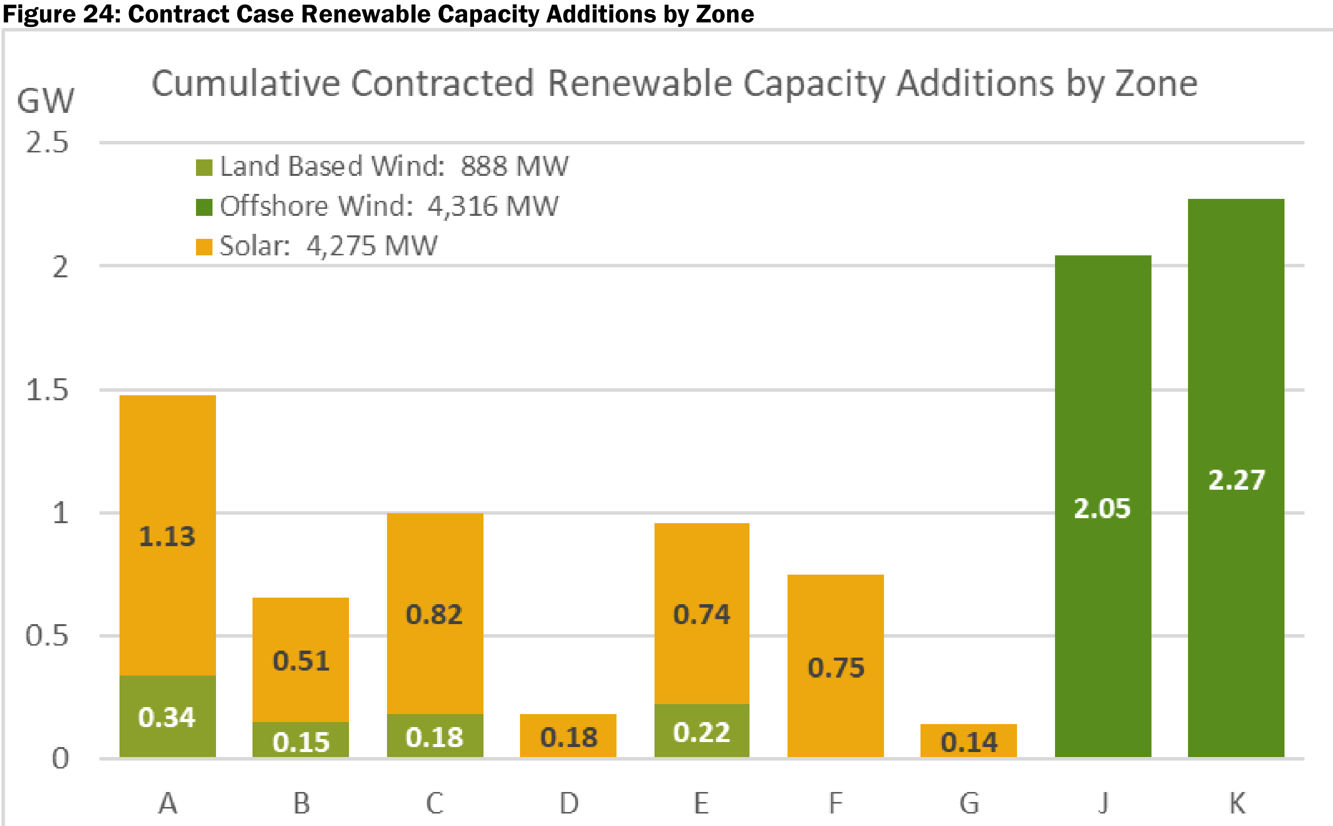


Figure 24: Contract Case Renewable Capacity Additions by Zone



E.2.1. REC Pricing

As noted above, the dispatch costs are based on REC prices received by the project. REC prices for each project[21] are modeled as a negative bid adder in the production cost model to represent the 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 calculate a representative negative bid adder for Index RECs. Assumed prices were developed to compare fixed and indexed RECs on the same basis and to preserve project-to-project price variations.[22] Each individual project's price is modeled as fixed or indexed as shown below. Given that index RECs are difficult to model in production cost simulations, 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.

The specific REC bidding prices used for each generation type can be found in Appendix C: Production Cost Assumptions Matrix.

E.2.2. Round-Trip Analysis

The NYISO leverages a "round-trip" modelling technique to capture changes in transmission congestion patterns as new generation is added to the model. The technique integrates the MAPS production cost model, PSS/E powerflow model, and a TARA transfer analysis model to correctly identify new contingencies relevant to the system configuration being modelled. Production cost models use a static list of contingency pairs whereby the "round-trip" technique makes the contingency list dynamic.

Figure 25: Roundtrip MAPS/TARA Analysis

[21] https://www.nyiso.com/documents/20142/26278859/System_Resource_Outlook-Contract_Case_Renewables.xlsx

[22] https://www.nyiso.com/documents/20142/27945979/04_System_Resource_Outlook.pdf

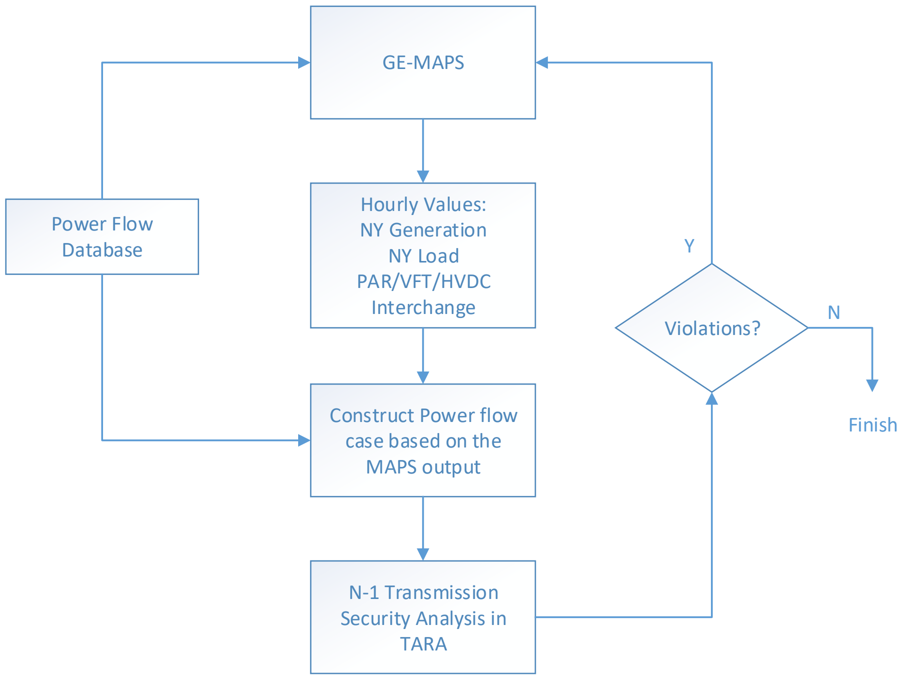


Figure 25 shows the flowchart for Roundtrip MAPS/TARA Analysis. This iterative analysis has three steps:

1. Start with the MAPS production cost run with constraints modeled in the Baseline Case. The resulting hourly MAPS output is utilized to construct power flow cases for each four-hour interval in a year (2,190 powerflow cases for one year) and solve each powerflow case in PSS/E using information including hourly NYCA zonal loads, hourly NYCA generation dispatches, hourly NYCA PAR schedules, and hourly NYCA interchange tie line flows.
2. Perform N-1 transmission security analysis on all created cases in TARA while monitoring NYCA facilities 115 kV and above, taking into account all bulk transmission system contingencies as well as local transmission system contingencies. Standard NYISO planning contingencies and additional TO contingencies are included in the TARA analysis. TO contingencies include those from the latest transmission planning studies, any additional project specific contingencies, and any contingencies requested by TOs.
3. Multiple iterations of N-1 transmission security analysis are run to ensure that consistent monitored facility/contingency pairs are observed in each iteration. Monitored facility/contingency pairs with the highest overloads are included in the production cost database.
4. Add the reported monitored facility and contingency pairs from TARA analysis into the existing production cost database. Secure the expanded list of monitor facilities and contingency pairs in

the successive runs.

Appendix E.3: Policy Case

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 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 generation capacity mix over the study period.

In this inaugural 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).

E.3.1. Capacity Expansion Modeling

Capacity Expansion Key Assumptions

As noted above, two capacity expansion scenarios, Scenario 1 ("S1") and Scenario 2 ("S2"), were selected to run through production cost simulation for this Outlook. The assumptions outlined in this section further describe these two capacity expansion cases and how they differ.

Based on the assumptions for the capacity expansion model, the model provides a projection of 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 future NYISO studies and stakeholders of potential generation buildouts under a multitude of scenarios.

The capacity expansion model is limited to the NYCA system only; it does not include neighboring regions, beyond imports of qualifying renewable hydropower from Hydro Quebec. This limitation extends to generation as well as transmission in neighboring regions. It is noteworthy because with the system represented in the capacity expansion model limited to the NYCA, the installed capacity and generation mix assumed to satisfy the CLCPA targets is limited to the NYCA as well. In other words, the capacity expansion model does not assume imports or exports, except that the contributions from Tier 4 projects are included as soon as the projects are assumed to be in-service in addition to the existing imports from Hydro Quebec. Additional detail on the specific policy constraints modeled as well as the transmission/system representation for the capacity expansion model are included in the following sections.

To maintain reasonable compute times, a set of time blocks was defined for the capacity expansion model to represent the hourly data for each year. These blocks are grouped by season and hour of the day to capture the seasonal and diurnal variations in system conditions. Additional details on the time block methodology used in the capacity expansion model are included in the model horizon and chronological representation section.

Load and Capacity Forecasts

To capture a range of future potential load conditions, two different load forecasts were assumed for the capacity expansion scenarios selected in this Outlook study.[23]

Assumptions Specific to S1

The load forecast used in the capacity expansion model S1 was based on the NYISO's 2019 Climate Change Phase I study. Following the publication of the Climate Change Phase I study, an incremental four GW additional BTM-PV CLCPA target for 2030 was recommended by DPS, and subsequently included in the load forecast for use in the Policy Case. For purposes of the Policy Case, the annual electrification forecasts between model years 2030 and 2040 were modified to smooth out the growth of electrification through 2040, while maintaining the original electrification forecasts for 2040. The Scenario 1 load forecast includes the following modifications:

- **10 GW BTM-PV by 2030 CLCPA target -** since the publication of the Climate Change Phase I study, the additional BTM-PV CLCPA target for 2030 was approved by the PSC[24], and

[23] https://www.nyiso.com/documents/20142/31279228/07_System_Resource_Outlook_Hourly_Load_Forecasts_Final.xlsx/

[24] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={498EE5D6-6211-4721-BA98-AF40EF3F620C}

subsequently included in the load forecast for use in this Outlook's Policy Case,

- **Removal of impact from energy storage resources -** the impact of energy storage resources was removed from the original forecast because energy storage resources are modeled explicitly in the capacity expansion model, and
- **Smoothed annual electrification forecasts -** the annual electrification forecasts between model years 2030 and 2040 were modified to smooth out the growth of electrification through 2040, while maintaining the original electrification forecasts for 2040.

Assumptions Specific to S2

The load forecast used in S2 was based on the Climate Action Council Draft Scoping Plan Strategic Use of Low Carbon Fuels Scenario ("Scenario 2")[25] with:

- no electrolysis loads (*i.e.*, hydrogen production), and
- "No End Use Flexibility."

Figure 26 includes annual energy (GWh) and peak (MW) forecasts assumed for scenarios S1 and S2. Comparatively, S2 assumes higher annual energy forecasts and lower seasonal peak forecasts than S1.

Figure 26: Policy Case Annual Load and Seasonal Peak Forecasts

[25] https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-2-Key-Drivers-Outputs.xlsx

Annual Energy Forecasts - GWh

Year	S1	S2
2025	144,704	150,047
2030	150,909	164,256
2035	172,566	204,702
2040	208,679	235,731

Summer Peak Forecasts - MW

Year	S1	S2
2025	31,679	29,612
2030	34,416	30,070
2035	40,033	34,402
2040	48,253	38,332

Winter Peak Forecasts - MW

Year	S1	S2
2025	26,491	21,758
2030	31,717	25,892
2035	41,681	35,093
2040	57,144	42,301

Generation

Existing generation, as well as planned generation builds and scheduled generation retirements, assumed in the capacity expansion model for the Policy Case are based on the Contract Case database. S1 did not assume any age-based retirements for fossil fuel-fired generators. S2 assumes that additional firm fossil fuel-fired generator retirements occur based on age, at: 62 years for steam turbines and 47 years for combustion turbines.[26] It was assumed that no combined cycle units retire based on age for this scenario. Incremental age-based retirements captured in Scenario 2 include approximately 12 GW, nearly half the initial 26 GW fossil fleet.

The capacity expansion model allows for retirement of existing generators throughout the model's horizon. Generator retirements are enabled such that individual generators could retire any year within the study period. The capacity expansion model considers each generator's fixed and variable operating and maintenance costs over the entire model horizon when determining whether to retire the generator each year of the study period. The capacity expansion model co-optimizes generation capital and production costs to determine a least cost future generation mix.

[26] https://climate.ny.gov/-/media/Project/Climate/Files/Draft-Scopping-Plan-Appendix-D.pdf

Generator expansion is enabled at the zonal level, such that one representative generator per type is allowed for each applicable NYCA zone. The capacity expansion model assumes linear expansion[27] for the new generators, such that the candidate generator can increase its capacity each year up to its maximum capacity (MW) limitation, if imposed[28], noting that a single generator would be built per zone. The generator builds assumed from the capacity expansion model are then translated into discrete generators in the production cost modeling for the Policy Case. Additional detail on the process of generator placement between capacity expansion and production cost modeling is included in Appendix Production Cost SimulationE.3.2. The capacity expansion model allows for generation expansion of the following generator types:

- Offshore wind (OSW)
- Land based wind (LBW)
- Utility PV (UPV)
- 4-hour battery storage
- Dispatchable Emission Free Resource (DEFR)

Generation expansion in the capacity expansion model is limited to renewable generation, battery storage, and DEFR generators to provide insight into the potential resource mix to comply with state policies. Of note, fossil fuel-fired generation, nuclear, BTM-PV, and hydro generation were not candidate generator types eligible for generation expansion in this Outlook study. The characteristics and capabilities of existing technologies (*i.e.*, renewables and battery storage) cannot solve for the 2040 zero emissions CLCPA target without significant capacity additions above and beyond the capacity requirements. Therefore, DEFR generation options were included in the capacity expansion model.

Given the significant uncertainty regarding potential technology options to serve future system needs

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27 Linear expansion allows for partial unit retirements and generation additions by 1 MW increments in order to reduce computational complexity.

28 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.

flexibly with zero emissions, a range of capital and operating costs informed by prior studies[29] [30] were assumed for the DEFR generators. The DEFR generators represent a commercially unavailable future technology that would be dispatchable and that would produce emissions-free energy (*e.g.*, hydrogen, RNG, nuclear, or other long-term seasonal storage). For this Outlook study, three cost options were allowed as DEFR generators eligible for generation expansion.[31] These options reflect the following cost ranges[32]:

- HcLo - High capital cost with low operating (fuel and variable O&M) cost
- McMo - Medium capital cost with medium operating (fuel and variable O&M) cost
- LcHo - Low capital cost with high operating (fuel and variable O&M) cost

S1 assumed all three DEFR options as candidates for generation expansion while S2 assumed only the Medium Capital/Medium Operating cost option. As observed through results of scenario testing, which is described in further detail in Appendix G: Detailed Capacity Expansion Scenarios, each of the DEFR options exhibits a different installed capacity and generation mix in the capacity expansion model. The DEFR options in S2 were limited to the Medium Capital/Medium Operating cost option only to produce a different operational profile for DEFRs between the two scenarios for further consideration in production cost analyses.

In the capacity expansion model, battery storage is modeled similar to candidate expansion generators, except that they are modeled in the Battery category in PLEXOS, which includes additional attributes (*e.g.*, state of charge, charge and discharge efficiencies, MWh capability).

Each generator is modeled as having technology specific attributes which help satisfy load and/or capacity contributions towards the resource adequacy constraints, as applicable to the technology type. Existing generators assumptions align with historic data (*e.g.*, max capability, monthly energy output, etc.). The candidate expansion generators assume cost and technological capabilities consistent with the 2021

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29 https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

30 https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf

31 A range of capital and operating costs for DEFRs were examined as part of this Outlook through scenarios. Additional details on these scenario assumptions are included in the following section.

32 The range of DEFR costs evaluated in this Outlook, as well as approximations from other studies, are included in slides 13 & 14 of the December 17, 2021 ESPWG presentation. https://www.nyiso.com/documents/20142/27019028/ESPWG_System_Resource_Outlook_Update2.pdf/

EIA Energy Outlook[33].

Intermittent generation resources (*e.g.*, LBW, OSW, UPV) use simulated hourly NREL profiles as an approximation of the energy output from each respective technology type[34]. Additionally, existing NYCA hydro generation uses monthly historic profiles at the generator level as an approximation of their energy contribution; hydro generation associated with qualifying imports from Hydro Quebec use hourly historic profiles to represent their energy contribution. Fossil fuel-fired generation, nuclear, and other qualified generators are modeled as dispatchable generation, consistent with their capabilities.

Additionally, generators in the capacity expansion model are assumed to have a capacity contribution towards satisfying the state's resource adequacy requirements. In addition to having an installed capacity (ICAP), each generator has an associated unforced capacity (UCAP) that ranges between 0%-100% of its installed capacity rating. The UCAP associated with each generator's contributes towards the Installed Reserve Margin (IRM) and/or Locational Capacity Requirements (LCRs), as applicable to the generator's location within the NYCA. Additional information on the IRM and LCR requirements, as modeled in the capacity expansion model, is included in the Resource Adequacy Constraints section of this Appendix.

The UCAP ratings for existing generators are based on the generators' historic performance or availability, as applicable to the generator type's UCAP rating methodology consistent with NYISO market rules. The UCAP ratings for candidate renewable generators (UPV, LBW, and OSW) and battery storage resources are modeled using declining capacity value curves related to the amount of each technology added to the system[35]. The UCAP ratings for candidate DEFR generators are consistent with the default derating factor value from the NERC GADS database for existing combined cycle generators.

Figure 27 represent the declining capacity value curves as a function of each technology type's installed capacity. The curves labeled as the generator type and "Outlook" designation represent the capacity value curves implemented in this Outlook study. The dotted curves used in this study are simplified representations of the curves that were implemented in the "Grid In Evolution Study," which

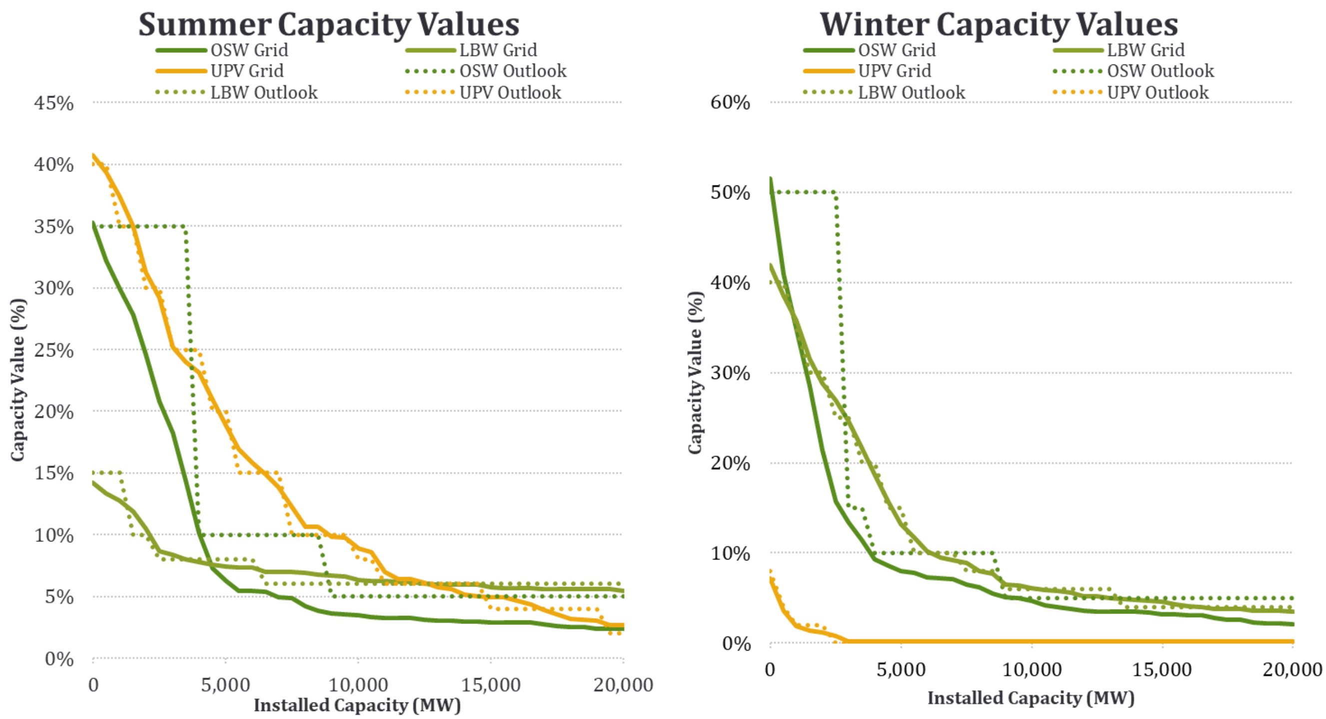
[33] https://www.eia.gov/outlooks/archive/aeo21/assumptions/pdf/electricity.pdf

[34] The hourly shapes for existing LBW generators are based on historic data at the generator/county level and the shapes for new LBW generators (candidates for generation expansion) are based on NREL simulated data at the zonal level. The hourly shapes for existing UPV generators are based on historic data, UPV generators included in Contract Case are based on shapes specific to each proposed project, and UPV candidates for generation expansion are based on zonal NREL data. The hourly shapes for OSW generators are based on NREL data; contracted projects are based on clustered site level data and candidates for generation expansion are based on zonal data.

[35] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

are shown as solid lines in the figure.[36]

Figure 27: Policy Case Declining Seasonal Capacity Values



Transmission representation

The transmission model used in the capacity expansion model is based on the NYCA transmission network in the Policy Case; it does not include neighboring regions, including ties to NYCA neighbors, beyond imports (of qualifying renewable hydropower) from Hydro Quebec and limited ties to PJM between Zones A and C. The capacity expansion model starts with the complete nodal database from the production cost model, as applicable to the Policy Case. The PLEXOS model performs a nodal to zonal reduction of this database to create a pipe-and-bubble equivalent model of the NYCA region for the capacity expansion model. In this reduction, intra-zonal lines are collapsed.

Of note, the Policy Case assumes three new transmission projects included as firm projects, incremental to what is included in the Baseline and Contract Cases. Planned additions to the New York transmission system assumed in the Policy Case include:

- **December 2025:** NYPA Northern New York Priority Transmission Project, the NYPA "Smart

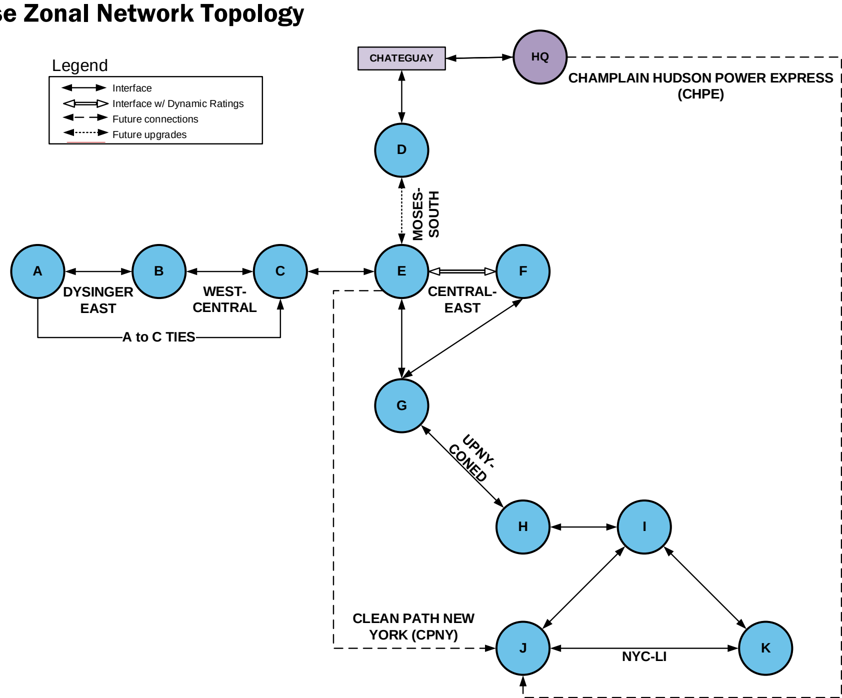
[36] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/ (Slide 111)

Path", modeled as a 1,000 MW upgrade to the Moses-South interface;

- **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 capacity expansion model does not allow for transmission expansion as a modeling option in this Outlook study. The pipe-and-bubble equivalent model used in the capacity expansion model is included in Figure 28 below.

Figure 28: Policy Case Zonal Network Topology



Model horizon and chronological representation

As referenced above, each year in the capacity expansion model is represented by 17 load blocks. This simplifying assumption on the model's chronology maintains a balance of computational time and a reasonable approximation of the seasonal and diurnal variations from the hourly input from the Policy Case's database.

For each year, 16 of the load blocks are represented by grouping hours of the year by season (Spring, Summer, Fall, and Winter) and time of the day (overnight, morning, afternoon, and evening) to capture the seasonal and diurnal variations in wind, solar, and load profiles. The 17^{th} load block per year represents a period of peak load hours. The peak load block is assumed to occur in the summer for model years 2021-

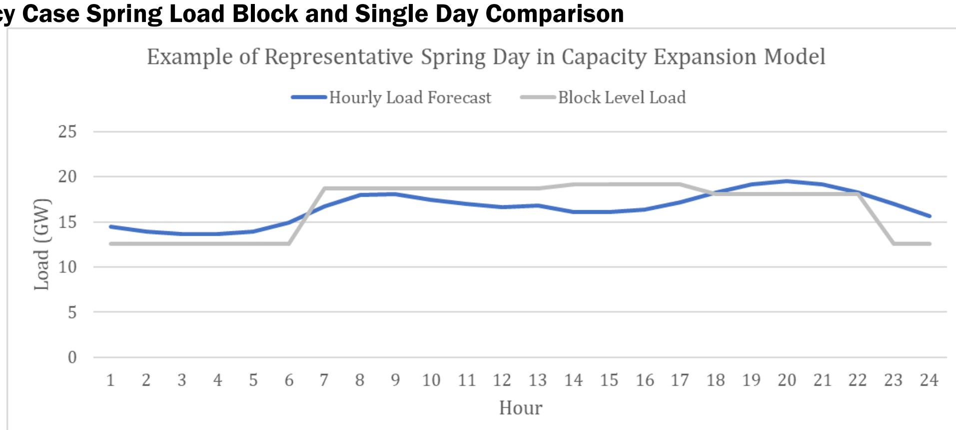
2033 and in the winter for model years 2034-2040, consistent with peak shifting in the load forecast from summer to winter around the year 2033.

Figure 29 displays the load blocks assumed in the capacity expansion model by season and time of day. The load blocks used for model years 2021-2033 are represented in the top panel, those used for model years 2034-2040 are represented in the lower panel.

Figure 29: Policy Case Load Block Definitions

PLEXOS performs a conversion of the hourly, monthly, and seasonal input assumptions from the Policy Case database by a weighted average into the input assumptions for each block represented in the capacity expansion model. In other words, the underlying hourly data included in each load block are averaged to develop the representative load blocks for each year in the model's horizon. The duration of each load block is accounted for such that each representative block is a weighted average of the underlying hourly data embedded in that time period. For example, the underlying hourly data included in each "spring afternoon" load block (HB 14 through HB 17 for March, April, and May) are averaged to develop the representative load block for "spring afternoon" for each model year. Figure 30 represents an example of how the PLEXOS model averages the input hourly load data for each of the four predefined "spring" load blocks (overnight, morning, afternoon, and evening) to create a representative load for the "spring" season for a given year, as shown in grey. The blue line displays the hourly load profile for a single spring day.

Figure 30: Policy Case Spring Load Block and Single Day Comparison



Targeted Policy Attainment

For purposes of the Policy Case, the CLCPA targets and other state policy goals are modeled in the capacity expansion model as constraints, such that the generation and capacity mix must satisfy each respective constraint. The capacity expansion model considers existing generation as well as candidate expansion generators to satisfy these constraints. The policy based constraints modeled in the capacity expansion model for this Outlook study focuses on the electric power sector and includes:

- 6 GW BTM-PV installed by 2025 (included in the load forecast)
- 3 GW energy storage installed by 2030
- 10 GW BTM-PV installed by 2030 (included in the load forecast)
- 70% renewable generation by 2030 (70 x 30)

- 9 GW offshore wind installed by 2035
- 100% emission free generation by 2040

The policy constraints specific to installed capacity of a certain generator type, for example the energy storage and offshore wind capacity targets, can only be satisfied by each respective generator type. The policy constraints specific to generation can be satisfied by the qualifying generator types, as applicable to each constraint. For example, the 70 x 30 constraint must be satisfied by generation from LBW, OSW, UPV, BTM-PV, hydro generation, and HQ imports. For comparison, the zero emissions by 2040 constraint can be satisfied by generation from renewable generator types eligible for the 70 x 30 constraint as well as storage (battery storage and pumped storage hydro), nuclear, and DEFRs.

The model does not attempt to achieve 85% green-house gas emission reduction by 2050.

Resource Adequacy Constraints

Capacity reserve margins are included in the capacity expansion model to approximate resource adequacy requirements at the NYCA wide and Locality levels for the three New York Localities (Zone J, Zone K and Zone G-J). Installed Capacity Reserve Margin (IRM) and Locational Capacity Requirement (LCRs) for the 2021-2022 Capability Year are translated to their respective unforced capacity (UCAP) equivalent per the NYISO's installed capacity (ICAP) to UCAP translation and are preserved for all model years. The IRM and LCRs are modeled as minimum capacity reserve margins, which enforce a lower bound for the respective reserve margins.

The UCAP equivalent of the resource adequacy requirements are utilized because it has been found to be a more stable metric through time, as compared to the ICAP equivalent, especially in a system with high renewable resource penetration.[37]

For purposes of the capacity expansion model in this Outlook study, adjustments were assumed to the LCRs to address the future impacts on LCRs due to new transmission from planned transmission projects. Although the actual (scale of the) impact on the LCRs is unknown at this time, the following estimates as to how the LCRs may be impacted due to future transmission projects were made for purposes of this Outlook[38]:

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[37] Whitepaper on "The Impacts of High Intermittent Renewable Resources" from the New York State Reliability Council https://www.nysrc.org/PDF/Reports/HR%20White%20Paper%20-%20Final%204-9-20.pdf

[38] Multiple scenarios were evaluated in the capacity expansion model and discussed with stakeholders at ESPWG to examine a range of potential IRM/LCR values. The approximate LCR impacts used in this study are illustrative and

- 10%-point reduction in Zones G-J LCR to accommodate AC Transmission projects entering service in 2024
- 650 MW reduction in Zone J & Zones G-J LCRs to accommodate the Clean Path New York HVDC project

The minimum UCAP requirements of the capacity reserve margins assumed in the capacity expansion model are as follows:

Figure 31: Capacity Expansion IRM and LCR Values

Capacity Reserve Margin	Summer Requirement (%)[39]	Winter Requirement (%)[40]
NYCA IRM	110.11	110.56
Zones G-J LCR	84.43 model years 2021-2023; 74.43 model years 2024-2040	83.69 model years 2021-2023; 73.69 model years 2024-2040
Zone J LCR	78.14	78.31
Zone K LCR	97.85	95.48

Maximum Capacity Constraints

As noted above, constraints on the maximum allowable capacity by technology type by zone are assumed in the capacity expansion model for use in the Policy Case. These limitations are imposed to reflect physical land constraints in each respective area[41] as well as propose an assumed constraint on the amount of generation expansion that can occur on an annual basis (*e.g.*, no more than 10% of maximum allowable capacity by zone could be installed each year). The total capacity (MW) constraints imposed reflect all new builds by each respective technology type in each applicable zone, which includes generators in both the Contract Case as well as candidates for generation expansion.

The maximum capacity constraints have a significant impact on the amount of capacity builds that occur in each zone. Scenario testing revealed that many of the technologies will wait to build capacity until later in the model horizon, as a direct result of the cost assumptions for generators as the candidate generators for expansion assume a declining capital cost through time due to technological

do not represent future study work to be performed to calculate actual values due to these transmission projects. https://www.nyiso.com/documents/20142/29418084/10%20System_Resource_Outlook_CapEx_Updates.pdf/

[39] Summer 2021 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

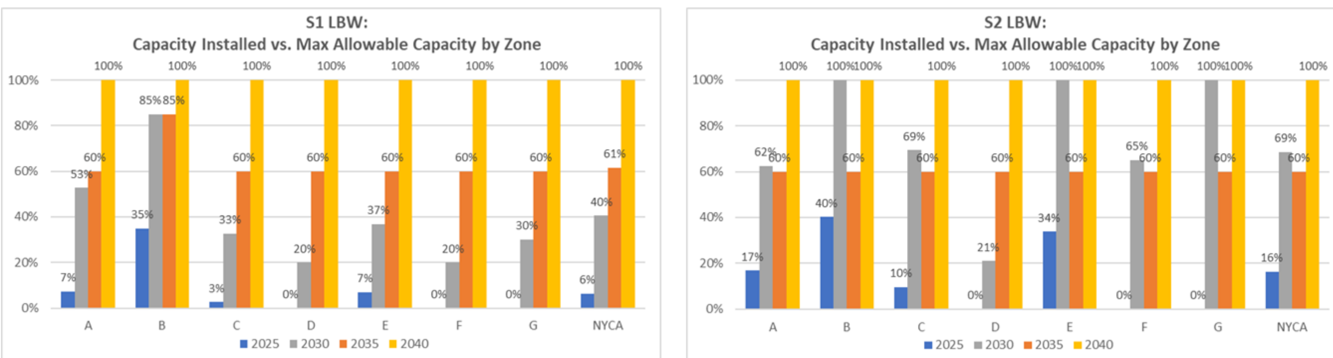
[40] Winter 2021-2022 http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

[41] Maximum allowable capacities are enforced for applicable generator types by zone based on 2040 limitations, per Appendix G: Annex 1: Inputs and Assumptions of the Climate Action Council Draft Scoping Plan. See: https://climate.ny.gov/-/media/Project/Climate/Files/IA-Tech-Supplement-Annex-1-Input-Assumptions.ashx

improvements[42]. Because the capacity expansion model seeks to optimize generation capital cost and production costs to determine a least cost future generation capacity buildout, the model will postpone construction of new units, if possible, to optimize the total system cost over the study period. However, it is unrealistic to assume that all construction will occur at the latest possible date (*e.g.*, 2035 for OSW capacity builds) due to construction, labor, and other realistic constraints; therefore, an annual build limit was imposed in each location to slow the growth of generation expansion for each generator type.

The following figure previews results for scenarios S1 and S2, which include the maximum capacity limitation assumptions described above, as a function of the maximum allowable capacity by zone. The percentage values show the amount of resource capability, by zone, that the optimization selected.

Figure 32: Land Based Wind Installed Capacity relative to Zonal Maximum Allowable Capacity

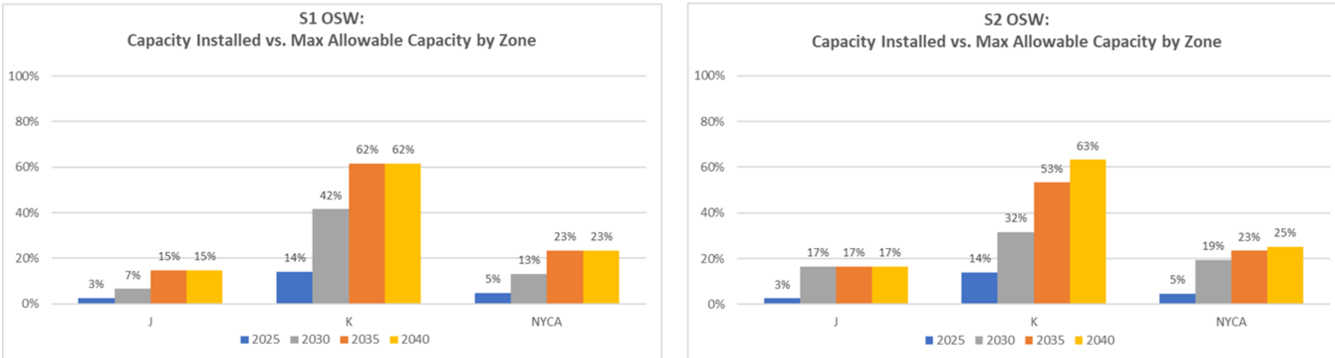


In both S1 and S2, the capacity builds from LBW reached its maximum allowable capacity for each zone by 2040, although the projection of LBW capacity builds throughout the model horizon differed due to differing constraints assumed for LBW[43].

Figure 33: Offshore Wind Installed Capacity relative to Zonal Maximum Allowable Capacity

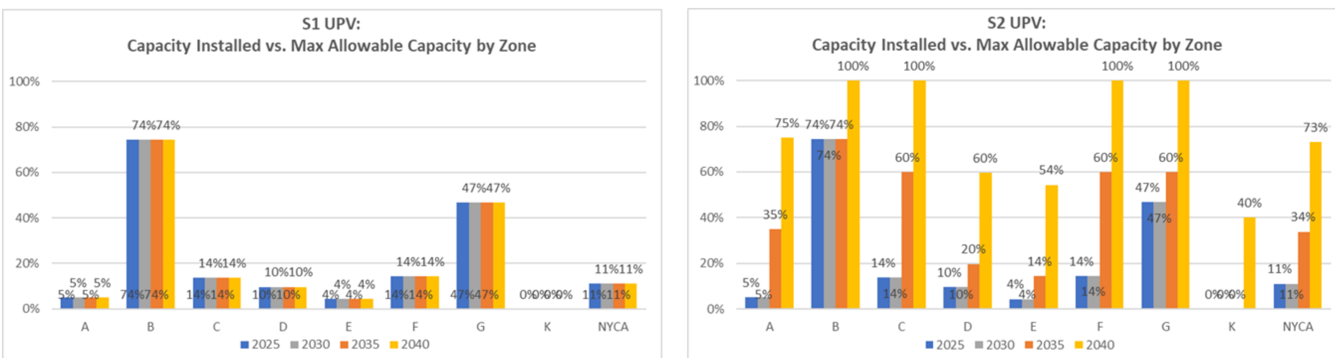
[42] Based on NREL 2020-ATB-data. See: https://data.nrel.gov/submissions/145

[43] S2 assumes a lower maximum allowable capacity for LBW for model years 2021-2030, based on the 2030 limitations per the Climate Action Council Draft Scoping Plan. For comparison, S1 assumes the 2040 limitations for all model years. Due to this tighter constrained, the percent of allowable capacity installed decreases between years 2030 and 2035 in S2 because the capacity limit (MW) was relaxed after 2030.



The progression of OSW capacity builds differed between S1 and S2; a higher amount of OSW capacity was built by 2030 in S2 comparatively, due to the lower limit on LBW capacity allowed by 2030, and the total amount of OSW capacity built by 2040 was slightly higher in S2 as compared to S1.

Figure 34: Utility Scale Solar Installed Capacity relative to Zonal Maximum Allowable Capacity



There was no generation expansion from UPV in S1, while S2 had a significant amount of UPV capacity built. The capacity installed shown in S1 is reflective of the planned UPV capacity from state contracts, whereas the UPV capacity in S2 includes both planned builds as well as generation expansion. In S2, the UPV capacity reaches the maximum allowable capacity limits by 2040 in four out of the eight zones where UPV was eligible to build.

Model Limitations and Caveats

The assumptions and results of the capacity expansion model are the result of development of a NYCA specific modeling framework in PLEXOS that was based on initial porting of the GE MAPS production cost database. The initial database was updated and amended to include parameters utilized in the capacity expansion portion of the PLEXOS model. This version of the capacity expansion model was developed as an initial reasoned trade-off between balancing model fidelity, runtime, and future uncertainty in knowledge of input assumptions to produce representations of possible outcomes of the future NYCA generation fleet and operations. Several versions of the model framework and assumptions were initially characterized by scenario testing to assess the sensitivity of the model to various input assumptions. While the model provides meaningful and logical insights into future capacity mix and generator operations, it should be viewed as a work in progress as additional improvements and capabilities accrete over the coming years. The capacity expansion model should be viewed as a potential projection of the future system mix and should not be understood as an endorsement of outcomes under any specific set of assumptions. It is primarily intended to inform NYISO studies and stakeholders of potential future generation fleet mixes under a multitude of scenarios.

Therefore, there are a number of important model limitations and caveats that need to be recognized when using and understanding the results of the capacity expansion model used in this Outlook study.

Model limitations

- The capacity expansion modeling framework employed will not capture curtailment of renewable resources due to specific transmission constraints. Curtailments will be reported as part of the Policy Case production cost model results.
- The capacity expansion model does not capture capacity market dynamics beyond simplified assumptions of satisfying current published IRM and LCR requirements on an unforced capacity (UCAP) basis.
- Zonal capacity expansion models include zonal limitations as a proxy for capacity siting constraints, however they do not provide insight into specific nodal locations where project interconnections are most likely or valuable to the system.

Model caveats

- The results of capacity expansion models are sensitive to the input assumptions related to cost and performance of resources and the modeling framework used to represent chronology and nodal/zonal representations.
- The state of charge for batteries is tracked (*i.e.*, the battery remains within its minimum and maximum state of charge levels) at the beginning and end of each model year. For each load block, the batteries can charge or discharge up to their maximum capacity (MW) rating.
- A set of proxy generic Dispatchable Emission Free Resources (DEFRs) was used to approximate a range of capital and operating costs given the uncertainty of future technology

pathways to serve the role of a dispatchable generator.

- All DEFRs are modeled as highly flexible resources with operational parameters (*i.e.*, heat rate, ramp rate, reserve contribution, start time, etc.) similar to a new natural gas combined cycle (but with zero emission rate).
- While these proxy DEFR options may ultimately prove to not be representative of actual future technologies, they were used as a modeling framework to highlight the desired resource characteristics to meet state policies and the operational needs that would have to be met by the DEFRs when performing production cost simulations.

- The capacity value curves implemented in the capacity expansion model were developed as part of the Grid In Evolution study work[44]. The declining capacity value of solar, wind, and energy storage resources is a function of the load and operational profiles of resources, which may not be consistent across studies with varying assumptions regarding load and generation profiles, but provide a reasonable approximation for purposes of this Outlook.

Scenario specific caveats

- The additional scenarios reflect a change in assumptions based on the adjustments outlined in Appendix G.1 Capacity Expansion Scenario Assumptions and are independent of other scenarios conducted.
- Given uncertainty of future policy, technology, and costs, scenarios are intended to examine a range of values for a single assumption change.
  - For example, multiple scenarios have been conducted on the load forecast to capture a range of potential future load conditions which helped inform different load forecasts selected in S1 and S2.
- Separately, multiple scenarios were conducted to represent a range of DEFR costs (capital cost and fuel price) to capture a range of potential costs for the Dispatchable Emission Free Resource technologies.
- Assumption changes included in the scenarios are not an endorsement of estimate of the validity of the values modified from the assumptions for S1 and S2. Some scenarios do not

[44] https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/

represent realistic system performance but are helpful in identifying directional impacts and sensitivity to key variables (*e.g.* scenario removing declining capacity value curves).

- Combinations of presented scenario options may also be informative as some system changes may correlate or are reasonably likely to occur together.

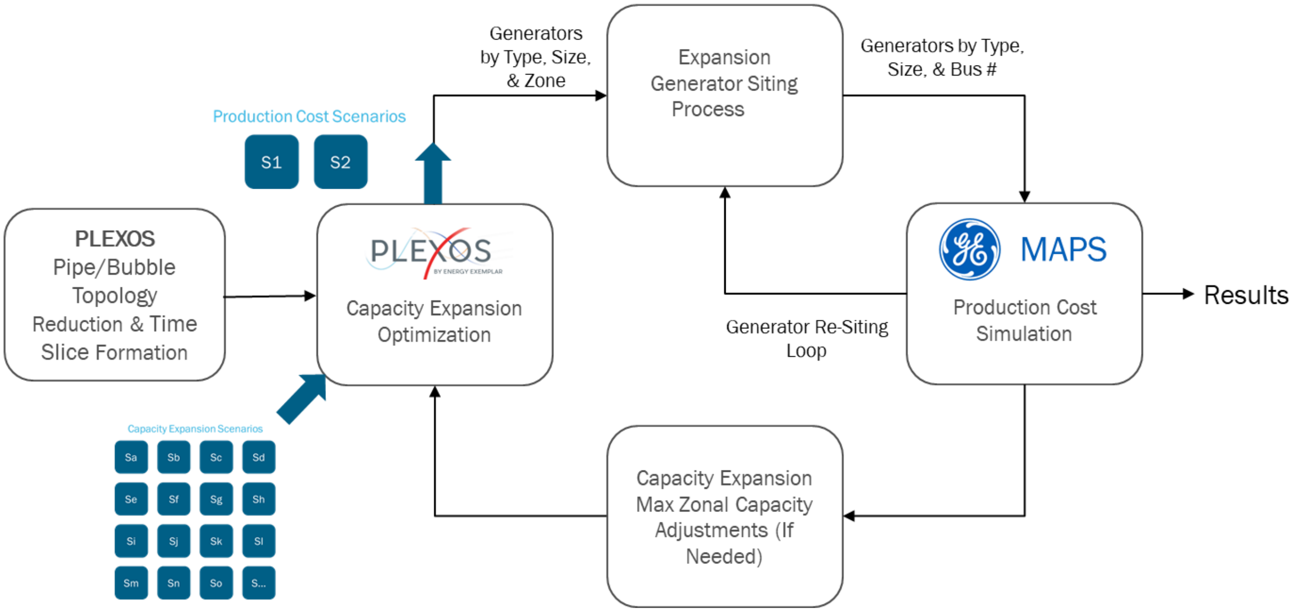
E.3.2. Production Cost Simulation

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 on an hourly basis under a high renewable penetration scenario. The model data-flow diagram in Figure 35 below highlights the process used in translating the capacity expansion model results to the production cost model.

Figure 35: Policy Case Modelling Process Diagram



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. Renewable generator additions were assigned REC prices based on current average contract prices by technology.[45]

[45] https://www.nyiso.com/documents/20142/28777318/04_System_Resource_Outlook_Update.pdf

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.

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", modelled as several 230kV to 345kV transmission upgrades on the Moses South corridor in Northern NY;
- **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 HVDC line, 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.

Process Feedback Loops

As depicted in Figure 35 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 E.2: Contract Case 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 NYCA 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 total 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.

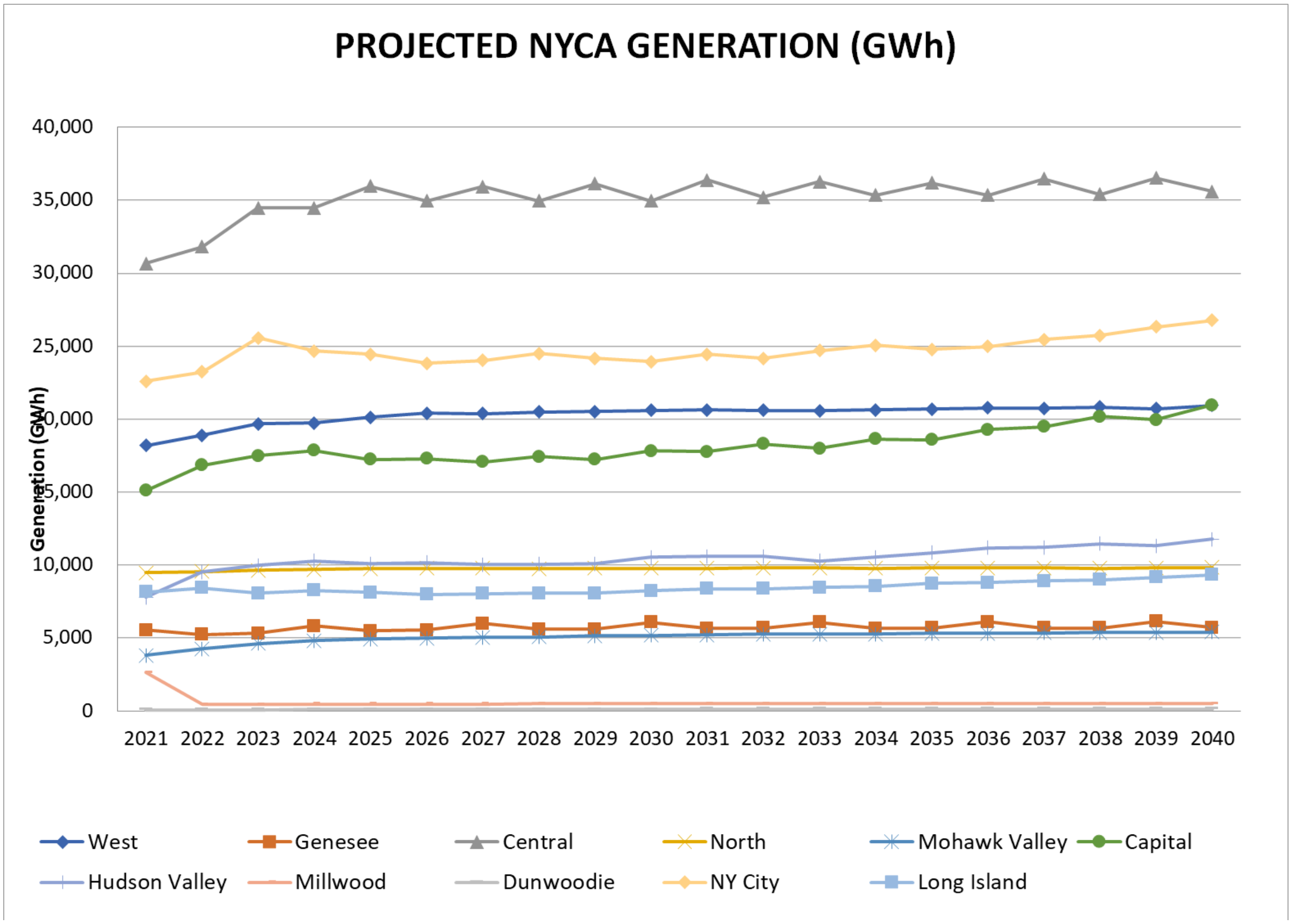
Appendix F: Study Results

Appendix F.1: Baseline Case Results

This section presents summary level results for the Outlook Baseline Case.

F.1.1. Generation

Figure 36: Projected NYCA Generation by Zone



F.1.2. Net Imports

Figure 37: Projected Net Imports by Interface

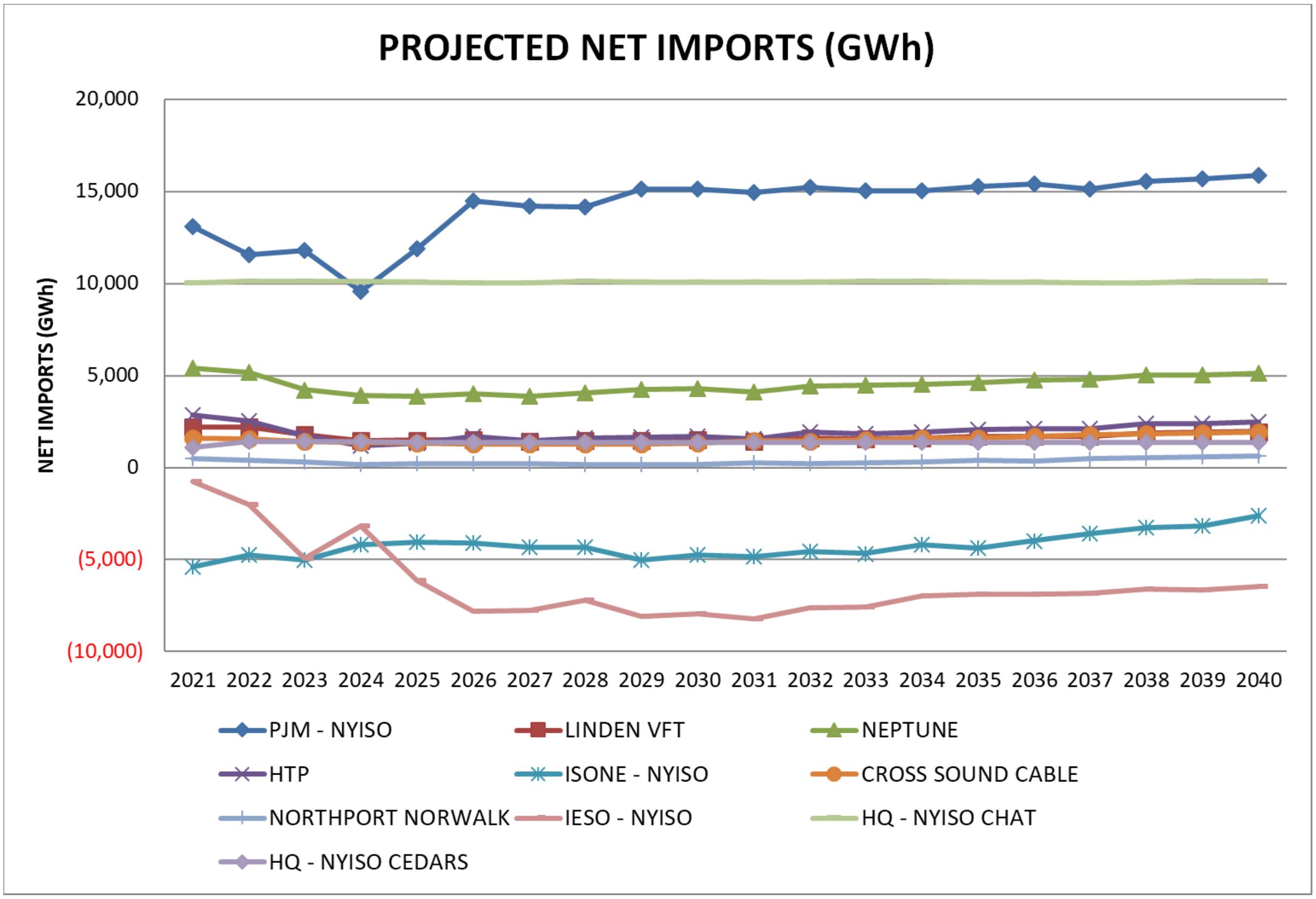


Figure 37 shows the projection of net imports on each interface for the Baseline Case. Net imports from Ontario decline with the retirement of the Pickering nuclear power plant in 2024 and 2025 and the refurbishment of the Darlington and Bruce nuclear power plants throughout the study period. Net imports from PJM increase in response to this refurbishment schedule. Across the other interfaces, net imports are largely flat through the study period.

F.1.3. Unserved Energy

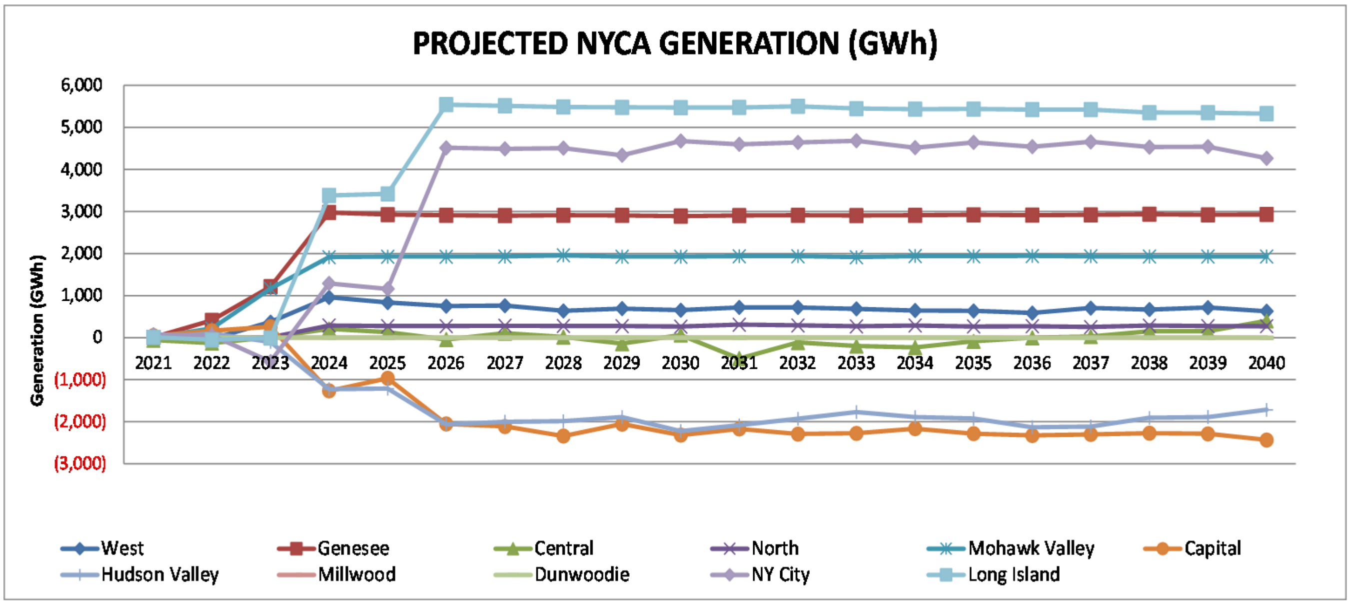
In the production cost model, unserved energy occurs when the model lacks sufficient resources to serve load in a given hour. Any unserved energy in a load zone is met by a zonal 'dummy' generator in the MAPS program. In the Baseline Case, four hours in Zone J in 2040 experience unserved load, which 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.

Appendix F.2: Contract Case Results

This section summarizes study results for the Outlook Contract Case.

F.2.1. Annual Generation

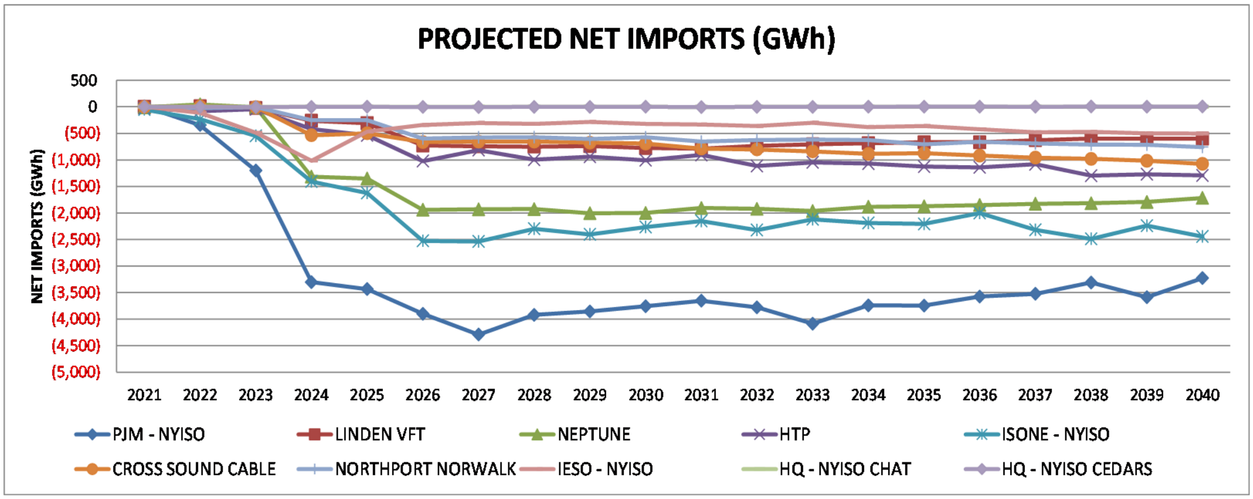
Figure 38: Projected NYCA Generation by Zone, Delta from Baseline Case



F.2.2. Net Imports

Figure 39 shows the change in net imports from the Baseline Case by interface.

Figure 39: Projected Net Imports by Interface, Delta from Baseline Case



F.2.3. Congestion

Figure 40: Projected Demand Congestion by Zone, Delta from Baseline Case

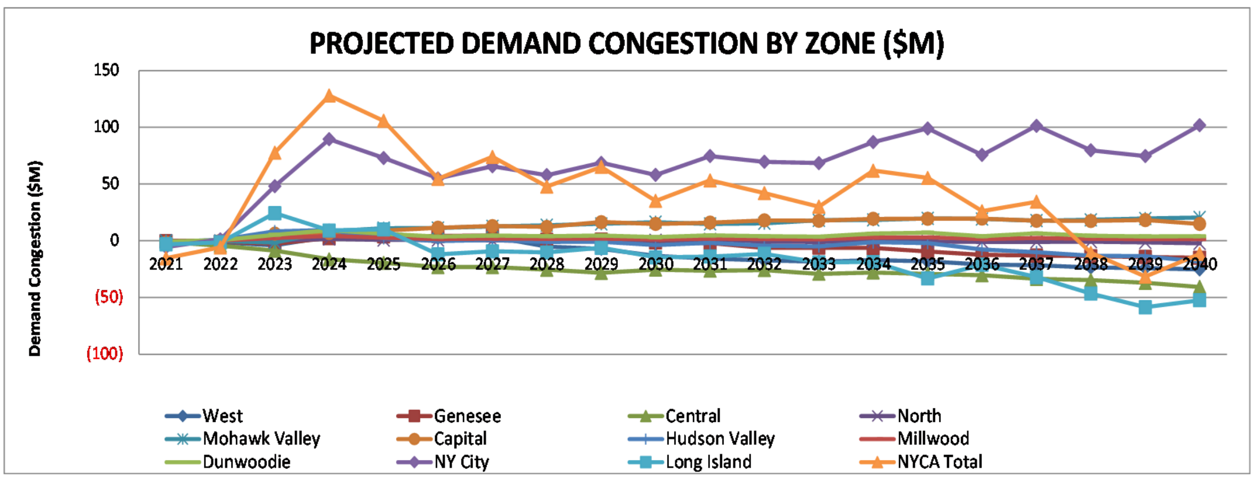


Figure 41: Demand Congestion by Constraint, Delta from Baseline Case

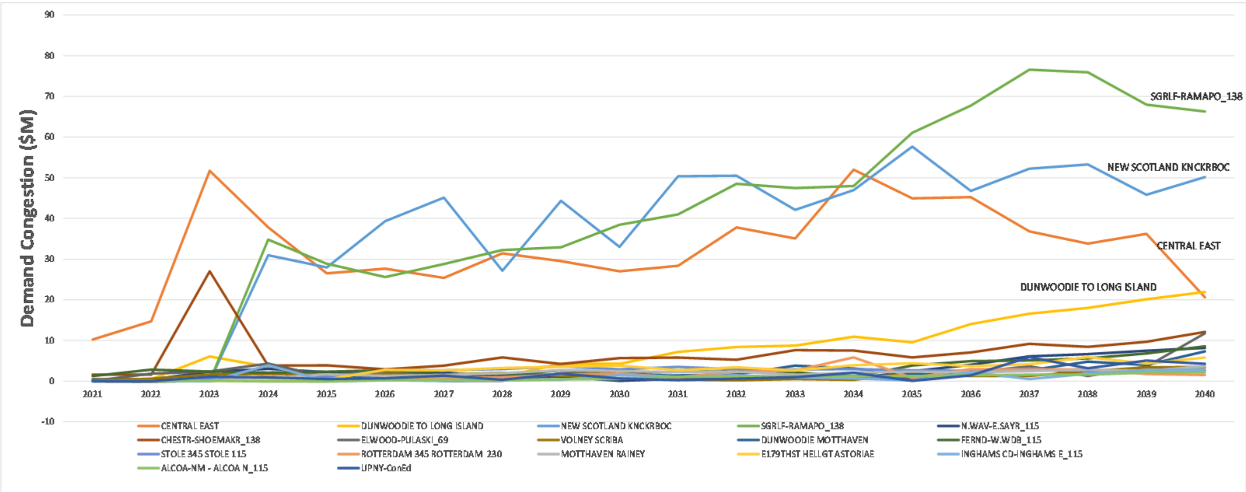


Figure 40 and Figure 41 show the changes from the Baseline Case in demand congestion both zonally and by constraint. Zone J sees the most significant increase in demand congestion while Central and Long Island see decreases in demand congestion. The constraints with the most prominent increases in demand congestion are Sugarloaf to Ramapo, New Scotland to Knickerbocker, Central East, and Dunwoodie to Long Island.

F.2.4. 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 42: Annual Generation by Unit Type and Zone

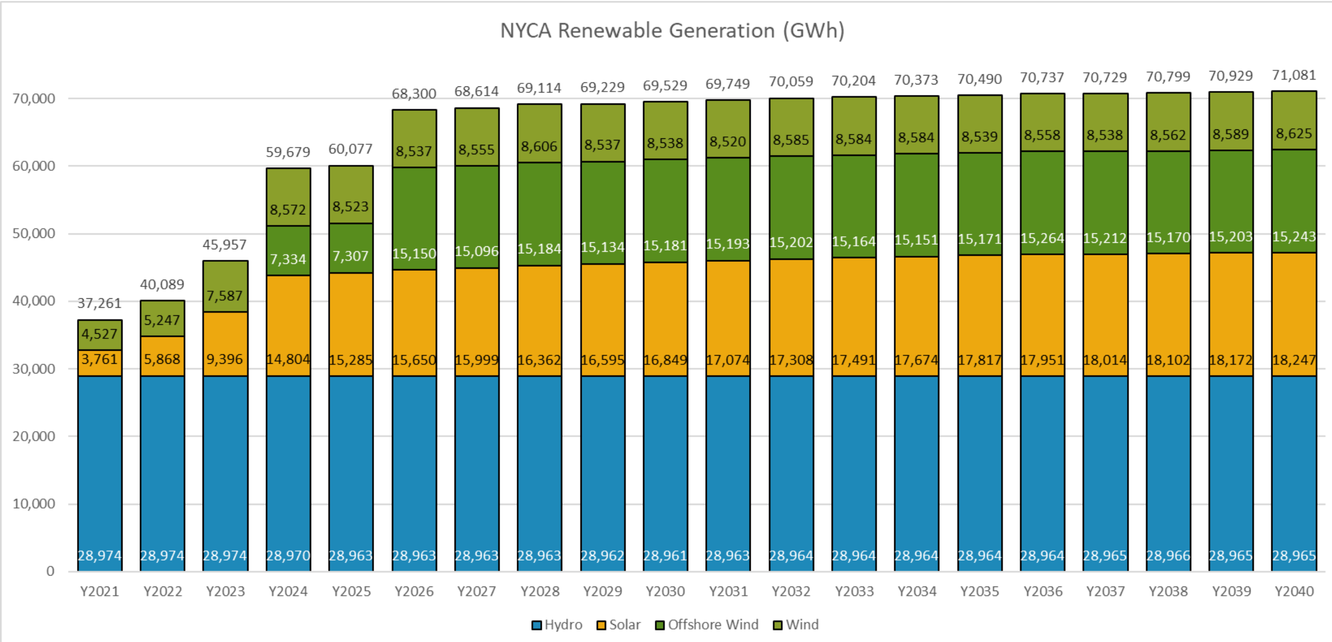
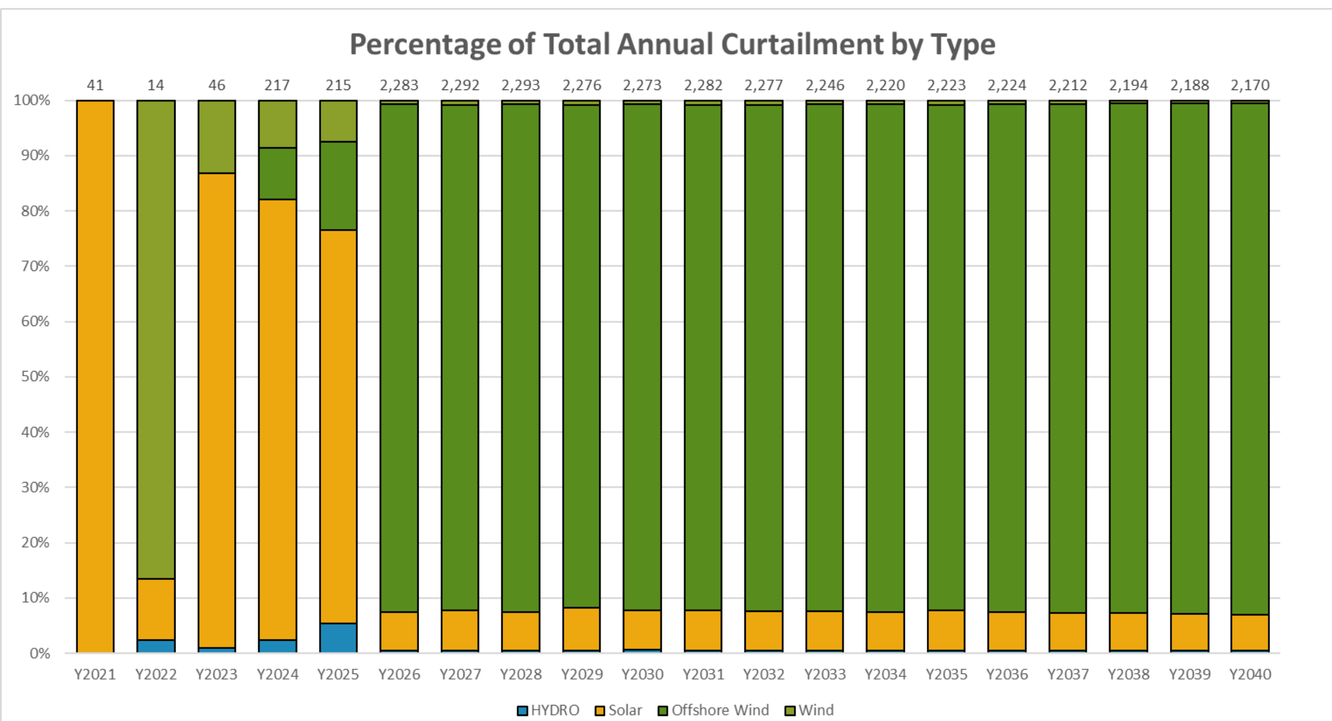


Figure 43: Annual Curtailment by Unit Type



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 Offshore Wind Renewable Energy Certificates (ORECs) from NYSERDA. The offshore wind curtailment can mostly be attributed to local constraints at the point of interconnection in Zone K. Specific substation configurations and transmission upgrades related to the interconnection of each project were not modeled as part of the production cost modeling. The numeric values displayed above the bars in Figure 43 identify the total annual renewable energy curtailment in GWh.

F.2.5. 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 (Dispatchable Demand), 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, which is similar to the unserved energy found in the Baseline Case.

Appendix F.3: Policy Case Results

This section presents summary level results for the Outlook Policy Case.

F.3.1. 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.

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.

Existing Generation

For purposes of this section, existing generation in the capacity expansion model is limited to 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 modeled all fossil fuel-fired units to retire by the 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.

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. Additionally, the 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.

Results Specific to S1

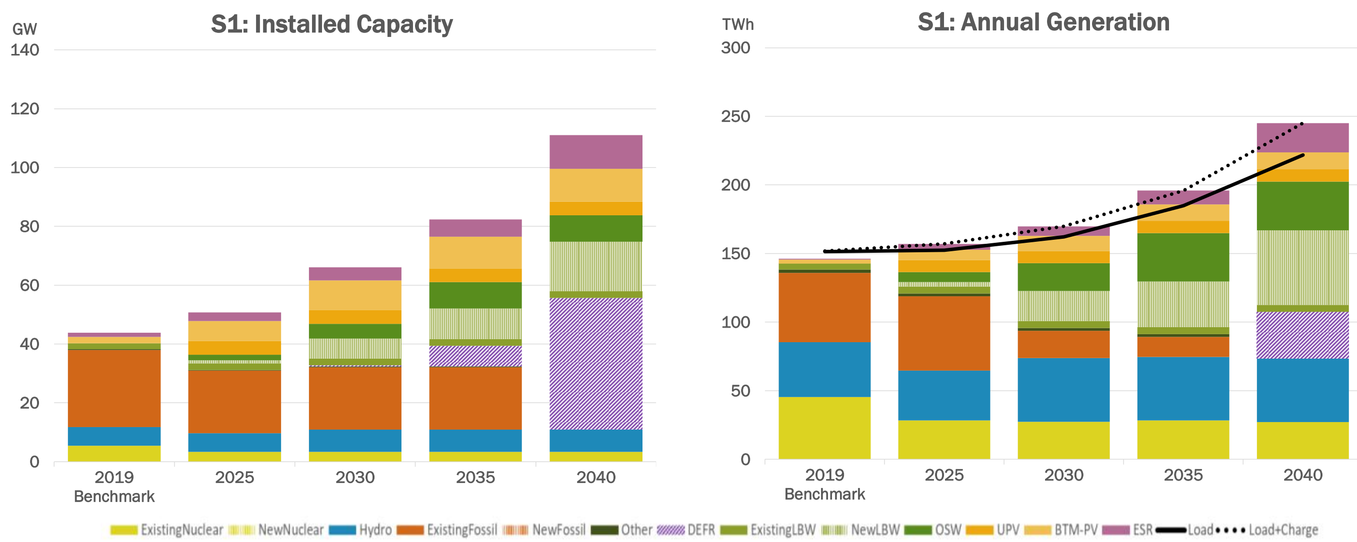
The results show that a significant amount of DEFR capacity is needed to support the higher loads and renewable penetration built by 2040. The High Capital/ Low Operating cost DEFR option generates a significant amount of energy in 2040; this DEFR option essentially operates as a baseload generator in 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 nine 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 nine GW 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 Figure 44 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 are also included in the figure.

Figure 44: S1 Capacity and Generation Results



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

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

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%

* 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), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)

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.

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.[46] 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.

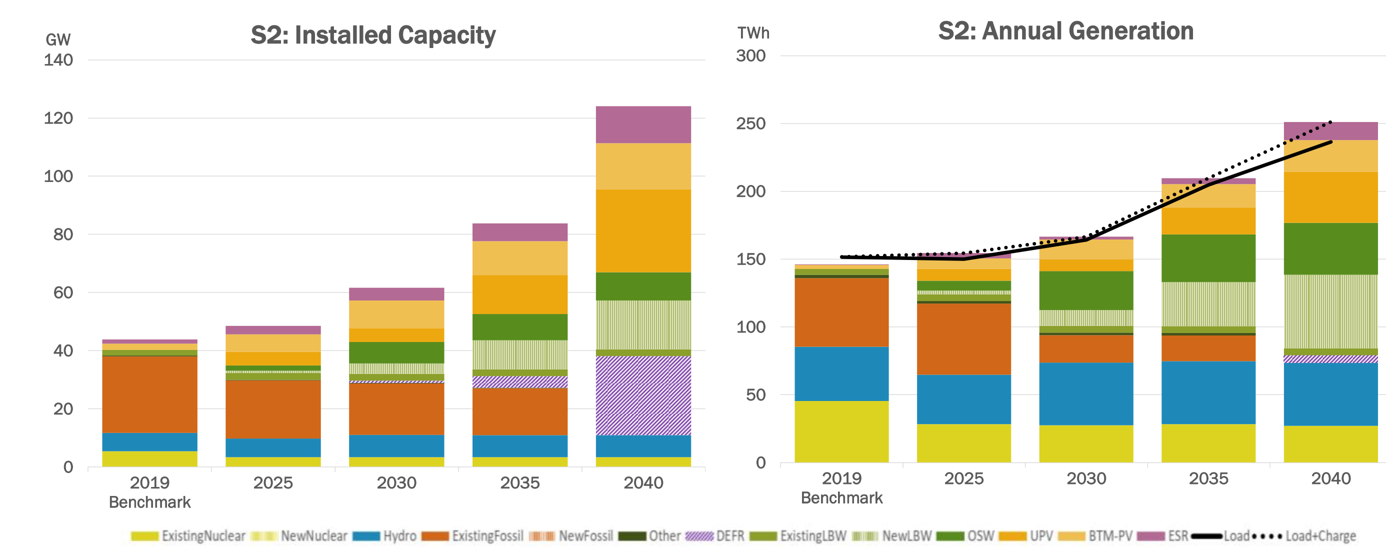
As compared to S1, which did not observe economic builds from UPV, a significant amount of UPV capacity is built in S2 later in the model horizon to help address the system's energy needs, most notably in the upstate zones. This is primarily driven by the load forecast and DEFR options allowed for generation 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 to build by 2030 due to the assumed build constraints for LBW in S2.

Results specific to S2 are included in the figure below.

[46] 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.

Figure 45: S2 Capacity and Generation Results



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

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO2 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

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%

* Land-Based Wind (LBW), Offshore Wind (OSW), Zero Emissions (ZE)
* Dispachable Emission Free Resource (DEFR), High Capital Low Operating (HcLo), Medium Capital Medium Operating (McMo), Low Capital High Operating (LcHo)

F.3.2. 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, and transmission congestion leading to decreased renewable generation energy deliverability within emerging generation pockets).

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 46 through Figure 51 show the system and zonal capacity, energy production, and curtailment results for both scenarios simulated (S1 and S2).

Figure 46: Scenario 1 Production Cost Capacity by Type by Zone

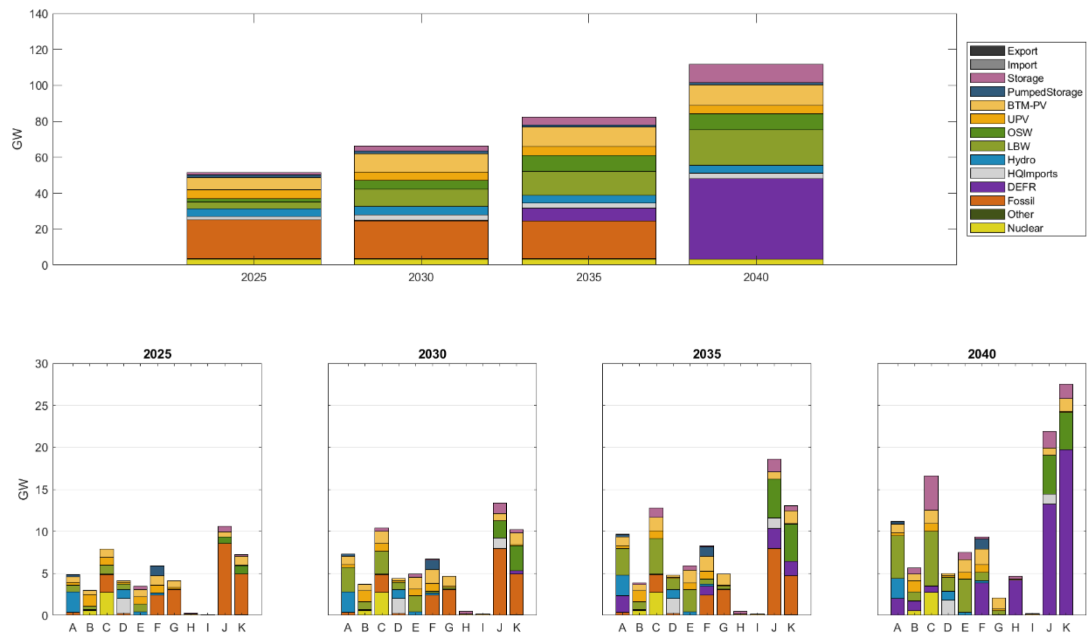


Figure 47: Scenario 2 Production Cost Capacity by Type by Zone

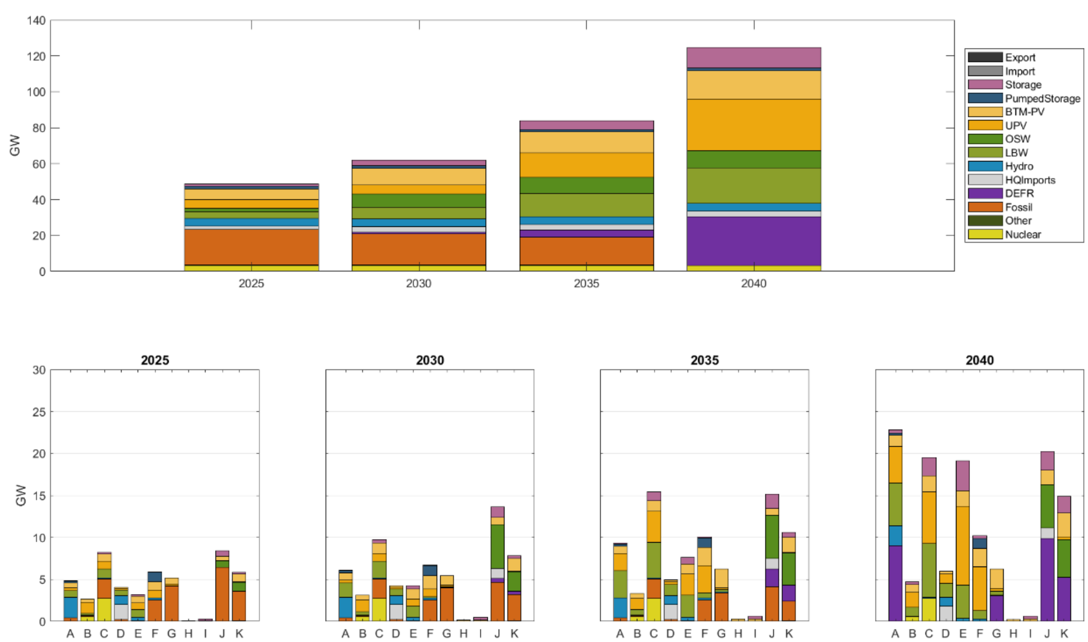


Figure 48: Scenario 1 Production Cost Energy by Type by Zone

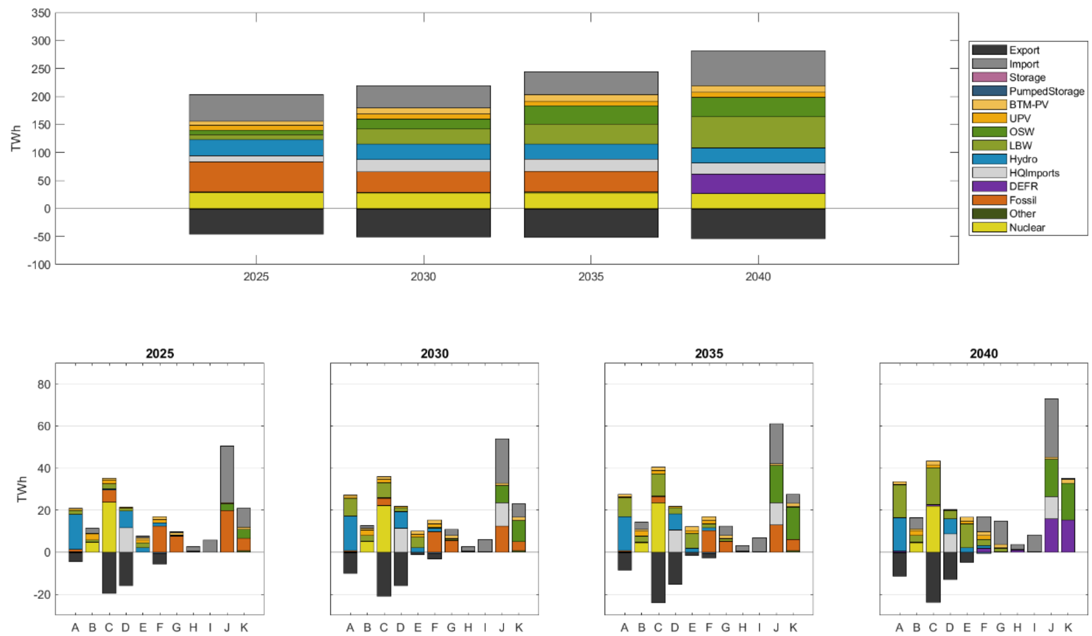


Figure 49: Scenario 2 Production Cost Energy by Type by Zone

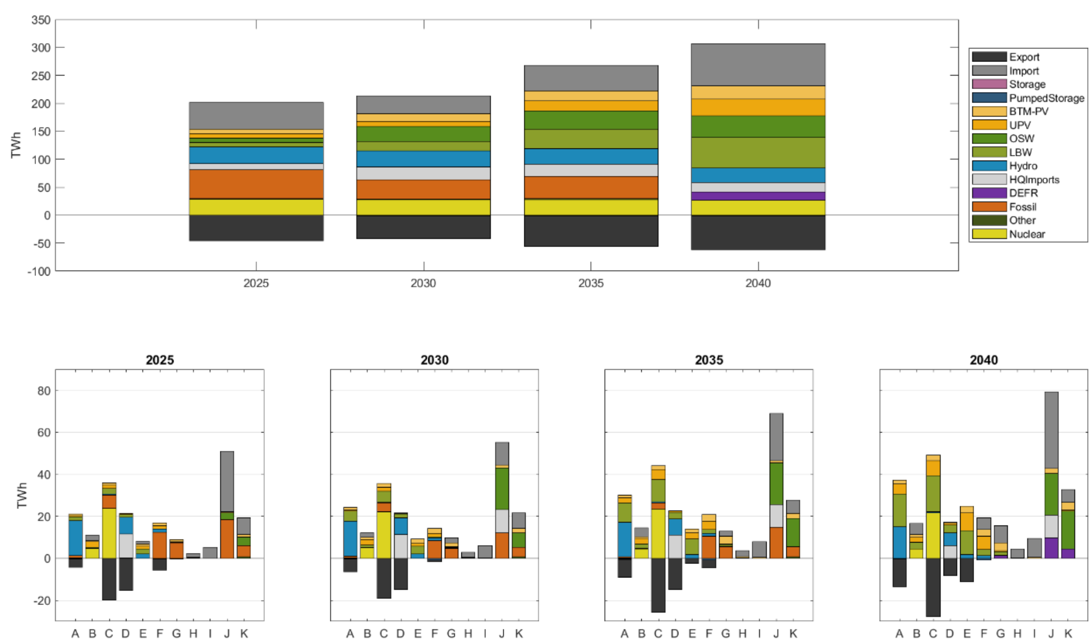


Figure 50: Scenario 1 Production Cost Curtailment by Type by Zone

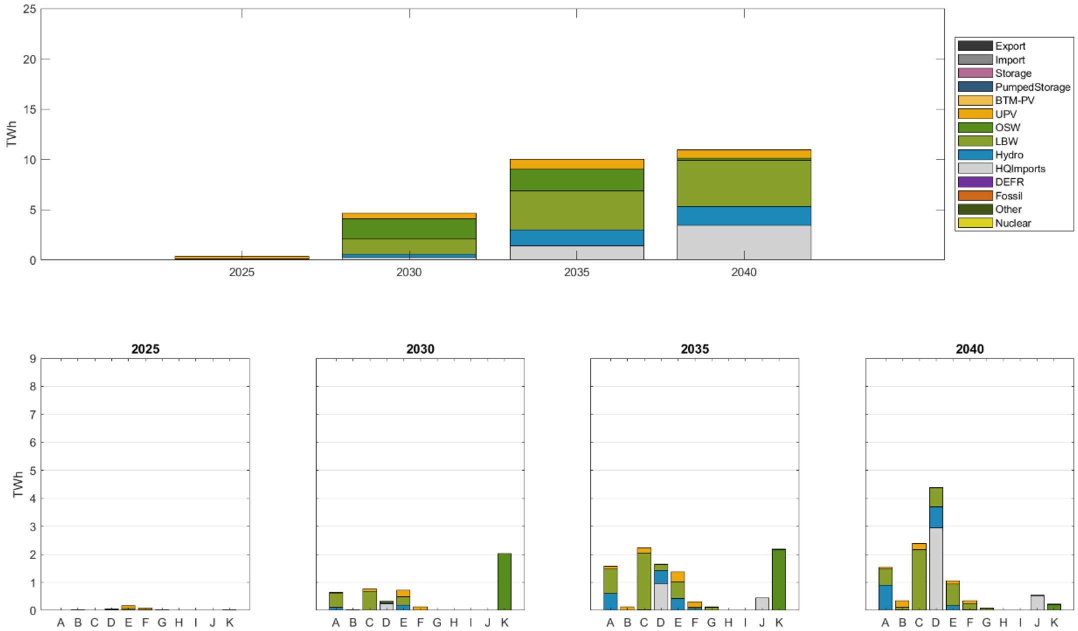
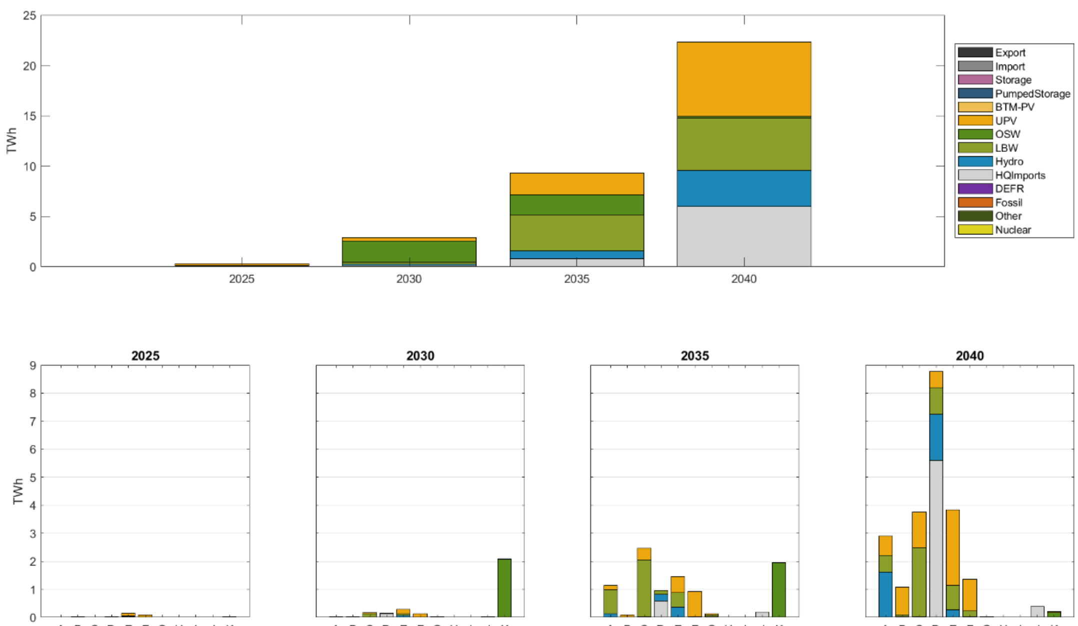
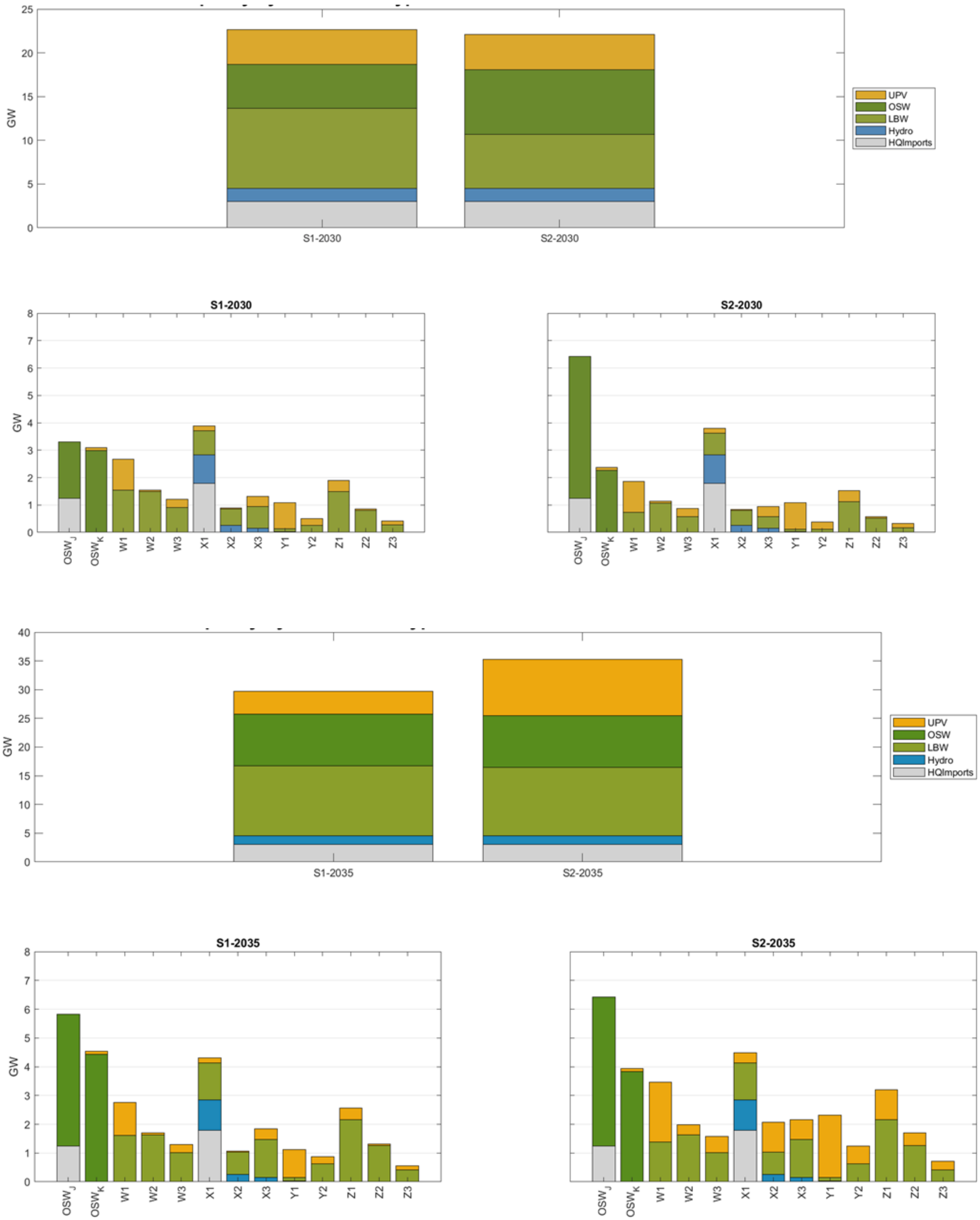


Figure 51: Scenario 2 Production Cost Curtailment by Type by Zone



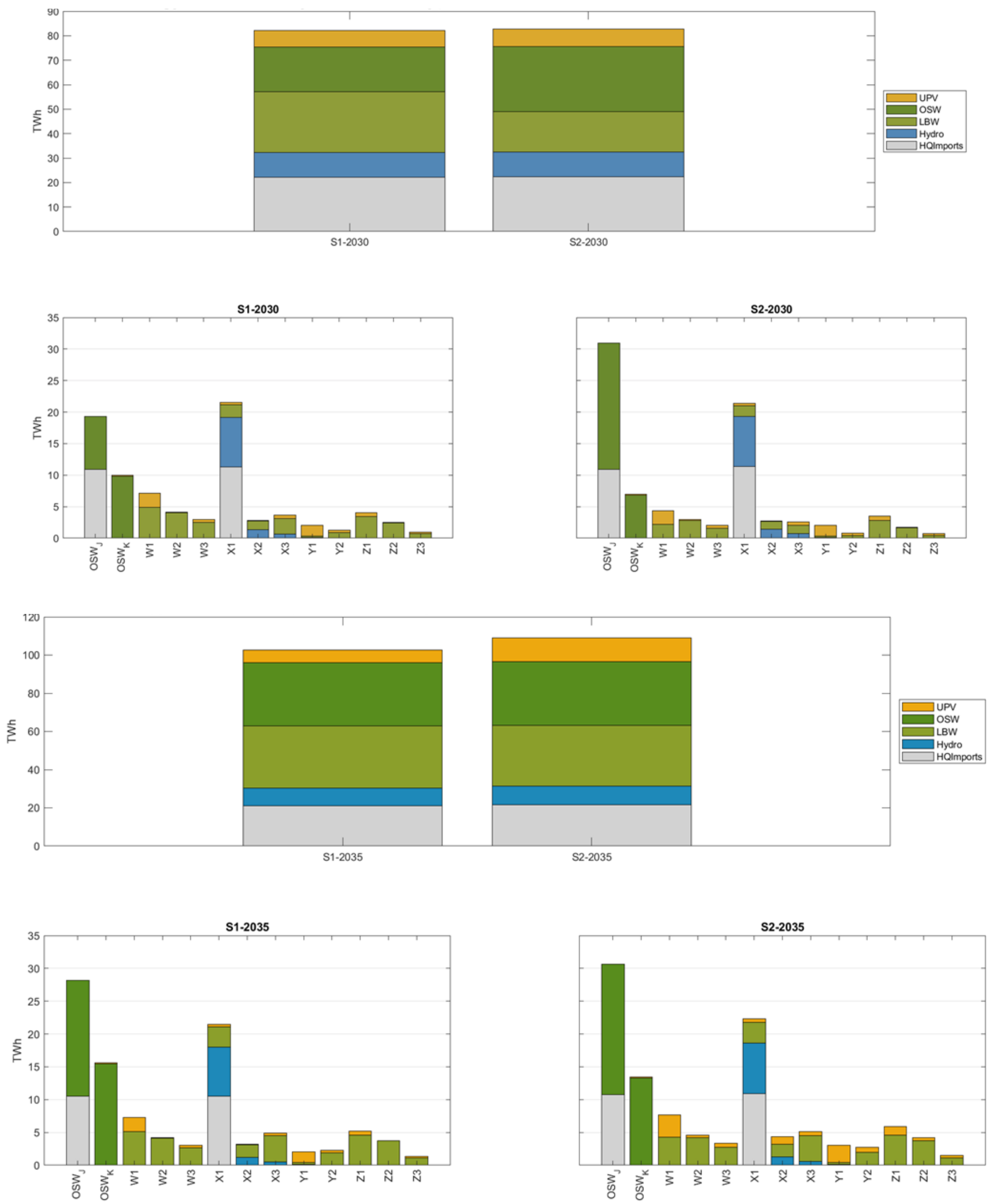
F.3.3. Policy Case Renewable Generation Pockets

Figure 52: Summer Capacity by Generation Type Across Identified Pockets



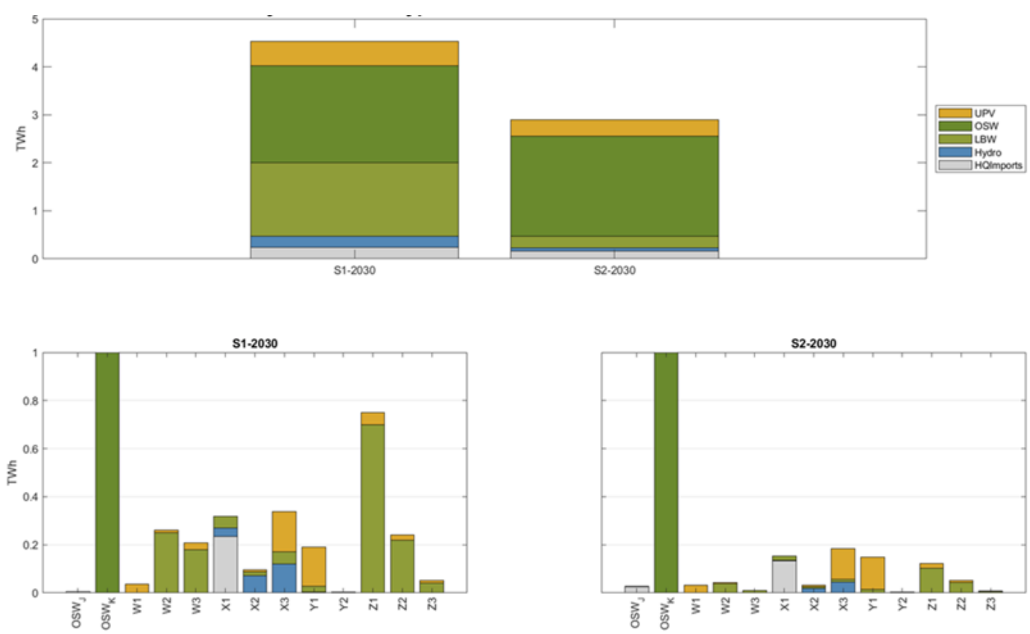
The energy production from generators within the pockets in 2030 is approximately the same on aggregate for S1 and S2. However, the distribution of energy between land-based wind and offshore wind is different, owing to the differences in installed capacity between the two scenarios. S2 has slightly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

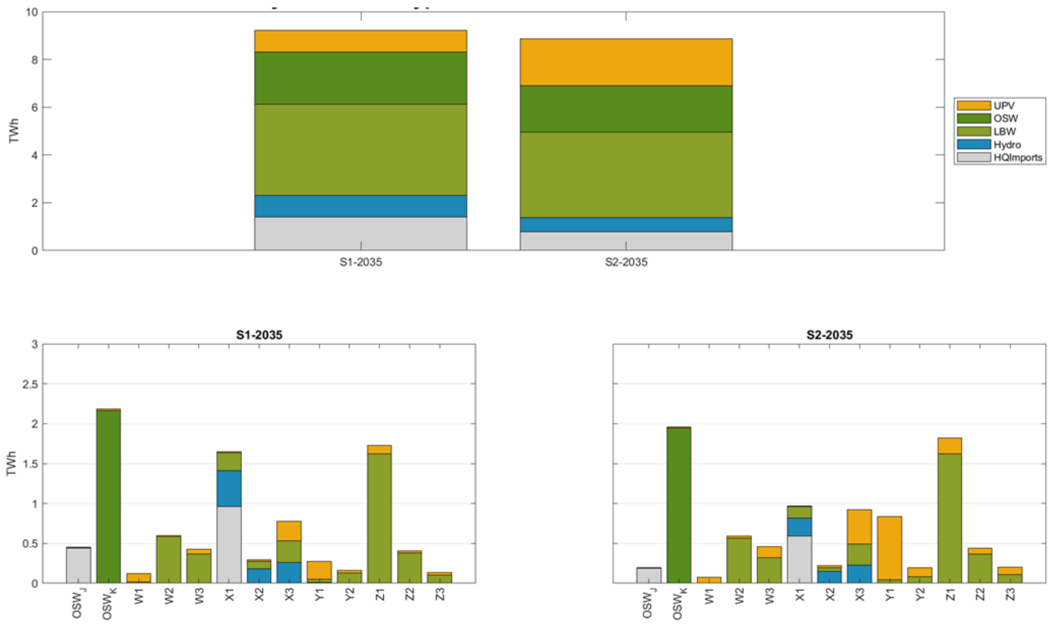
Figure 53: Energy Production by Generator Type Across Identified Pockets



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 more available.

Figure 54: Curtailment by Generation Type Across the Identified Generation Pockets





F.3.4. Policy Case Bulk Transmission Congestion

Both Policy S1 and S2 cases have significant amounts of congestion on the bulk transmission system. Constraints which are already constrained in the Base and Contract cases see persistent congestion in the Policy Cases with additional resources injecting power into paths carrying power to load centers especially from upstate to downstate. Some constrained paths might have less congestion depending on where resources are added. For example, Dunwoodie to Long Island which historically flows from Zone I to K has less congestion in the Contract and Policy case compared to the Baseline Case as Offshore Wind resources are added downstream of the constraint which pushes back on some of the flow on the line. The 2040-year case highlights the congestion on the bulk system when all lower kV constraints are removed. Higher congestion can be seen on most constraints in this case as relieving lower kV constraints allows for more energy to be delivered to the bulk system. Overall, bulk level constraints which are identified in the Baseline and Contract Cases do show significant congestion in the Policy Cases as highlighted in the tables below.

Figure 55: 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 56: 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%

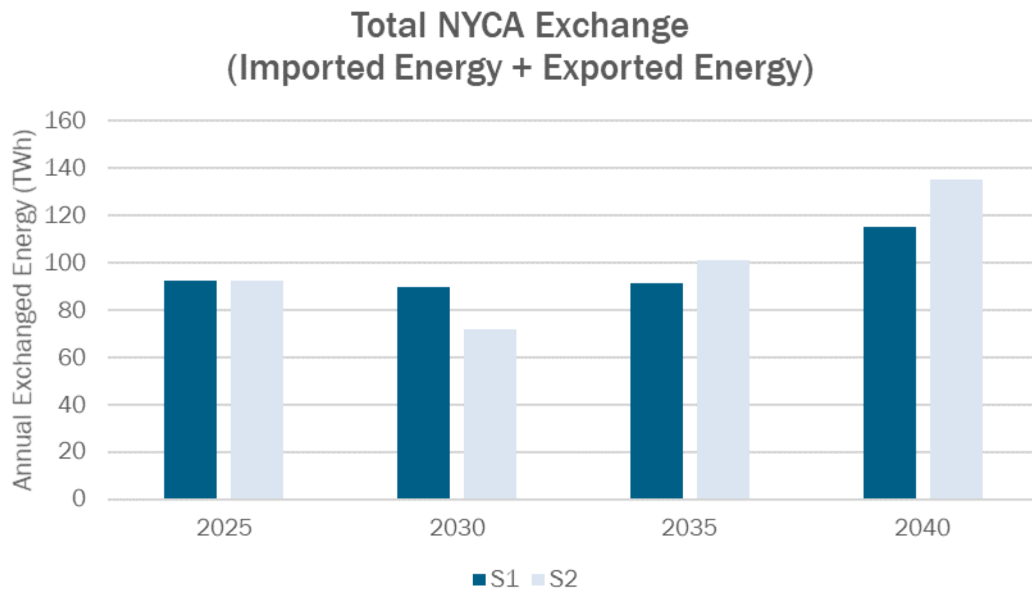
F.3.5. Policy Case Hourly Seasonal Analysis

Leveraging the hourly results from the Policy simulations a detailed seasonal dispatch analysis was performed. 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 (approximately 12 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 57 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. Exchange increases in 2040 as high cost DEFR generators lead to additional economic imports.

Figure 57: 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 or load changes were 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.

Hourly generation, imports/exports, curtailment, and loads are shown over three monthly periods for each Policy Case and year studied in the following figures. January, April, and July are selected because they coincide with the systems seasonal peaks in July and January. April on the other hand represents a spring shoulder month period with lower loads and higher renewable energy resource output. The fall season is very similar to the spring season and was therefore not presented for simplicity. The figures show NYCA-wide generation and net imports relative to load. The charts are presented with a data range between -20GW and 70GW and colors corresponding to the following chart key.

Figure 58: Hourly Seasonal Analysis Chart Key

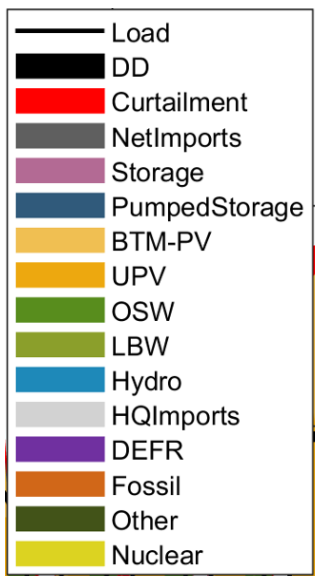


Figure 59: Scenario 1 2025 Summer Month Hourly Dispatch

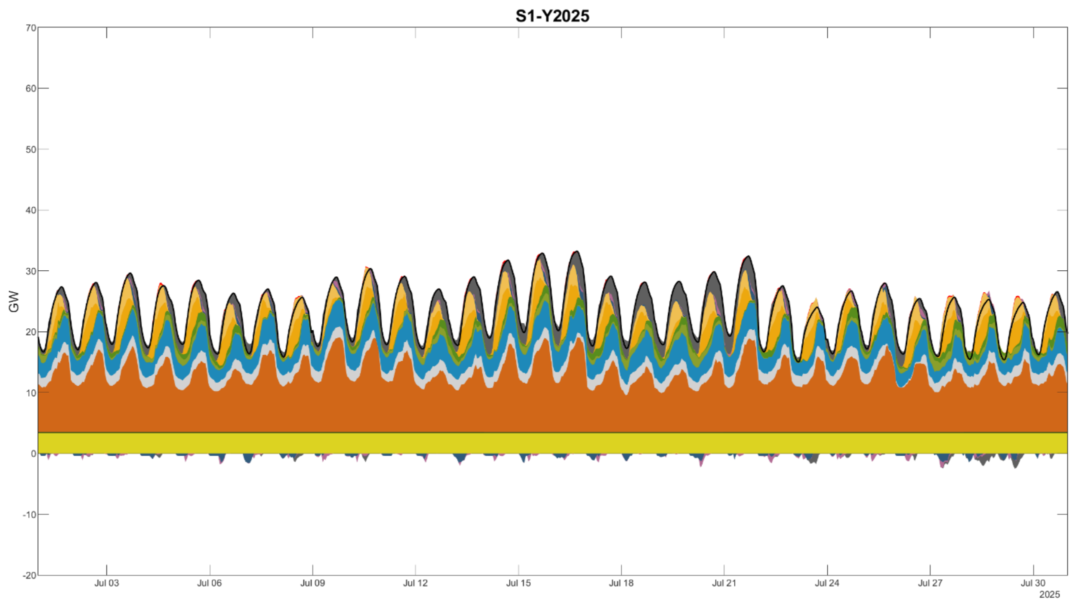


Figure 60: Scenario 1 2025 Spring Month Hourly Dispatch

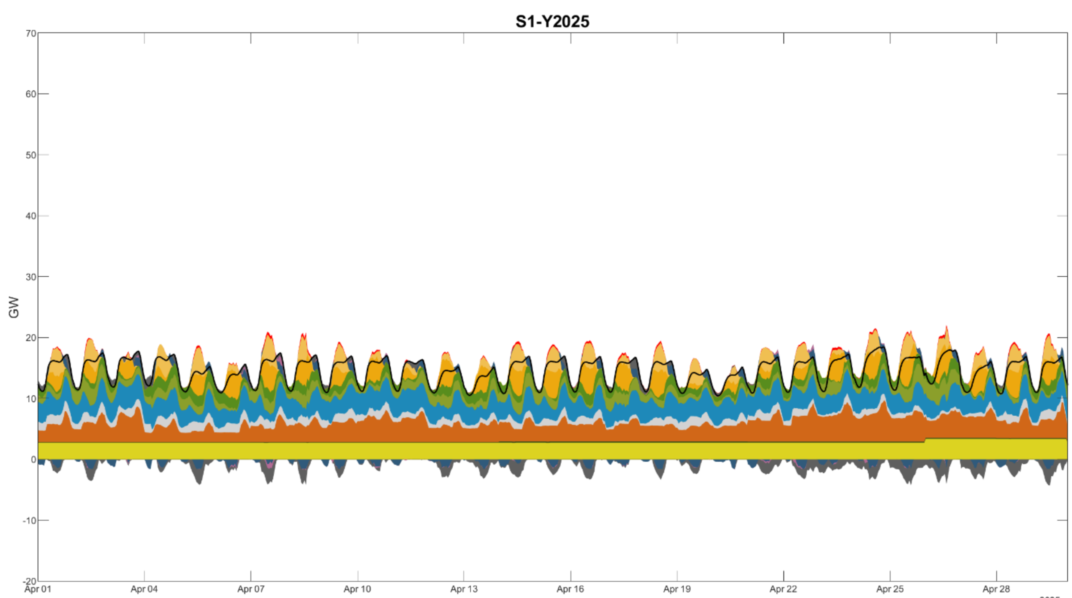


Figure 61: Scenario 1 2025 Winter Month Hourly Dispatch

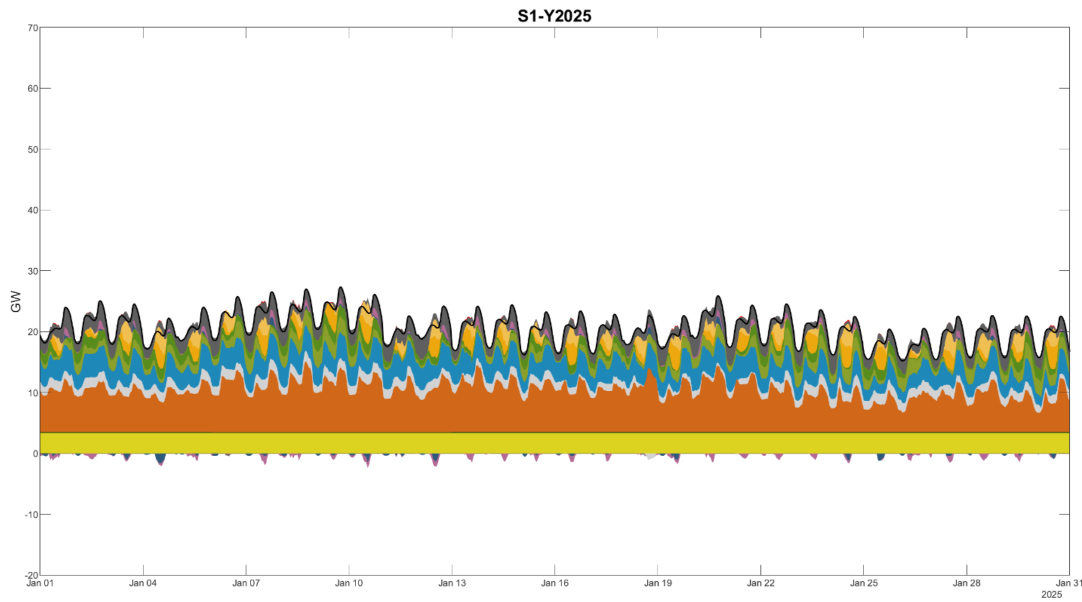


Figure 62: Scenario 1 2030 Summer Month Hourly Dispatch

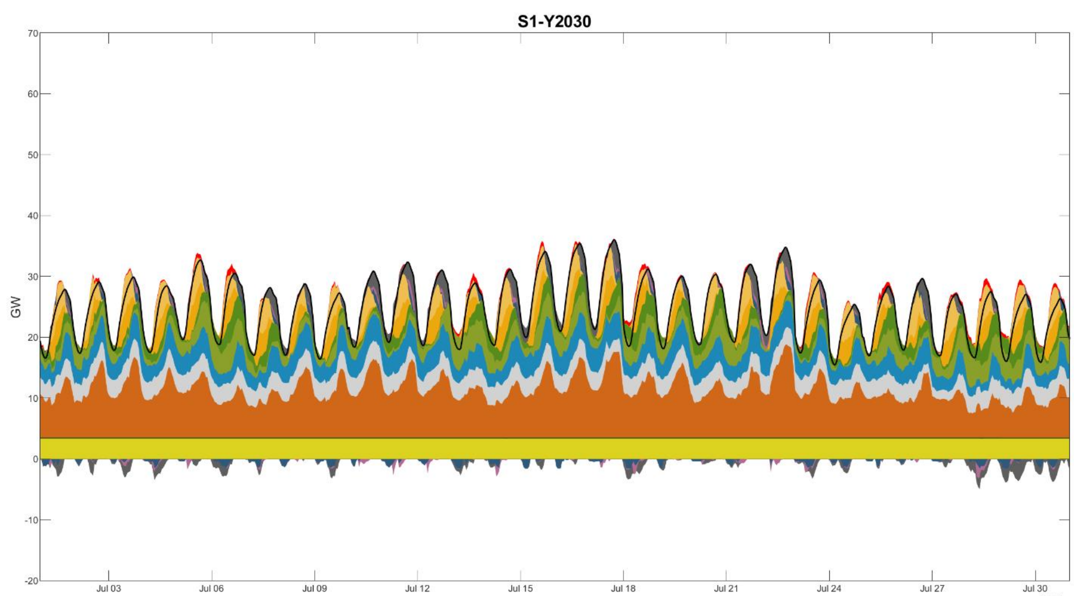


Figure 63: Scenario 1 2030 Spring Month Hourly Dispatch

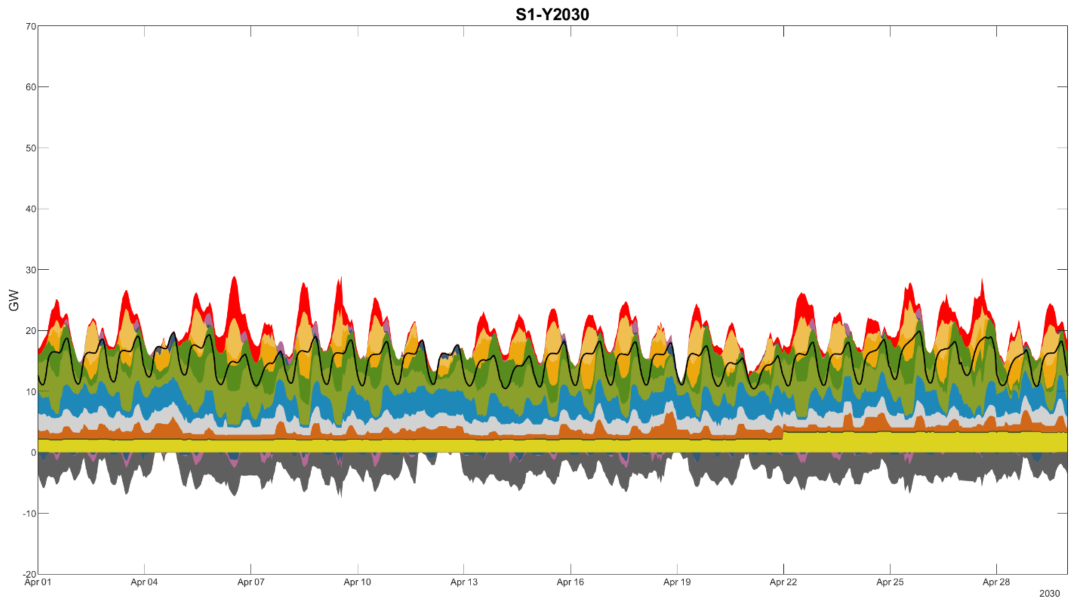


Figure 64: Scenario 1 2030 Winter Month Hourly Dispatch

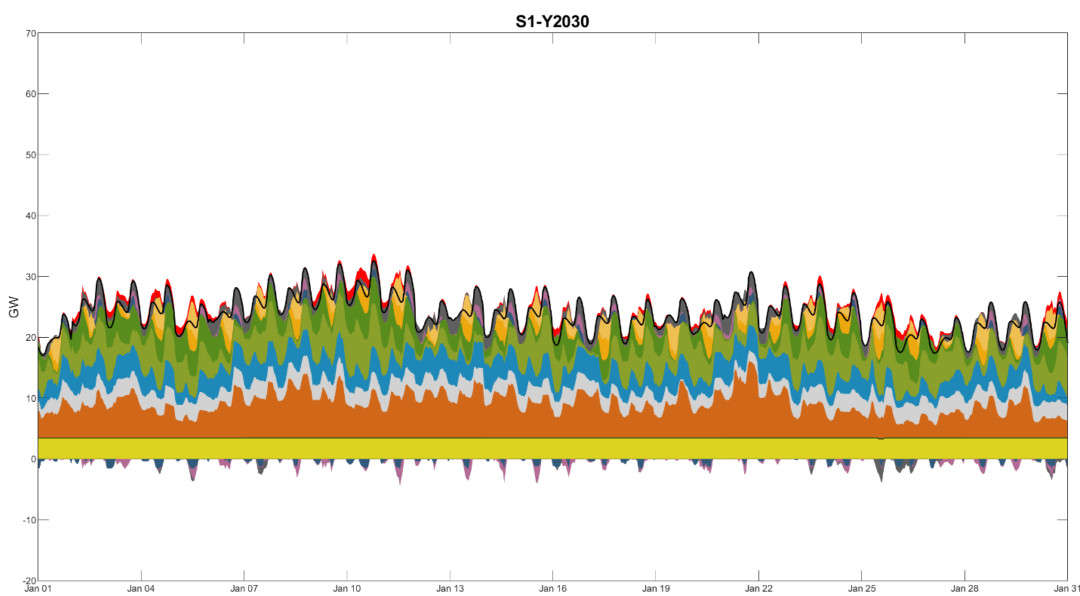


Figure 65: Scenario 1 2035 Summer Month Hourly Dispatch

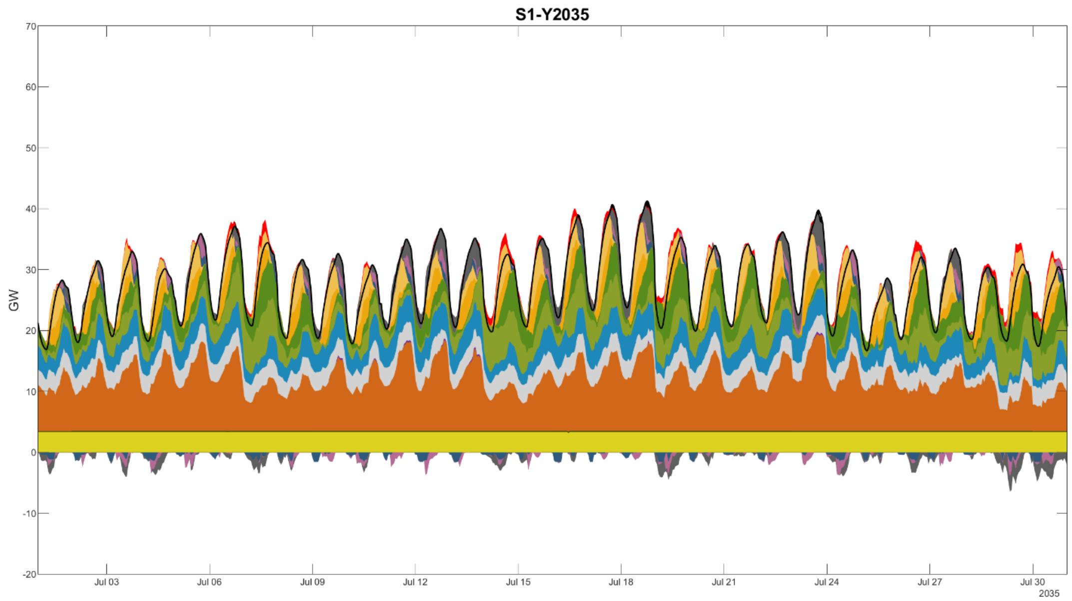


Figure 66: Scenario 1 2035 Spring Month Hourly Dispatch

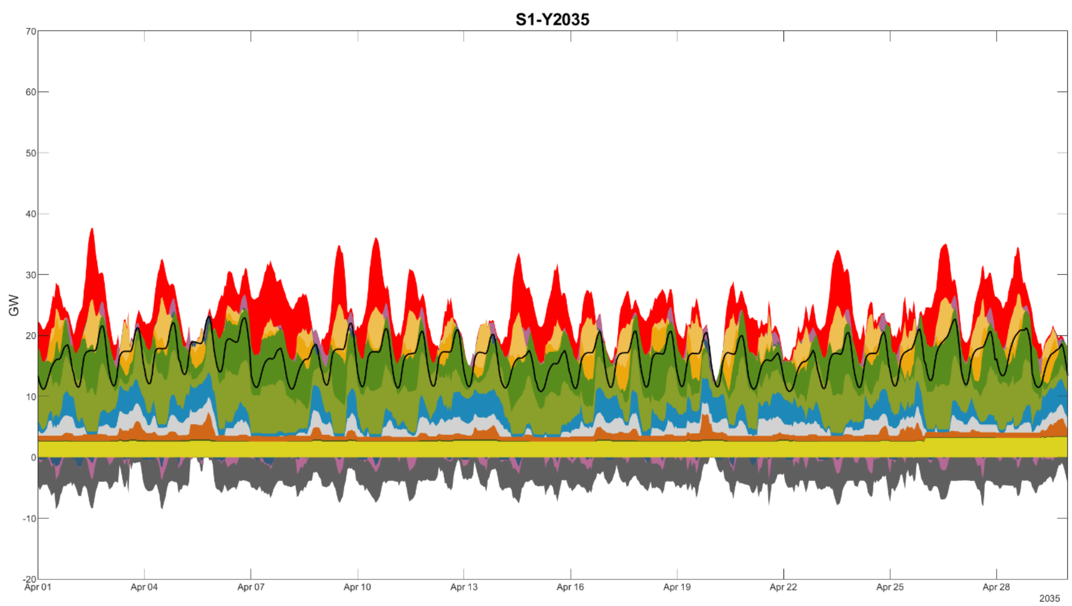


Figure 67: Scenario 1 2035 Winter Month Hourly Dispatch

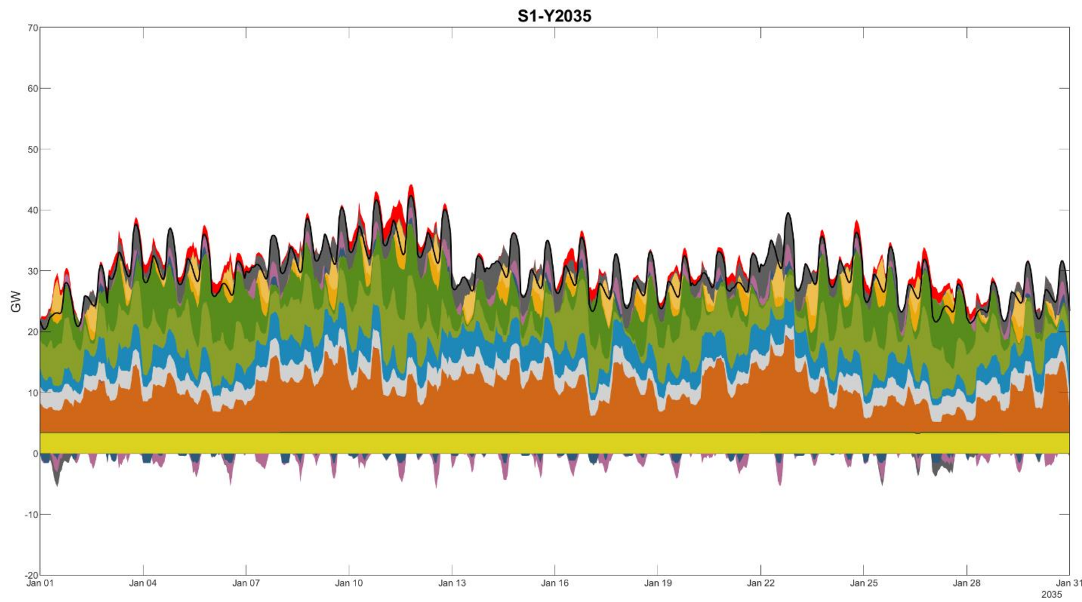


Figure 68: Scenario 1 2040 Summer Month Hourly Dispatch

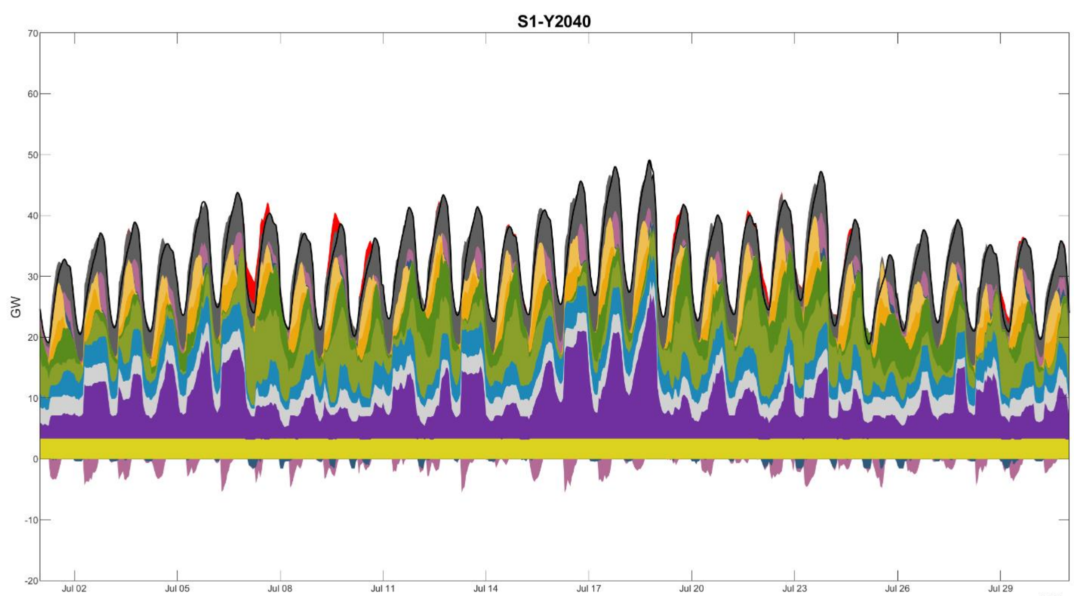


Figure 69: Scenario 1 2040 Spring Month Hourly Dispatch

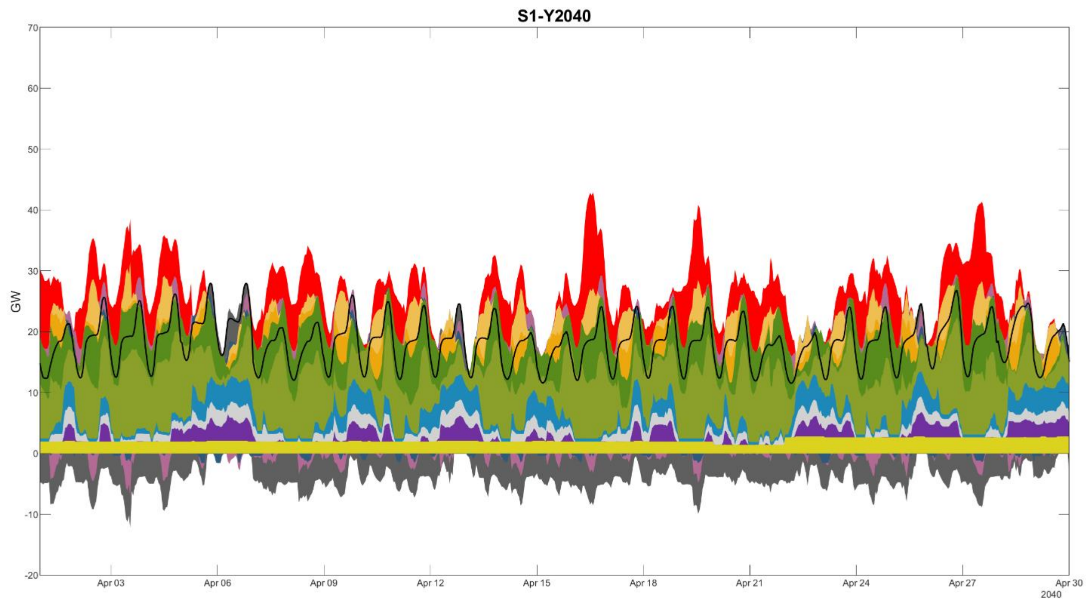


Figure 70: Scenario 1 2040 Winter Month Hourly Dispatch

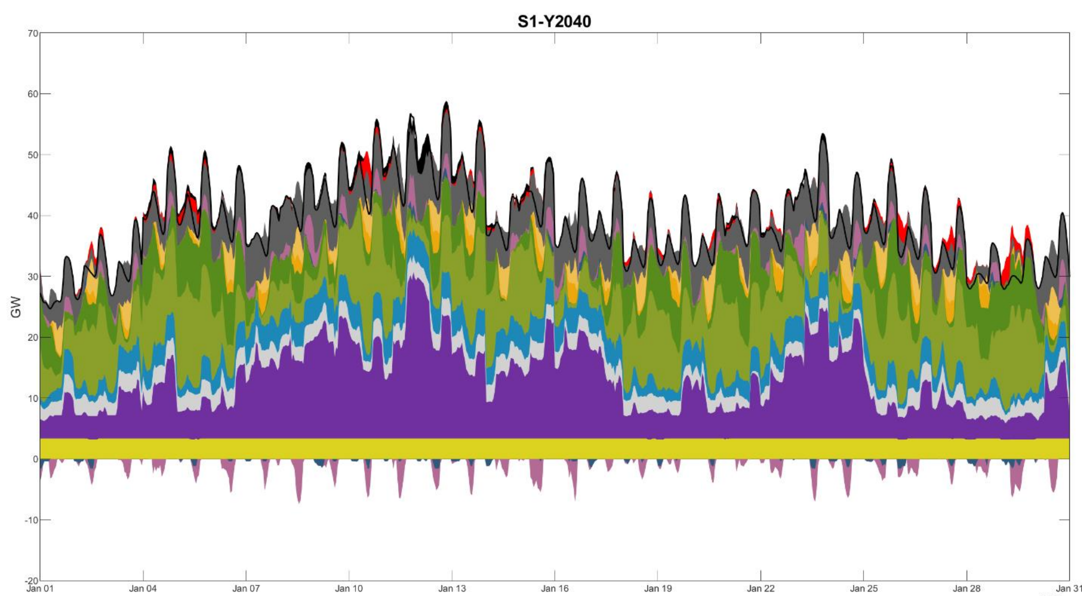


Figure 71: Scenario 2 2025 Summer Month Hourly Dispatch

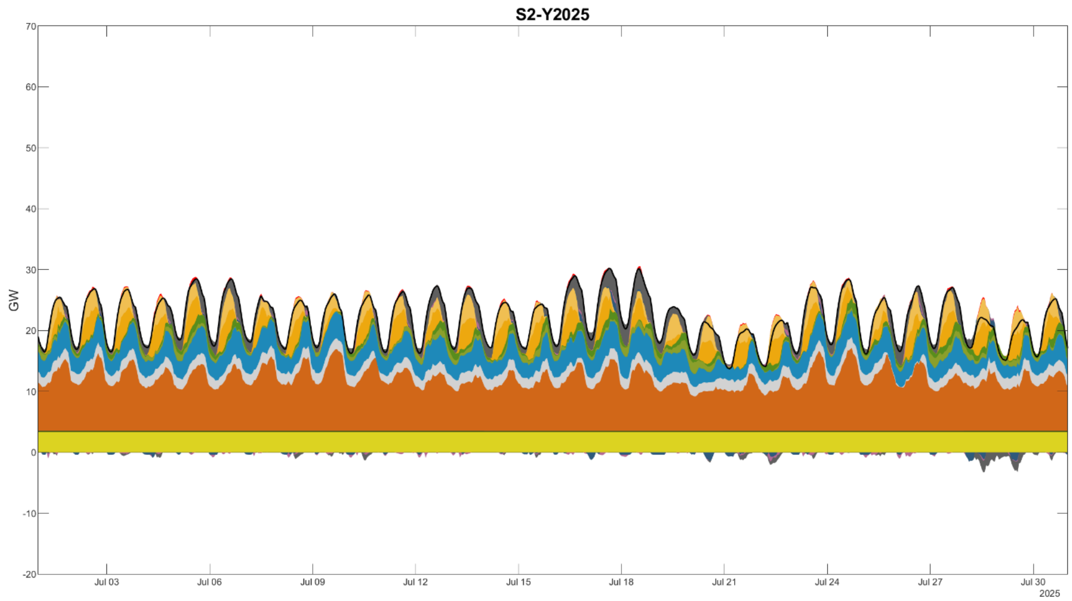


Figure 72: Scenario 2 2025 Spring Month Hourly Dispatch

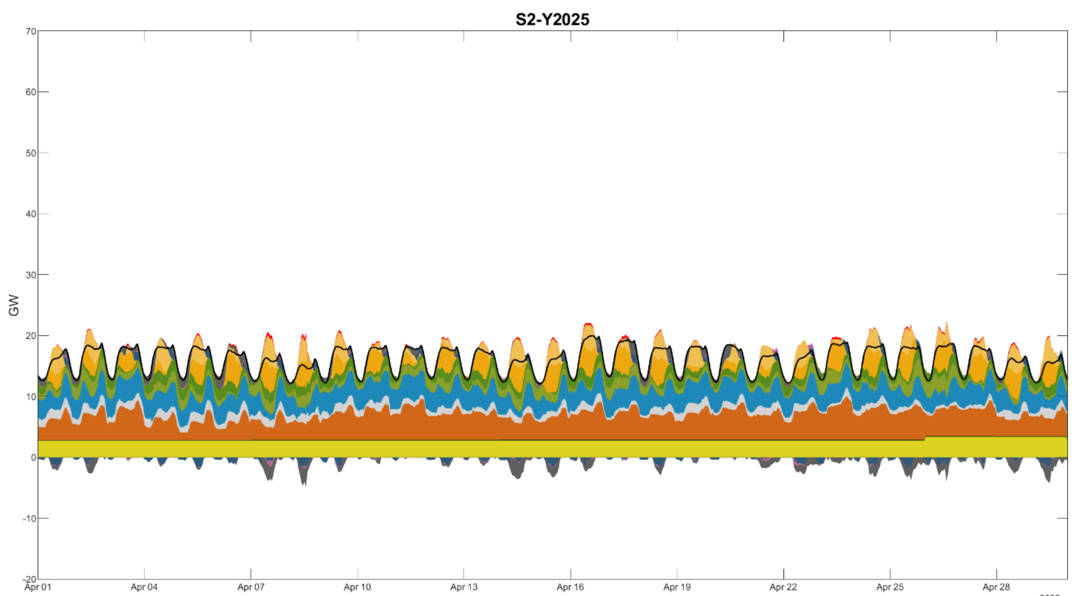


Figure 73: Scenario 2 2025 Winter Month Hourly Dispatch

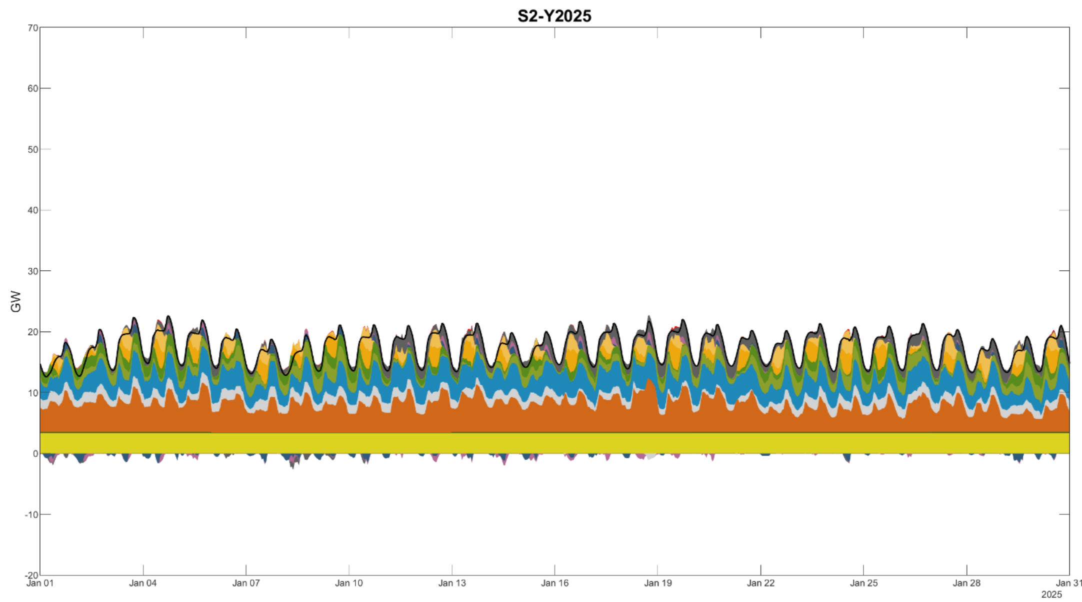


Figure 74: Scenario 2 2030 Summer Month Hourly Dispatch

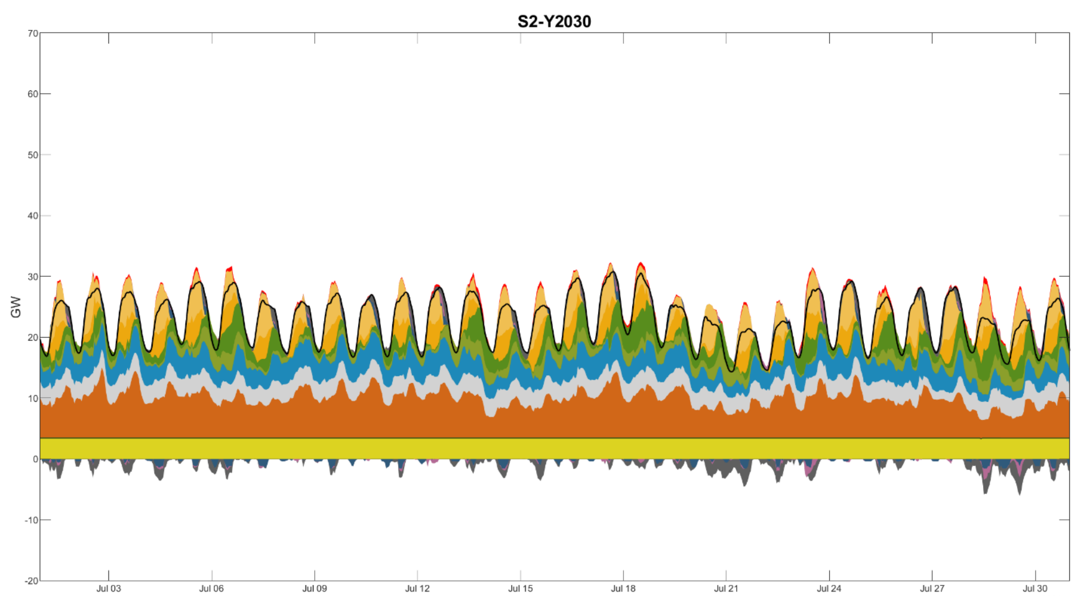


Figure 75: Scenario 2 2030 Spring Month Hourly Dispatch

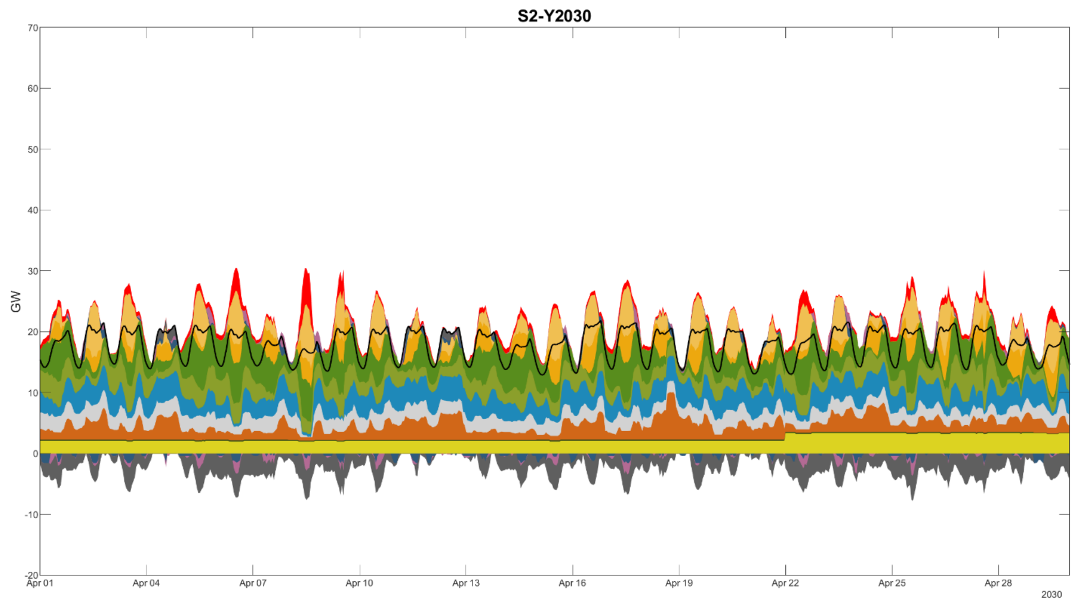


Figure 76: Scenario 2 2030 Winter Month Hourly Dispatch

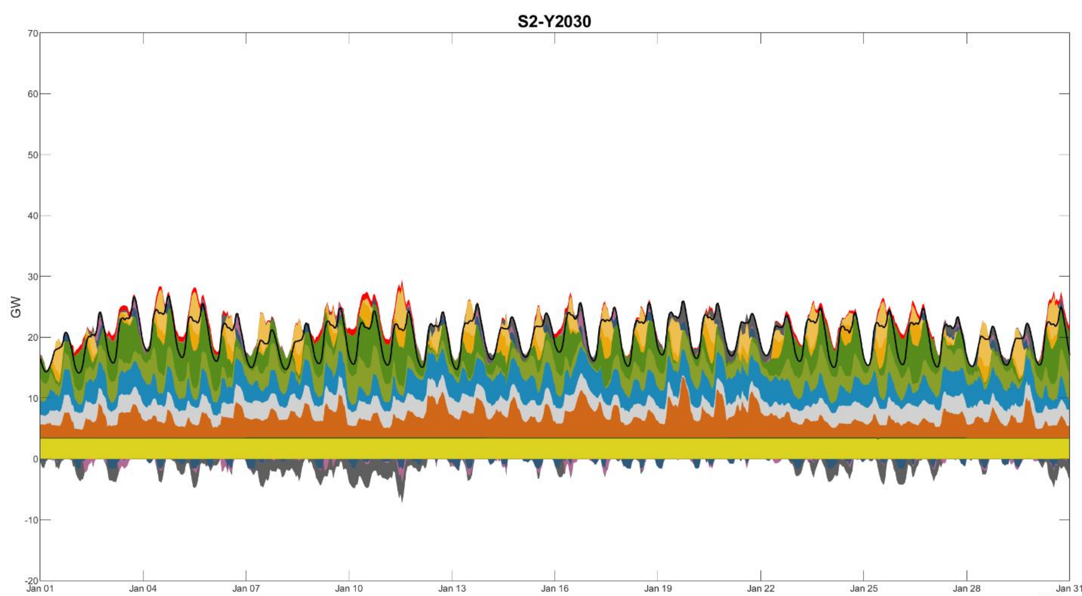


Figure 77: Scenario 2 2035 Summer Month Hourly Dispatch

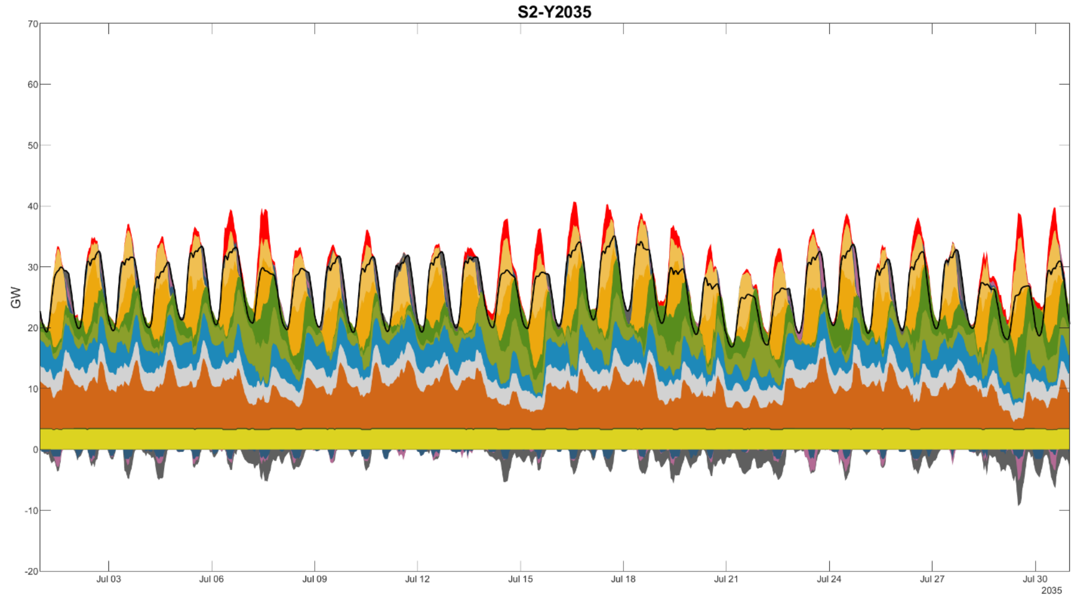


Figure 78: Scenario 2 2035 Spring Month Hourly Dispatch

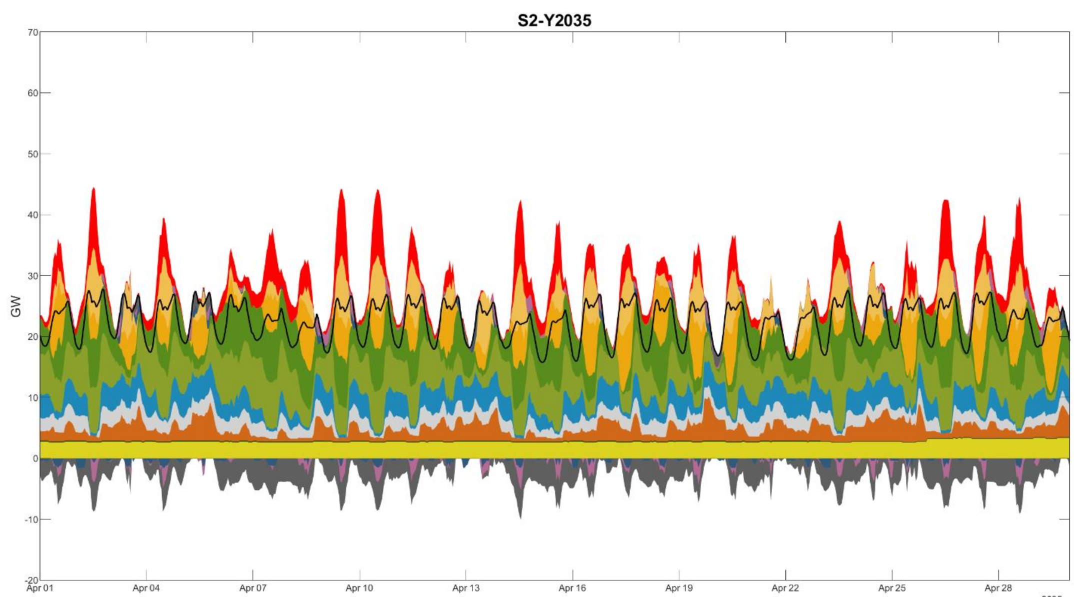


Figure 79: Scenario 2 2035 Winter Month Hourly Dispatch

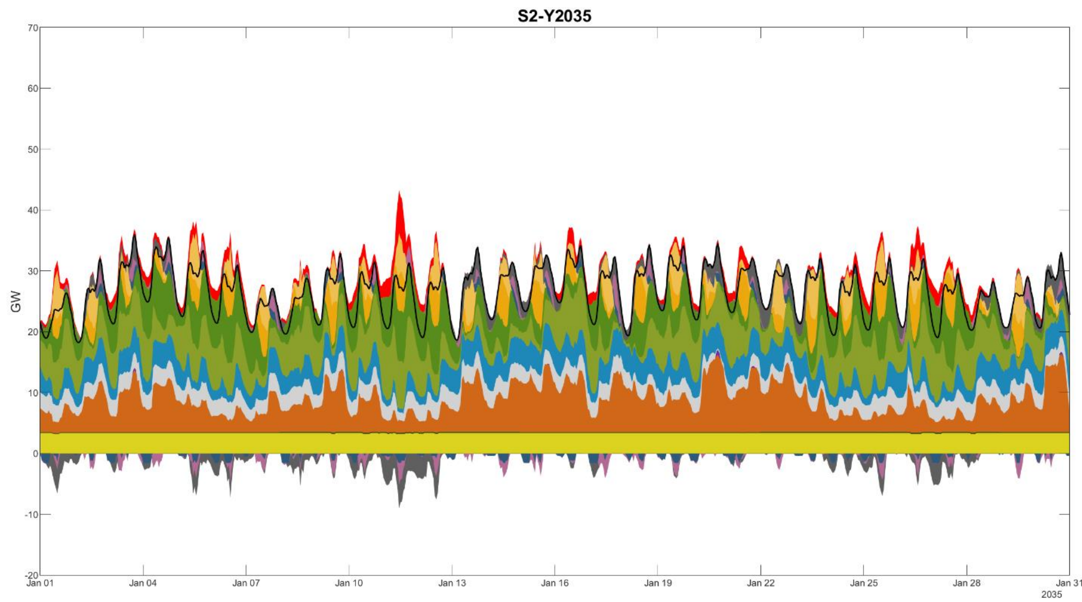


Figure 80: Scenario 2 2040 Summer Month Hourly Dispatch

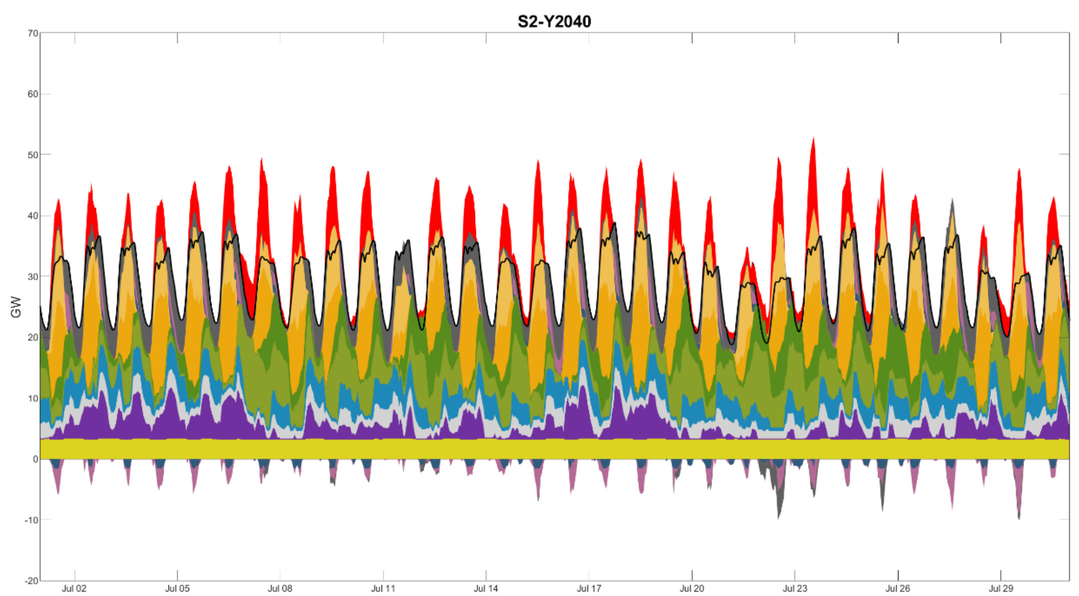


Figure 81: Scenario 2 2040 Spring Month Hourly Dispatch

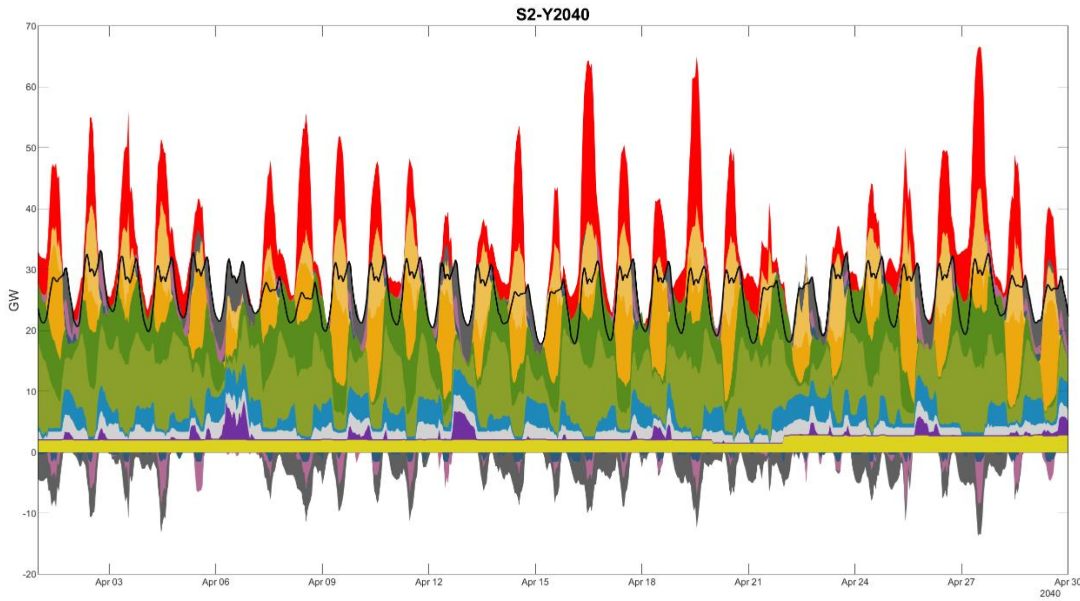
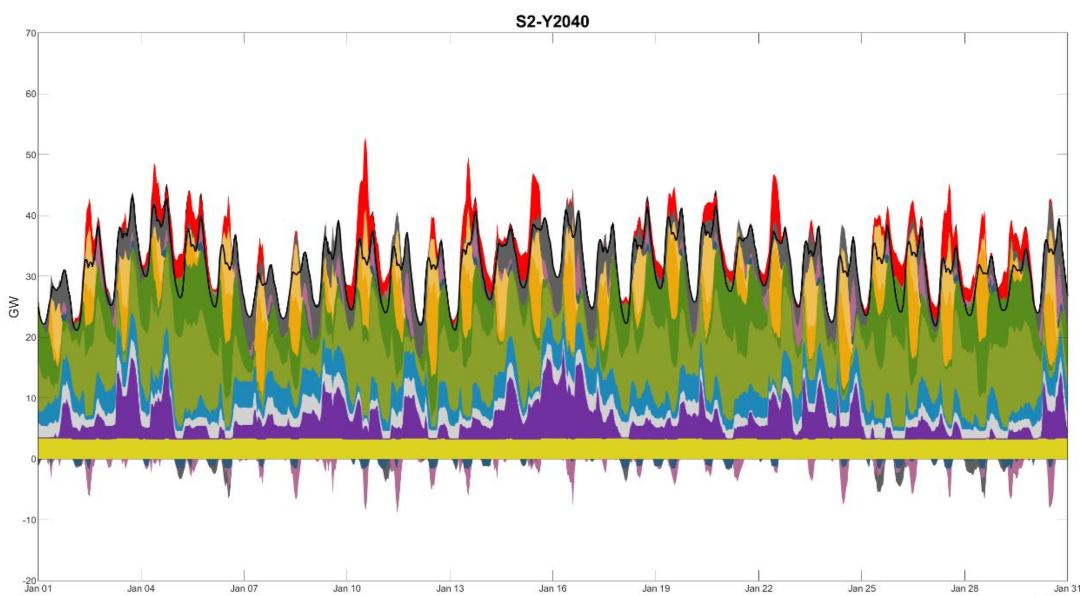


Figure 82: Scenario 2 2040 Winter Month Hourly Dispatch



F.3.6. Policy Case Operational Analysis

This section reviews the impacts of increased renewable resource output and shifting load patterns on the dispatchable fleets modeled. Average utilization, number of starts, and ramp parameters are reviewed for both fossil and DEFR generators.

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 83: Fossil Fleet Cumulative Capacity Curve: Unit Level Capacity Factors

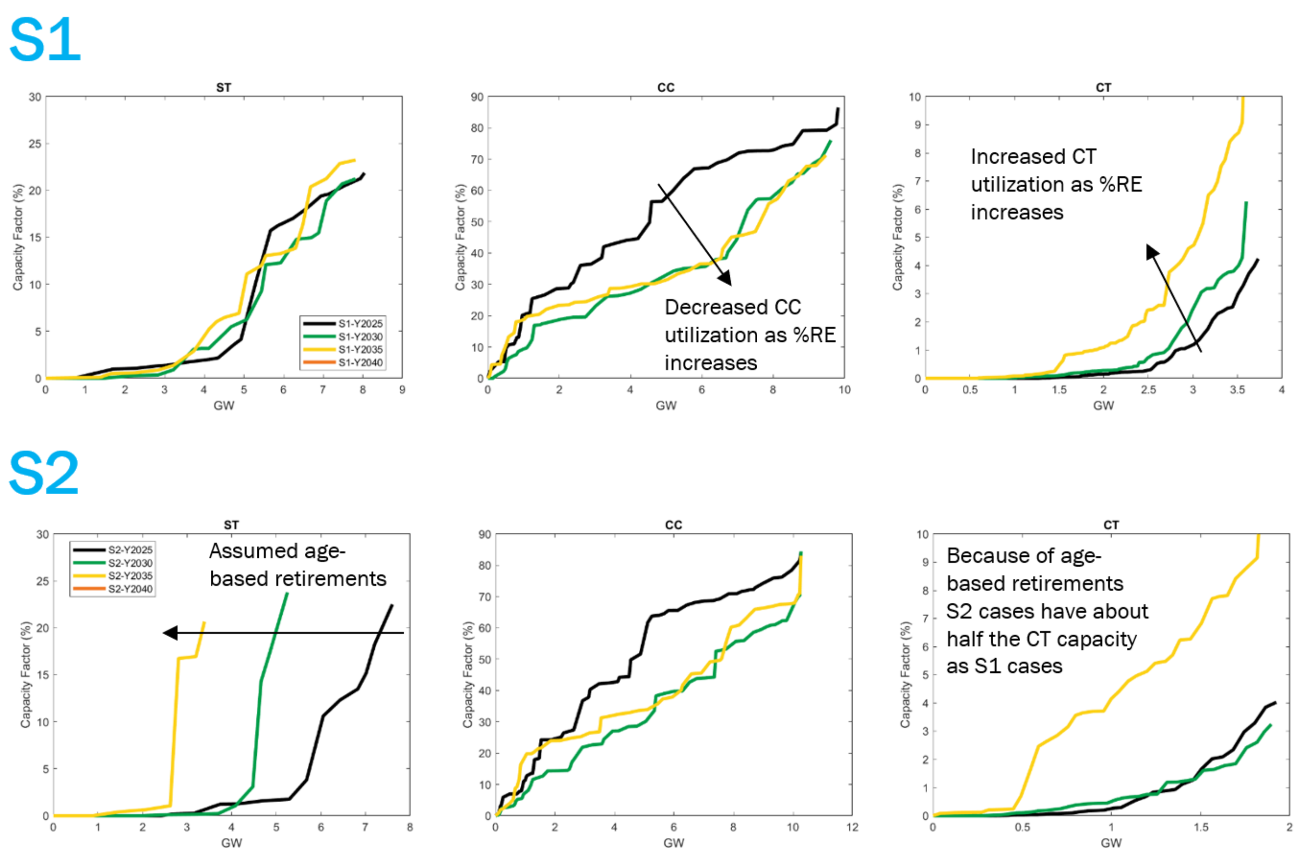


Figure 84: Fossil Fleet Cumulative Capacity Curve: Unit Level Number of Starts

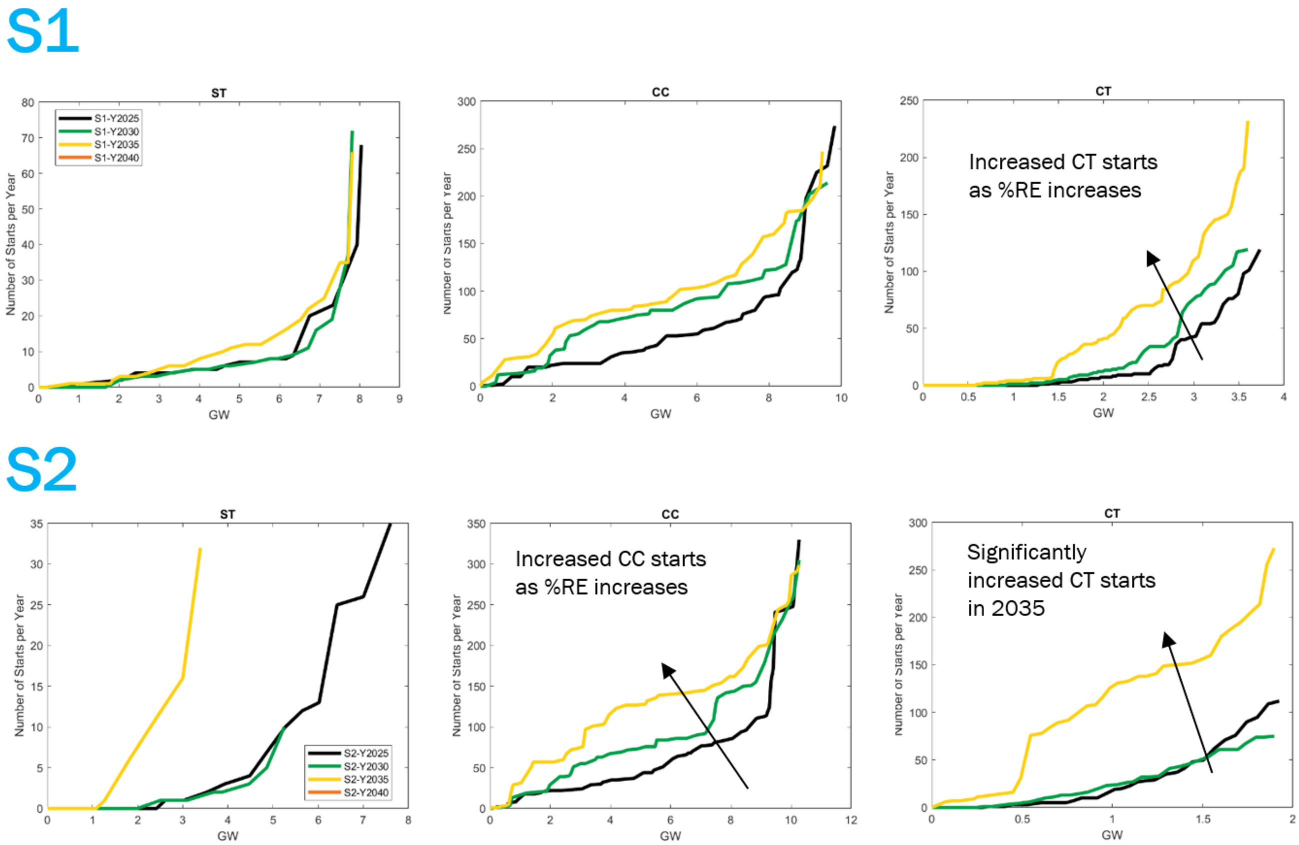
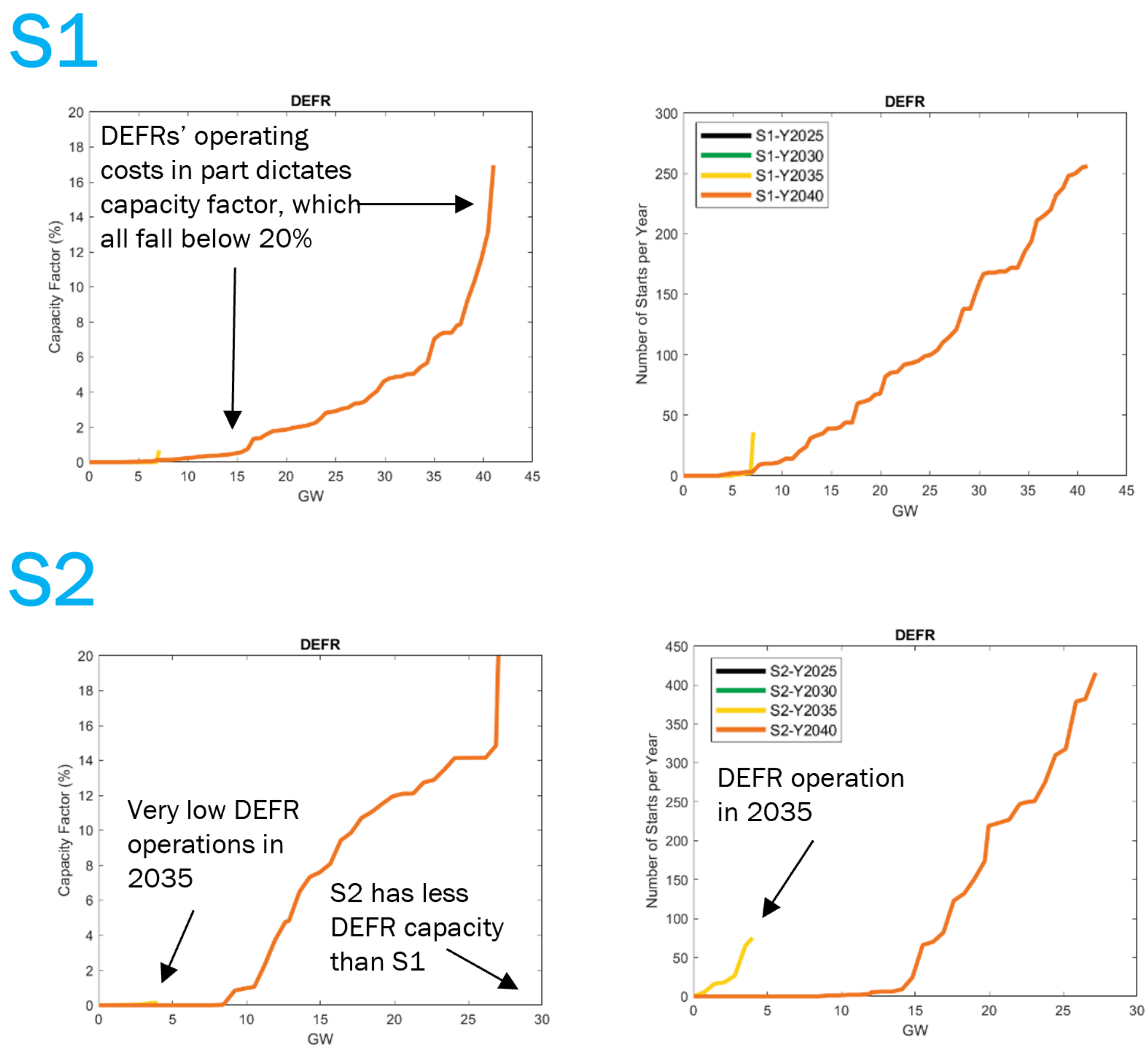


Figure 85: DEFR Cumulative Capacity Curve: Unit Level Capacity Factors and Number of Starts



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 F.3.5. 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 86: Maximum Fossil Fleet Up-Ramp (MW/hour) by Month and Hour

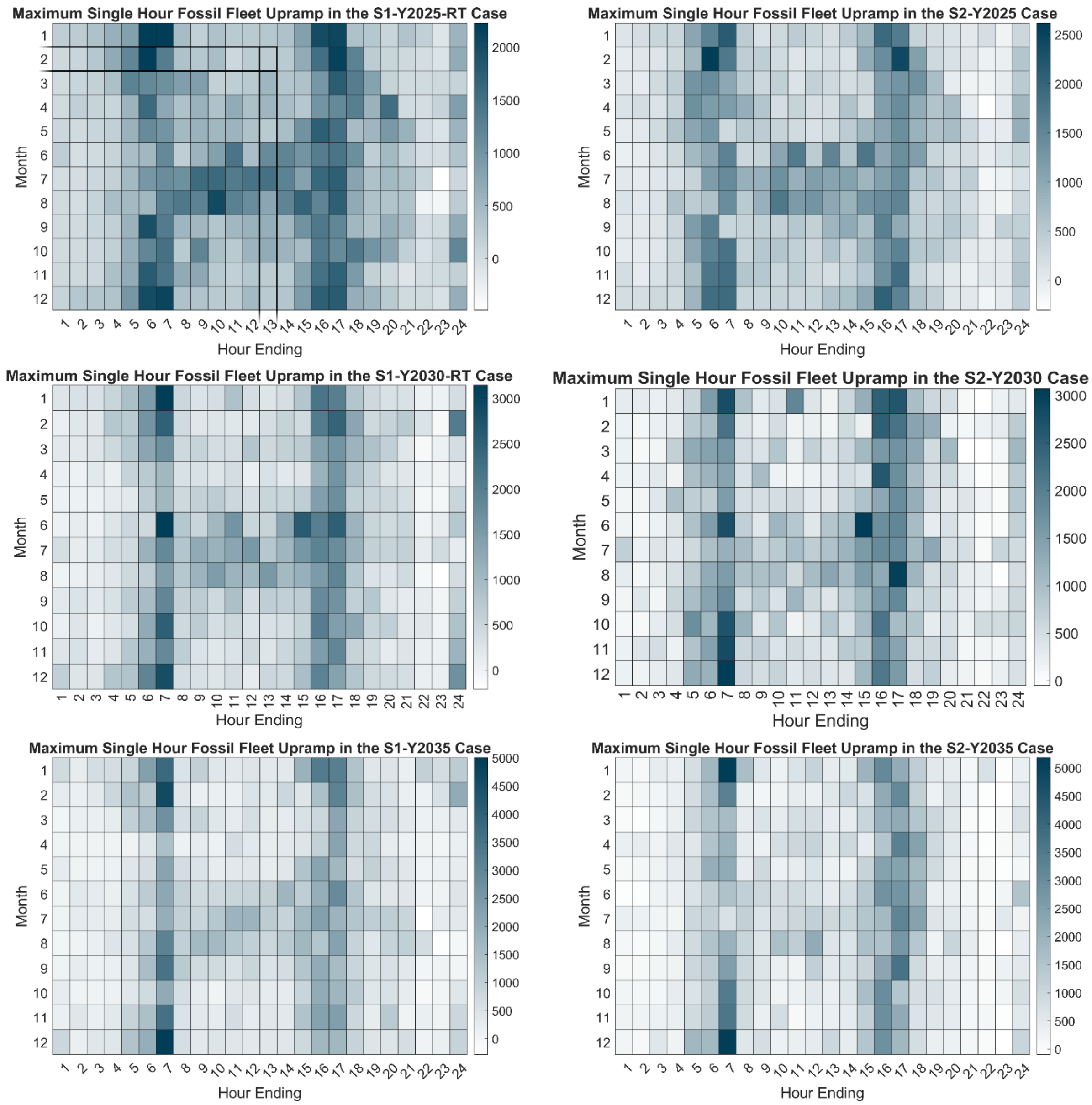
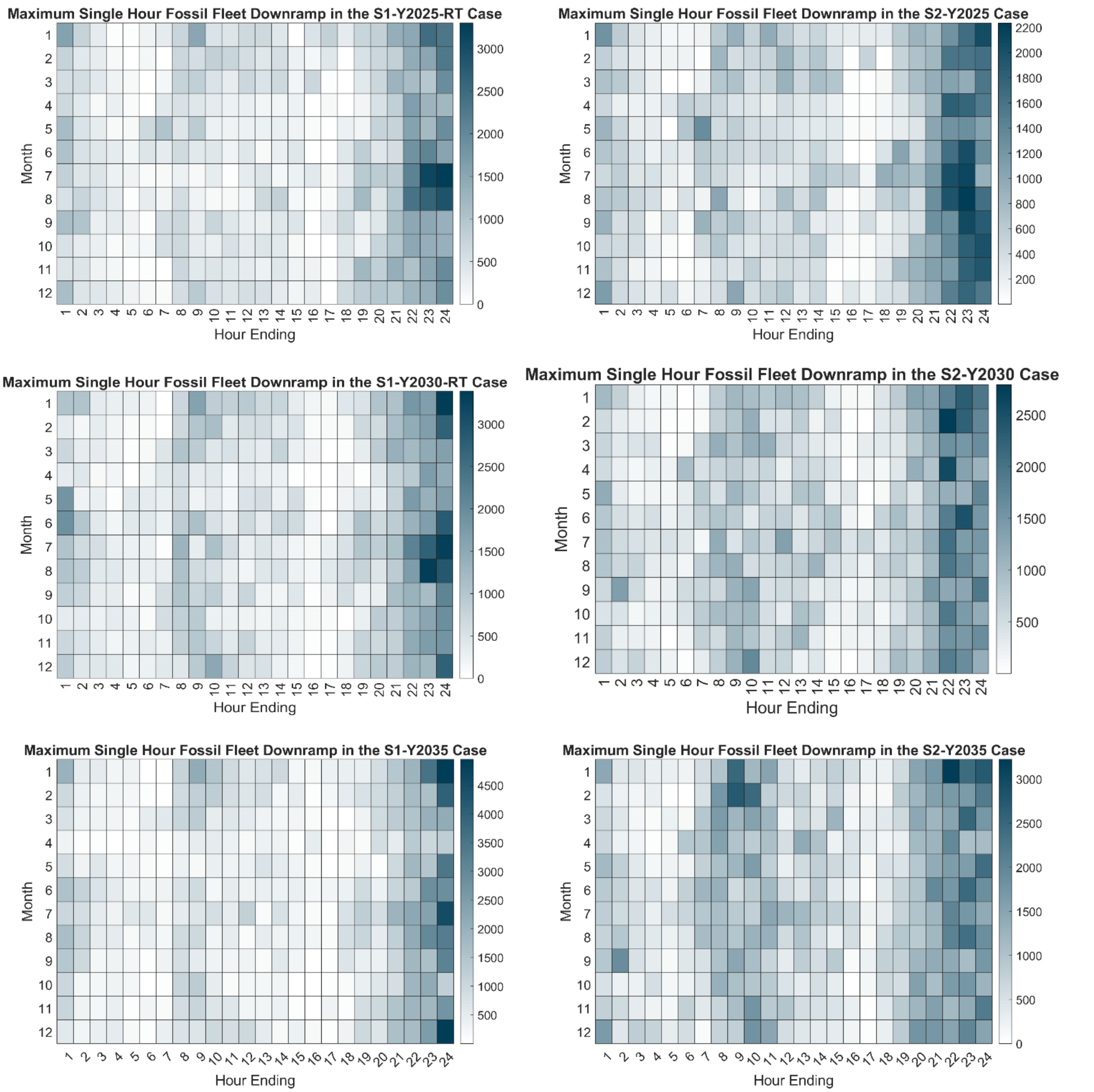


Figure 87: Maximum Fossil Fleet Down-Ramp (MW/hour) by Month and Hour



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 monthly-hourly bins, 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; however, the buildout capacities of the two scenarios are 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 88: Average and Maximum DEFR Fleet Capacity Factors by Month and Hour: 2040 S1

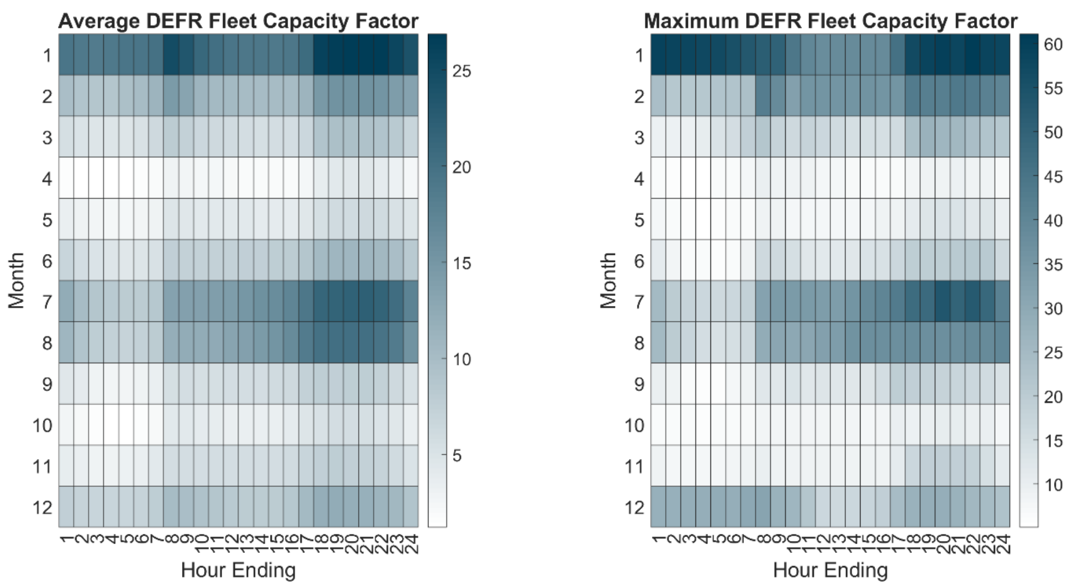
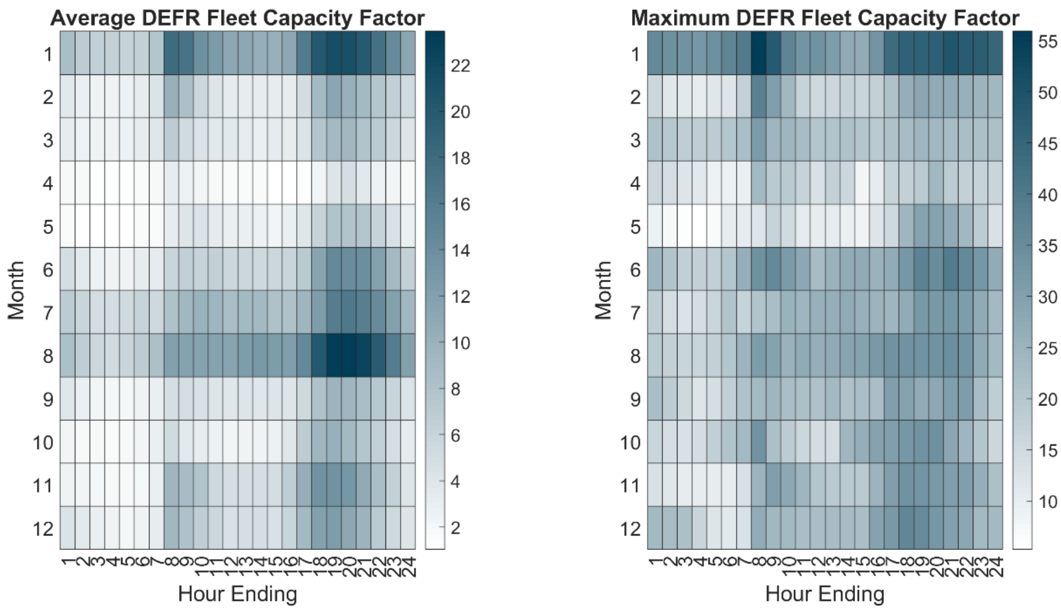
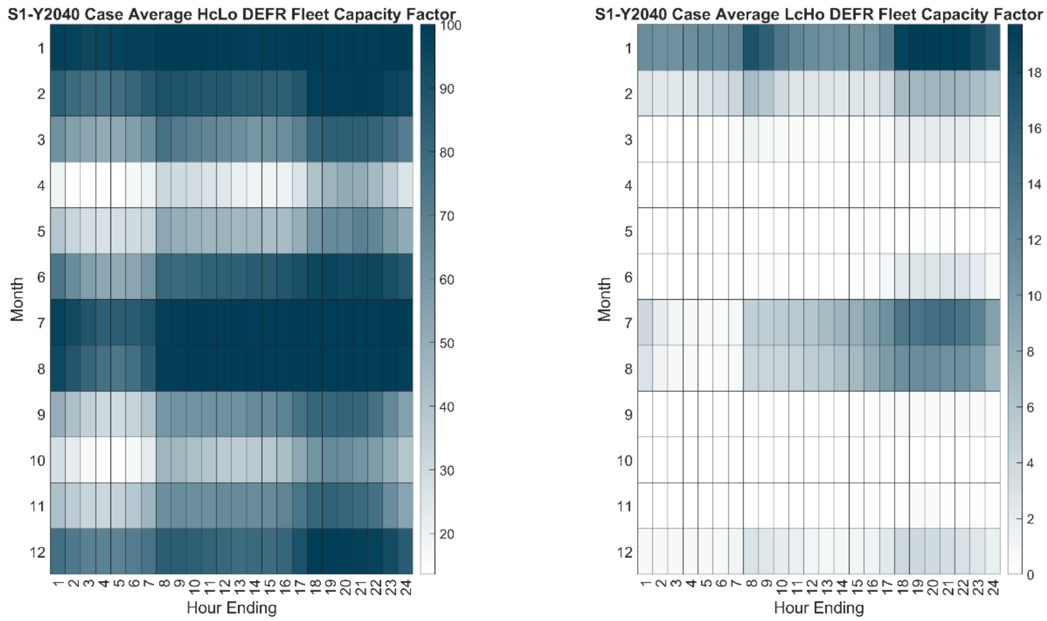


Figure 89: Average and Maximum DEFR Fleet Capacity Factors by Month and Hour: 2040 S2



In S1, two types of DEFRs were modeled in production cost while in S2 a single intermediate DEFR option was included. Figure 90 below 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 90: Average DEFR Fleet Capacity Factor 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 91: Maximum DEFR Fleet Up-Ramp (MW/hour) by Month and Hour: 2040 S1 and S2

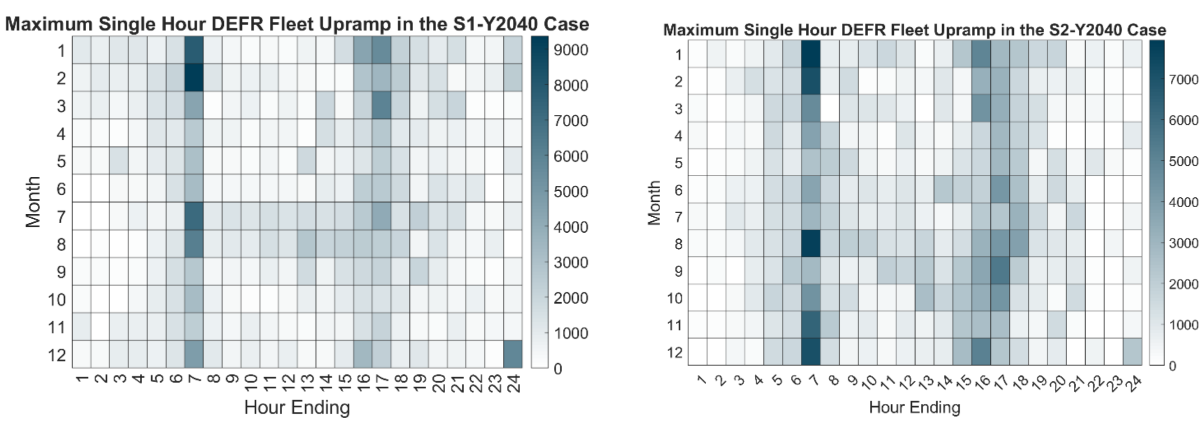
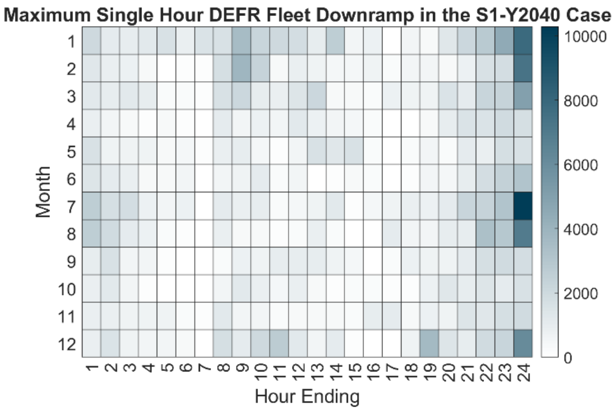
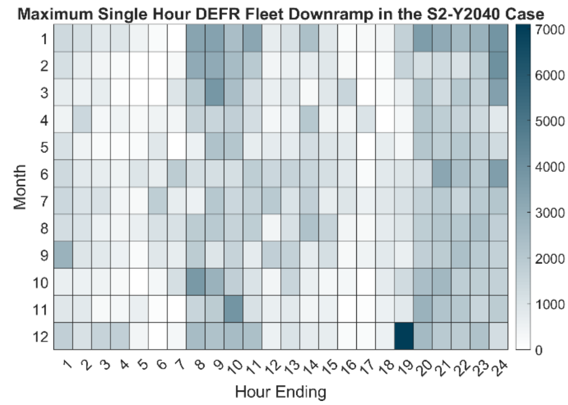


Figure 92: Maximum DEFR Fleet Down-Ramp (MW/hour) by Month and Hour: 2040 S1 and S2





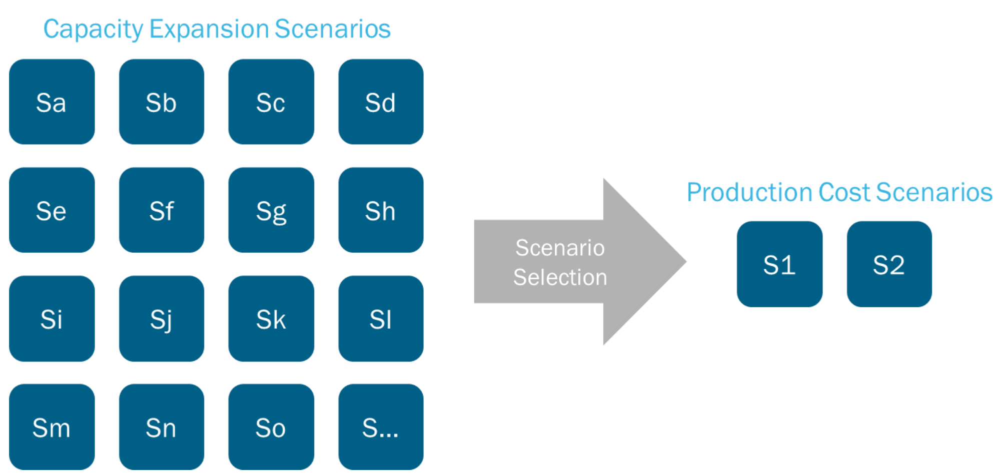
The hourly model does not capture sub-hourly variations, day-ahead to real-time market arbitrage, forecast uncertainty, transmission outages and other unplanned events. These real-world considerations could tend to increase flexibility demand on the DEFR generators. As stated in the assumptions section, 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.

Appendix G: Detailed Capacity Expansion Scenarios

Dozens of preliminary scenarios were evaluated in the capacity expansion model and presented to stakeholders over the course of multiple ESPWG meetings for use in the Policy Case. Key factors such as technology capital cost and load forecast were adjusted to investigate the key drivers for resource additions and impacts on the projections of resource growth in NYS. In addition to generator capital cost and load forecast, assumptions surrounding operating costs (fuel and/or emission price forecasts), existing generator retirements, energy output associated with certain generator types, and policy targets were analyzed through scenario testing. Through these scenarios, various assumption changes were examined to assess their impact on the capacity expansion model results. These scenarios were informative by showing trends in installed capacity and/or generation mix, as applicable to the scenario, throughout the study period. The scenarios provide insight on which assumptions drive certain results and the scale to which the capacity and/or generation mix is impacted.

Figure 93 portrays a visual representation of the myriad of scenarios conducted in the capacity expansion model, prior to the selection of the two final scenarios S1 and S2.

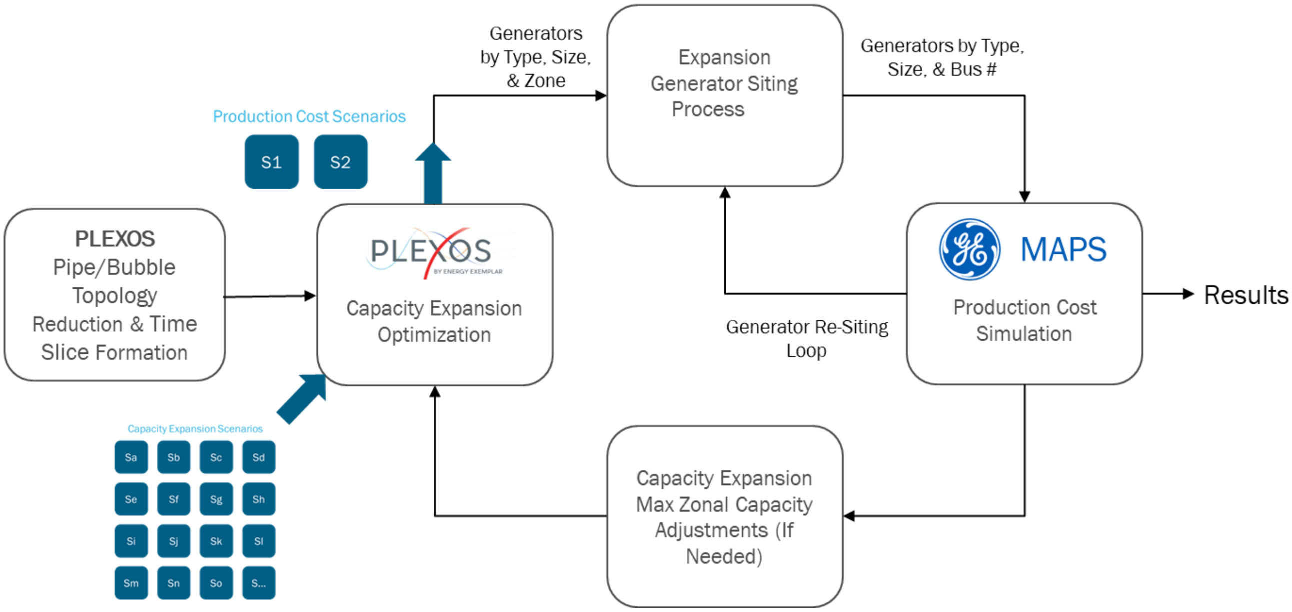
Figure 93: Policy Case Capacity Expansion Scenario Selection



Results from the capacity expansion model for scenarios S1 and S2 were the basis for the generation capacity input assumptions for the production cost modeling in the Policy Case. Further analysis was conducted in production cost modeling to assess the impacts of increased renewable and DEFR penetration on New York's system throughout the 20-year study period.

Figure 94 provides an overview of the process flow used for the Policy Case.

Figure 94: Policy Case Process Flow Chart



G.1 Capacity Expansion Scenario Assumptions

The following table describes some of the scenarios that were tested in the capacity expansion model for the Policy Case. A brief description of the assumption(s) as well as the scale to which the assumption(s) were adjusted in S1 and S2 are included below for each scenario.

Scenario	Assumption Adjusted	Value
High Natural Gas Price	Natural gas price forecast	2x baseline forecast
High CO_2 Price	CO_2 price forecast	2x baseline forecast
Higher CO_2 Price	CO_2 price forecast	10x baseline forecast
Increase ESR Policy Target	ESR specific policy target	6 GW by 2030
Nuclear Retirements at Relicensing	Retirement date for nuclear units	Set retirement date to relicense date for select units
OSW Distribution Zones J&K	Minimum amount of OSW capacity built in Zones J&K	At least 2/3 of total OSW capacity to be located in Zone J, remaining in Zone K
Reduced Hydro Output	Monthly hydro energy output	10% decrease in assumed energy for each month
Low Capital Cost UPV Candidate Generators	Capital cost for CapEx UPV	0.5x baseline costs
Low Capital Cost LBW Candidate Generators	Capital cost for CapEx LBW	0.5x baseline costs
Low Capital Cost UPV, LBW, & OSW Candidate Generators	Capital cost for CapEx UPV, LBW, and OSW units	0.5x baseline costs

Low Capital Cost DEFR Candidate Generators	Capital cost for CapEx DEFRs	0.5x baseline costs
High Capital Cost DEFR Candidate Generators	Capital cost for CapEx DEFRs	2x baseline costs
Low Operating Cost DEFR Candidate Generators	Operating cost for CapEx DEFRs	0.5x baseline forecast
High Operating Cost DEFR Candidate Generators	Operating cost for CapEx DEFRs	2x baseline forecast
Remove Declining Capacity Value Curves	UCAP rating of renewable and energy storage resources	Fixed at initial UCAP rating

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.

G.2 Capacity Expansion Scenario Results

The following charts provide a comparison of the capacity expansion results for each of the scenarios examined as part of this Outlook. 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 each of the scenarios examined are included in this section.

Figure 95: Policy Case S1 Scenario Installed Capacity Change in 2040

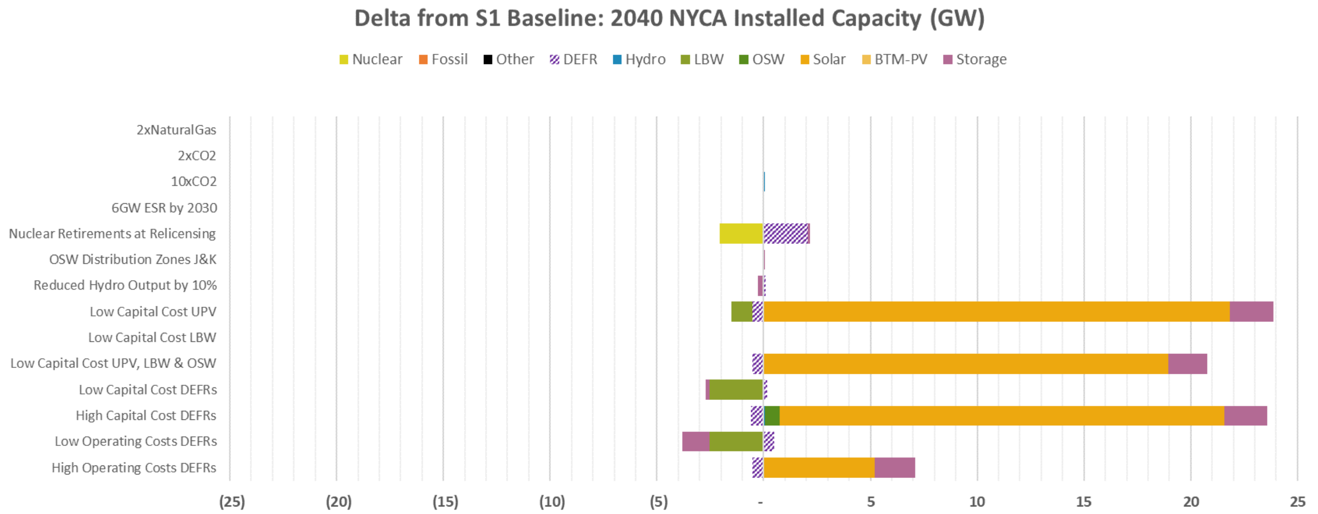


Figure 96: Policy Case S2 Scenario Installed Capacity Change in 2040

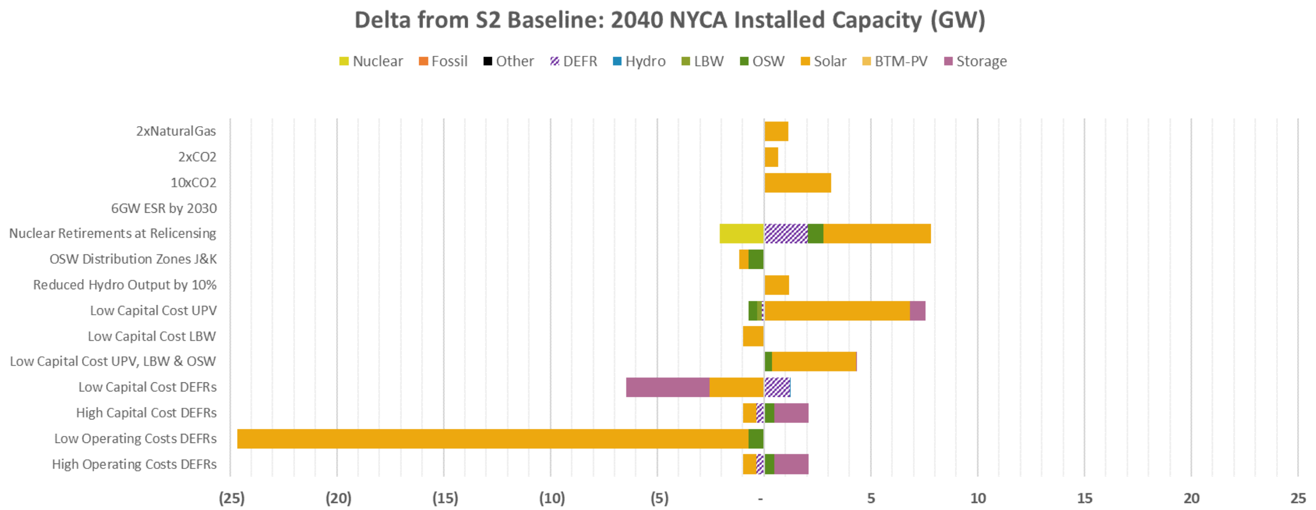


Figure 97: Policy Case S1 Scenario Annual Generation Change in 2040

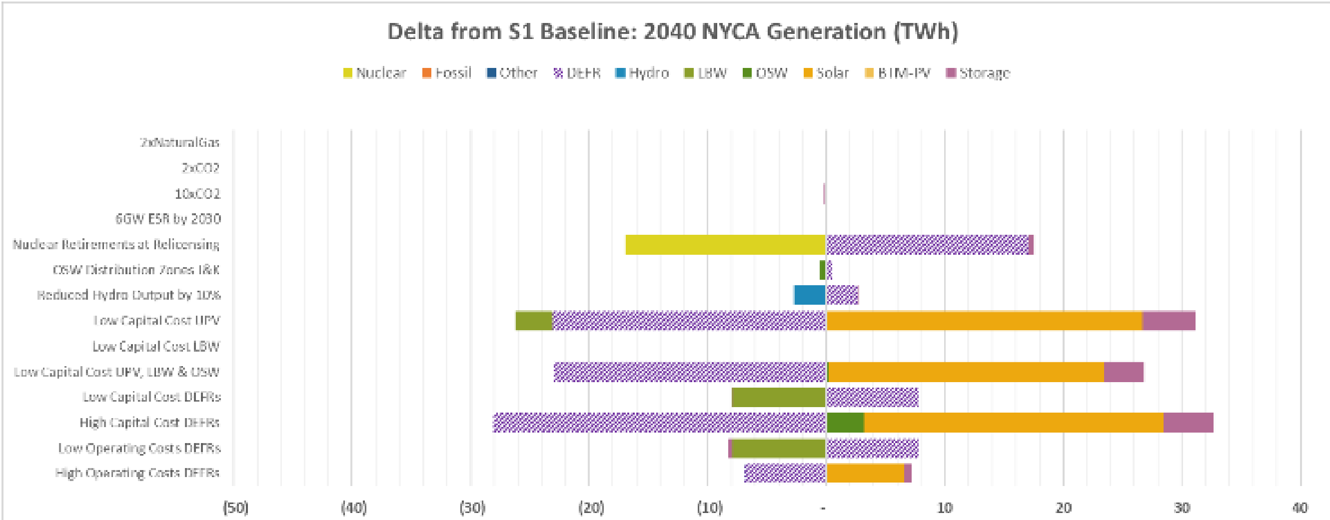
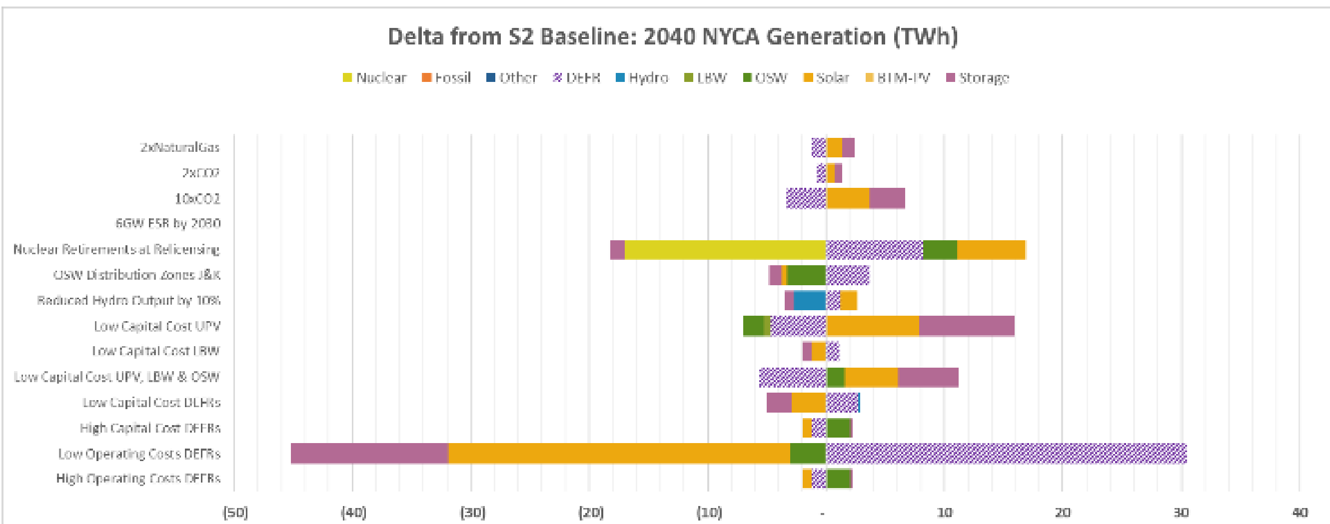
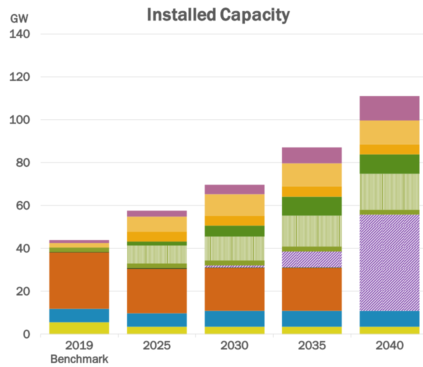
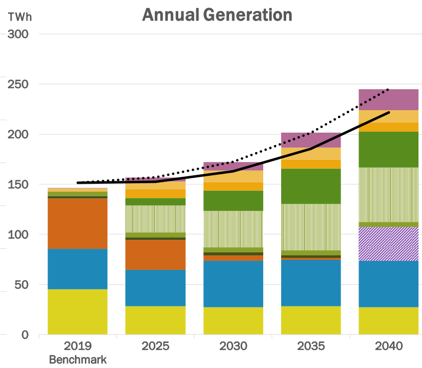


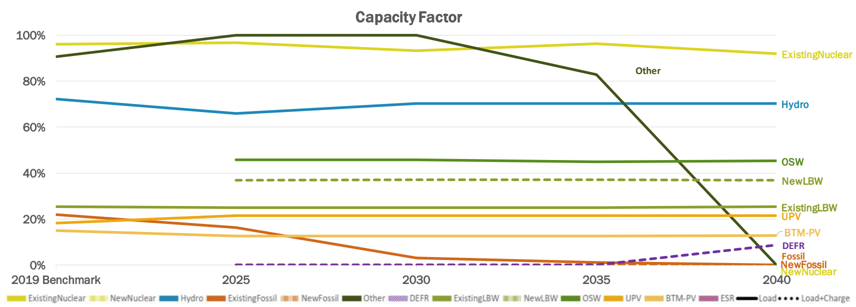
Figure 98: Policy Case S2 Scenario Annual Generation Change in 2040



S1 Scenario: High Natural Gas Price







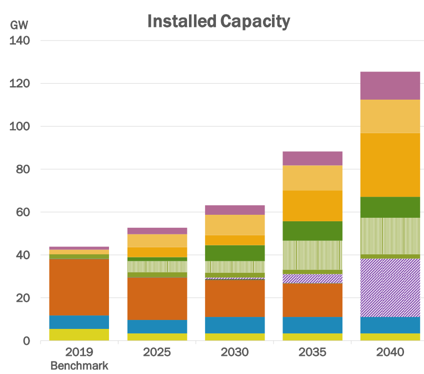
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	20,755	19,913	19,915	-
DEFR - HcLo	-	-	-	-	3,811
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	856	7,394	40,939
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	10,613	13,522	16,606	19,087
OSW	-	1,826	5,036	9,000	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	7,357	11,450
Total	43,838	57,583	70,547	94,395	111,066

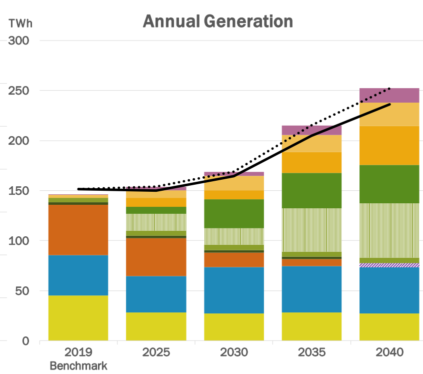
Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	29,620	5,410	1,817	-
DEFR - HcLo	-	-	-	-	33,479
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	523
Hydro	40,034	36,418	46,342	46,359	46,391
LBW	4,416	31,894	41,461	51,439	59,362
OSW	-	7,331	20,186	35,463	35,651
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,025	8,712	14,926	21,339
Total Generation	146,262	156,765	172,278	201,477	245,109
RE Generation	47,261	91,943	127,873	154,061	162,676
ZE Generation	93,301	124,305	164,030	197,325	245,109
Load	151,386	152,397	163,167	185,223	221,828
Load+Charge	151,773	156,765	172,279	201,478	245,109
% RE [RE/Load]	31%	60%	78%	83%	73%
% ZE [ZE/(Load+Charge)]	61%	79%	95%	98%	100%

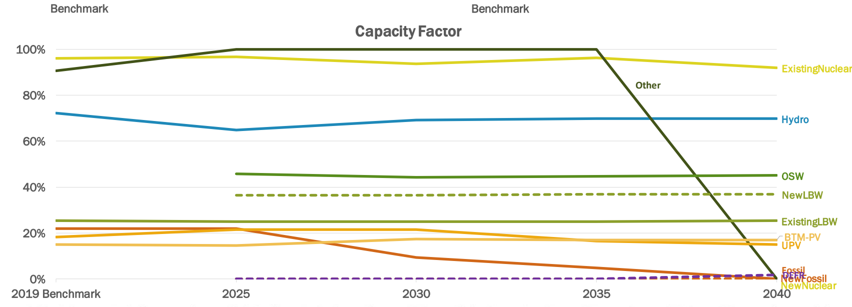
Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	12.92	2.26	0.76	-

* 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)

S2 Scenario: High Natural Gas Price







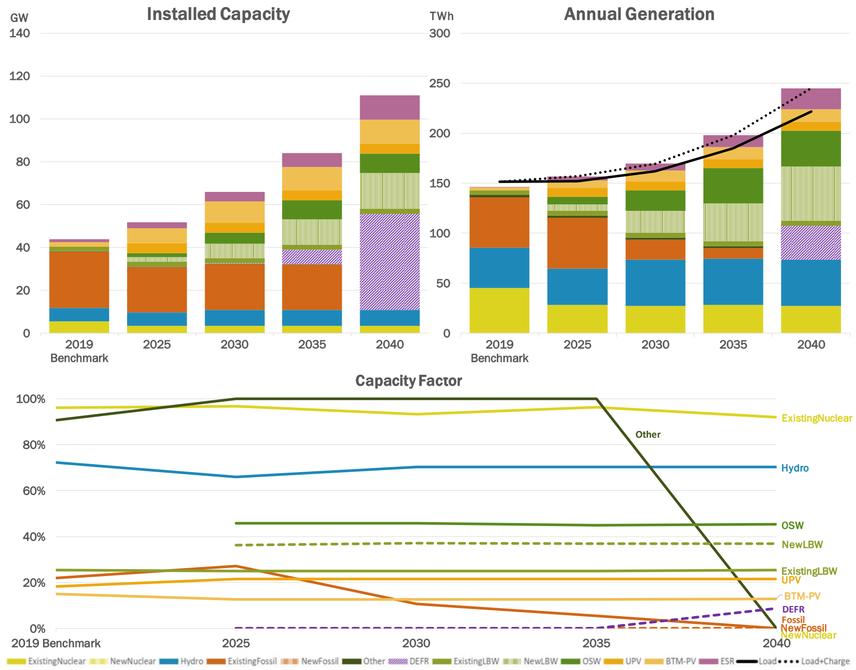
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,620	17,282	15,691	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	7,469	7,547	15,629	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	4,676	14,603	29,761
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,376	12,810
Total	43,838	52,583	63,840	92,151	125,290

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	37,581	14,127	6,586	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	4,314
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	21,559	21,815	48,088	59,362
OSW	-	7,331	28,865	35,247	38,388
UPV	51	8,817	8,816	21,047	39,091
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	3,396	4,215	9,366	14,488
Total Generation	146,262	153,909	168,925	215,127	252,345
RE Generation	47,261	81,755	120,301	167,998	206,451
ZE Generation	93,301	113,489	151,959	205,701	252,345
Load	151,386	150,222	164,255	204,775	236,334
Load+Charge	151,773	153,910	168,926	215,127	252,345
% RE [RE/Load]	31%	54%	73%	82%	87%
% ZE [ZE/(Load+Charge)]	61%	74%	90%	96%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	16.41	6.51	3.42	-

* 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)

S1 Scenario: High CO2 Price



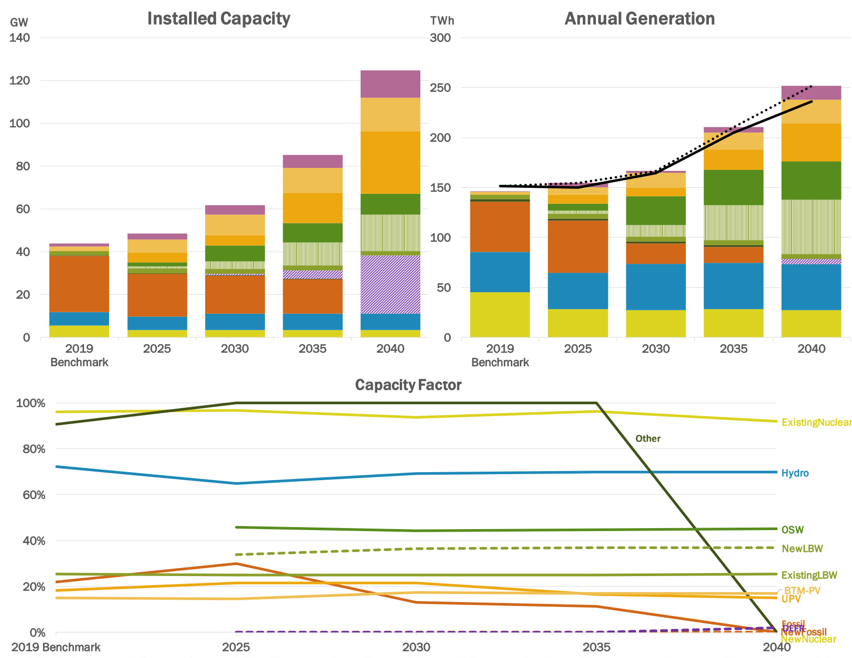
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,258	21,218	21,169	-
DEFR - HcLo	-	-	-	-	3,812
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	6,760	40,938
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	4,360	9,051	13,970	19,087
OSW	-	1,826	5,036	9,000	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	6,485	11,450
Total	43,838	51,736	66,411	90,777	111,066

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	50,688	19,890	10,165	-
DEFR - HcLo	-	-	-	-	33,482
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	523
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	11,572	26,971	42,781	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	4,168	6,830	11,928	21,339
Total Generation	146,262	156,806	169,539	197,856	245,109
RE Generation	47,261	71,620	113,383	145,433	162,672
ZE Generation	93,301	104,126	147,658	185,700	245,109
Load	151,386	152,186	161,976	184,704	221,828
Load+Charge	151,773	156,806	169,540	197,857	245,109
% RE [RE/Load]	31%	47%	70%	79%	73%
% ZE [ZE/(Load+Charge)]	61%	66%	87%	94%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	21.93	8.43	4.36	-

* 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)

S2 Scenario: High CO2 Price



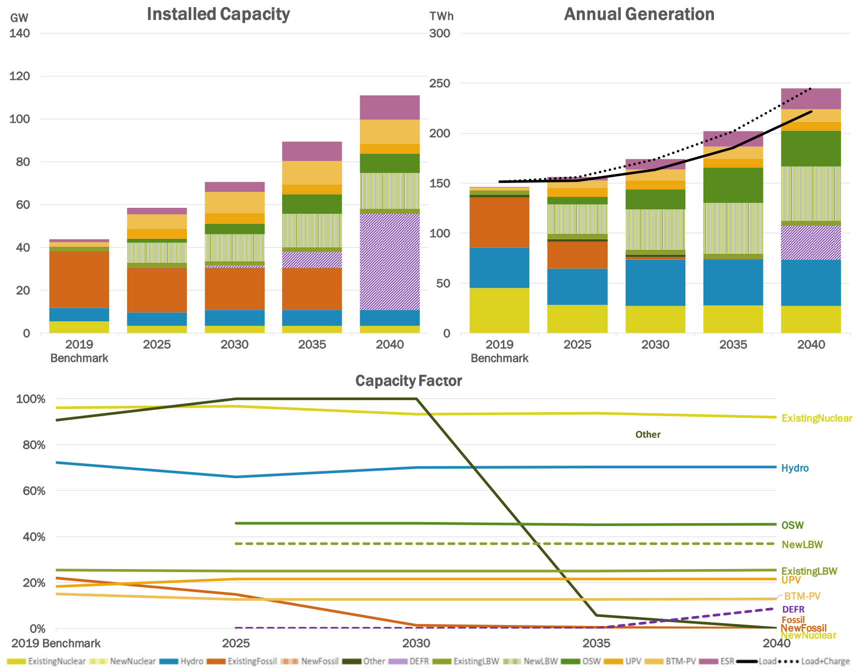
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,978	17,640	16,059	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,160	5,877	13,097	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	4,676	14,118	29,275
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,050	12,810
Total	43,838	48,535	62,431	89,078	124,805

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,383	20,067	15,749	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	4,848
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,593	16,494	39,895	59,362
OSW	-	7,331	28,865	35,247	38,388
UPV	51	8,817	8,816	20,458	38,501
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,203	2,090	5,206	13,977
Total Generation	146,262	154,705	166,571	210,501	251,778
RE Generation	47,261	67,790	114,979	159,215	205,862
ZE Generation	93,301	100,331	144,512	192,760	251,778
Load	151,386	150,047	164,255	204,755	236,334
Load+Charge	151,773	154,706	166,572	210,502	251,778
% RE [RE/Load]	31%	45%	70%	78%	87%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	92%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.76	8.97	7.17	-

* 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)

S1 Scenario: Higher CO2 Price



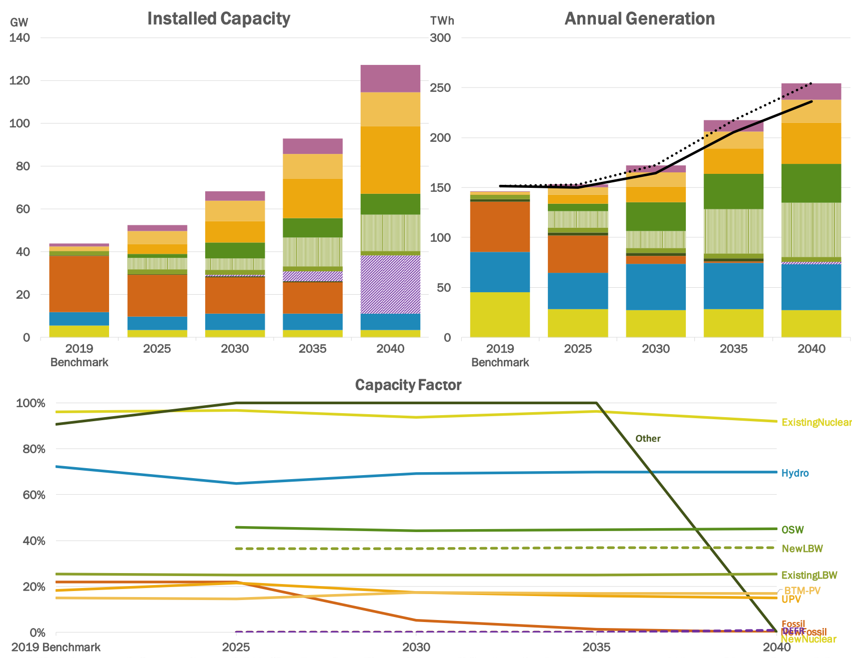
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	20,708	19,349	19,349	-
DEFR - HcLo	-	-	-	-	3,803
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	856	7,234	40,949
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	11,539	14,664	17,898	19,087
OSW	-	1,826	5,036	9,000	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	4,699	9,170	11,444
Total	43,838	58,462	71,414	96,615	111,062

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	27,575	27,092
Fossil	50,520	26,652	2,180	609	-
DEFR - HcLo	-	-	-	-	33,408
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	525
Hydro	40,034	36,418	46,228	46,392	46,391
LBW	4,416	34,800	45,094	55,525	59,362
OSW	-	7,331	20,186	35,532	35,719
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	3,424	10,239	15,347	21,336
Total Generation	146,262	156,101	174,094	201,939	245,105
RE Generation	47,261	94,848	131,392	158,250	162,745
ZE Generation	93,301	126,611	169,075	201,172	245,105
Load	151,386	152,400	163,477	185,203	221,828
Load+Charge	151,773	156,102	174,095	201,939	245,105
% RE [RE/Load]	31%	62%	80%	85%	73%
% ZE [ZE/(Load+Charge)]	61%	81%	97%	100%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	13.03	1.03	0.32	-

* 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)

S2 Scenario: Higher CO2 Price



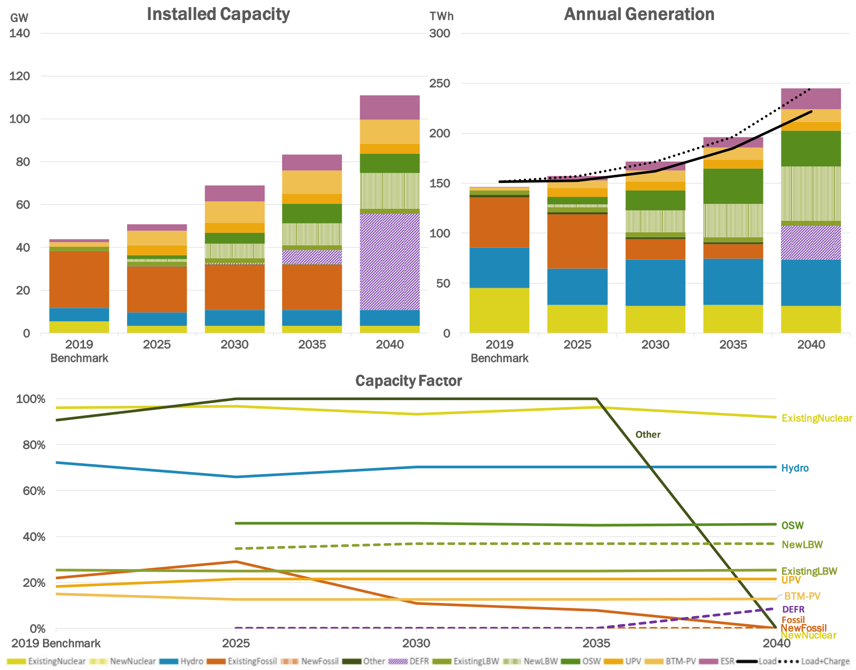
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,432	17,094	14,811	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	828	4,680	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	7,547	7,547	15,948	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	10,162	18,298	31,765
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	7,230	12,810
Total	43,838	52,473	69,154	97,518	127,295

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	37,166	7,818	1,580	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	2,213
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	21,802	21,815	49,098	59,362
OSW	-	7,331	28,865	35,247	38,388
UPV	51	8,817	15,524	25,479	41,403
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	2,724	7,099	11,102	16,443
Total Generation	146,262	153,066	172,208	217,298	254,512
RE Generation	47,261	81,998	127,008	173,439	208,763
ZE Generation	93,301	113,060	161,551	212,880	254,512
Load	151,386	150,047	164,419	205,255	236,334
Load+Charge	151,773	153,066	172,209	217,299	254,512
% RE [RE/Load]	31%	55%	77%	84%	88%
% ZE [ZE/(Load+Charge)]	61%	74%	94%	98%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	16.10	3.94	0.85	-

* 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)

S1 Scenario: Increase ESR CLCPA to 6 GW by 2030



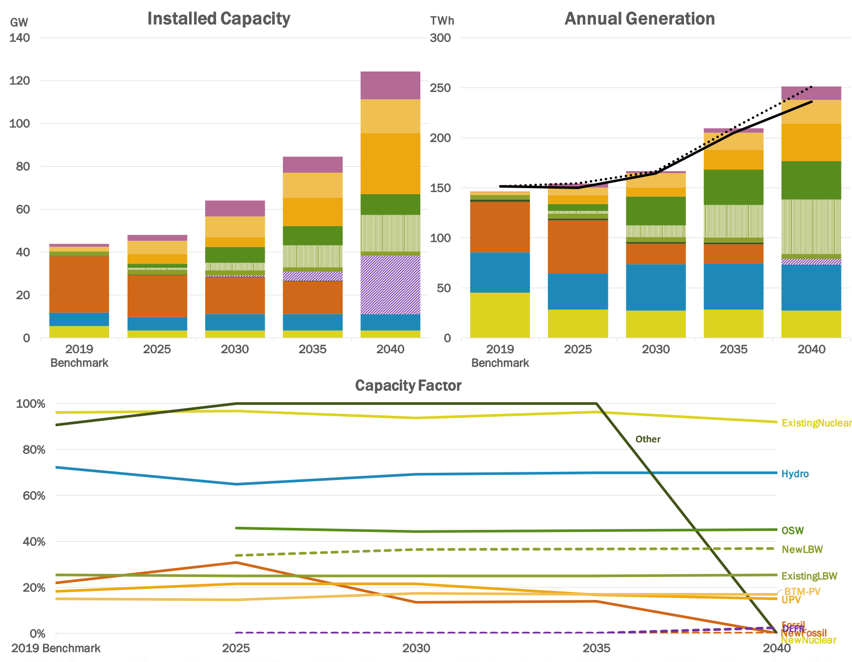
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	21,112	21,114	-
DEFR - HcLo	-	-	-	-	3,812
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	6,511	40,938
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,086	12,612	19,087
OSW	-	1,826	5,036	9,000	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	7,410	7,410	11,450
Total	43,838	50,763	69,341	89,791	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	20,091	14,487	-
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	8,637	10,544	21,339
Total Generation	146,262	157,088	171,548	196,310	245,109
RE Generation	47,261	68,238	113,383	140,949	162,672
ZE Generation	93,301	100,922	149,464	179,830	245,109
Load	151,386	152,336	161,976	184,697	221,828
Load+Charge	151,773	157,089	171,548	196,310	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	8.46	6.20	-

* 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)

S2 Scenario: Increase ESR CLCPA to 6 GW by 2030



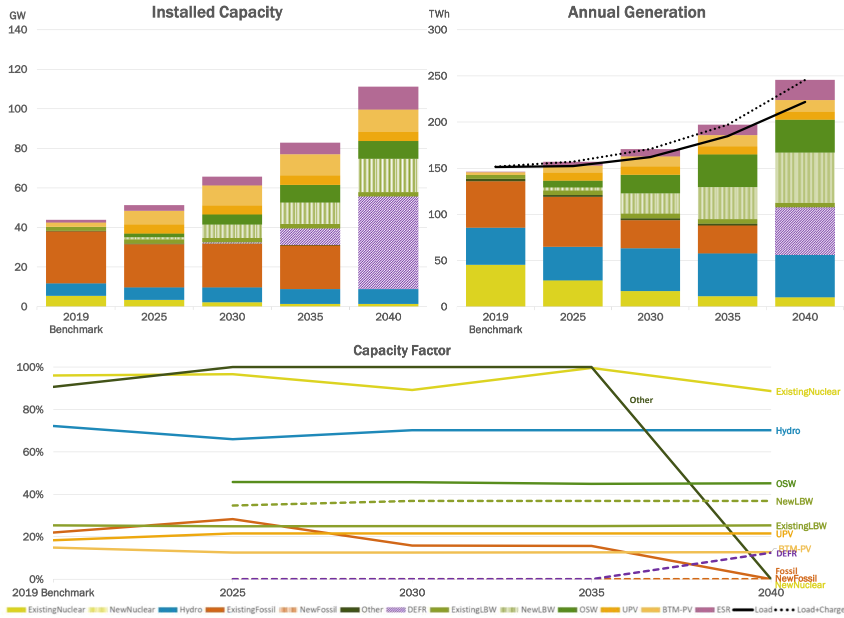
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,480	17,142	15,549	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	9,720
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	7,410	7,410	12,810
Total	43,838	48,015	64,946	88,528	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	20,080	18,903	-
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	2,199	4,498	13,414
Total Generation	146,262	154,488	166,694	209,714	251,155
RE Generation	47,261	67,715	114,979	155,984	205,065
ZE Generation	93,301	100,059	144,622	188,820	251,155
Load	151,386	150,047	164,255	204,754	236,334
Load+Charge	151,773	154,488	166,694	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	8.99	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)

S1 Scenario: Nuclear Retirements at Relicensing



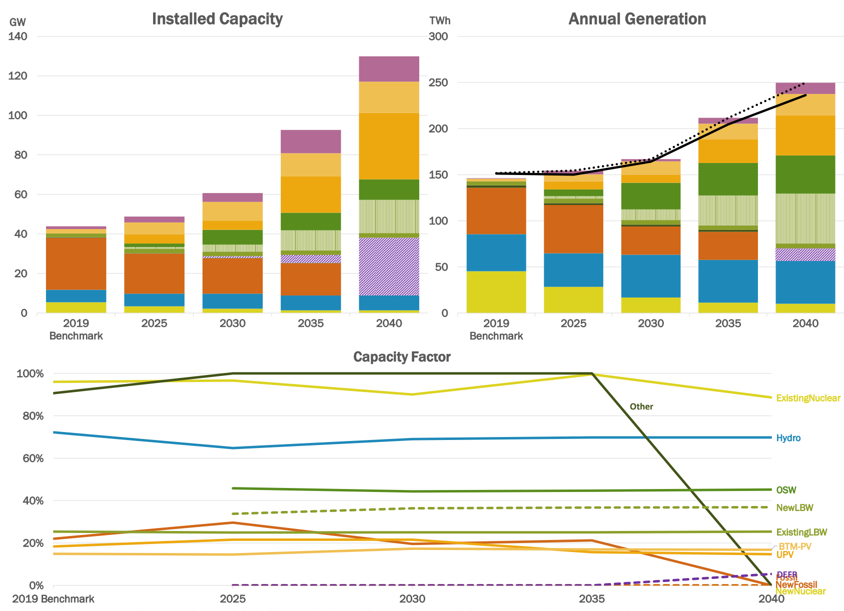
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	2,154	1,299	1,299
Fossil	26,262	21,879	22,062	22,064	-
DEFR - HcLo	-	-	-	-	5,754
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	8,403	41,051
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,086	13,027	19,087
OSW	-	1,826	5,036	9,000	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	5,857	11,566
Total	43,838	51,332	66,081	91,322	111,171

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	16,829	11,330	10,086
Fossil	50,520	54,174	30,627	30,197	-
DEFR - HcLo	-	-	-	-	50,543
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	524
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	8,189	26,971	39,679	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	7,983	11,283	21,863
Total Generation	146,262	157,088	170,814	197,132	245,689
RE Generation	47,261	68,238	113,383	142,331	162,672
ZE Generation	93,301	100,922	138,195	164,943	245,689
Load	151,386	152,336	161,976	184,697	221,828
Load+Charge	151,773	157,089	170,815	197,133	245,689
% RE [RE/Load]	31%	45%	70%	77%	73%
% ZE [ZE/(Load+Charge)]	61%	64%	81%	84%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.52	12.97	12.80	-

* 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)

S2 Scenario: Nuclear Retirements at Relicensing



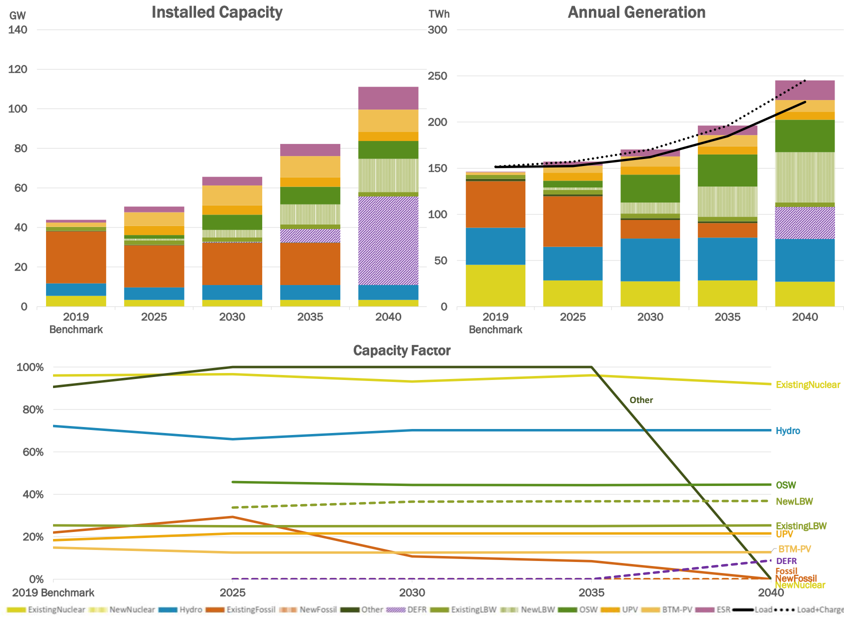
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	2,133	1,299	1,299
Fossil	26,262	20,234	17,896	16,320	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	29,253
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	10,440
UPV	32	4,676	4,676	18,472	33,630
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	11,775	12,810
Total	43,838	48,768	61,487	96,623	129,867

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	16,829	11,330	10,086
Fossil	50,520	52,436	30,718	30,337	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	13,755
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	41,340
UPV	51	8,817	8,816	25,406	43,450
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	3,999	2,414	6,323	12,143
Total Generation	146,262	154,479	166,931	211,710	249,747
RE Generation	47,261	67,715	114,979	161,729	213,762
ZE Generation	93,301	100,051	134,222	179,381	249,747
Load	151,386	150,047	164,255	204,701	236,334
Load+Charge	151,773	154,480	166,931	211,711	249,747
% RE [RE/Load]	31%	45%	70%	79%	90%
% ZE [ZE/(Load+Charge)]	61%	65%	80%	85%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.86	13.42	13.25	-

* 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)

S1 Scenario: OSW Distribution Specified in Zones J&K



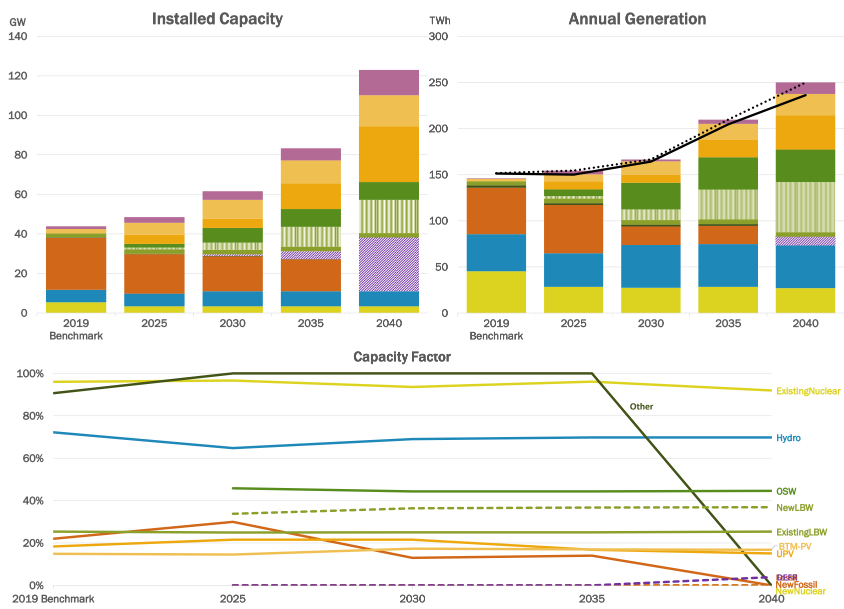
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,318	21,255	21,257	-
DEFR - HcLo	-	-	-	-	3,871
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	319	6,877	40,866
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,138	6,035	12,366	19,087
OSW	-	1,826	7,749	9,000	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	6,052	11,492
Total	43,838	50,574	65,943	89,062	111,095

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,873	20,030	15,845	-
DEFR - HcLo	-	-	-	-	34,004
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	510
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,518	17,014	37,460	59,362
OSW	-	7,331	30,142	34,949	35,141
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,399	7,450	10,346	21,365
Total Generation	146,262	157,168	170,299	196,123	245,137
RE Generation	47,261	67,567	113,383	139,602	162,166
ZE Generation	93,301	100,304	148,277	178,286	245,137
Load	151,386	152,376	162,111	184,754	221,828
Load+Charge	151,773	157,169	170,299	196,124	245,137
% RE [RE/Load]	31%	44%	70%	76%	73%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	91%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.82	8.58	6.88	-

* 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)

S2 Scenario: OSW Distribution Specified in Zones J&K



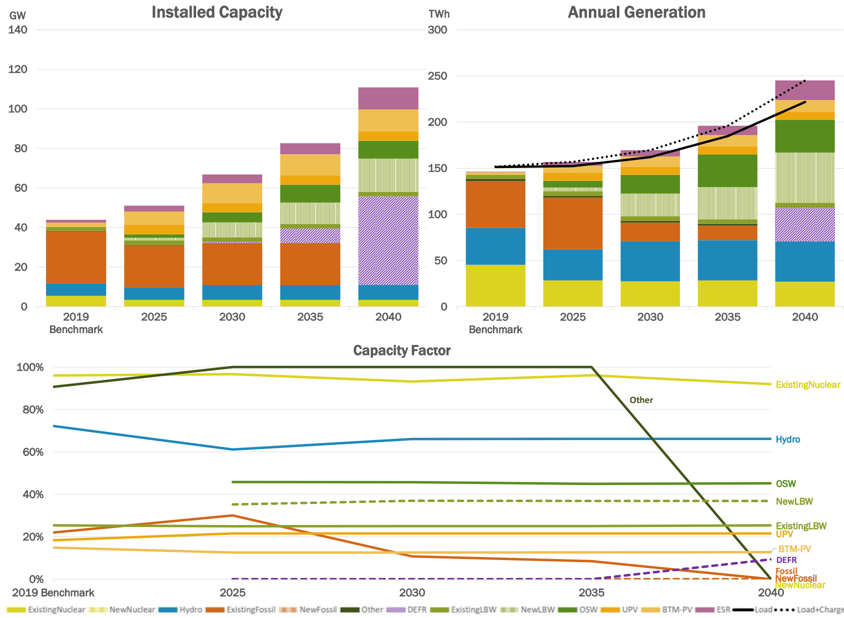
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,988	17,650	16,071	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,237
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	9,000
UPV	32	4,676	4,676	13,011	28,169
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	87,350	123,016

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	19,720	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	9,242
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,390
LBW	4,416	7,518	16,494	37,460	59,362
OSW	-	7,331	28,865	34,949	35,141
UPV	51	8,817	8,816	19,142	37,186
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,007	2,086	4,582	12,414
Total Generation	146,262	154,488	166,567	209,799	250,047
RE Generation	47,261	67,715	114,979	155,167	201,299
ZE Generation	93,301	100,059	144,509	188,087	250,047
Load	151,386	150,047	164,255	204,737	236,334
Load+Charge	151,773	154,488	166,567	209,799	250,047
% RE [RE/Load]	31%	45%	70%	76%	85%
% 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	8.85	-

* 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)

S1 Scenario: Reduced Hydro Output by 10%



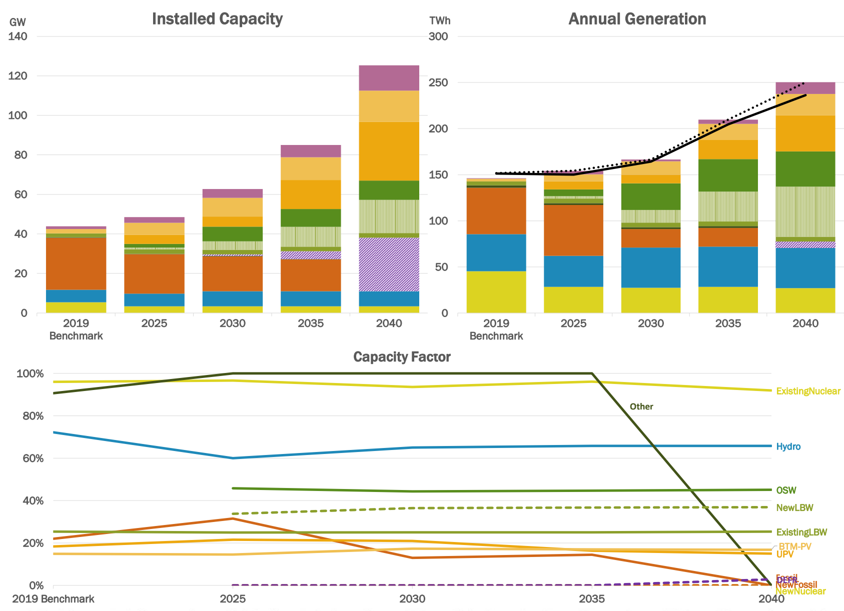
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,300	21,168	21,170	-
DEFR - HcLo	-	-	-	-	4,119
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	7,167	40,721
Hydro	6,331	6,302	7,537	7,539	7,540
LBW	1,985	3,564	9,897	13,095	19,087
OSW	-	1,826	5,036	9,000	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	5,555	11,162
Total	43,838	50,982	67,208	89,789	110,868

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	56,052	19,893	15,638	-
DEFR - HcLo	-	-	-	-	36,178
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	521
Hydro	40,034	33,727	43,652	43,695	43,700
LBW	4,416	8,943	29,662	39,898	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	4,203	6,865	10,125	21,355
Total Generation	146,262	156,886	169,577	195,945	245,128
RE Generation	47,261	66,301	113,383	139,853	159,981
ZE Generation	93,301	98,842	147,692	178,316	245,128
Load	151,386	152,260	161,980	184,860	221,828
Load+Charge	151,773	156,887	169,577	195,946	245,128
% RE [RE/Load]	31%	44%	70%	76%	72%
% ZE [ZE/(Load+Charge)]	61%	63%	87%	91%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	24.31	8.47	6.69	-

* 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)

S2 Scenario: Reduced Hydro Output by 10%



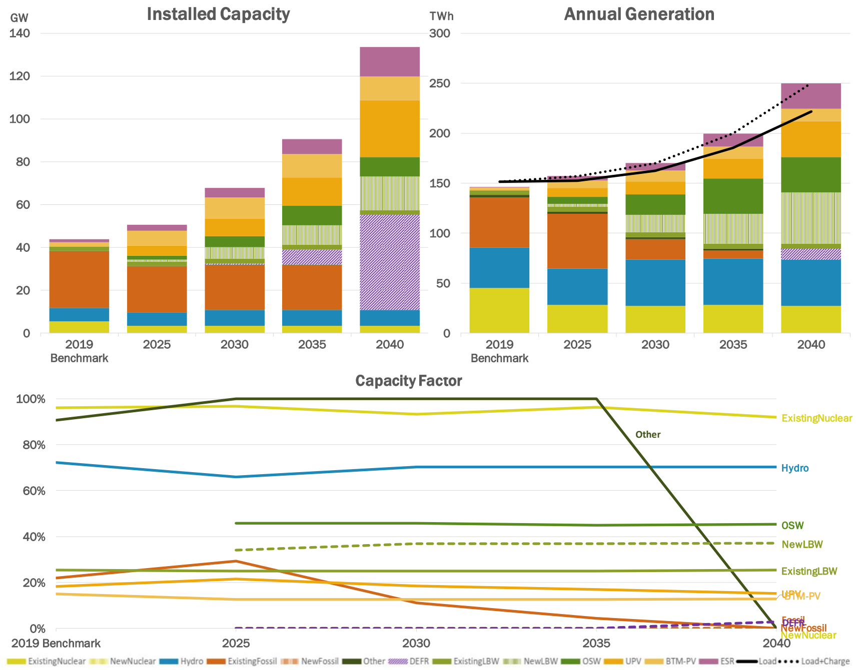
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,988	17,650	16,071	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,200
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,414	7,660	7,584	7,584
LBW	1,985	3,138	6,545	12,366	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	5,106	14,632	29,790
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	63,539	88,970	125,319

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	55,110	20,058	20,278	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	6,857
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	33,727	43,652	43,695	43,700
LBW	4,416	7,518	18,626	37,460	59,362
OSW	-	7,331	28,865	35,247	38,388
UPV	51	8,817	9,374	20,992	39,035
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	3,842	2,004	4,538	12,612
Total Generation	146,262	154,305	166,476	209,763	250,267
RE Generation	47,261	65,024	114,979	154,618	203,705
ZE Generation	93,301	97,204	144,427	187,493	250,267
Load	151,386	150,047	164,255	204,762	236,334
Load+Charge	151,773	154,306	166,477	209,764	250,267
% RE [RE/Load]	31%	43%	70%	76%	86%
% ZE [ZE/(Load+Charge)]	61%	63%	87%	89%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	24.00	8.98	9.07	-

* 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)

S1 Scenario: Low Capital Cost UPV



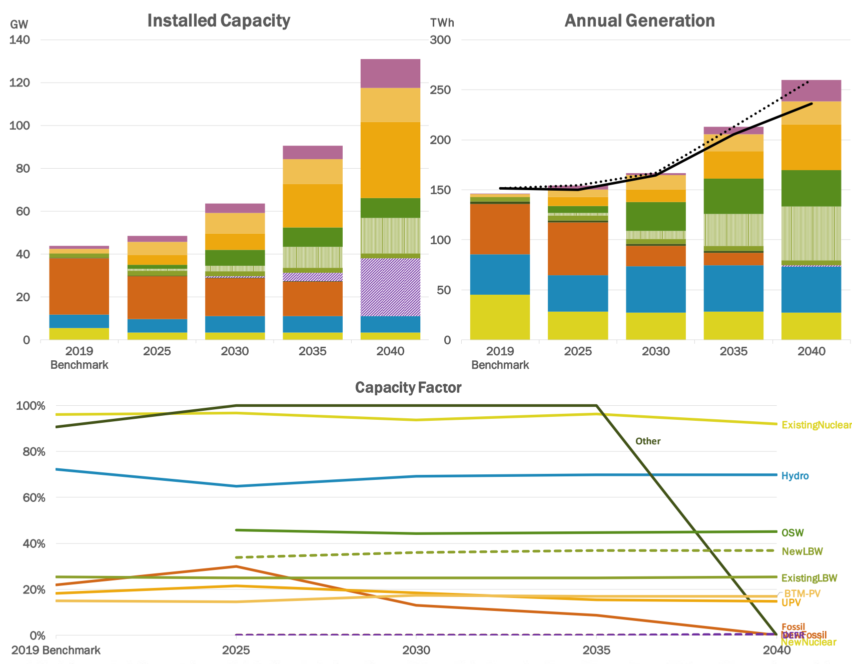
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,318	20,884	20,835	-
DEFR - HcLo	-	-	-	-	1,167
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	6,934	43,059
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,188	7,738	11,462	18,085
OSW	-	1,826	5,036	9,000	9,000
UPV	32	4,676	8,132	13,272	26,509
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	7,010	13,492
Total	43,838	50,625	68,221	97,406	133,413

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,695	20,150	7,958	-
DEFR - HcLo	-	-	-	-	10,247
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	647
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,688	22,616	34,694	56,259
OSW	-	7,331	20,186	35,460	35,647
UPV	51	8,817	13,172	19,629	35,512
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,381	7,164	13,208	25,838
Total Generation	146,262	157,143	170,134	199,650	250,087
RE Generation	47,261	67,737	113,383	148,158	186,263
ZE Generation	93,301	100,456	147,992	189,704	250,087
Load	151,386	152,366	162,376	185,443	221,828
Load+Charge	151,773	157,144	170,134	199,650	250,087
% RE [RE/Load]	31%	44%	70%	80%	84%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	95%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.74	8.56	3.46	-

* 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)

S2 Scenario: Low Capital Cost UPV



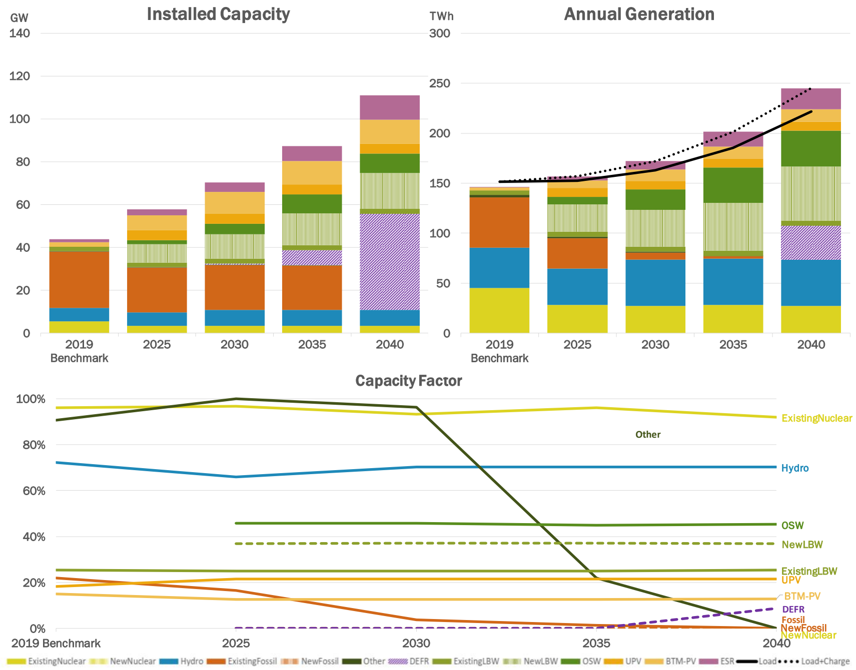
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,969	17,631	16,051	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,084
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	4,765	12,165	18,885
OSW	-	1,826	7,436	9,000	9,297
UPV	32	4,676	7,712	20,289	35,447
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,244	13,512
Total	43,838	48,493	64,335	94,492	130,938

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,528	20,196	12,299	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	952
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,385
LBW	4,416	7,518	12,843	36,840	58,741
OSW	-	7,331	28,865	35,247	36,654
UPV	51	8,817	12,467	27,517	45,560
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	3,983	2,413	7,220	21,440
Total Generation	146,262	154,461	166,930	212,975	260,045
RE Generation	47,261	67,715	114,979	163,219	210,561
ZE Generation	93,301	100,036	144,836	198,778	260,045
Load	151,386	150,047	164,255	205,194	236,334
Load+Charge	151,773	154,462	166,930	212,975	260,045
% RE [RE/Load]	31%	45%	70%	80%	89%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	93%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.91	9.02	5.77	-

* 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)

S1 Scenario: Low Capital Cost LBW



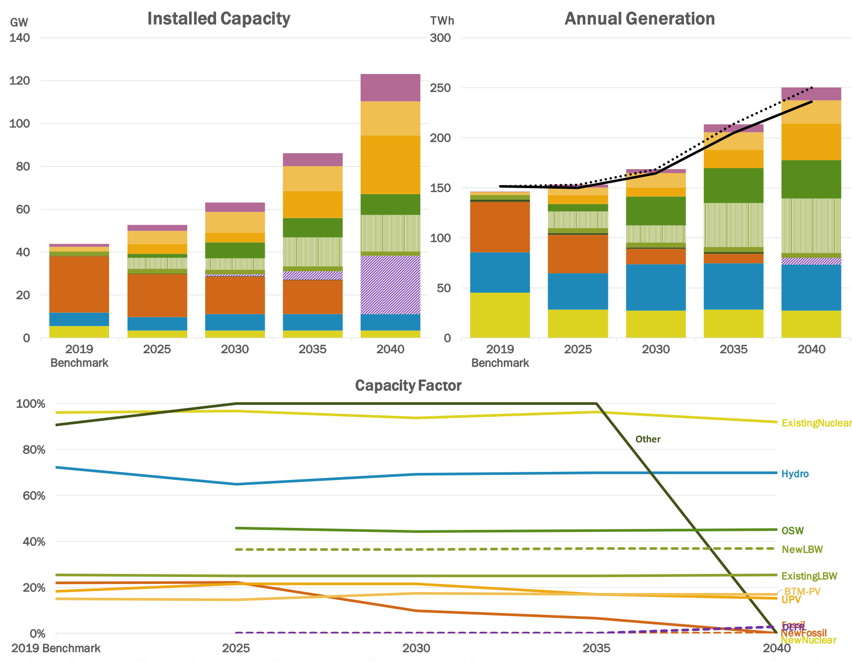
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	20,919	20,891	20,705	-
DEFR - HcLo	-	-	-	-	3,812
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	469	7,001	40,938
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	10,892	13,644	17,087	19,087
OSW	-	1,826	5,036	9,000	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	7,010	11,450
Total	43,838	57,836	70,682	94,342	111,066

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,311	27,092
Fossil	50,520	30,363	6,643	2,406	-
DEFR - HcLo	-	-	-	-	33,482
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	523
Hydro	40,034	36,418	46,342	46,359	46,391
LBW	4,416	32,790	41,883	52,988	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	4,118	8,491	14,958	21,339
Total Generation	146,262	156,824	171,974	201,532	245,109
RE Generation	47,261	92,838	128,295	155,606	162,672
ZE Generation	93,301	125,294	164,231	198,876	245,109
Load	151,386	152,317	163,040	185,263	221,828
Load+Charge	151,773	156,824	171,975	201,533	245,109
% RE [RE/Load]	31%	61%	79%	84%	73%
% ZE [ZE/(Load+Charge)]	61%	80%	95%	99%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	13.28	2.92	1.09	-

* 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)

S2 Scenario: Low Capital Cost LBW



Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,854	17,516	15,932	-
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	7,469	7,547	15,870	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	4,676	12,453	27,610
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,068	12,810
Total	43,838	52,710	63,967	90,067	123,140

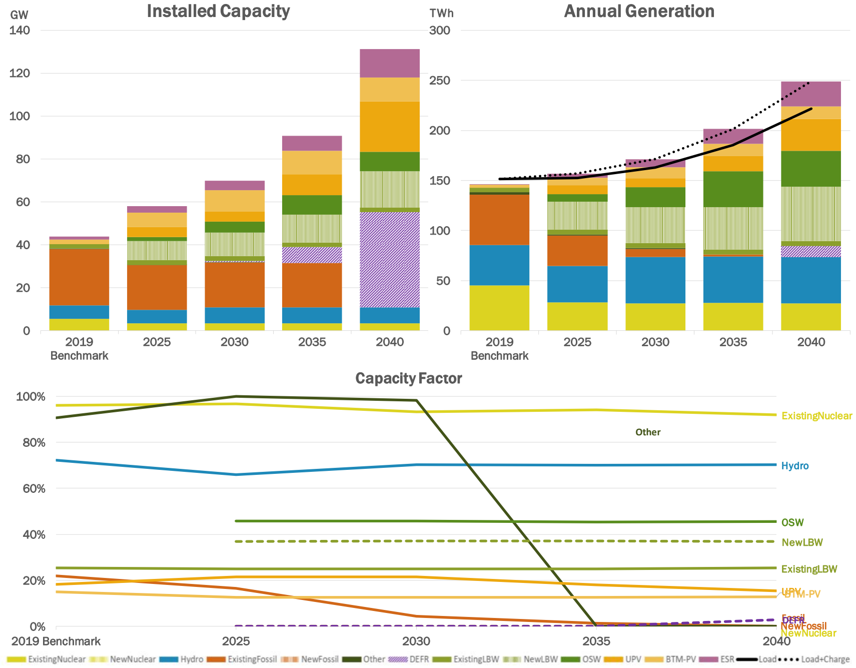
Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	38,349	15,032	9,178	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	6,702
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	21,559	21,815	48,855	59,362
OSW	-	7,331	28,865	35,203	38,344
UPV	51	8,817	8,816	18,497	36,540
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	2,708	3,879	8,160	12,577
Total Generation	146,262	153,048	168,553	213,743	250,228
RE Generation	47,261	81,755	120,301	166,170	203,857
ZE Generation	93,301	112,801	151,624	202,668	250,228
Load	151,386	150,047	164,255	204,701	236,334
Load+Charge	151,773	153,049	168,554	213,744	250,228
% RE [RE/Load]	31%	54%	73%	81%	86%
% ZE [ZE/(Load+Charge)]	61%	74%	90%	95%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	16.79	6.88	4.48	-

* 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)

New York ISO

S1 Scenario: Low Capital Cost UPV, LBW & OSW



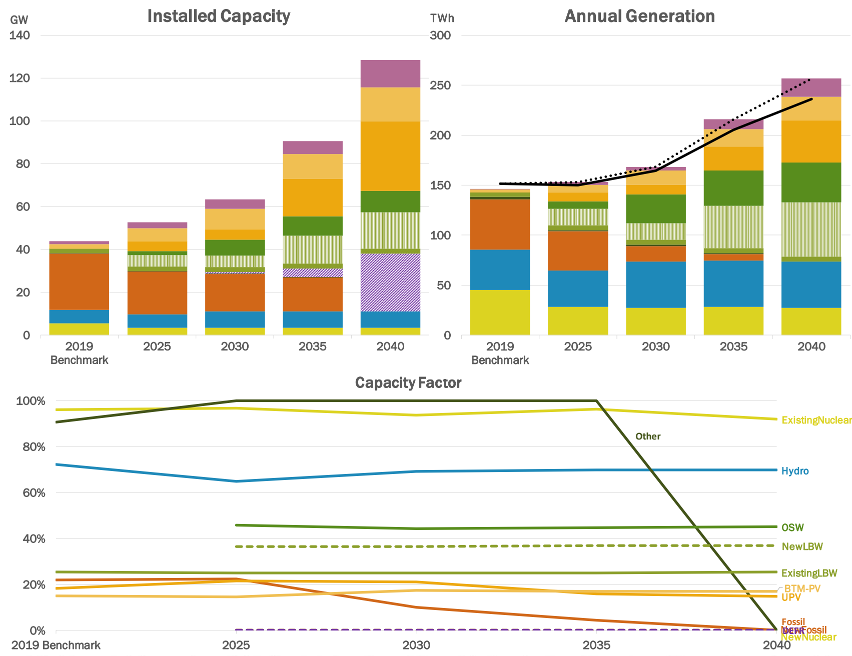
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	20,913	20,922	20,539	-
DEFR - HcLo	-	-	-	-	1,178
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	469	7,390	43,050
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	10,967	13,278	15,299	19,087
OSW	-	1,826	5,036	9,000	9,000
UPV	32	4,676	4,676	9,804	23,614
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	7,010	13,280
Total	43,838	57,906	70,328	98,165	131,312

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	27,726	27,092
Fossil	50,520	30,122	7,873	2,337	-
DEFR - HcLo	-	-	-	-	10,350
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	623
Hydro	40,034	36,418	46,342	46,200	46,391
LBW	4,416	33,017	40,671	47,217	59,362
OSW	-	7,331	20,186	35,716	35,902
UPV	51	8,817	8,816	15,433	31,961
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,086	8,011	14,788	24,774
Total Generation	146,262	156,778	171,370	201,400	248,908
RE Generation	47,261	93,066	127,083	156,550	186,069
ZE Generation	93,301	125,490	162,538	199,063	248,908
Load	151,386	152,300	162,910	185,379	221,828
Load+Charge	151,773	156,779	171,371	201,401	248,908
% RE [RE/Load]	31%	61%	78%	84%	84%
% ZE [ZE/(Load+Charge)]	61%	80%	95%	99%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	13.18	3.42	0.97	-

* 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)

S2 Scenario: Low Capital Costs UPV, LBW & OSW



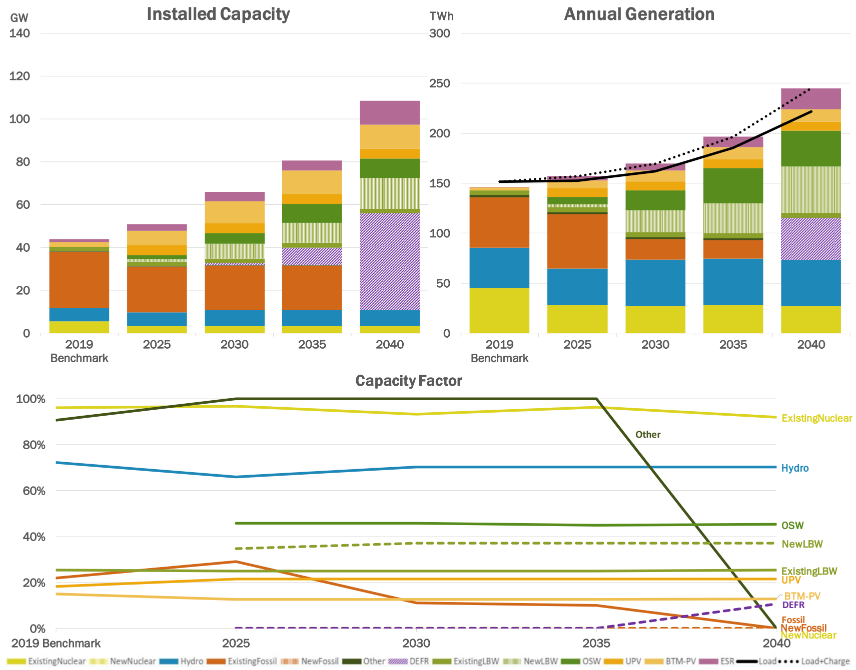
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,897	17,559	15,976	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,170
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	7,469	7,547	15,379	19,087
OSW	-	1,826	7,436	9,000	10,098
UPV	32	4,676	5,011	17,385	32,543
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,218	12,861
Total	43,838	52,669	64,261	94,619	128,471

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	39,100	15,347	6,175	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,385
LBW	4,416	21,559	21,815	47,281	59,362
OSW	-	7,331	28,865	35,247	39,936
UPV	51	8,817	9,223	24,252	42,296
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	2,888	3,787	9,816	18,500
Total Generation	146,262	153,247	168,452	215,891	256,790
RE Generation	47,261	81,755	120,708	170,396	211,198
ZE Generation	93,301	112,981	151,939	208,550	256,790
Load	151,386	150,047	164,255	205,228	236,334
Load+Charge	151,773	153,248	168,452	215,891	256,790
% RE [RE/Load]	31%	54%	73%	83%	89%
% ZE [ZE/(Load+Charge)]	61%	74%	90%	97%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	17.11	7.02	3.25	-

* 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)

S1 Scenario: Low Capital Cost DEFRs



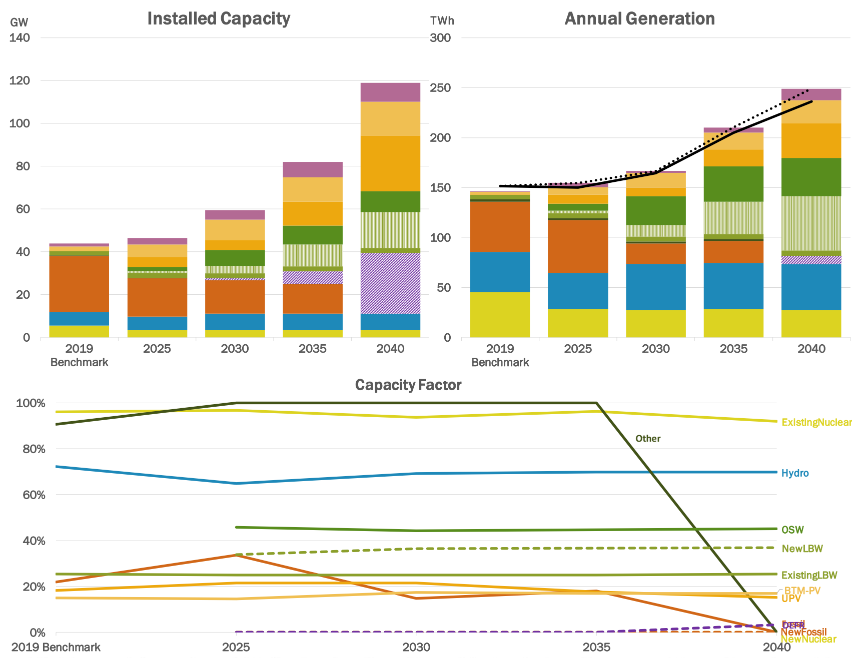
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	20,596	20,598	-
DEFR - HcLo	-	-	-	-	4,703
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	856	8,179	40,216
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,062	11,498	16,561
OSW	-	1,826	5,036	9,000	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	4,691	11,247
Total	43,838	50,763	66,672	88,778	108,505

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,174	19,992	18,190	-
DEFR - HcLo	-	-	-	-	41,312
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	562
Hydro	40,034	36,418	46,342	46,392	46,377
LBW	4,416	8,189	26,971	34,943	51,495
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	6,856	10,368	21,226
Total Generation	146,262	157,088	169,667	196,483	244,985
RE Generation	47,261	68,238	113,383	137,595	154,792
ZE Generation	93,301	100,922	147,683	176,301	244,985
Load	151,386	152,336	162,154	185,347	221,828
Load+Charge	151,773	157,089	169,668	196,483	244,985
% RE [RE/Load]	31%	45%	70%	74%	70%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	90%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.53	8.33	7.61	-

* 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)

S2 Scenario: Low Capital Cost DEFRs



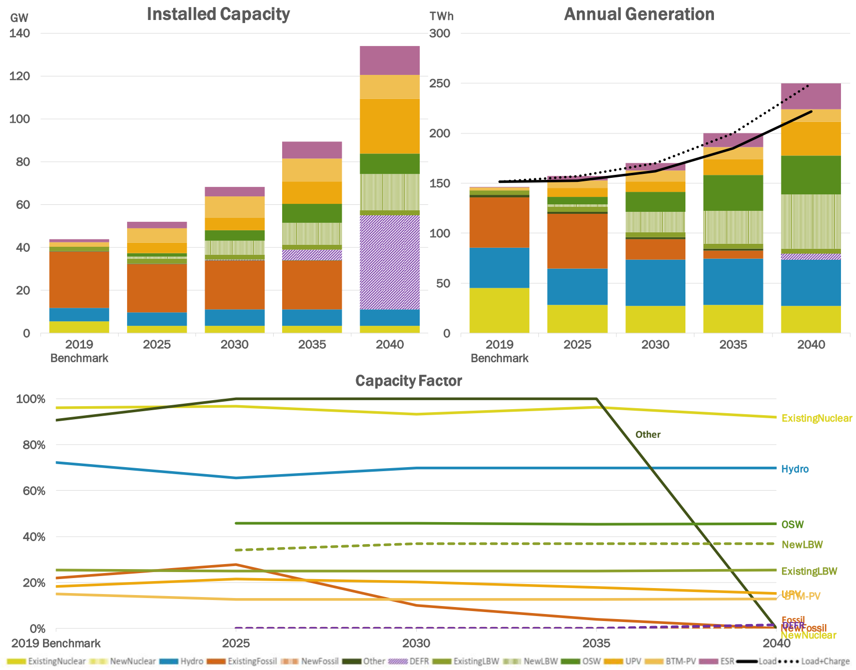
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	17,844	15,506	13,858	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	5,872	28,418
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,661	7,584	7,585
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	9,720
UPV	32	4,676	4,676	10,959	26,070
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	7,010	8,907
Total	43,838	46,379	60,310	87,713	118,915

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,443	20,078	21,754	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	8,314
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	16,820	34,801
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,071	2,194	4,854	11,335
Total Generation	146,262	154,558	166,687	210,080	248,903
RE Generation	47,261	67,715	114,979	153,142	202,162
ZE Generation	93,301	100,123	144,617	186,334	248,903
Load	151,386	150,047	164,255	204,701	236,403
Load+Charge	151,773	154,559	166,687	210,081	248,903
% RE [RE/Load]	31%	45%	70%	75%	86%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	89%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.88	8.98	9.67	-

* 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)

S1 Scenario: High Capital Cost DEFRs



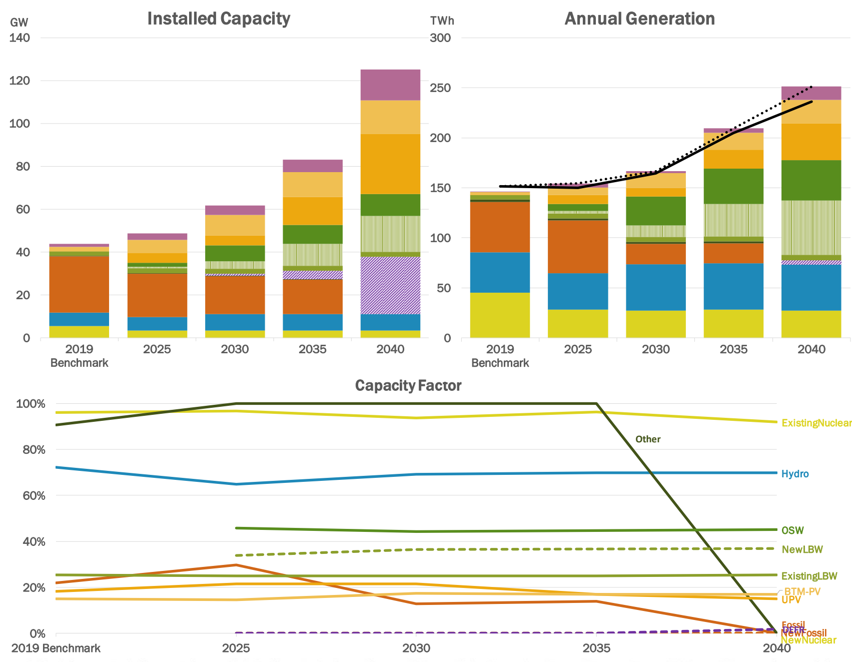
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	22,494	22,921	22,935	-
DEFR - HcLo	-	-	-	-	582
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	276	4,811	43,555
Hydro	6,331	6,346	7,581	7,584	7,584
LBW	1,985	3,188	8,656	12,465	19,087
OSW	-	1,826	5,036	9,000	9,720
UPV	32	4,676	5,783	10,372	25,483
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	7,797	13,467
Total	43,838	51,843	68,585	94,192	134,040

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,677	20,059	7,781	-
DEFR - HcLo	-	-	-	-	5,111
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	796
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,688	25,543	37,796	59,362
OSW	-	7,331	20,186	35,716	38,854
UPV	51	8,817	10,244	16,114	34,095
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,351	7,241	13,747	25,595
Total Generation	146,262	157,094	170,119	199,860	249,750
RE Generation	47,261	67,737	113,383	148,002	191,155
ZE Generation	93,301	100,426	148,068	190,087	249,750
Load	151,386	152,339	162,198	184,697	221,679
Load+Charge	151,773	157,095	170,119	199,860	249,750
% RE [RE/Load]	31%	44%	70%	80%	86%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	95%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.74	8.58	3.43	-

* 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)

S2 Scenario: High Capital Cost DEFRs



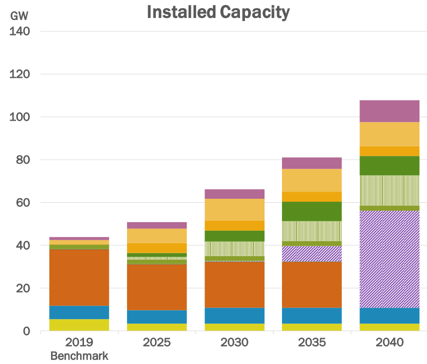
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	20,112	17,773	16,195	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	26,842
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	10,211
UPV	32	4,676	4,676	12,870	27,981
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	5,843	14,410
Total	43,838	48,646	62,577	87,029	125,244

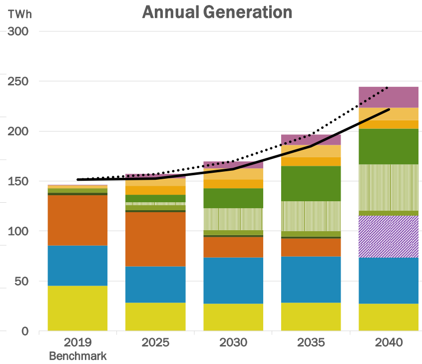
Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,437	20,066	19,594	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	4,341
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,518	16,494	37,460	59,362
OSW	-	7,331	28,865	35,247	40,402
UPV	51	8,817	8,816	18,968	36,949
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,007	2,086	4,281	13,613
Total Generation	146,262	154,488	166,567	209,495	251,370
RE Generation	47,261	67,715	114,979	155,291	206,324
ZE Generation	93,301	100,059	144,509	187,910	251,370
Load	151,386	150,047	164,255	204,791	236,334
Load+Charge	151,773	154,488	166,567	209,496	251,370
% RE [RE/Load]	31%	45%	70%	76%	87%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	90%	100%

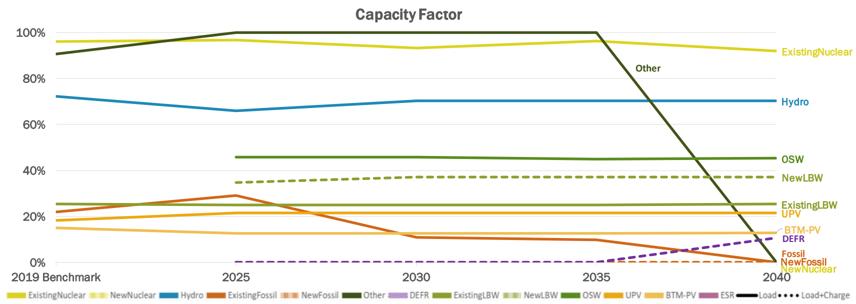
Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.86	8.98	8.78	-

* 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)

S1 Scenario: Low Operating Costs DEFRs







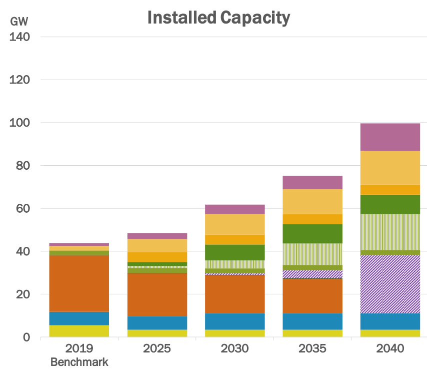
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	21,234	21,236	-
DEFR - HcLo	-	-	-	-	4,621
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	7,371	40,639
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,062	11,494	16,557
OSW	-	1,826	5,036	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	5,191	10,155
Total	43,838	50,763	66,438	88,296	107,750

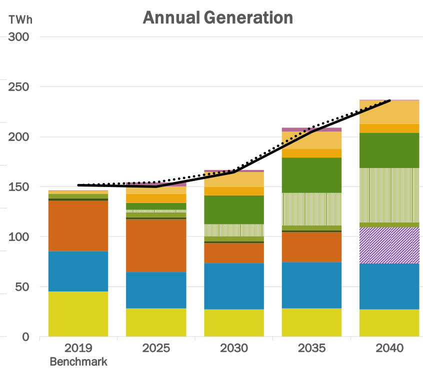
Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	54,174	19,986	18,019	-
DEFR - HcLo	-	-	-	-	40,587
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	1,255
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	8,189	26,971	34,929	51,482
OSW	-	7,331	20,186	35,460	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	7,015	10,454	20,895
Total Generation	146,262	157,088	169,820	196,385	244,621
RE Generation	47,261	68,238	113,383	137,581	154,792
ZE Generation	93,301	100,922	147,842	176,374	244,621
Load	151,386	152,336	162,117	184,969	221,828
Load+Charge	151,773	157,089	169,820	196,385	244,621
% RE [RE/Load]	31%	45%	70%	74%	70%
% ZE [ZE/(Load+Charge)]	61%	64%	87%	90%	100%

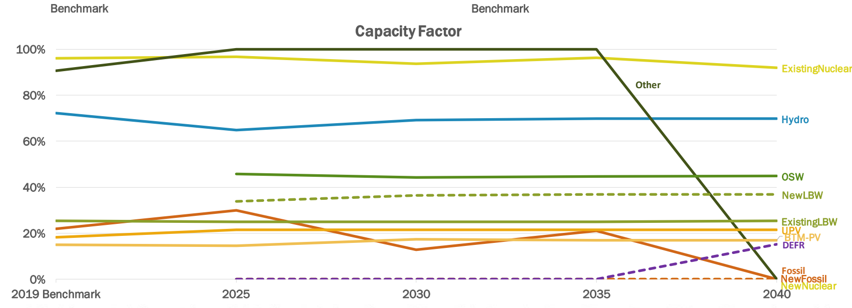
Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.53	8.53	7.75	-

* 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)

S2 Scenario: Low Operating Costs DEFRs







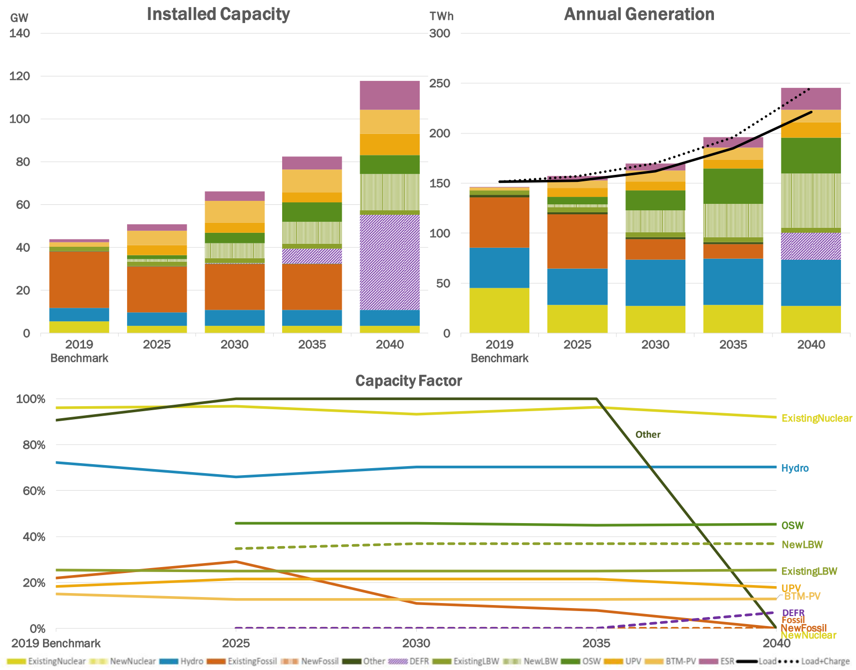
Installed Capacity (MW)					
	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,988	17,650	16,071	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,237
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,979	12,437	19,087
OSW	-	1,826	7,436	9,000	9,000
UPV	32	4,676	4,676	4,676	4,676
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	2,910	4,410	6,137	12,810
Total	43,838	48,523	62,543	79,075	99,523

Generation (GWh)					
	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,437	19,778	29,494	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	36,031
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,518	16,790	37,701	59,362
OSW	-	7,331	28,865	35,203	35,392
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,007	2,147	4,118	136
Total Generation	146,262	154,488	166,636	209,278	236,442
RE Generation	47,261	67,715	115,276	145,336	173,184
ZE Generation	93,301	100,059	144,866	177,792	236,442
Load	151,386	150,047	164,255	204,725	236,334
Load+Charge	151,773	154,488	166,637	209,279	236,442
% RE [RE/Load]	31%	45%	70%	71%	73%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	85%	100%

Emissions (million tons)					
	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.87	8.87	12.92	-

* 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)

S1 Scenario: High Operating Costs DEFRs



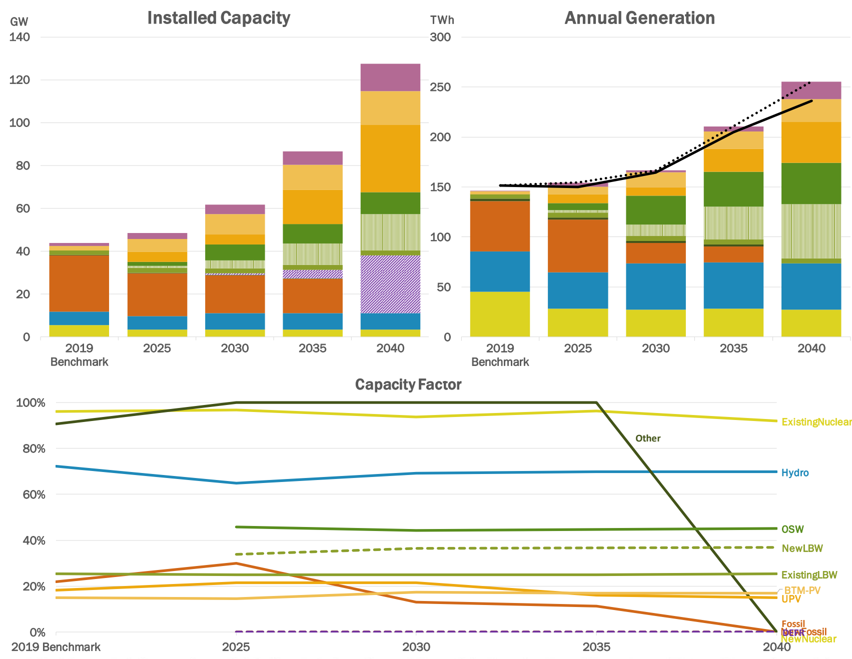
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	21,310	21,232	21,234	-
DEFR - HcLo	-	-	-	-	3,049
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	420	6,985	41,163
Hydro	6,331	6,302	7,537	7,540	7,540
LBW	1,985	3,335	9,086	12,612	19,087
OSW	-	1,826	5,036	9,000	9,000
UPV	32	4,676	4,676	4,676	9,863
BTM-PV	2,116	6,834	10,055	10,828	11,198
Storage	1,405	2,910	4,410	5,956	13,357
Total	43,838	50,763	66,461	89,404	117,622

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	14,459	-
DEFR - HcLo	-	-	-	-	26,783
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	374
Hydro	40,034	36,418	46,342	46,392	46,377
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	15,440
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,347	7,004	10,141	21,886
Total Generation	146,262	157,088	169,810	195,879	245,415
RE Generation	47,261	68,238	113,383	140,949	169,280
ZE Generation	93,301	100,922	147,831	179,428	245,415
Load	151,386	152,336	162,122	184,697	221,277
Load+Charge	151,773	157,088	169,811	195,879	245,415
% RE [RE/Load]	31%	45%	70%	76%	77%
% 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	6.20	-

* 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)

S2 Scenario: High Operating Costs DEFRs



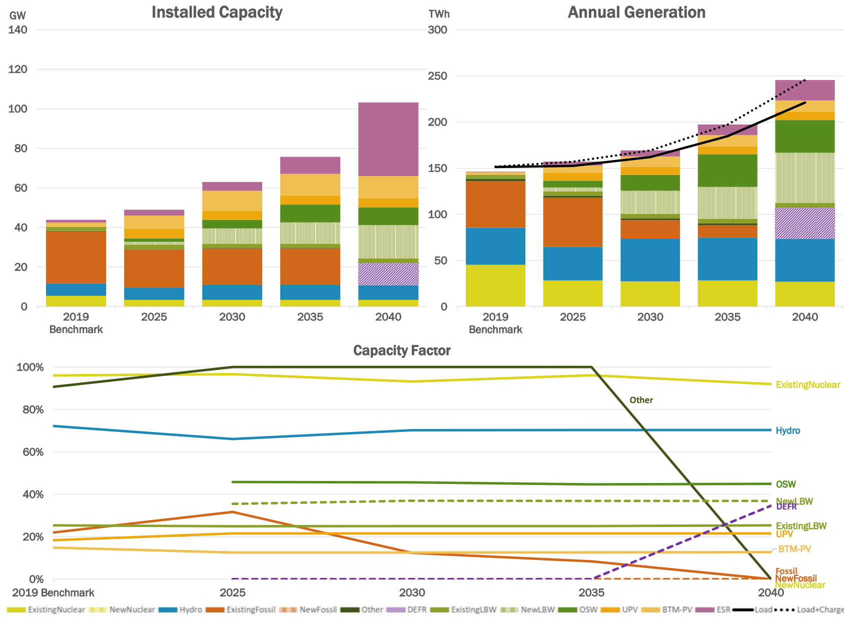
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	19,988	17,650	16,071	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	819	3,990	27,163
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,415	7,660	7,584	7,584
LBW	1,985	3,138	5,890	12,366	19,087
OSW	-	1,826	7,436	9,000	10,440
UPV	32	4,676	4,676	16,130	31,288
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	90,469	127,500

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	15,953	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	-
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	35,232	41,325
UPV	51	8,817	8,816	22,740	40,784
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,007	2,086	5,374	17,419
Total Generation	146,262	154,488	166,567	210,706	255,593
RE Generation	47,261	67,715	114,979	159,048	211,082
ZE Generation	93,301	100,059	144,509	192,761	255,593
Load	151,386	150,047	164,255	204,789	236,334
Load+Charge	151,773	154,488	166,567	210,706	255,593
% RE [RE/Load]	31%	45%	70%	78%	89%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	91%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	22.87	8.98	7.28	-

* 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)

S1 Scenario: Remove Declining Capacity Value Curves



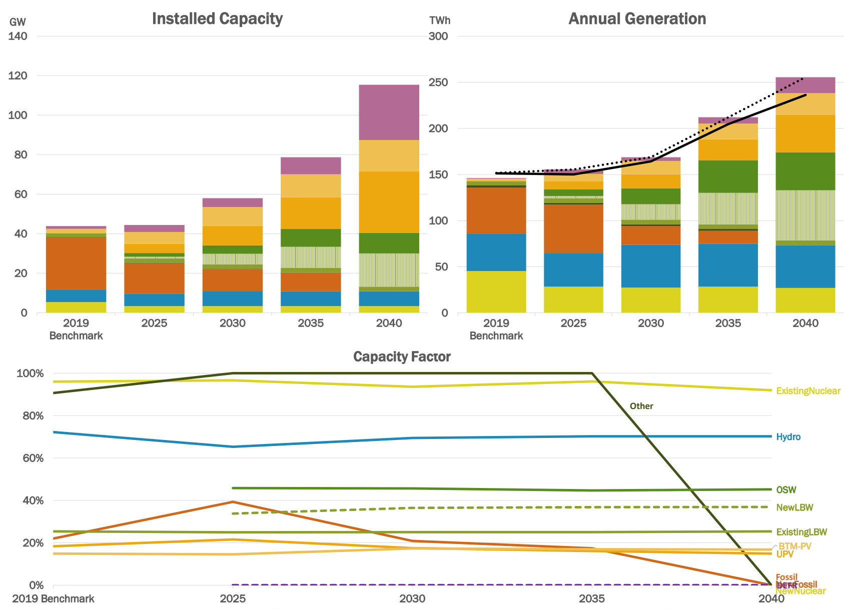
Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,364	3,364	3,364
Fossil	26,262	19,186	18,424	18,426	-
DEFR - HcLo	-	-	-	-	3,853
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	7,306
Hydro	6,331	6,294	7,529	7,532	7,532
LBW	1,985	3,636	9,969	13,013	19,087
OSW	-	1,826	4,316	9,000	9,000
UPV	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	8,668	37,247
Total	43,838	48,932	62,968	75,732	103,264

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	53,251	19,896	13,467	-
DEFR - HcLo	-	-	-	-	33,849
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,416	46,341	46,392	46,391
LBW	4,416	9,192	29,910	39,633	59,362
OSW	-	7,331	17,248	35,247	35,436
UPV	51	8,817	8,816	8,817	8,819
BTM-PV	2,761	7,483	11,068	11,983	12,454
Storage	612	4,374	6,598	11,496	22,176
Total Generation	146,262	157,194	169,313	197,365	245,579
RE Generation	47,261	69,239	113,383	142,072	162,461
ZE Generation	93,301	101,951	147,426	181,906	245,579
Load	151,386	152,472	162,015	184,697	221,132
Load+Charge	151,773	157,194	169,314	197,365	245,579
% RE [RE/Load]	31%	45%	70%	77%	73%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	92%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.15	8.32	5.58	-

* 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)

S2 Scenario: Remove Declining Capacity Value Curve



Installed Capacity (MW)	2019	2025	2030	2035	2040
Nuclear	5,400	3,346	3,346	3,364	3,364
Fossil	26,262	15,271	11,088	9,341	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	-
Hydro	6,331	6,370	7,616	7,539	7,539
LBW	1,985	3,138	7,547	12,904	19,087
OSW	-	1,826	4,316	9,000	10,440
UPV	32	4,676	9,870	16,110	31,220
BTM-PV	2,116	6,000	9,523	11,601	15,764
Storage	1,405	3,565	4,410	8,595	27,997
Total	43,838	44,416	57,939	78,679	115,412

Generation (GWh)	2019	2025	2030	2035	2040
Nuclear	45,429	28,338	27,444	28,338	27,092
Fossil	50,520	52,539	20,279	14,248	-
DEFR - HcLo	-	-	-	-	-
DEFR - McMo	-	-	-	-	-
DEFR - LcHo	-	-	-	-	-
Hydro	40,034	36,418	46,342	46,392	46,391
LBW	4,416	7,518	21,815	39,247	59,362
OSW	-	7,331	17,248	35,247	41,340
UPV	51	8,817	15,112	22,738	40,719
BTM-PV	2,761	7,631	14,461	17,223	23,220
Storage	612	4,962	4,058	6,694	17,428
Total Generation	146,262	155,545	168,752	212,119	255,551
RE Generation	47,261	67,715	114,979	160,847	211,031
ZE Generation	93,301	101,014	146,481	195,879	255,551
Load	151,386	150,047	164,255	204,701	236,334
Load+Charge	151,773	155,545	168,753	212,119	255,551
% RE [RE/Load]	31%	45%	70%	79%	89%
% ZE [ZE/(Load+Charge)]	61%	65%	87%	92%	100%

Emissions (million tons)	2019	2025	2030	2035	2040
CO_2 Emissions	22.24	23.36	8.42	5.86	-

* 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)

Appendix H: Detailed Baseline and Contract Case Results Tables

H.1. Baseline Case Results

Figure 99: Projected Baseline Case Results 2021-2040 (nominal $M)

Case Summary	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYCA-Wide Production Cost ($M)	3,007	2,675	2,743	2,535	2,440	2,352	2,258	2,267	2,192	2,160
NYCA Demand Congestion ($M)	848	427	215	105	81	90	82	84	88	88
Load LBMP Payment ($M)	5,086	4,486	4,749	4,380	4,348	4,308	4,204	4,174	4,185	4,093
Generator LBMP Payment ($M)	3,725	3,408	3,823	3,557	3,563	3,514	3,458	3,419	3,428	3,353
Load Payment Losses ($M)	334	307	336	281	277	268	264	259	267	260
SO2 Costs ($M)	0	0	0	0	0	0	0	0	0	0
SO2 Emission (Short Tons)	532	544	548	550	547	546	544	548	545	548
CO2 Costs ($M)	233	259	275	279	280	279	278	284	284	289
CO2 Emission (Short Tons)	25,571	28,286	30,027	30,302	29,986	29,704	29,432	29,832	29,615	29,996
NOX Costs ($M)	5.56	2.00	0.68	0.28	0.13	0.06	0.06	0.05	0.05	0.05
NOX Emission (Short Tons)	9,795	10,496	11,017	11,029	10,979	10,789	10,760	10,857	10,847	10,861
NYCA Avg. LBMP ($/MWh)	31.10	27.53	29.25	26.91	26.91	26.74	26.04	25.75	25.64	24.97

Case Summary	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NYCA-Wide Production Cost ($M)	2,085	2,103	2,065	2,046	2,009	1,993	1,952	1,947	1,897	1,916
NYCA Demand Congestion ($M)	90	92	96	89	93	95	94	100	103	98
Load LBMP Payment ($M)	3,992	3,940	3,862	3,776	3,722	3,656	3,573	3,537	3,436	3,458
Generator LBMP Payment ($M)	3,272	3,204	3,132	3,048	2,979	2,944	2,855	2,815	2,721	2,725
Load Payment Losses ($M)	257	254	253	246	247	243	241	238	235	235
SO2 Costs ($M)	0	0	0	0	0	0	0	0	0	0
SO2 Emission (Short Tons)	549	550	549	551	551	556	557	562	566	570
CO2 Costs ($M)	295	296	298	305	306	316	320	328	331	344
CO2 Emission (Short Tons)	30,357	30,255	30,266	30,828	30,753	31,513	31,830	32,475	32,545	33,688
NOX Costs ($M)	0.05	0.04	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03
NOX Emission (Short Tons)	11,084	10,946	11,086	11,117	11,221	11,400	11,500	11,706	11,776	12,189
NYCA Avg. LBMP ($/MWh)	24.23	23.75	23.07	22.36	21.79	21.21	20.47	20.04	19.20	19.02

Figure 100: Projected Baseline Case Production Costs (2021-2040) by Zone (nominal $M)

Production Cost ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	30	39	55	55	71	85	86	92	96	103
Genesee	43	42	44	48	49	52	57	55	57	64
Central	310	343	395	408	442	456	475	491	523	535
North	1	1	3	6	8	9	9	7	9	9
Mohawk Valley	1	2	2	3	5	6	6	4	7	6
Capital	454	442	493	484	491	524	540	575	609	657
Hudson Valley	208	235	269	272	281	298	304	317	341	370
Millwood	22	6	6	6	6	6	6	6	6	7
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	820	752	908	865	908	922	974	1,051	1,104	1,146
Long Island	290	263	270	274	275	282	295	310	332	351
NYCA Total	**2,180**	**2,125**	**2,445**	**2,423**	**2,535**	**2,639**	**2,752**	**2,909**	**3,084**	**3,248**
NYCA Imports	1,023	920	1,004	922	1,038	1,184	1,208	1,286	1,403	1,467
NYCA Exports	297	278	411	339	476	627	674	664	831	858
NYCA + Imports - Exports	**2,906**	**2,767**	**3,039**	**3,006**	**3,098**	**3,196**	**3,286**	**3,532**	**3,656**	**3,856**
Total IESO	1,269	1,296	1,477	1,439	1,795	2,558	2,732	2,778	3,394	3,676
Total PJM	14,175	13,602	15,501	15,483	16,360	16,899	17,597	18,570	19,208	19,937
Total ISONE	2,485	2,342	2,570	2,597	2,724	2,894	3,085	3,299	3,555	3,832
Total System	**20,109**	**19,365**	**21,993**	**21,942**	**23,415**	**24,990**	**26,166**	**27,556**	**29,241**	**30,692**

Production Cost ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	110	112	113	118	124	133	135	146	142	160
Genesee	61	64	69	65	67	74	70	71	79	76
Central	567	578	604	622	638	663	690	709	731	759
North	9	10	10	8	10	11	11	10	11	13
Mohawk Valley	7	7	8	6	7	7	7	9	9	11
Capital	679	736	748	792	829	888	921	990	1,010	1,121
Hudson Valley	386	402	402	428	464	496	512	547	555	606
Millwood	7	7	7	7	7	7	7	7	8	8
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	1,198	1,231	1,342	1,391	1,438	1,502	1,582	1,656	1,749	1,834
Long Island	365	382	404	417	443	469	487	512	537	571
NYCA Total	**3,388**	**3,529**	**3,706**	**3,853**	**4,025**	**4,251**	**4,423**	**4,658**	**4,830**	**5,158**
NYCA Imports	1,508	1,618	1,689	1,767	1,864	1,963	2,027	2,173	2,264	2,428
NYCA Exports	911	844	872	822	848	857	835	835	839	823
NYCA + Imports - Exports	**3,985**	**4,303**	**4,523**	**4,798**	**5,042**	**5,357**	**5,614**	**5,996**	**6,254**	**6,763**
Total IESO	3,830	3,514	3,452	3,471	3,540	3,577	3,648	3,721	3,764	3,805
Total PJM	20,702	21,113	21,913	22,697	23,127	23,800	24,657	25,163	25,887	26,933
Total ISONE	3,953	4,136	4,335	4,475	4,650	4,837	4,997	5,212	5,386	5,607
Total System	**31,873**	**32,291**	**33,406**	**34,497**	**35,344**	**36,464**	**37,724**	**38,753**	**39,866**	**41,503**

Figure 101: Projected Baseline Case Generation (2021-2040) by Zone (GWh)

Generation (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	18,200	18,882	19,667	19,723	20,129	20,411	20,385	20,484	20,508	20,595
Genesee	5,548	5,235	5,308	5,827	5,483	5,554	6,010	5,592	5,617	6,079
Central	30,659	31,813	34,474	34,488	35,951	34,959	35,929	34,966	36,137	34,964
North	9,469	9,544	9,626	9,704	9,747	9,770	9,778	9,768	9,779	9,779
Mohawk Valley	3,807	4,272	4,632	4,813	4,918	5,002	5,055	5,066	5,154	5,175
Capital	15,097	16,850	17,503	17,864	17,237	17,301	17,059	17,425	17,248	17,815
Hudson Valley	7,795	9,540	9,965	10,296	10,090	10,172	10,038	10,060	10,097	10,549
Millwood	2,638	454	461	471	474	479	484	490	491	494
Dunwoodie	75	83	89	99	104	108	112	117	122	125
NY City	22,596	23,248	25,575	24,666	24,448	23,818	24,017	24,487	24,174	23,948
Long Island	8,149	8,435	8,084	8,264	8,130	7,999	8,053	8,078	8,080	8,225
NYCA Total	**124,032**	**128,356**	**135,384**	**136,214**	**136,710**	**135,574**	**136,918**	**136,532**	**137,407**	**137,747**
Total IESO	154,707	151,934	144,492	150,996	145,892	145,595	146,639	149,180	152,171	154,251
Total PJM	807,913	812,614	823,605	823,484	831,111	838,249	839,805	844,395	846,465	847,978
Total ISONE	104,628	107,241	107,648	108,995	109,644	110,492	111,728	113,707	114,732	117,371
Total HQ *	25,204	25,650	25,619	25,640	25,544	25,520	25,495	25,672	25,566	25,543
Total System	**1,216,484**	**1,225,795**	**1,236,746**	**1,245,330**	**1,248,901**	**1,255,432**	**1,260,585**	**1,269,486**	**1,276,341**	**1,282,891**

Generation (GWh)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	20,634	20,613	20,585	20,627	20,686	20,779	20,732	20,824	20,720	20,945
Genesee	5,653	5,685	6,085	5,659	5,680	6,124	5,681	5,686	6,125	5,714
Central	36,388	35,219	36,275	35,353	36,182	35,348	36,478	35,415	36,512	35,612
North	9,769	9,800	9,802	9,786	9,795	9,806	9,798	9,777	9,811	9,842
Mohawk Valley	5,211	5,262	5,276	5,278	5,314	5,334	5,345	5,373	5,371	5,413
Capital	17,773	18,297	18,002	18,634	18,587	19,275	19,490	20,169	19,953	20,980
Hudson Valley	10,587	10,584	10,294	10,547	10,852	11,190	11,197	11,451	11,320	11,774
Millwood	497	501	503	505	505	509	510	511	511	512
Dunwoodie	129	132	134	136	139	142	144	145	144	146
NY City	24,432	24,152	24,695	25,051	24,790	24,963	25,464	25,745	26,323	26,779
Long Island	8,384	8,373	8,476	8,554	8,744	8,814	8,901	9,000	9,154	9,320
NYCA Total	**139,458**	**138,616**	**140,127**	**140,129**	**141,274**	**142,286**	**143,740**	**144,095**	**145,944**	**147,035**
Total IESO	153,938	154,739	154,764	155,490	155,663	155,780	155,747	155,950	155,988	156,233
Total PJM	847,815	849,118	849,311	849,427	850,240	850,995	851,111	852,202	852,997	853,337
Total ISONE	117,585	117,784	117,887	118,546	118,444	118,926	119,619	120,032	120,303	120,937
Total HQ *	25,532	25,569	25,614	25,593	25,568	25,591	25,517	25,494	25,616	25,645
Total System	**1,284,328**	**1,285,826**	**1,287,703**	**1,289,184**	**1,291,189**	**1,293,578**	**1,295,734**	**1,297,773**	**1,300,848**	**1,303,187**

Figure 102: Projected Baseline Case Generator Payments (2021-2040) by Zone (nominal $M)

Generator Payment ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	490	499	606	609	673	725	754	806	859	901
Genesee	141	134	159	174	180	193	217	217	233	260
Central	729	760	963	976	1,093	1,150	1,232	1,268	1,386	1,409
North	212	222	272	278	303	324	339	359	382	398
Mohawk Valley	88	101	129	136	151	163	171	182	198	208
Capital	525	517	581	566	585	623	646	695	740	793
Hudson Valley	240	272	319	326	342	363	374	395	426	459
Millwood	90	13	15	15	16	18	19	20	21	22
Dunwoodie	3	3	3	3	4	4	4	5	5	6
NY City	754	710	881	831	868	892	941	1,020	1,078	1,118
Long Island	328	294	306	303	309	320	335	358	387	412
NYCA Total	3,601	3,526	4,235	4,218	4,523	4,776	5,032	5,325	5,715	5,985

Generator Payment ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	938	985	1,022	1,059	1,110	1,170	1,204	1,273	1,295	1,392
Genesee	253	266	293	286	296	334	322	339	372	373
Central	1,500	1,542	1,611	1,654	1,722	1,810	1,882	1,950	2,013	2,106
North	411	435	452	466	487	508	522	547	562	599
Mohawk Valley	215	229	238	247	261	272	281	297	303	327
Capital	824	891	911	968	1,012	1,084	1,129	1,214	1,237	1,376
Hudson Valley	479	502	507	541	584	624	645	690	700	770
Millwood	23	24	25	27	28	29	31	32	33	35
Dunwoodie	6	7	7	7	8	8	9	9	10	10
NY City	1,175	1,216	1,306	1,380	1,426	1,495	1,581	1,672	1,763	1,893
Long Island	430	458	487	511	545	576	606	647	681	735
NYCA Total	6,253	6,555	6,860	7,146	7,478	7,910	8,212	8,669	8,969	9,616

Figure 103: Projected Baseline Case Load Payments (2021-2040) by Zone (nominal $M)

Load Payment ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	403	417	522	527	579	629	658	700	748	782
Genesee	265	264	308	309	331	352	364	387	413	430
Central	439	444	514	526	575	622	643	683	728	755
North	125	157	208	216	240	261	277	294	313	326
Mohawk Valley	215	214	251	251	272	290	304	323	345	361
Capital	415	370	406	412	432	457	477	509	545	570
Hudson Valley	309	280	315	302	320	338	354	376	402	421
Millwood	92	85	96	95	100	106	112	119	127	133
Dunwoodie	189	174	197	192	201	212	222	236	253	265
NY City	1,633	1,501	1,672	1,630	1,708	1,799	1,884	2,004	2,158	2,262
Long Island	829	733	771	734	762	790	821	870	945	1,001
NYCA Total	4,915	4,641	5,260	5,194	5,519	5,855	6,117	6,500	6,978	7,307

Load Payment ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	815	859	894	931	978	1,033	1,072	1,135	1,170	1,255
Genesee	447	472	491	512	538	566	588	623	643	692
Central	779	815	847	875	915	961	1,001	1,056	1,094	1,174
North	338	357	370	384	401	420	433	455	467	498
Mohawk Valley	373	393	411	429	450	471	487	514	531	569
Capital	596	630	665	696	728	765	797	841	871	932
Hudson Valley	438	462	485	508	535	562	585	620	645	694
Millwood	138	146	153	160	169	178	186	197	205	221
Dunwoodie	277	293	308	324	342	360	379	402	419	452
NY City	2,364	2,505	2,634	2,769	2,930	3,088	3,249	3,446	3,595	3,902
Long Island	1,062	1,127	1,199	1,266	1,356	1,420	1,502	1,603	1,688	1,817
NYCA Total	7,628	8,060	8,457	8,854	9,341	9,823	10,277	10,892	11,328	12,203

Figure 104: Projected Baseline Case Loss Payments (2021-2040) by Zone (nominal $M)

Loss Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	13	15	19	14	18	18	18	18	18	17
Genesee	7	9	11	9	11	12	11	12	12	12
Central	13	13	16	15	16	17	17	18	19	19
North	-4	-3	-3	-3	-2	-2	-2	-3	-3	-3
Mohawk Valley	9	9	11	9	10	10	11	11	12	13
Capital	21	19	23	19	21	21	23	24	27	28
Hudson Valley	25	24	28	24	26	27	28	30	33	35
Millwood	8	8	9	8	9	9	10	10	12	12
Dunwoodie	16	16	19	17	18	18	20	21	23	24
NY City	151	146	168	156	159	164	175	185	206	217
Long Island	64	60	70	64	67	69	73	77	87	91
NYCA Total	322	317	372	333	351	364	384	404	445	464

Loss Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	19	17	17	18	18	18	20	20	22	23
Genesee	13	13	12	14	14	14	16	16	16	19
Central	20	21	21	22	23	24	25	28	28	31
North	-3	-4	-4	-4	-4	-4	-4	-5	-5	-6
Mohawk Valley	13	14	15	15	16	17	18	19	20	21
Capital	29	31	33	34	36	38	40	41	44	46
Hudson Valley	36	39	41	43	46	48	51	54	57	61
Millwood	13	14	15	15	16	17	18	19	20	21
Dunwoodie	25	27	29	30	32	34	36	38	41	43
NY City	228	244	262	272	294	311	329	349	370	396
Long Island	97	104	113	118	128	136	144	153	162	173
NYCA Total	492	519	555	577	620	652	692	732	775	830

Figure 105: Projected Baseline Case SO_2 Emissions Costs (2021-2040) by Zone (nominal $M)

SO2 Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SO_2 Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 106: Projected Baseline Case SO_2 Emissions (2021-2040) by Zone (Tons)

SO2 Emissions (Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	188	188	189	190	190	191	191	192	191	191
Genesee	0	0	0	0	1	1	1	1	1	1
Central	10	14	16	17	18	18	17	18	18	18
North	0	0	0	0	0	0	0	0	0	0
Mohawk Valley	0	0	0	0	0	0	0	0	0	0
Capital	57	59	60	61	60	60	59	60	59	60
Hudson Valley	17	18	19	20	19	19	19	19	19	20
Millwood	106	106	106	106	106	106	106	106	106	106
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	57	59	64	62	61	59	60	61	60	59
Long Island	98	98	92	93	92	91	91	91	91	91
NYCA Total	532	544	548	550	547	546	544	548	545	548

SO_2 Emissions (Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	191	192	191	191	191	192	191	192	191	192
Genesee	1	1	1	1	1	1	1	1	1	1
Central	18	18	18	18	17	18	18	19	18	19
North	0	0	0	0	0	0	0	0	0	0
Mohawk Valley	0	0	0	0	0	0	0	0	0	0
Capital	60	61	60	62	61	63	63	65	64	66
Hudson Valley	20	20	19	19	20	21	21	21	21	23
Millwood	106	106	106	106	106	106	106	106	106	106
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	61	59	62	62	61	62	63	64	65	66
Long Island	92	92	92	92	92	93	93	95	99	97
NYCA Total	549	550	549	551	551	556	557	562	566	570

Figure 107: Projected Baseline Case CO_2 Emissions Costs (2021-2040) by Zone (nominal $M)

CO2 Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	3.0	5.0	7.4	7.9	10.7	13.2	13.8	15.1	16.2	18.0
Genesee	0.5	0.8	0.9	1.0	1.5	1.9	2.0	2.0	2.3	2.6
Central	16.9	26.4	31.3	37.5	41.3	46.0	47.3	52.3	55.9	61.1
North	0.1	0.1	0.3	0.8	1.1	1.2	1.3	1.1	1.4	1.5
Mohawk Valley	0.1	0.1	0.2	0.3	0.5	0.7	0.7	0.5	0.9	0.8
Capital	48.9	58.0	64.3	70.7	72.9	78.9	83.3	91.5	97.2	108.8
Hudson Valley	26.6	35.3	39.0	43.2	45.2	48.8	51.4	55.4	59.5	67.3
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	98.7	108.4	127.9	132.9	143.2	148.5	161.8	178.1	190.0	201.7
Long Island	30.0	33.4	33.5	37.1	38.5	40.3	43.4	46.6	49.9	54.8
NYCA Total	224.8	267.7	304.8	331.4	354.8	379.4	405.0	442.5	473.2	516.5

CO_2 Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	19.9	21.1	21.9	24.0	26.1	29.3	30.9	34.8	35.4	41.7
Genesee	2.7	3.0	2.9	3.1	3.4	3.5	3.8	4.1	4.4	4.8
Central	66.3	71.8	75.2	84.4	86.4	97.0	103.4	114.2	119.5	134.3
North	1.5	1.8	1.7	1.5	2.0	2.3	2.4	2.1	2.6	3.1
Mohawk Valley	0.9	1.0	1.1	0.8	1.0	1.1	1.2	1.5	1.7	2.1
Capital	116.5	129.4	135.9	151.9	162.5	182.5	198.5	221.8	235.1	268.1
Hudson Valley	72.9	78.3	81.6	90.0	99.8	111.0	120.2	132.4	140.5	158.7
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	222.4	234.7	262.1	283.5	302.9	329.1	361.0	391.3	431.3	469.3
Long Island	60.4	64.2	70.3	76.3	84.7	92.1	100.4	109.4	120.7	132.9
NYCA Total	563.6	605.3	652.7	715.5	768.9	847.9	921.6	1,011.6	1,091.0	1,214.8

Figure 108: Projected Baseline Case CO_2 Emissions (2021-2040) by Zone (1,000 Tons)

CO2 Emissions (1000 Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	331	514	719	705	892	1,029	993	1,006	1,002	1,035
Genesee	51	80	80	86	118	141	141	129	139	146
Central	1,900	2,792	3,087	3,443	3,521	3,640	3,475	3,563	3,531	3,582
North	8	11	27	66	85	90	87	69	81	79
Mohawk Valley	8	11	13	27	42	49	45	28	50	42
Capital	5,444	5,998	6,225	6,363	6,073	6,082	5,955	6,075	6,001	6,236
Hudson Valley	2,986	3,680	3,812	3,908	3,797	3,790	3,715	3,712	3,709	3,886
Millwood	0	0	0	0	0	0	0	0	0	0
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	11,395	11,627	12,745	12,297	12,175	11,703	11,832	12,075	11,944	11,771
Long Island	3,449	3,573	3,319	3,409	3,281	3,180	3,189	3,174	3,158	3,219
NYCA Total	25,571	28,286	30,027	30,302	29,986	29,704	29,432	29,832	29,615	29,996

CO_2 Emissions (1000 Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	1,064	1,044	1,004	1,022	1,035	1,079	1,057	1,107	1,045	1,146
Genesee	141	144	129	126	130	126	126	126	127	128
Central	3,606	3,626	3,525	3,669	3,483	3,635	3,594	3,687	3,580	3,735
North	75	81	73	60	74	78	76	61	70	79
Mohawk Valley	44	45	47	33	39	38	39	45	45	55
Capital	6,185	6,385	6,219	6,468	6,423	6,711	6,781	7,061	6,949	7,367
Hudson Valley	3,898	3,887	3,756	3,852	3,968	4,100	4,116	4,213	4,158	4,353
Millwood	0	0	0	0	0	0	0	0	0	0
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	12,053	11,799	12,211	12,270	12,176	12,290	12,542	12,634	12,943	13,119
Long Island	3,290	3,244	3,302	3,327	3,427	3,457	3,500	3,541	3,629	3,707
NYCA Total	30,357	30,255	30,266	30,828	30,753	31,513	31,830	32,475	32,545	33,688

Figure 109: Projected Baseline Case NO_X Emissions Costs (2021-2040) by Zone (nominal $M)

NOX Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.6	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	2.4	0.9	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Long Island	1.3	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	5.4	2.1	0.8	0.3	0.2	0.1	0.1	0.1	0.1	0.1

NOX Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Figure 110: Projected Baseline Case NO_X Emissions (2021-2040) by Zone (Tons)

NOX Emissions (Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	1,567	1,853	2,118	2,101	2,327	2,452	2,426	2,459	2,466	2,494
Genesee	193	202	205	208	218	228	228	220	228	230
Central	495	614	657	718	750	782	754	750	761	773
North	43	52	72	94	129	136	138	121	119	110
Mohawk Valley	42	47	49	56	67	69	69	57	70	65
Capital	745	835	812	845	804	806	777	782	775	794
Hudson Valley	404	530	527	504	514	464	459	473	465	468
Millwood	994	994	994	997	994	994	994	997	994	994
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	2,590	2,626	2,981	2,864	2,582	2,324	2,376	2,447	2,426	2,374
Long Island	2,721	2,741	2,602	2,643	2,594	2,535	2,539	2,550	2,544	2,558
NYCA Total	9,795	10,496	11,017	11,029	10,979	10,789	10,760	10,857	10,847	10,861

NOX Emissions (Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	2,502	2,493	2,462	2,477	2,504	2,541	2,519	2,573	2,526	2,635
Genesee	228	233	225	220	223	223	222	221	221	222
Central	774	782	745	762	751	766	765	779	758	793
North	124	129	129	116	115	115	116	109	125	114
Mohawk Valley	69	69	66	59	63	64	66	66	65	72
Capital	790	817	794	816	813	851	842	896	880	922
Hudson Valley	493	488	477	486	487	480	510	515	524	570
Millwood	994	997	994	994	994	997	994	994	994	993
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	2,509	2,370	2,596	2,563	2,602	2,678	2,763	2,818	2,904	3,059
Long Island	2,601	2,567	2,596	2,623	2,669	2,685	2,703	2,734	2,779	2,810
NYCA Total	11,084	10,946	11,086	11,117	11,221	11,400	11,500	11,706	11,776	12,189

Figure 111: Projected Baseline Case Congestion Rents (2021-2040) (nominal $M)

Congestion Rent ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYCA Total	462	350	290	245	284	370	391	389	503	527

Congestion Rent ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NYCA Total	579	527	566	547	615	571	629	633	674	712

Figure 112: Projected Baseline Case LBMP (2021-2040) by Zone ($/MWh)

LBMP ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	27.20	26.53	30.94	30.70	33.41	35.97	37.39	39.64	42.30	44.18
Genesee	26.29	26.37	30.81	30.73	33.39	35.85	37.23	39.54	42.12	43.91
Central	28.01	28.05	31.77	31.91	34.77	37.59	38.94	41.30	43.99	45.76
North	22.51	23.60	28.64	28.96	31.35	33.38	34.82	36.90	39.25	40.91
Mohawk Valley	26.58	26.43	30.86	30.81	33.16	35.38	36.87	39.03	41.53	43.42
Capital	33.75	29.88	32.74	31.99	33.85	35.95	37.52	39.72	42.26	44.02
Hudson Valley	32.06	29.50	33.34	32.31	34.33	36.32	37.95	40.15	42.80	44.57
Millwood	32.39	29.82	33.66	32.80	34.80	36.80	38.46	40.71	43.43	45.21
Dunwoodie	32.22	29.72	33.58	32.78	34.76	36.73	38.39	40.63	43.35	45.12
NY City	32.53	30.06	33.84	33.06	34.92	36.95	38.63	40.81	43.56	45.39
Long Island	37.15	33.39	36.19	34.98	36.98	38.90	40.62	42.68	45.73	47.77
Average LBMP ($/MWh)	30.06	28.49	32.40	31.91	34.16	36.35	37.89	40.10	42.76	44.57

LBMP ($/MWh)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	45.97	48.17	49.85	51.66	53.83	56.50	58.22	61.27	62.64	66.54
Genesee	45.66	47.98	49.58	51.46	53.68	56.18	57.96	61.00	62.33	66.35
Central	47.44	49.67	51.54	53.27	55.45	58.01	60.03	62.92	64.54	68.59
North	42.32	44.65	46.32	48.01	49.99	52.18	53.76	56.40	57.77	61.35
Mohawk Valley	44.81	47.09	48.97	50.80	52.91	55.19	56.79	59.61	61.05	64.81
Capital	45.67	47.95	50.02	51.95	53.86	56.18	58.01	60.68	62.15	65.67
Hudson Valley	46.28	48.56	50.54	52.52	54.70	56.91	58.68	61.41	62.95	66.55
Millwood	46.96	49.28	51.29	53.31	55.56	57.78	59.77	62.55	64.14	67.92
Dunwoodie	46.88	49.20	51.20	53.22	55.48	57.68	59.69	62.45	64.03	67.83
NY City	47.18	49.55	51.55	53.53	55.84	58.11	60.17	62.90	64.47	68.54
Long Island	50.08	52.38	54.94	57.06	60.27	62.08	64.55	67.78	70.10	74.17
Average LBMP ($/MWh)	46.30	48.59	50.53	52.44	54.69	56.98	58.87	61.72	63.29	67.12

H.2. Contract Case Results

Figure 113: Projected Contract Case Results 2021-2040 (nominal $M)

Case Summary	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYCA-Wide Production Cost ($M)	2,904	2,743	2,861	2,404	2,464	2,242	2,294	2,479	2,532	2,672
NYCA Demand Congestion ($M)	804	436	316	253	208	177	193	178	213	192
Load LBMP Payment ($M)	4,906	4,591	5,128	4,779	5,055	5,165	5,382	5,753	6,113	6,450
Generator LBMP Payment ($M)	3,601	3,519	4,177	4,093	4,360	4,484	4,713	5,012	5,316	5,601
Load Payment Losses ($M)	322	314	360	296	312	299	316	335	363	383
SO2 Costs ($M)	0	0	0	0	0	0	0	0	0	0
SO2 Emission (Short Tons)	532	544	541	529	526	515	514	517	514	516
CO2 Costs ($M)	225	267	291	286	306	304	325	352	378	412
CO2 Emission (Short Tons)	25,577	28,248	28,703	26,096	25,791	23,622	23,434	23,570	23,450	23,715
NOX Costs ($M)	5.43	2.06	0.69	0.26	0.13	0.06	0.06	0.06	0.06	0.06
NOX Emission (Short Tons)	9,787	10,536	10,524	9,643	9,520	9,117	9,141	9,117	9,165	9,103
NYCA Avg. LBMP ($/MWh)	30.02	28.19	31.56	29.46	31.37	32.28	33.54	35.72	37.76	39.61

Case Summary	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NYCA-Wide Production Cost ($M)	2,762	3,026	3,198	3,429	3,607	3,859	4,073	4,395	4,601	5,003
NYCA Demand Congestion ($M)	225	230	239	271	289	282	304	297	309	334
Load LBMP Payment ($M)	6,710	7,107	7,516	7,863	8,241	8,696	9,127	9,649	10,065	10,793
Generator LBMP Payment ($M)	5,835	6,141	6,508	6,746	7,019	7,411	7,768	8,164	8,493	9,048
Load Payment Losses ($M)	402	425	461	479	511	541	577	611	652	697
SO2 Costs ($M)	0	0	0	0	0	0	0	0	0	0
SO2 Emission (Short Tons)	518	519	518	521	520	524	525	529	530	535
CO2 Costs ($M)	450	486	524	575	618	680	744	823	888	992
CO2 Emission (Short Tons)	24,020	24,061	24,122	24,562	24,524	25,054	25,509	26,195	26,274	27,261
NOX Costs ($M)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08
NOX Emission (Short Tons)	9,379	9,194	9,340	9,268	9,321	9,472	9,624	9,758	9,801	10,044
NYCA Avg. LBMP ($/MWh)	40.98	43.10	45.15	46.85	48.54	50.74	52.67	55.09	56.65	59.81

Figure 114: Projected Contract Case Production Costs (2021-2040) by Zone (nominal $M)

Production Cost ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	30	37	43	34	45	56	56	55	61	65
Genesee	43	42	42	45	44	46	51	48	51	56
Central	306	335	366	359	387	393	415	422	446	461
North	1	1	2	3	4	5	6	3	5	4
Mohawk Valley	1	1	1	1	2	2	2	1	3	2
Capital	456	441	474	411	418	411	421	440	474	502
Hudson Valley	208	235	255	222	232	216	222	229	252	262
Millwood	22	6	6	6	6	6	6	6	6	7
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	821	764	892	799	835	777	824	891	927	976
Long Island	291	265	271	241	243	230	241	251	268	283
NYCA Total	**2,180**	**2,127**	**2,351**	**2,121**	**2,216**	**2,144**	**2,243**	**2,347**	**2,493**	**2,617**
NYCA Imports	1,023	904	950	688	788	835	840	911	1,000	1,049
NYCA Exports	299	288	440	405	540	737	790	779	960	994
NYCA + Imports - Exports	**2,904**	**2,743**	**2,861**	**2,404**	**2,464**	**2,242**	**2,294**	**2,479**	**2,532**	**2,672**
Total IESO	1,269	1,296	1,477	1,446	1,793	2,548	2,727	2,776	3,380	3,657
Total PJM	14,177	13,586	15,437	15,260	16,121	16,575	17,264	18,199	18,836	19,554
Total ISONE	2,481	2,331	2,550	2,515	2,633	2,745	2,929	3,146	3,386	3,664
Total System	**20,107**	**19,339**	**21,816**	**21,342**	**22,762**	**24,012**	**25,163**	**26,468**	**28,095**	**29,492**

Production Cost ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	72	72	70	70	74	79	85	91	87	99
Genesee	54	56	60	57	59	65	62	63	69	66
Central	471	491	509	523	540	566	590	611	631	665
North	7	7	4	4	4	6	4	4	5	6
Mohawk Valley	3	3	2	2	2	3	2	2	2	4
Capital	529	570	577	627	647	699	731	794	803	889
Hudson Valley	282	299	302	319	348	363	377	416	423	480
Millwood	7	7	7	7	7	7	7	7	8	8
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	1,017	1,046	1,150	1,182	1,229	1,273	1,354	1,415	1,504	1,556
Long Island	294	308	326	334	353	374	392	407	425	450
NYCA Total	**2,736**	**2,858**	**3,006**	**3,125**	**3,265**	**3,435**	**3,603**	**3,812**	**3,957**	**4,223**
NYCA Imports	1,077	1,152	1,196	1,265	1,332	1,416	1,469	1,584	1,641	1,769
NYCA Exports	1,050	984	1,005	961	990	991	998	1,001	997	989
NYCA + Imports - Exports	**2,762**	**3,026**	**3,198**	**3,429**	**3,607**	**3,859**	**4,073**	**4,395**	**4,601**	**5,003**
Total IESO	3,804	3,492	3,439	3,460	3,526	3,552	3,623	3,695	3,735	3,781
Total PJM	20,312	20,730	21,458	22,237	22,642	23,349	24,181	24,660	25,344	26,343
Total ISONE	3,770	3,936	4,136	4,265	4,424	4,617	4,746	4,937	5,120	5,305
Total System	**30,622**	**31,017**	**32,039**	**33,086**	**33,857**	**34,953**	**36,152**	**37,104**	**38,156**	**39,653**

Figure 115: Projected Contract Case Generation (2021-2040) by Zone (GWh)

Generation (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	18,202	18,854	20,039	20,683	20,965	21,162	21,145	21,122	21,199	21,249
Genesee	5,555	5,647	6,519	8,804	8,411	8,463	8,914	8,502	8,525	8,970
Central	30,602	31,685	34,484	34,696	36,083	34,915	36,035	34,980	35,995	35,028
North	9,465	9,539	9,634	9,993	10,021	10,047	10,063	10,045	10,055	10,044
Mohawk Valley	3,813	4,492	5,795	6,728	6,845	6,928	6,987	7,023	7,079	7,103
Capital	15,145	17,015	17,764	16,597	16,272	15,250	14,947	15,085	15,193	15,498
Hudson Valley	7,804	9,641	9,864	9,069	8,879	8,108	8,038	8,075	8,207	8,328
Millwood	2,638	454	461	471	474	479	484	490	491	494
Dunwoodie	75	83	89	99	104	108	112	117	122	125
NY City	22,667	23,304	25,004	25,955	25,608	28,336	28,508	28,995	28,513	28,625
Long Island	8,159	8,381	8,078	11,646	11,550	13,542	13,567	13,565	13,559	13,698
NYCA Total	**124,125**	**129,095**	**137,730**	**144,740**	**145,213**	**147,340**	**148,798**	**147,999**	**148,938**	**149,162**
Total IESO	154,692	151,957	144,433	151,089	145,803	145,405	146,540	149,128	151,998	154,080
Total PJM	807,901	812,128	822,017	817,181	825,260	830,766	831,952	836,705	838,935	840,429
Total ISONE	104,560	106,989	107,105	106,808	107,286	106,735	107,974	110,201	111,064	113,856
Total HQ *	25,204	25,650	25,614	25,640	25,544	25,517	25,490	25,671	25,565	25,545
Total System	**1,216,482**	**1,225,819**	**1,236,899**	**1,245,458**	**1,249,106**	**1,255,762**	**1,260,754**	**1,269,705**	**1,276,501**	**1,283,071**

Generation (GWh)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	21,353	21,334	21,272	21,273	21,323	21,367	21,436	21,493	21,438	21,574
Genesee	8,559	8,595	8,991	8,570	8,602	9,036	8,603	8,621	9,046	8,643
Central	35,893	35,106	36,075	35,121	36,095	35,348	36,504	35,568	36,668	36,013
North	10,079	10,092	10,071	10,075	10,063	10,079	10,051	10,063	10,087	10,116
Mohawk Valley	7,149	7,200	7,190	7,220	7,252	7,277	7,279	7,302	7,301	7,341
Capital	15,603	16,006	15,729	16,469	16,305	16,949	17,189	17,897	17,667	18,546
Hudson Valley	8,504	8,653	8,526	8,658	8,929	9,061	9,083	9,545	9,433	10,061
Millwood	497	501	503	505	505	509	510	511	511	512
Dunwoodie	129	132	134	136	139	142	144	145	144	146
NY City	29,031	28,795	29,379	29,572	29,435	29,506	30,121	30,279	30,865	31,048
Long Island	13,859	13,875	13,926	13,989	14,184	14,238	14,324	14,354	14,506	14,647
NYCA Total	**150,657**	**150,288**	**151,795**	**151,588**	**152,831**	**153,514**	**155,244**	**155,775**	**157,666**	**158,644**
Total IESO	153,674	154,504	154,588	155,339	155,507	155,518	155,462	155,649	155,656	155,893
Total PJM	840,521	841,445	841,293	841,773	842,570	843,509	843,779	845,034	845,564	846,268
Total ISONE	113,993	114,031	114,300	114,836	114,648	115,334	115,640	115,852	116,330	116,648
Total HQ *	25,527	25,568	25,614	25,594	25,570	25,595	25,519	25,498	25,619	25,651
Total System	**1,284,372**	**1,285,835**	**1,287,589**	**1,289,130**	**1,291,127**	**1,293,470**	**1,295,645**	**1,297,808**	**1,300,835**	**1,303,104**

Figure 116: Projected Contract Case Generator Payments (2021-2040) by Zone (nominal $M)

Generator Payment ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	489	491	585	561	612	635	657	707	743	789
Genesee	142	143	184	223	228	234	257	265	278	310
Central	728	753	939	906	1,010	1,028	1,101	1,146	1,231	1,265
North	213	220	262	259	281	292	304	324	341	358
Mohawk Valley	89	105	150	153	166	174	181	195	206	218
Capital	526	516	570	493	510	490	504	543	579	618
Hudson Valley	240	272	308	269	282	263	272	288	313	329
Millwood	90	13	15	15	16	16	17	18	19	20
Dunwoodie	2	2	3	3	3	4	4	4	5	5
NY City	755	709	857	838	872	963	1,015	1,094	1,144	1,203
Long Island	327	295	305	373	382	384	401	428	457	486
NYCA Total	3,601	3,519	4,177	4,093	4,360	4,484	4,713	5,012	5,316	5,601

Generator Payment ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	818	865	906	938	976	1,027	1,070	1,128	1,157	1,235
Genesee	305	324	354	353	362	403	399	421	453	462
Central	1,327	1,375	1,465	1,487	1,547	1,623	1,722	1,767	1,845	1,936
North	370	391	409	422	436	458	474	497	512	544
Mohawk Valley	225	240	251	262	271	285	297	313	322	345
Capital	644	695	720	777	800	863	904	980	996	1,100
Hudson Valley	349	372	383	405	438	458	476	521	534	599
Millwood	21	22	23	25	25	27	28	30	30	32
Dunwoodie	6	6	6	7	7	8	8	8	9	9
NY City	1,263	1,312	1,416	1,473	1,530	1,598	1,692	1,770	1,871	1,970
Long Island	507	538	574	599	626	663	698	729	763	816
NYCA Total	5,835	6,141	6,508	6,746	7,019	7,411	7,768	8,164	8,493	9,048

Figure 117: Projected Contract Case Load Payments (2021-2040) by Zone (nominal $M)

Load Payment ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	403	411	496	466	508	535	558	599	631	669
Genesee	265	260	291	270	288	296	304	327	343	363
Central	439	435	484	460	501	525	541	579	608	640
North	126	156	200	196	217	229	242	259	273	287
Mohawk Valley	215	211	236	215	230	238	247	265	278	294
Capital	414	366	395	380	398	411	428	459	489	515
Hudson Valley	308	279	311	282	299	307	320	341	361	380
Millwood	92	85	95	90	95	98	103	109	116	122
Dunwoodie	189	173	195	184	192	196	205	218	232	244
NY City	1,629	1,488	1,657	1,564	1,632	1,659	1,734	1,849	1,975	2,079
Long Island	827	726	768	671	695	673	700	747	806	856
NYCA Total	4,906	4,591	5,128	4,779	5,055	5,165	5,382	5,753	6,113	6,450

Load Payment ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	693	734	771	804	839	887	925	979	1,013	1,083
Genesee	376	398	418	436	456	481	502	532	551	591
Central	658	689	721	745	774	816	853	900	935	1,000
North	296	312	327	338	352	369	384	404	415	441
Mohawk Valley	304	321	337	352	365	385	402	425	440	471
Capital	535	567	603	631	655	690	720	758	789	837
Hudson Valley	394	416	440	461	482	507	529	560	586	627
Millwood	127	134	142	148	156	164	172	182	190	203
Dunwoodie	255	270	286	300	316	333	351	372	389	416
NY City	2,167	2,300	2,439	2,558	2,698	2,847	3,000	3,178	3,325	3,578
Long Island	906	965	1,031	1,090	1,149	1,217	1,287	1,361	1,432	1,546
NYCA Total	6,710	7,107	7,516	7,863	8,241	8,696	9,127	9,649	10,065	10,793

Figure 118: Projected Contract Case Loss Payments (2021-2040) by Zone (nominal $M)

Loss Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	13	15	17	10	13	13	13	12	12	11
Genesee	7	9	9	5	7	7	7	7	7	7
Central	13	13	14	11	12	12	12	13	13	14
North	-4	-3	-2	-2	-2	-2	-1	-2	-2	-2
Mohawk Valley	9	9	8	5	6	6	6	6	7	7
Capital	21	19	22	18	19	20	21	23	25	26
Hudson Valley	25	24	28	23	25	24	25	27	29	31
Millwood	8	8	9	8	8	8	9	9	10	11
Dunwoodie	16	16	18	16	17	16	17	18	20	21
NY City	151	146	167	147	150	142	151	162	176	187
Long Island	64	60	70	54	57	52	55	59	65	70
NYCA Total	322	314	360	296	312	299	316	335	363	383

Loss Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	13	11	11	11	12	11	13	12	13	14
Genesee	8	7	7	8	8	8	9	9	9	11
Central	14	14	15	16	16	17	18	19	20	22
North	-2	-2	-2	-3	-3	-3	-3	-3	-3	-4
Mohawk Valley	7	8	8	9	9	9	10	11	11	12
Capital	27	28	31	32	34	35	37	39	41	43
Hudson Valley	32	34	37	38	41	43	46	48	52	55
Millwood	11	12	13	13	14	15	16	17	18	19
Dunwoodie	22	24	26	26	28	30	32	34	36	39
NY City	195	209	227	236	253	270	287	305	325	348
Long Island	74	79	88	91	99	105	112	120	129	138
NYCA Total	402	425	461	479	511	541	577	611	652	697

Figure 119: Projected Contract Case SO_2 Emissions Costs (2019-2028) by Zone (nominal $M)

SO2 Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SO_2 Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure 120: Projected Contract Case SO_2 Emissions (2021-2040) by Zone (Tons)

SO2 Emissions (Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	188	188	189	188	188	189	189	189	189	189
Genesee	0	0	0	0	0	0	0	0	0	0
Central	9	13	13	13	14	14	13	13	13	14
North	0	0	0	0	0	0	0	0	0	0
Mohawk Valley	0	0	0	0	0	0	0	0	0	0
Capital	57	59	59	56	55	53	53	53	53	53
Hudson Valley	16	19	19	17	16	14	14	14	14	14
Millwood	106	106	106	106	106	106	106	106	106	106
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	58	59	63	57	57	50	51	52	51	51
Long Island	98	98	92	90	90	88	88	88	88	88
NYCA Total	532	544	541	529	526	515	514	517	514	516

SO_2 Emissions (Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	189	190	189	189	189	189	189	189	189	189
Genesee	0	0	0	0	0	0	0	0	0	0
Central	13	13	13	13	13	14	14	14	14	15
North	0	0	0	0	0	0	0	0	0	0
Mohawk Valley	0	0	0	0	0	0	0	0	0	0
Capital	54	54	54	55	55	56	56	58	57	59
Hudson Valley	15	15	15	15	15	16	16	17	16	18
Millwood	106	106	106	106	106	106	106	106	106	106
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	52	51	53	53	53	53	54	55	56	56
Long Island	88	88	88	89	89	90	90	89	90	92
NYCA Total	518	519	518	521	520	524	525	529	530	535

Figure 121: Projected Contract Case CO_2 Emissions Costs (2021-2040) by Zone (nominal $M)

CO2 Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	3.0	4.7	5.6	4.4	6.3	8.2	8.5	8.6	9.7	10.7
Genesee	0.4	0.8	0.6	0.5	0.7	1.0	1.0	0.9	1.2	1.2
Central	16.5	25.4	26.8	29.2	31.9	35.0	36.4	39.6	41.6	47.0
North	0.1	0.1	0.2	0.4	0.5	0.7	0.8	0.4	0.7	0.6
Mohawk Valley	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.3	0.2
Capital	49.1	57.8	61.8	59.9	62.8	63.3	66.1	71.2	77.3	85.0
Hudson Valley	26.6	35.4	37.3	35.9	37.7	36.3	38.5	41.1	45.0	49.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	98.9	109.8	125.4	123.3	132.1	126.8	138.6	152.4	161.8	173.6
Long Island	30.1	33.2	33.6	32.6	34.1	32.8	35.4	37.6	40.3	44.2
NYCA Total	224.9	267.3	291.4	286.2	306.3	304.3	325.4	351.9	377.9	411.5

CO_2 Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	12.4	12.8	12.8	13.5	14.8	16.5	18.5	20.7	20.8	24.8
Genesee	1.4	1.5	1.2	1.3	1.7	1.5	1.7	2.0	1.9	2.2
Central	46.9	54.0	55.3	62.6	64.2	74.1	78.6	89.2	92.6	108.3
North	1.1	1.0	0.6	0.6	0.8	1.0	0.7	0.8	1.0	1.3
Mohawk Valley	0.4	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.3	0.6
Capital	92.7	102.7	107.3	122.4	129.4	146.0	159.9	180.1	190.3	216.4
Hudson Valley	54.7	59.9	62.9	68.8	76.3	83.8	91.0	104.0	109.7	127.8
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	191.4	201.6	226.9	243.9	262.2	283.0	313.0	338.7	375.5	404.5
Long Island	48.7	51.8	56.6	61.4	68.1	73.6	80.8	87.2	95.9	105.5
NYCA Total	449.7	485.6	523.8	574.7	617.8	679.7	744.5	823.0	888.0	991.6

Figure 122: Projected Contract Case CO_2 Emissions (2021-2040) by Zone (1000 Tons)

CO2 Emissions (1000 Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	331	484	540	381	511	616	591	553	582	593
Genesee	46	75	54	37	53	68	63	52	65	64
Central	1,853	2,677	2,633	2,646	2,688	2,735	2,630	2,669	2,583	2,710
North	7	9	16	28	41	49	48	25	38	30
Mohawk Valley	9	8	4	5	8	14	13	5	17	8
Capital	5,462	5,988	5,986	5,363	5,211	4,826	4,675	4,690	4,726	4,832
Hudson Valley	2,987	3,696	3,654	3,261	3,163	2,809	2,764	2,757	2,799	2,830
Millwood	0	0	0	0	0	0	0	0	0	0
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	11,420	11,758	12,489	11,390	11,216	9,933	10,074	10,285	10,118	10,083
Long Island	3,462	3,551	3,327	2,985	2,901	2,572	2,577	2,533	2,521	2,565
NYCA Total	25,577	28,248	28,703	26,096	25,791	23,622	23,434	23,570	23,450	23,715

CO_2 Emissions (1000 Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	642	613	570	553	566	584	613	637	595	660
Genesee	67	67	51	50	59	50	54	59	53	56
Central	2,515	2,685	2,544	2,682	2,552	2,738	2,701	2,850	2,744	2,989
North	49	45	26	23	27	33	21	22	26	33
Mohawk Valley	17	13	6	6	9	9	6	7	8	14
Capital	4,871	5,015	4,873	5,162	5,075	5,317	5,406	5,671	5,569	5,897
Hudson Valley	2,912	2,960	2,894	2,939	3,032	3,087	3,106	3,296	3,238	3,503
Millwood	0	0	0	0	0	0	0	0	0	0
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	10,319	10,077	10,529	10,498	10,473	10,501	10,816	10,861	11,185	11,195
Long Island	2,628	2,587	2,628	2,649	2,731	2,734	2,785	2,792	2,856	2,913
NYCA Total	24,020	24,061	24,122	24,562	24,524	25,054	25,509	26,195	26,274	27,261

Figure 123: Projected Contract Case NO_X Emissions Costs (2021-2040) by Zone (nominal $M)

NOX Emissions Costs ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.5	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.6	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	2.5	0.9	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Long Island	1.3	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	5.4	2.1	0.7	0.3	0.1	0.1	0.1	0.1	0.1	0.1

NOX Emissions Costs ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Genesee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mohawk Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hudson Valley	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Millwood	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dunwoodie	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NY City	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Long Island	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYCA Total	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1

Figure 124: Projected Contract Case NO_X Emissions (2021-2040) by Zone (Tons)

NOX Emissions (Tons)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	1,566	1,814	1,914	1,672	1,839	1,939	1,912	1,893	1,934	1,938
Genesee	191	200	195	184	186	189	186	183	186	186
Central	491	601	575	564	580	598	582	575	576	584
North	43	52	57	65	77	107	112	73	88	63
Mohawk Valley	43	44	41	38	37	41	42	37	43	37
Capital	749	825	753	710	688	665	655	646	643	653
Hudson Valley	403	541	494	394	411	351	355	348	337	320
Millwood	995	994	994	997	994	994	994	997	994	994
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	2,578	2,737	2,898	2,533	2,253	1,894	1,963	2,021	2,032	1,981
Long Island	2,728	2,727	2,602	2,486	2,455	2,339	2,340	2,344	2,331	2,346
NYCA Total	9,787	10,536	10,524	9,643	9,520	9,117	9,141	9,117	9,165	9,103

NOX Emissions (Tons)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	1,973	1,949	1,917	1,889	1,910	1,917	1,970	2,007	1,960	2,056
Genesee	188	191	185	184	188	188	188	189	188	191
Central	571	595	559	570	563	585	584	601	584	619
North	106	100	69	68	67	79	69	64	75	78
Mohawk Valley	44	42	37	37	39	41	39	39	39	44
Capital	661	672	661	684	666	686	701	732	720	745
Hudson Valley	377	374	363	377	335	353	386	411	391	429
Millwood	994	997	994	994	994	997	994	994	994	993
Dunwoodie	0	0	0	0	0	0	0	0	0	0
NY City	2,099	1,937	2,188	2,082	2,156	2,211	2,270	2,288	2,396	2,416
Long Island	2,366	2,337	2,366	2,382	2,403	2,416	2,421	2,431	2,453	2,474
NYCA Total	9,379	9,194	9,340	9,268	9,321	9,472	9,624	9,758	9,801	10,044

Figure 125: Projected Contract Case Congestion Rents (2021-2040) by Zone (nominal $M)

Congestion Rent ($M)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NYCA Total	455	334	307	281	326	518	545	532	662	696

Congestion Rent ($M)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
NYCA Total	744	690	693	690	745	720	741	748	766	792

Figure 126: Projected Contract Case LBMP (2021-2040) by Zone ($/MWh)

LBMP ($/MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
West	27.17	26.19	29.52	27.52	29.71	31.09	32.21	34.49	36.33	38.32
Genesee	26.27	25.98	29.31	27.39	29.55	30.78	31.84	34.17	35.90	37.89
Central	27.98	27.51	30.09	28.34	30.75	32.28	33.33	35.63	37.51	39.51
North	22.56	23.40	27.58	26.34	28.46	29.51	30.61	32.70	34.44	36.13
Mohawk Valley	26.58	26.09	29.28	27.04	28.91	29.99	31.03	33.16	34.83	36.70
Capital	33.64	29.61	32.10	30.01	31.72	32.85	34.21	36.42	38.54	40.33
Hudson Valley	31.99	29.33	33.00	30.60	32.43	33.34	34.71	36.84	39.01	40.75
Millwood	32.32	29.63	33.34	31.47	33.21	34.04	35.48	37.66	39.91	41.72
Dunwoodie	32.15	29.54	33.29	31.51	33.23	34.00	35.45	37.62	39.87	41.68
NY City	32.46	29.82	33.58	31.84	33.46	34.14	35.61	37.74	40.03	41.84
Long Island	37.04	33.02	36.07	32.04	33.62	33.03	34.43	36.49	38.99	40.80
Average LBMP ($/MWh)	30.02	28.19	31.56	29.46	31.37	32.28	33.54	35.72	37.76	39.61

LBMP ($/MWh)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
West	39.66	41.72	43.56	45.16	46.75	49.14	50.93	53.47	54.85	58.07
Genesee	39.18	41.35	43.10	44.76	46.40	48.67	50.48	53.04	54.40	57.69
Central	40.76	42.77	44.67	46.17	47.77	50.11	52.08	54.52	56.11	59.30
North	37.25	39.25	41.12	42.52	44.08	46.18	48.00	50.29	51.64	54.61
Mohawk Valley	37.86	39.82	41.67	43.21	44.64	46.82	48.67	51.02	52.43	55.45
Capital	41.65	43.82	46.05	47.84	49.25	51.44	53.26	55.55	57.13	59.97
Hudson Valley	42.18	44.30	46.44	48.24	49.96	52.02	53.84	56.25	57.93	60.96
Millwood	43.20	45.41	47.58	49.43	51.31	53.46	55.48	57.92	59.56	62.74
Dunwoodie	43.15	45.38	47.54	49.39	51.30	53.43	55.47	57.90	59.53	62.71
NY City	43.37	45.58	47.80	49.61	51.53	53.72	55.80	58.24	59.88	63.17
Long Island	42.55	44.68	47.15	49.05	50.97	53.18	55.38	57.79	59.73	63.19
Average LBMP ($/MWh)	40.98	43.10	45.15	46.85	48.54	50.74	52.67	55.09	56.65	59.81

Appendix I: Detailed Baseline and Contract Case Congestion Analysis

This appendix provides detailed analysis of the congestion identified in the baseline and contract cases.

In order to assess and identify the most congested elements of the grid, 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 substation near Utica, New York. In the absence of losses, any location with a locational-based marginal price (LBMP) greater than the Marcy LBMP has positive congestion, and any location with an 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.

I.1. 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.[47]

Historic congestion costs by Zone, expressed as Demand$ Congestion, are presented in Figure 127, indicating that the highest congestion occurred in New York City and Long Island.

Figure 127: Historic Demand$ Congestion by Zone 2016-2020 (nominal $M)[48]

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

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

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 128 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.

Figure 128: 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

I.2. 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 C: Production Cost Assumptions Matrix.

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 historical levels due to the factors cited.

Figure 129 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 129: 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 130.

Figure 130: 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

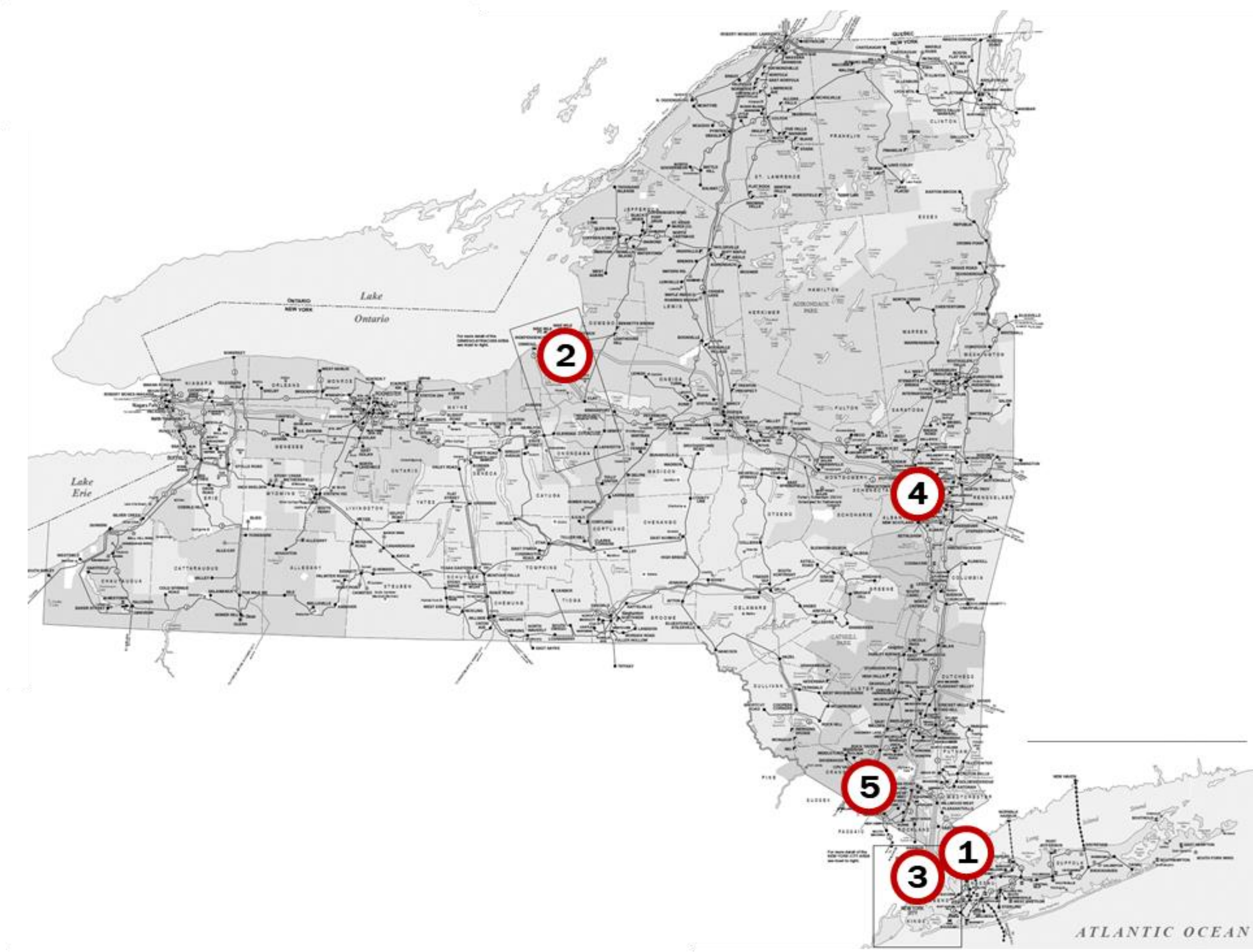
I.3. Baseline Case Congestion Analysis

Prior CARIS cycles examined the top three congested elements in the system and impacts of various solutions to alleviate congestion on those paths. In the System and Resource Outlook, we focus on congestion on lines which are projected to have congestion in the future system. These lines may or may not have been studied in prior cycles.

Five congested paths are selected for congestion analysis in the Baseline Case as shown in Figure 131.

1. Dunwoodie – Long Island 345 kV
2. Volney – Scriba 345 kV
3. Dunwoodie – Motthaven 345 kV
4. New Scotland – Knickerbocker 345 kV
5. Sugarloaf – Ramapo 138 kV

Figure 131: Locations of Constraints on New York State Map

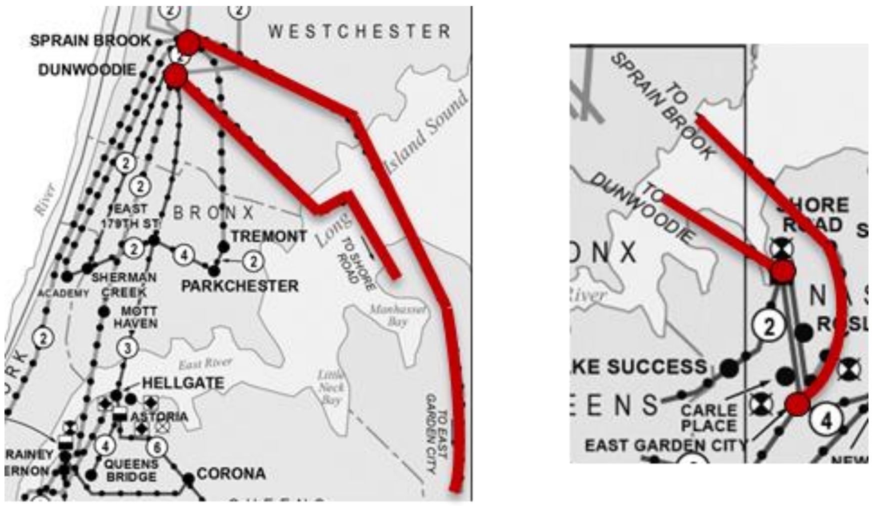


Each constrained path is separately evaluated by 'relaxing' the limits on the line or contingency that is binding in the Baseline Case. Results from the 'relaxed' cases compared to the Baseline Case estimate the impact of relieving congestion on each individual constraint. Individual constrained path congestion and relaxation results are discussed below.

Dunwoodie- Long Island 345 kV

The Dunwoodie-Long Island interface consists for two single circuit lines – Sprainbrook-East Garden City 345 kV (Y49) and Dunwoodie-Shore Road 345 kV (Y50). This interface transfers power from Dunwoodie (Zone I) to Long Island (Zone K). Line parameters for each line is listed below and their location in the NYCA system are shown in Figure 132.

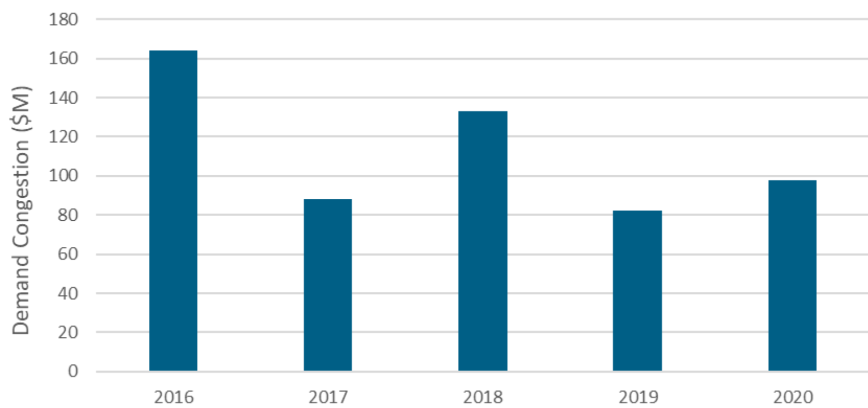
Figure 132: Dunwoodie to Long Island Location and Line Parameters



	Y49	Y50
Type	Single Circuit 345kV	
Normal Op. Rating	637/693 MW	656/741 MW
Contingency Op. Rating	900/940 MW	916/977 MW
Length	~26 Miles	>10 Miles
Owner	NYPA	Con Edison/LIPA

Historically, this path is congested due to transmission outage of one of the lines while the other one is still in service. The demand congestion (nominal $M) for the past five years is presented below in Figure 133.

Figure 133: Dunwoodie to Long Island Demand Congestion (nominal $M)



In the Baseline case, changes in series reactor status causes increased flow on the parallel circuit, thereby increasing congestion on the line. For 2021-2022, the series reactor on Y49 is in service all year round, which causes heavy congestion on Y50. Starting 2023, the series reactor on Y49 is bypassed during summer, which reduces congestion on this path. Congestion is observed on both Y49 and Y50 instead of being concentrated on Y50 as in the first two years.

Figure 134: Projected Baseline Case Demand Congestion and Congested Hours

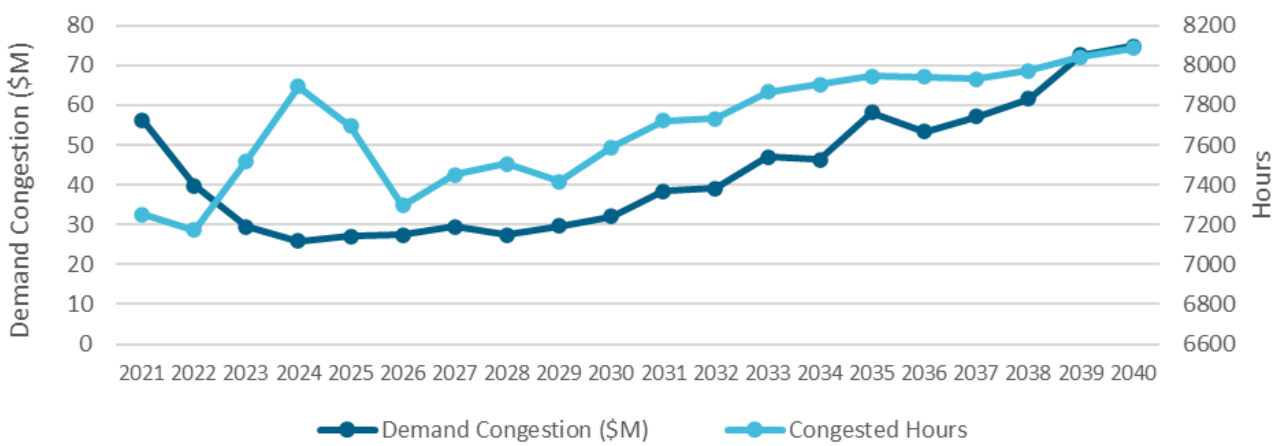


Figure 135 below shows the line utilization on the Dunwoodie to Long Island interface in forms of violin charts. A violin plot is a hybrid of a box plot and a kernel density plot, which shows peaks in the data. It is used to visualize the distribution of numerical data. Unlike a box plot that can only show summary statistics, violin plots depict summary statistics and the density of each variable. Wider sections of the violin plot represent a higher probability that members of the population will take on the given value; the skinnier sections represent a lower probability. Shaded area of the violin plot represents all the points in the population.

Freed energy in GWh is presented below the annual violin plots which shows the increased flow on the line when limits are removed relative to the total Contract Case flows The Freed energy metric is defined as the sum of the hourly delta between the relaxed case compared to the Contract Case flows.

$$\text{Freed Energy} = \sum_{h=1}^{8760}[Max(Relax\ Case\ Flow)_h - Max(Contract\ Case\ Flow)_h]$$

Figure 135: Dunwoodie to Long Island Baseline Case Hourly Line Utilization

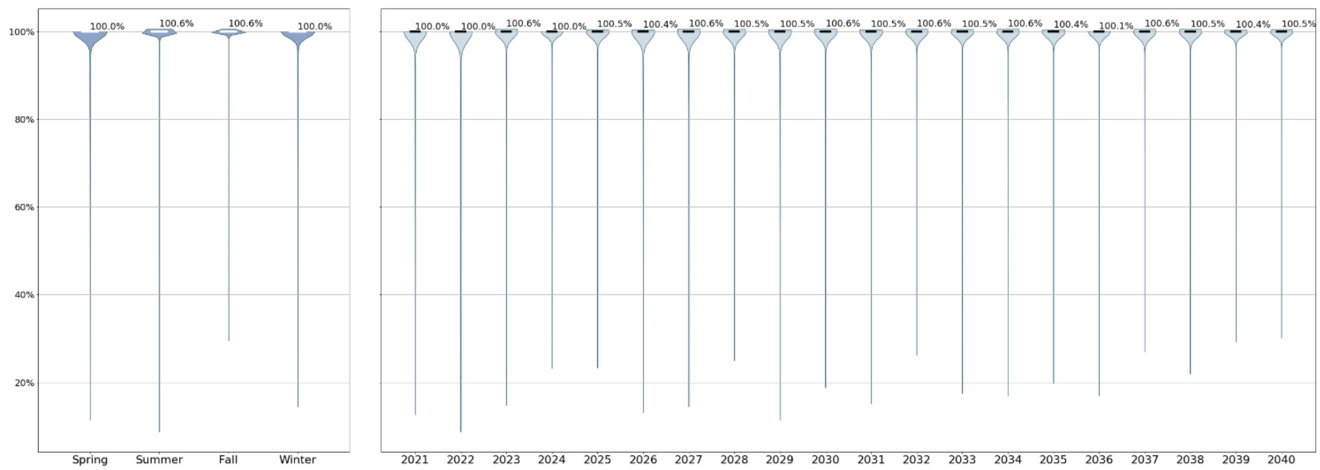


Figure 135 is divided into two parts. The seasonal plot on the left side depicts the line utilization for four seasons[49] using data from all 20 years in the study period. It bulges in the summer and fall seasons show that the line is highly utilized during these seasons and the flow on the line is lower in the winter and spring seasons. The yearly plot on the right shows that the line is highly utilized (flow on the line is near the limit) during most hours of the year. The 'Black' lines in the body of the plots represent the median value of hourly line utilization. Since this median is close to 100% in most years, the line is projected to be operating at or close to its limit in most hours of the year. Price differentials across the zones is the main driver behind high flows across this interface.

A 'relaxed' case was run where the limits on the lines were removed to examine the impact of eliminating any congestion on the interface. The flow duration curve in Figure 136 below shows the delta flows on the interface in the *relaxed* case relative to the flows in the Baseline case. A positive

[49] Seasons included in the analysis are Spring: February-April, Summer: May-July, Fall: August-October, and Winter: November-January. For comparison, the NYISO Summer Capability Period is May – October and the Winter Capability Period is from November – April.

value means that the flow increases in the same hour when the limits are removed in the relaxed case. Some sample years are presented as colored lines and the grey shaded area represents the entire range of values for the whole twenty-year period.

Figure 136: Dunwoodie-Long Island Flow Duration Curve (Relax-Baseline)

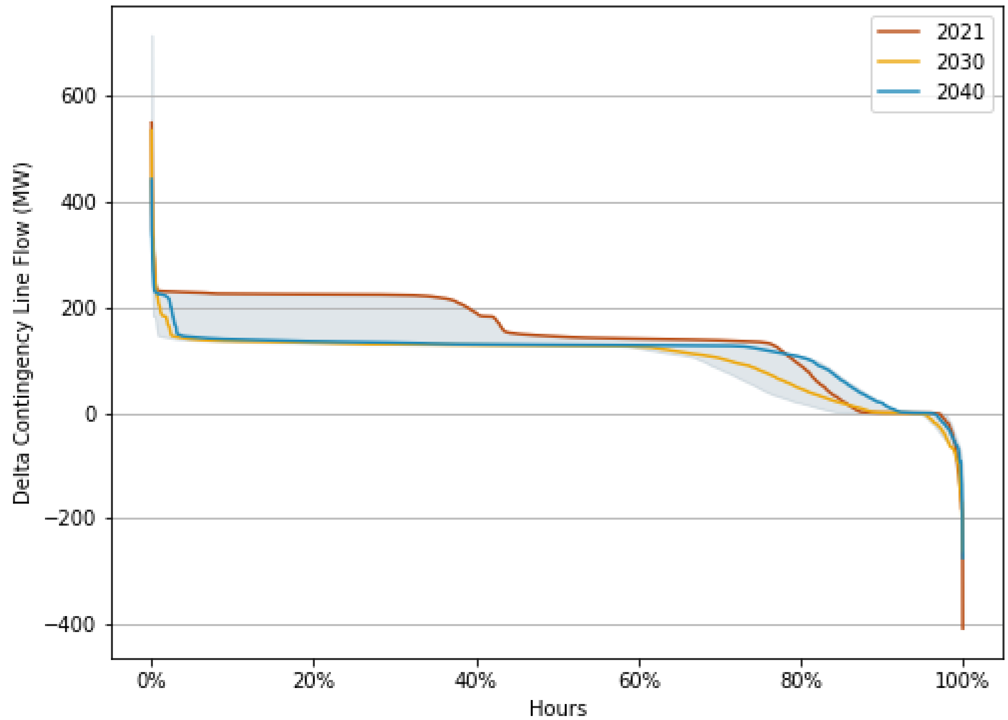


Figure 137: Dunwoodie-Long Island Average Delta Flow (MW)

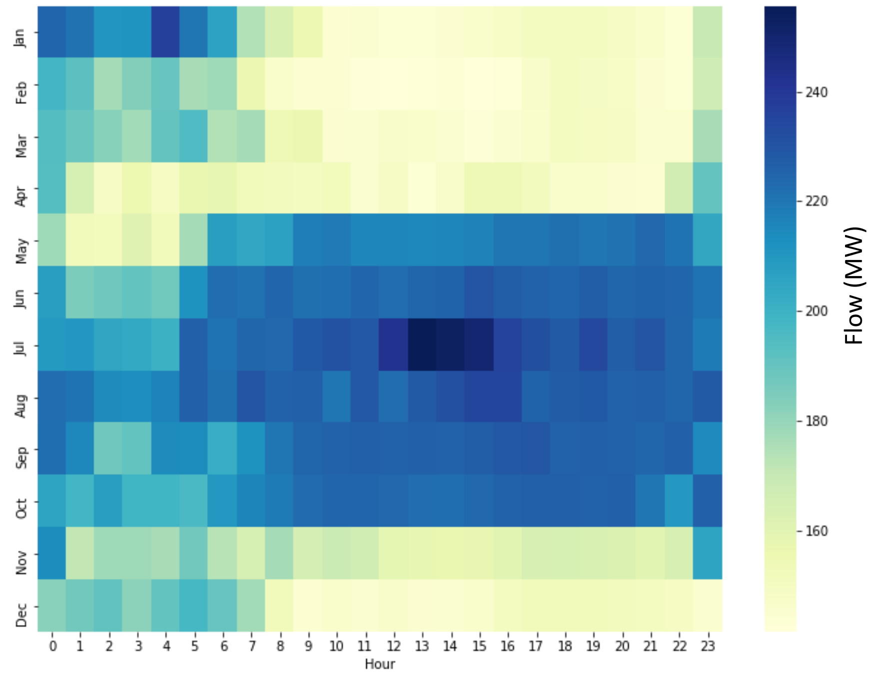
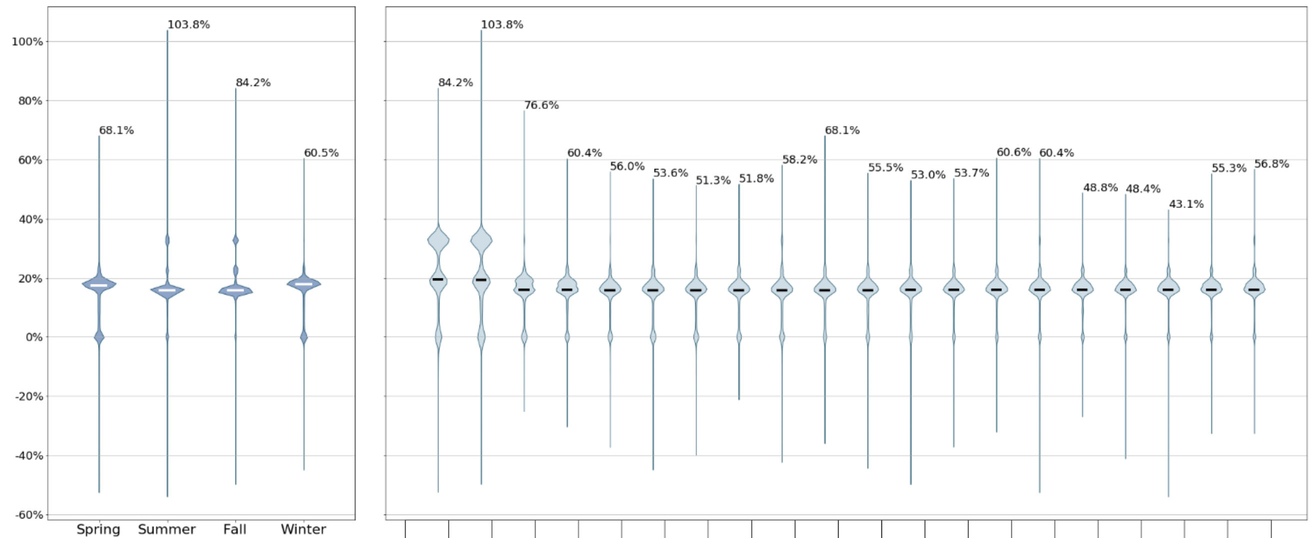


Figure 137 depicts a heat map that represents the average delta flows in each hour for each month in the whole study period. It shows that the largest increase in flows in the relaxed case occurs during the summer peak hours. This can also be seen in the delta violin plots in Figure 138 below which show the largest spikes during the summer and fall seasons. Overall, the line utilization on the relaxed interface increases by approximately 18-20% on average. Freed energy in GWh is presented below the annual violin plots and shows the increased flow on the line when limits are removed relative to the total Baseline flows.

Figure 138: Dunwoodie-Long Island Delta Hourly Line Utilization

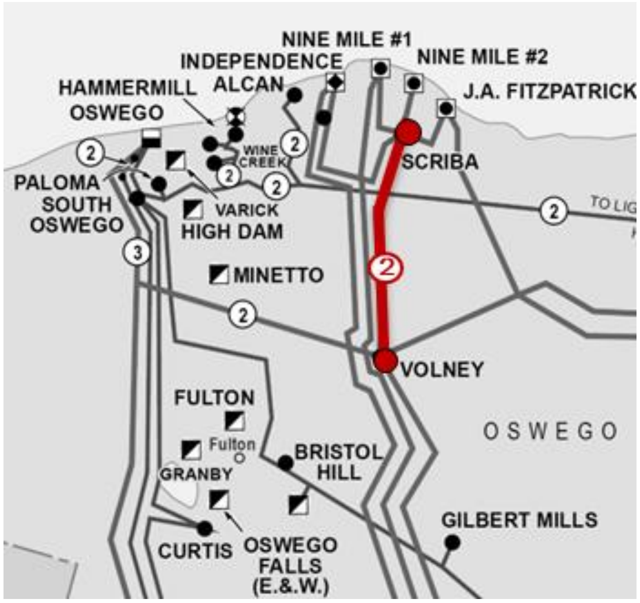


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	1291	1205	920	941	868	811	843	860	846	871	871	899	935	928	942	929	959	951	971	981

Volney-Scriba 345 kV

The Volney-Scriba constraint consists of two parallel lines from Scriba 345 kV to Volney 345 kV substation. These two lines have unequal ratings so the flow on one of the lines is larger than the other. The limiting contingency for this constraint is the loss of the line with higher rating while monitoring the one with lower rating.

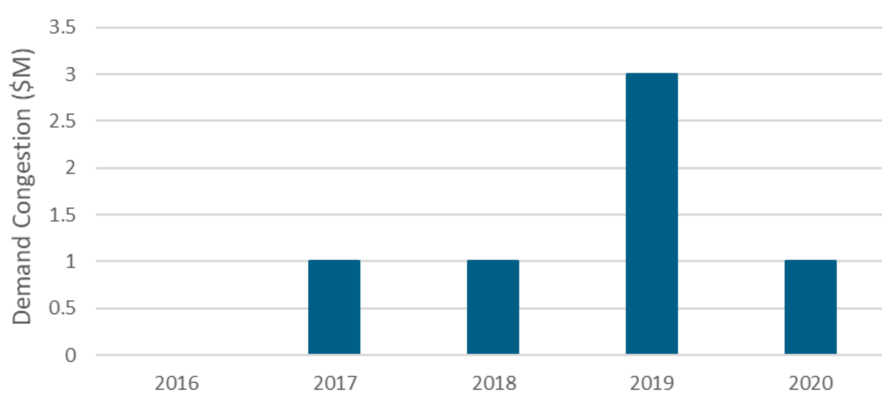
Figure 139: Volney-Scriba 345 kV Line Location and Parameters



Type	Single Circuit 345kV
Normal Op. Rating	1200/1474 MVA
Contingency Op. Rating	1396/1626 MVA
Length	~9 Miles
Owner	National Grid

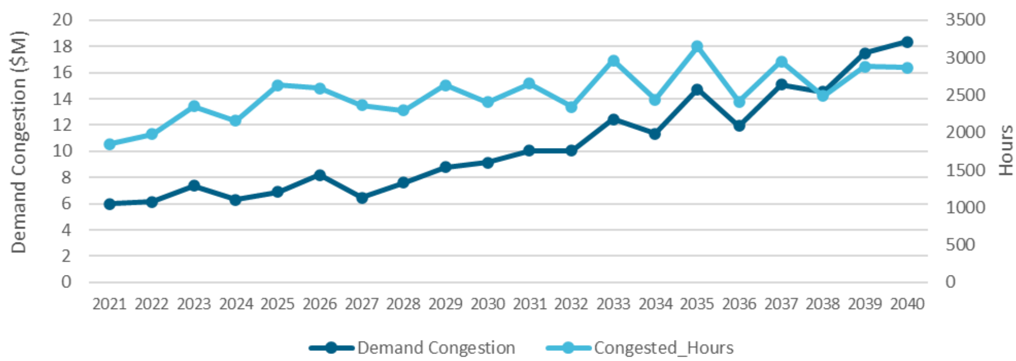
Historical congestion on this path for the past five years is shown below.

Figure 140: Volney-Scriba Demand Congestion (nominal $M)



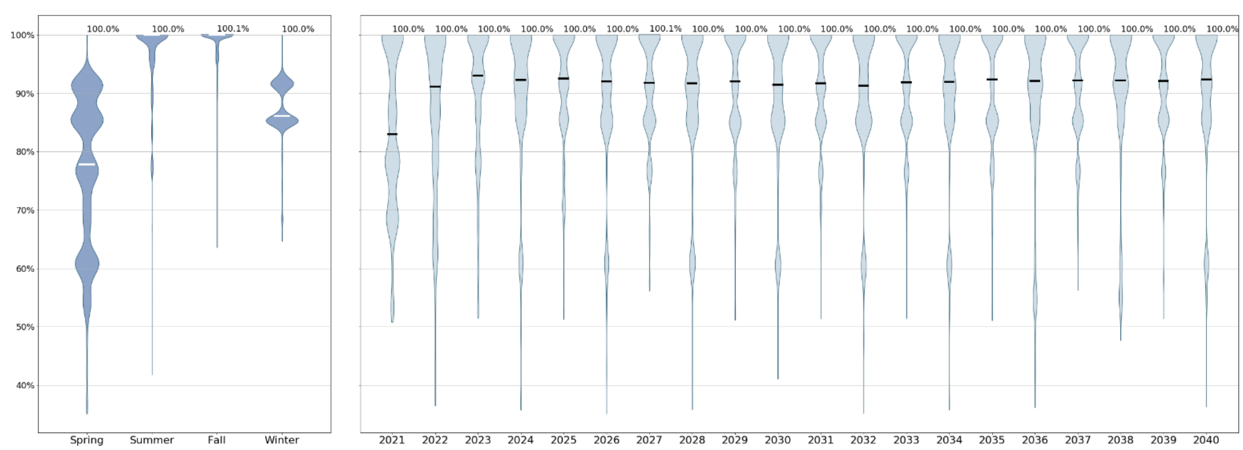
This path is located directly downstream of major generators in the New York System in and around the Oswego complex. Projected congestion on this path is directly related to generators operating upstream of the constraint and the contingency securing the flow on the line with lower limits.

Figure 141: Volney-Scriba Baseline Projected Demand Congestion and Congested Hours



The violin plots below show line utilization for this path broken down by seasons and by year for the entire study period. The seasonal plot shows that the line is mostly congested during the summer period. The summer seasonal rating is lower than the winter rating for these lines. Increased output from Sithe Independence during the peak summer period causes increase in flow along this path. The average line utilization for both lines is above 90% for most years in the study period.

Figure 142:Volney-Scriba Baseline Case Hourly Line Utilization



The relaxed case when compared to the Baseline case flows show that the flows on the lines increase when the limits on the lines are removed. The flow duration curve below shows that the flows increase in the relaxed case for 40% of the year compared to the Baseline Case flows. The heatmap chart shows that the flow increase is mostly during the high peak load periods in the summer season. The relaxed case has higher flows overall in all years in the study period. The flow increases mostly in the summer peak periods. Since the line was binding during the summer period in the Baseline Case, relaxing the limit on the line causes higher flows during this period.

Figure 143: Volney-Scriba Delta Flow Duration Curve (Relax-Baseline)

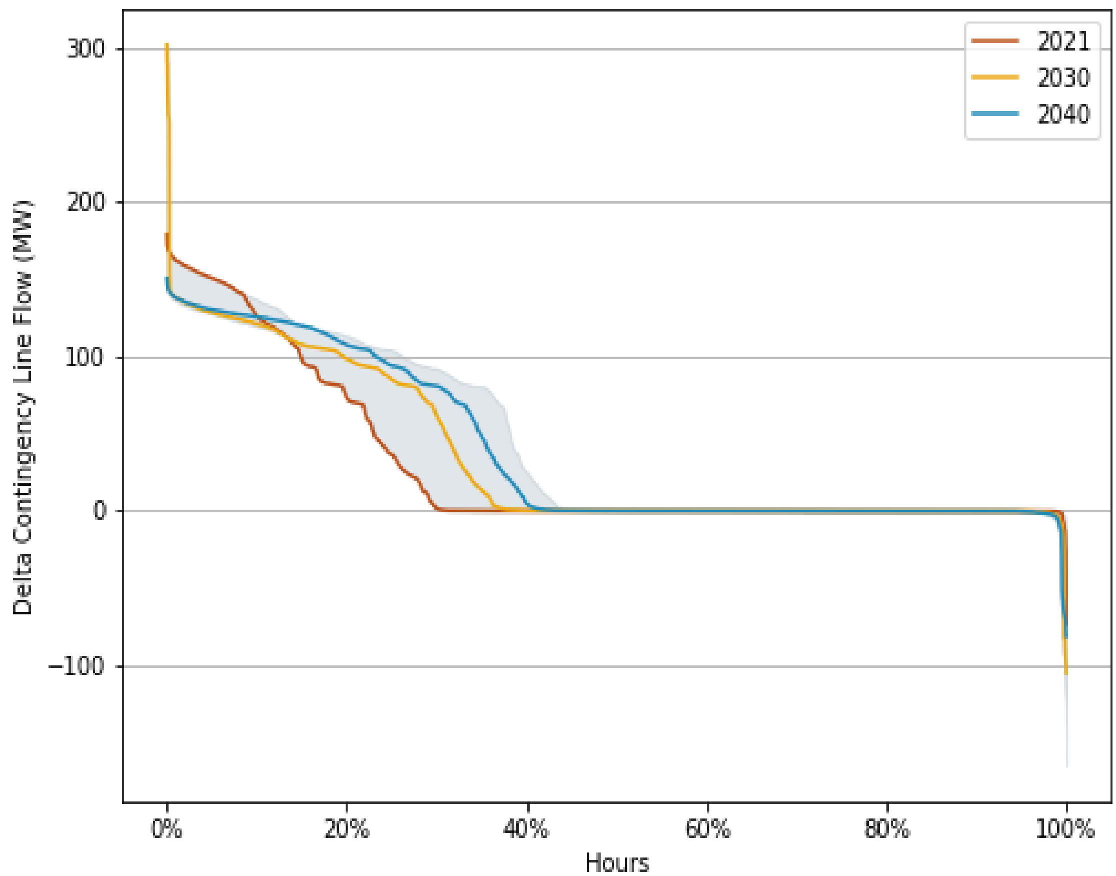
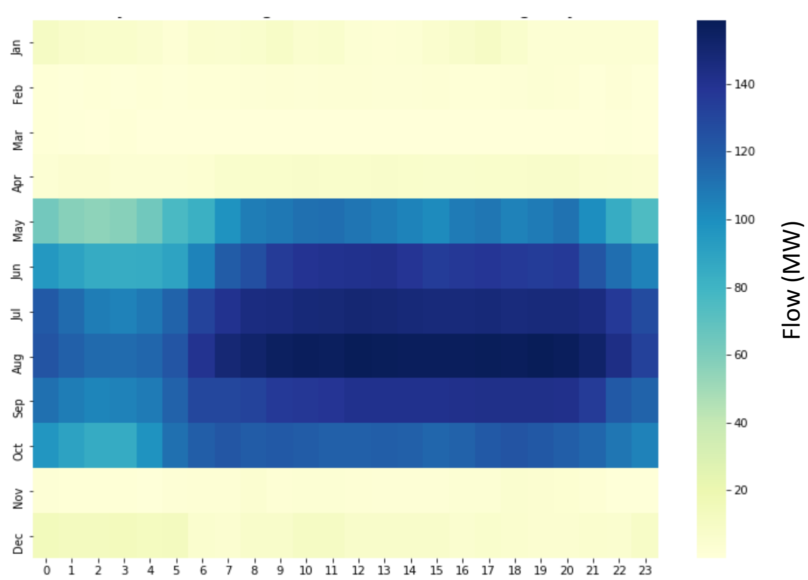
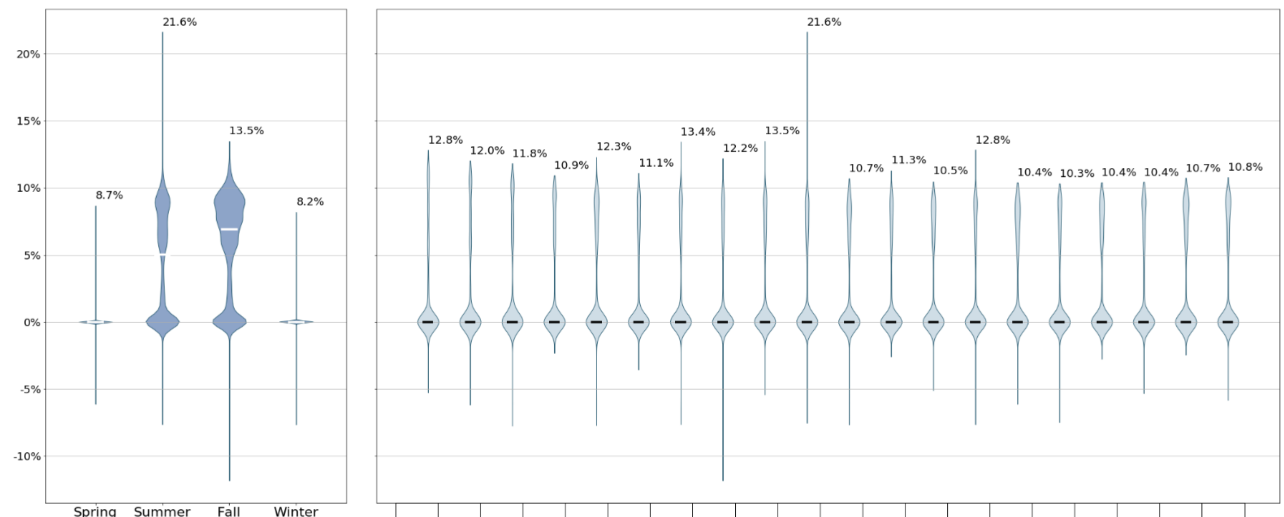


Figure 144: Volney-Scriba Average Delta Flow



The impacts of removing line limits can also be seen in the violin plots below for delta line utilization in the relaxed case compared to the Baseline Case. The seasonal plot shows that the line utilization increases in the summer and fall months with average increases of about 5-7%. Line utilization does not change significantly in the winter period as the Baseline Case had lower utilization and lower congestion during this period as well. The freed energy by relaxing the constraint amounts to a range between approximately 250 to 370 GWh.

Figure 145: Volney-Scriba Delta Hourly Line Utilization (Relax-Baseline)

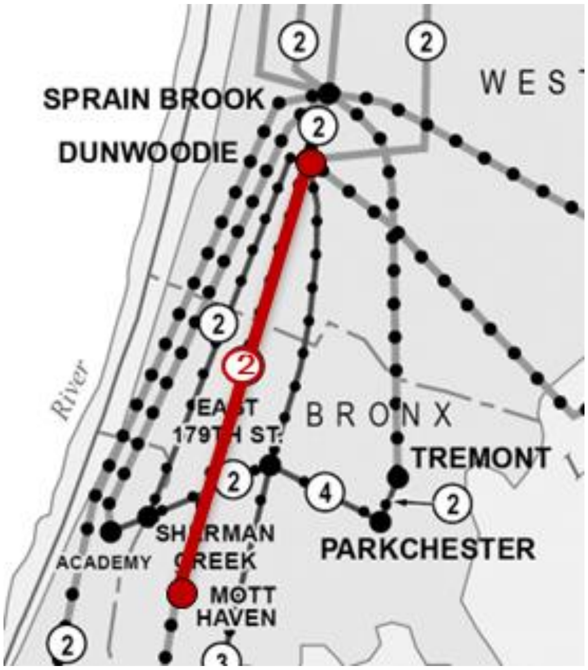


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	252	287	312	301	350	304	273	263	285	300	323	278	326	277	359	293	350	300	373	339

Dunwoodie – Motthaven 345 kV

The Dunwoodie-Motthaven 345 kV path consists of two parallel 345 kV lines 71 and 72. This is one of the main paths through which power flows from the lower Hudson Valley to New York City. The line location and parameters are presented below in Figure 146.

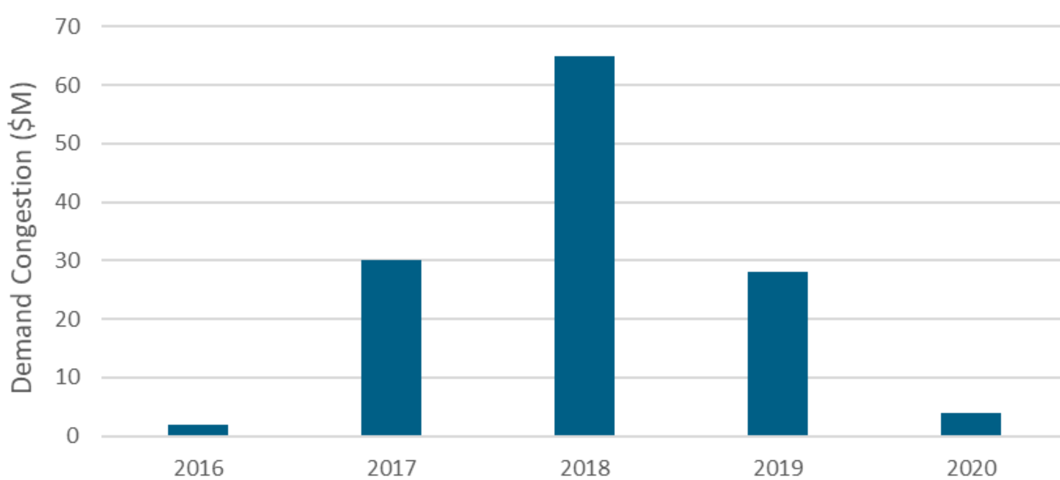
Figure 146: Dunwoodie-Motthaven 345 kV Line Location and Parameters



Type	Double Circuit 345kV
Normal Op. Rating	707/741 MVA
Contingency Op. Rating	1066/1083 MVA
Length	~12 Miles
Owner	Con Edison

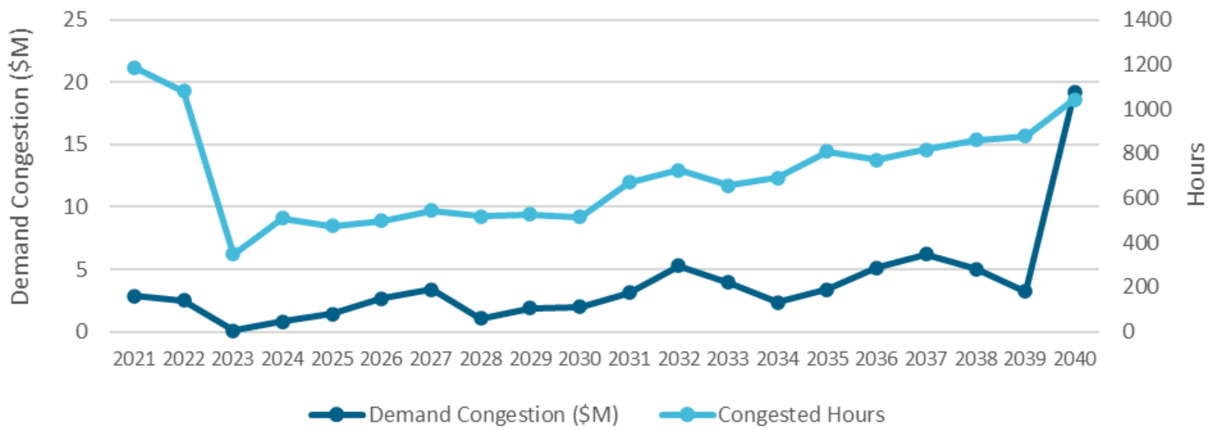
Figure 147 provides a look at historical congestion shows an increase after 2017. After the ConEd/PSEG wheeling agreement expired in 2017, the flow on this path into New York City increases, contributing to increased congestion. Outages in parallel circuits also contribute to congestion along this path.

Figure 147: Dunwoodie-Motthaven Demand Congestion (nominal $M)



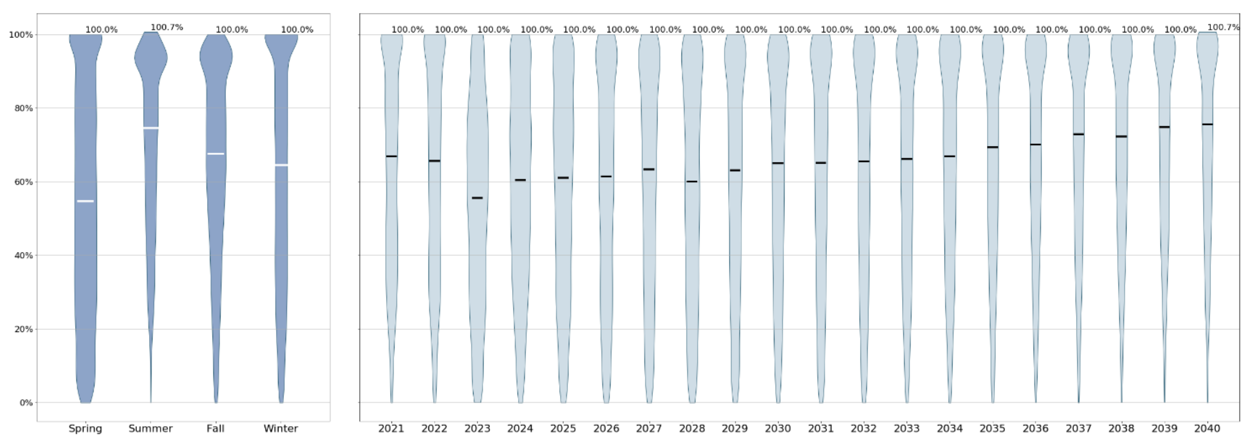
The projected demand congestion on this path along with the congested hours is presented in Figure 148 below. Congestion on this path increases over the years in the Baseline case as New York City load increases over the study period.

Figure 148: Dunwoodie-Motthaven Baseline Projected Demand Congestion and Congested Hours



The line utilization levels for the Dunwoodie to Motthaven lines are very spread out across the years. There is slightly higher utilization in the summer and fall periods that is driven by lower ratings in the summer as seen in the seasonal plots below. The average utilization also increases across the study period following load growth downstate as depicted by the dark colored lines within the body of the violin charts.

Figure 149: Dunwoodie-Motthaven Baseline Case Hourly Line Utilization



The relaxed case delta duration curve shows slight increase in flows when line limits are removed. For about 20% of the year, the flow increases on this path in the relaxed case compared to the Baseline Case. The heatmap for delta flows shows increased flow in the early morning and evening hours in the winter and slight increase in flow during the summer peak period.

Figure 150: Dunwoodie-Motthaven Delta Flow Duration Curve (Relax-Base)

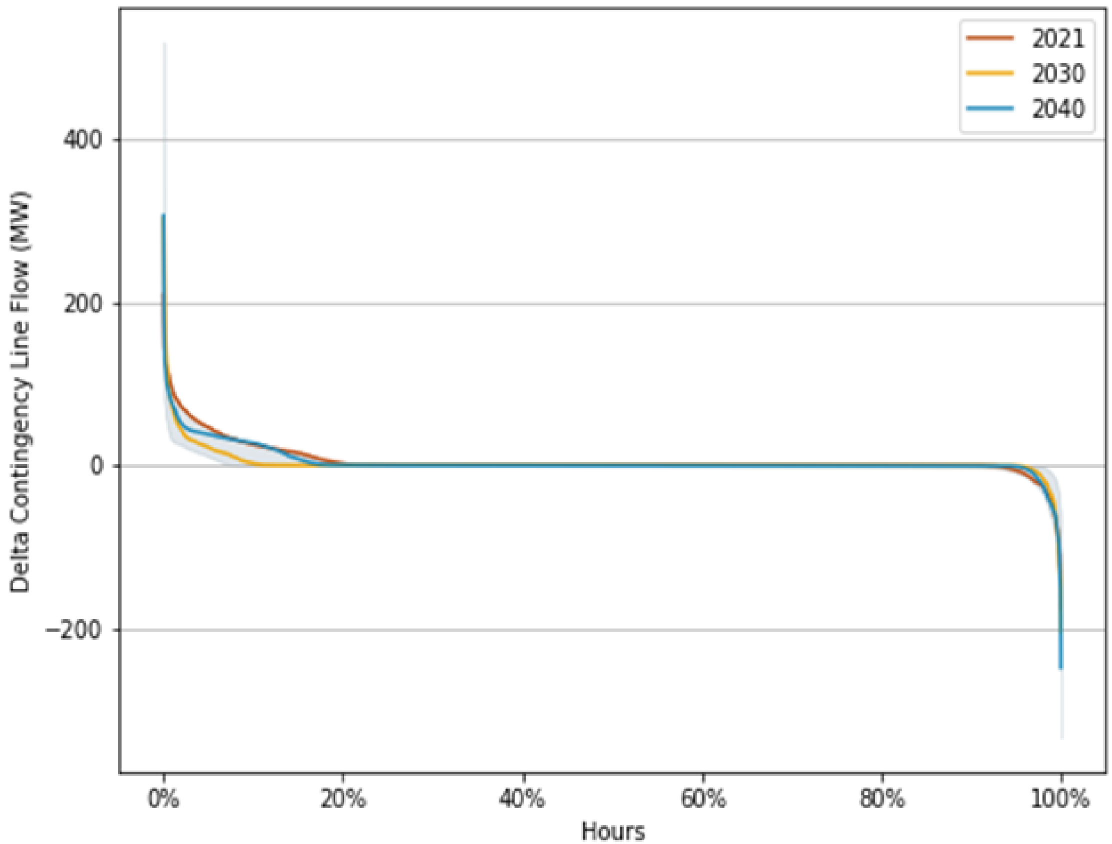
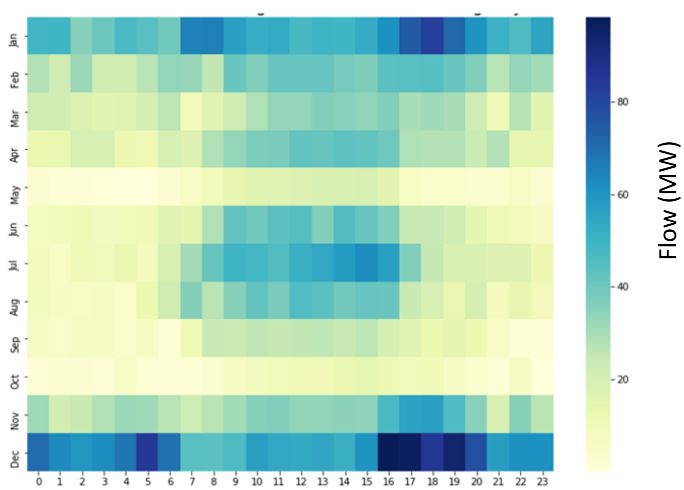
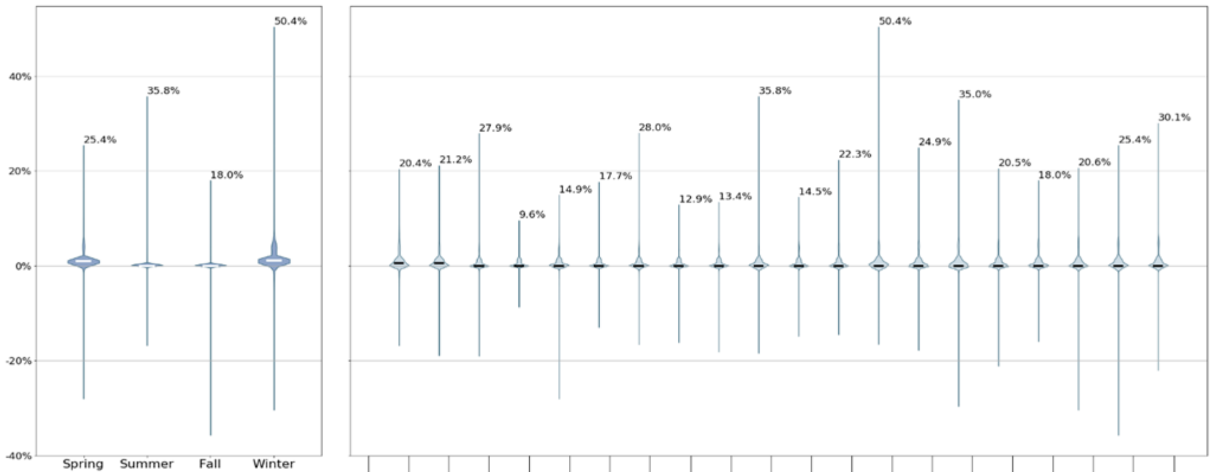


Figure 151: Dunwoodie-Motthaven Average Delta Flow



The delta line utilization violin plots show similar increase in utilization during the winter periods. Overall, the freed energy by relaxing the limits on the constraint is in the range of 5-45 GWh in the study period. There are not substantial increases in flows on this path when line limits are relaxed since only a limited number of hours were binding in the Baseline Case. Constraints further downstream of this path also limit the flow on the lines.

Figure 152: Dunwoodie-Motthaven Delta Hourly Line Utilization (Relax-Baseline)



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	45	40	5	9	8	14	16	10	10	17	13	17	20	19	23	19	23	34	21	35

New Scotland – Knickerbocker 345 kV

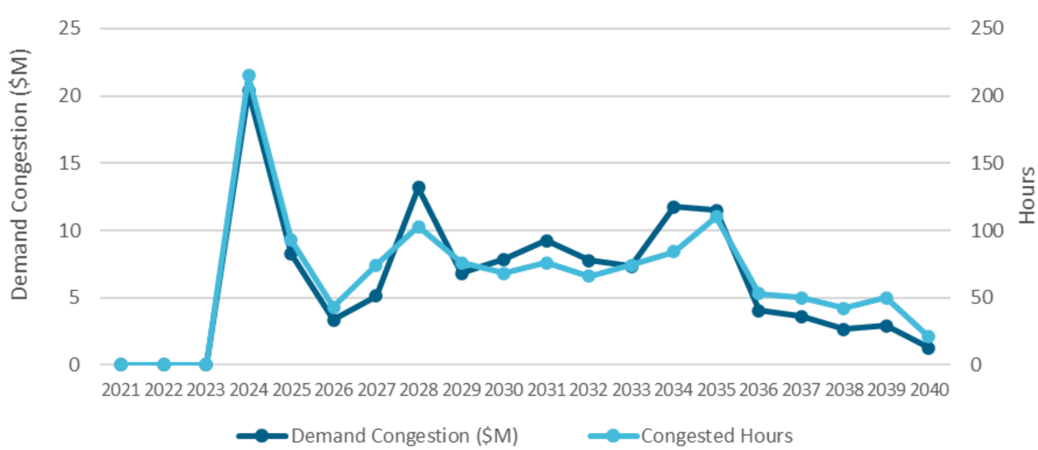
The New Scotland to Knickerbocker 345 kV line is part of the AC Transmission project which is scheduled to be in service by 2024. Segment B of AC transmission project adds a new substation at Knickerbocker which taps the line from New-Scotland 345 kV to Alps 345 kV substation. Congestion on this new line is not reported since this segment is modeled to go into service in 2024.

Figure 153: New Scotland-Knickerbocker Line Location and Parameters

Type	Single Circuit 345kV
Normal Op. Rating	1423/1852 MVA
Contingency Op. Rating	
Length	~12 mile
Owner	National Grid

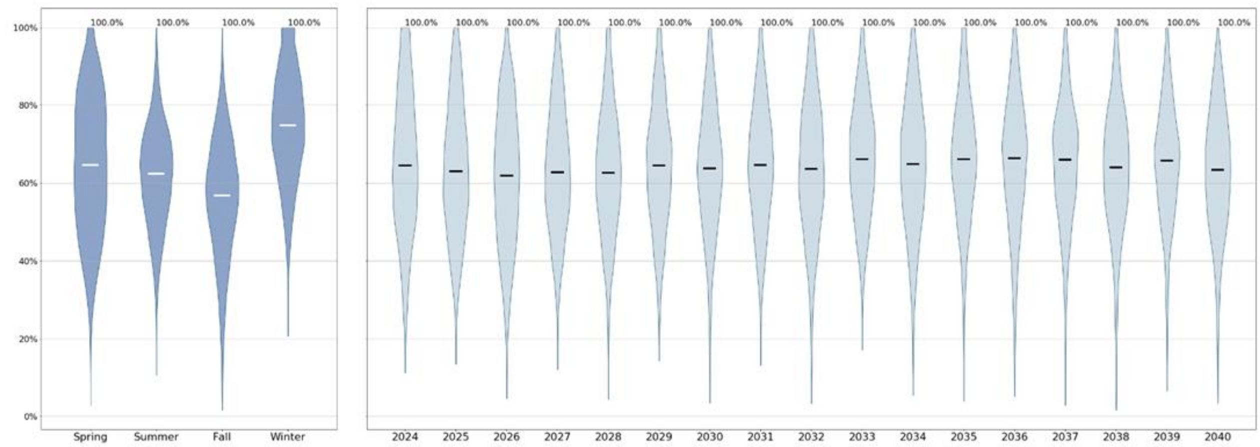
Congestion on this path is primarily due to increased flow on Central East due to increased transmission capacity as a result of AC transmission being modeled. The projected congestion and limited hours in the Baseline Case for this path is shown below.

Figure 154: New Scotland - Knickerbocker Demand Congestion and Congested Hours



The line utilization for New Scotland to Knickerbocker is slightly higher in the winter months as a result of Marcy South Series Compensation being bypassed which diverts more flow on Central East and through New Scotland – Knickerbocker as shown in the seasonal plots in Figure 155 below. Across the study period, average line utilization remains around 60-65%.

Figure 155: New Scotland-Knickerbocker Projected Baseline Hourly Line Utilization



Relaxing the constraints on this line results in higher flows especially during the evening hours in the winter period, as can be seen from the delta flow heat map plot below. The relaxed case does not show a significant increase in flows compared to the Baseline Case flows. Only about 10% of hours are seen to have higher flows along this path.

Figure 156: New Scotland-Knickerbocker Delta Flow Duration Curves (Relax-Baseline)

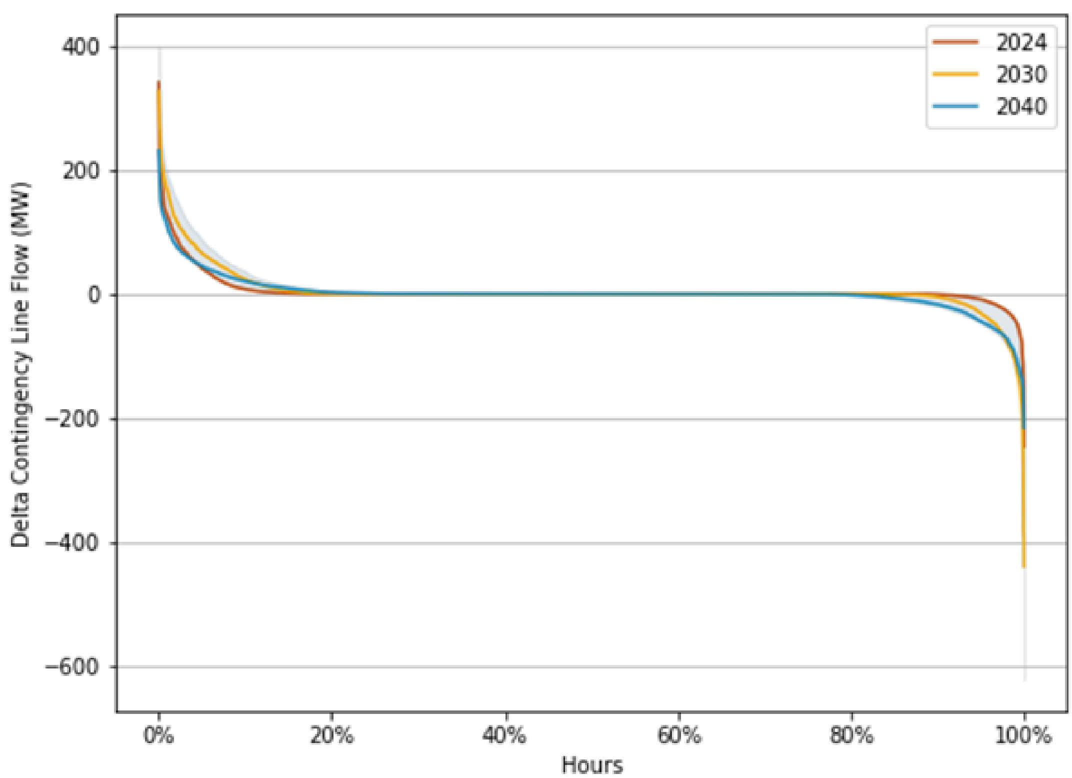
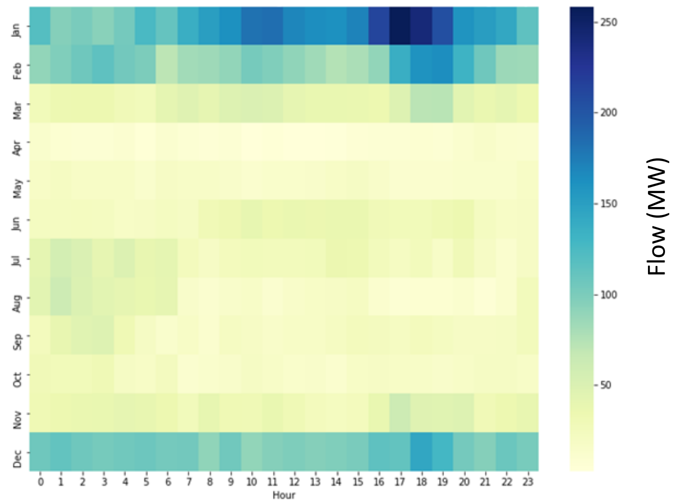
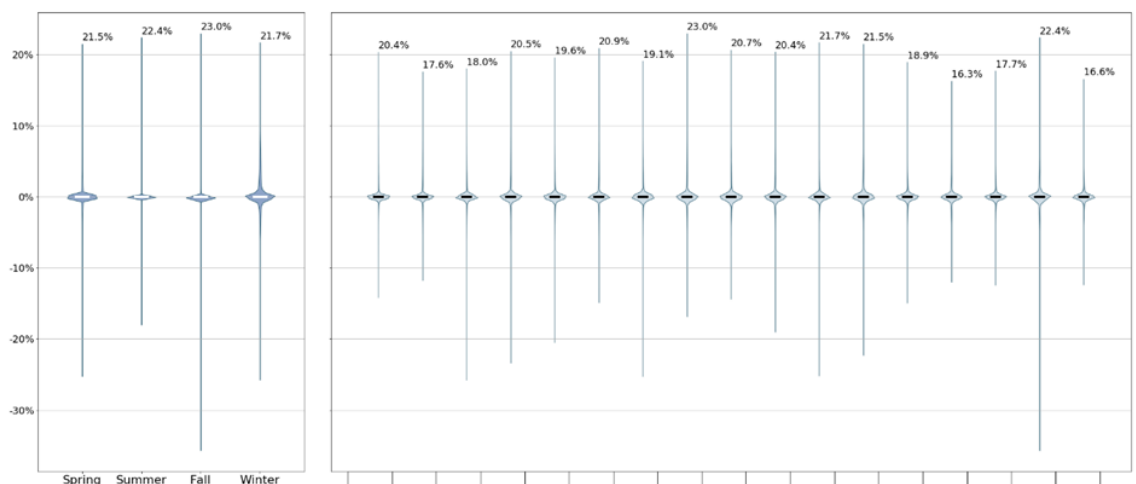


Figure 157: New Scotland-Knickerbocker Average Delta Flow



The delta violin plots for New Scotland-Knickerbocker shows higher spikes in the winter periods. Overall, the total increase in flow by relaxing this constraint ranges from 4-61 GWh from 2024-2040. Relaxing this constraint also increases flows and congestion on Central East and constraints further downstream of Knickerbocker.

Figure 158: New Scotland-Knickerbocker Delta Hourly Line Utilization



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	35	29	19	29	19	32	34	57	61	37	30	40	26	23	20	8	4

Sugarloaf-Ramapo 138 kV

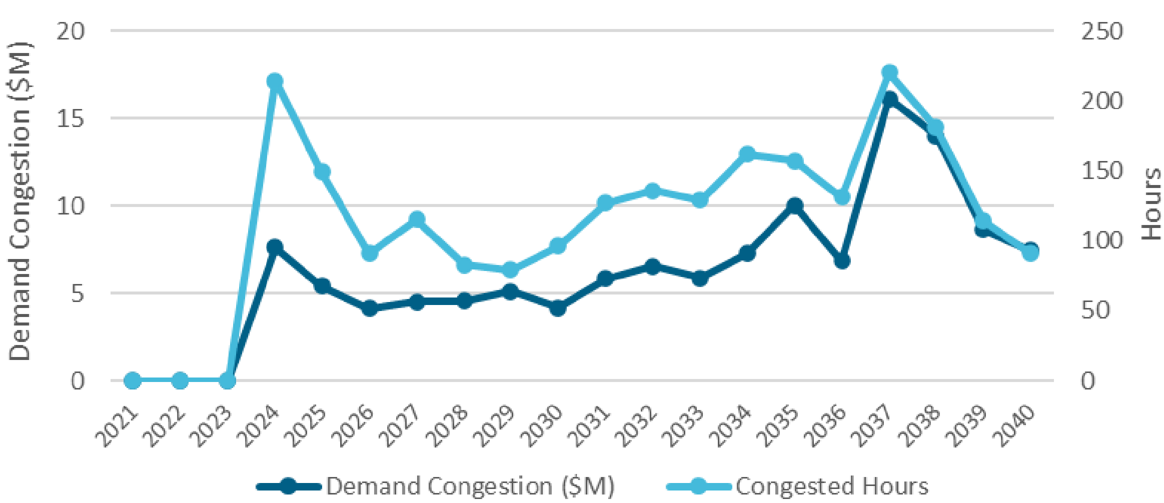
Sugarloaf to Ramapo 138 kV line is located along the Marcy South path which carries flows from Zone E to the lower Hudson Valley. The line location and parameters are as shown in Figure 159.

Figure 159: Sugarloaf-Ramapo Line Location and Parameters

Type	Single Circuit 138kV
Normal Op. Rating	236/282 MW
Contingency Op. Rating	270/309 MW
Length	~ 17 miles
Owner	O&R

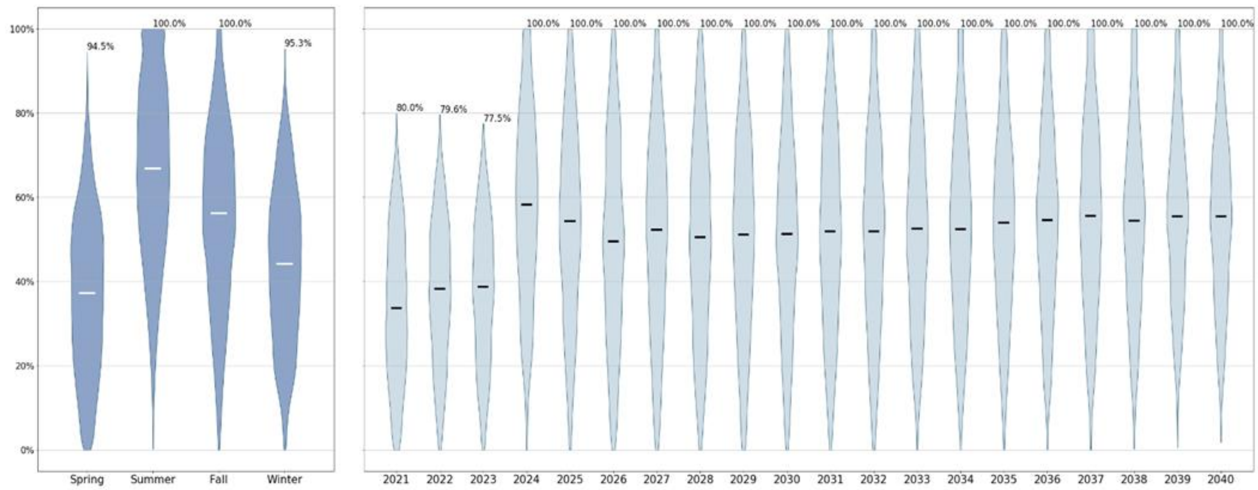
With upgrades associated with Segment B of AC Transmission, increased flow is observed on the 138 kV line from Sugarloaf to Ramapo. The projected congestion in the future years, starting in 2024 when AC transmission is modeled in service, is shown in the chart. Limiting contingencies include loss of higher kV circuits while securing this path.

Figure 160: Sugarloaf-Ramapo Baseline Case Projected Demand Congestion and Congested Hours



The line utilization and flow along this line is significantly increased after segment B is placed into service. Line utilization is higher in summer and fall due to the rating being lower compared to the winter months. Average line utilization increases from close to 40% prior the AC transmission, to over 50% starting in 2024. Overall, the limiting hours for the constraint are on the low side and occur in the summer and fall periods.

Figure 161: Sugarloaf-Ramapo Baseline Case Hourly Line Utilization



Since the line was only limiting for a low percentage of total hours, relaxing the limits on the line does not increase the flows to a great extent. The delta flow duration curve shows a slight increase in flows for less that 10% of hours in a year. The highest delta in flows occur during the peak load hours in June and July.

Figure 162: Sugarloaf-Ramapo Delta Flow Duration Curve (Relax-Baseline)

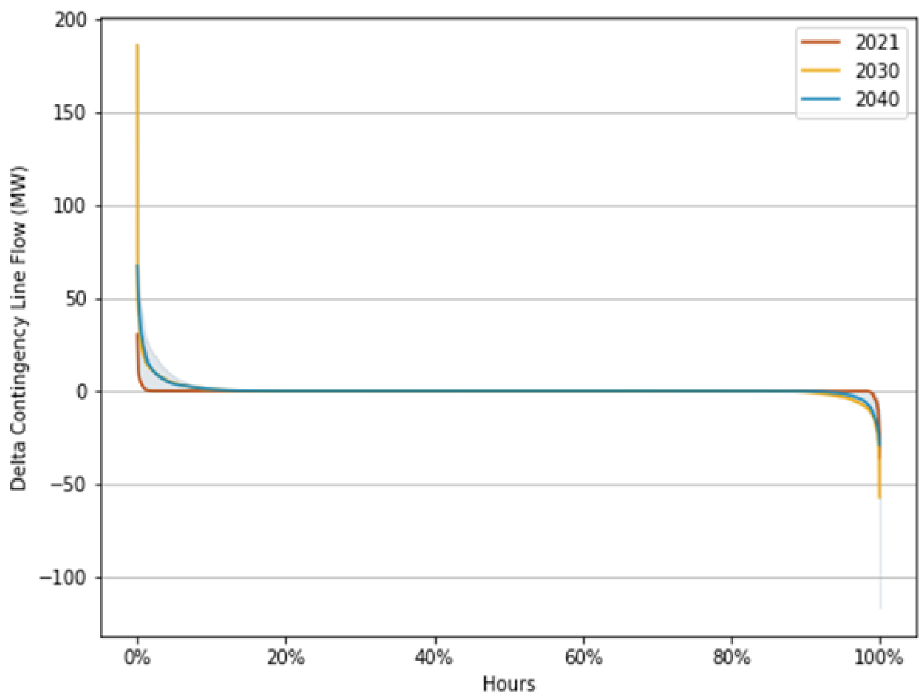
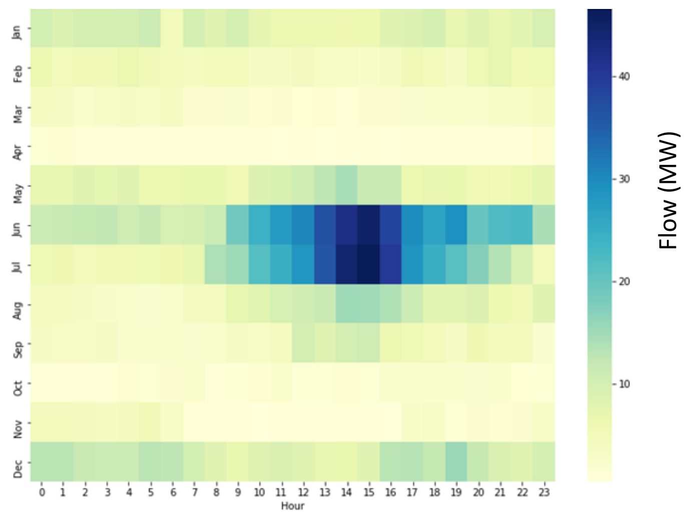
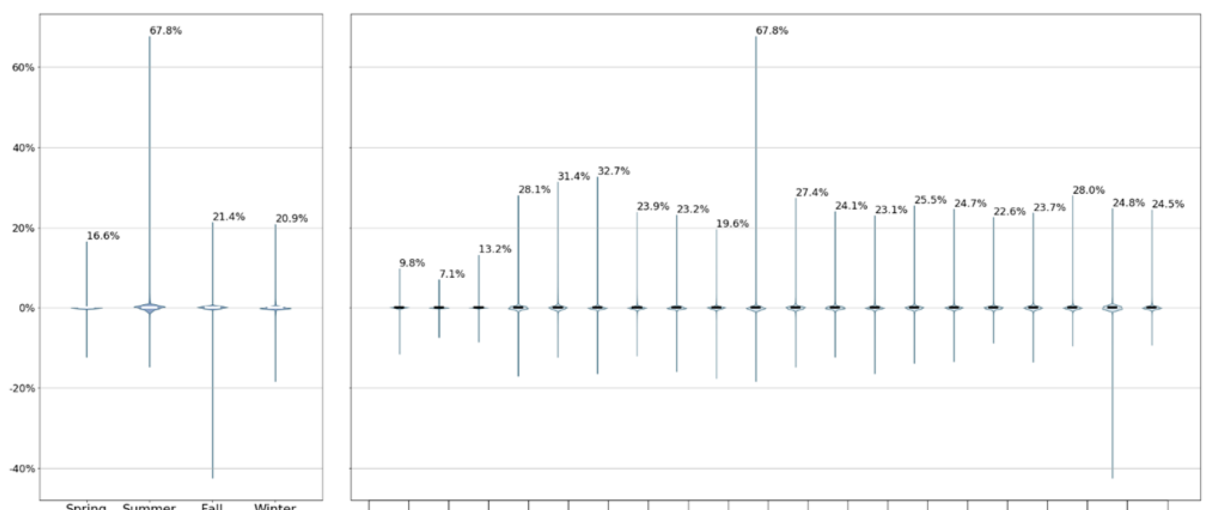


Figure 163: Sugarloaf-Ramapo Average Delta Flow



Constraints on this line are binding for less than 3% of the year in the Baseline Case. Relieving limits on this line only produces marginal increase in flows which are limited to the summer periods as shown by the spikes on the seasonal violin plots. Freed energy as a result of relieving this constraint is in the range of approximately 6-8 GWh in a year.

Figure 164: Sugarloaf-Ramapo Delta Hourly Line Utilization



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	0	0	0	6	6	1	2	1	2	2	5	6	4	3	4	5	8	6	4	4

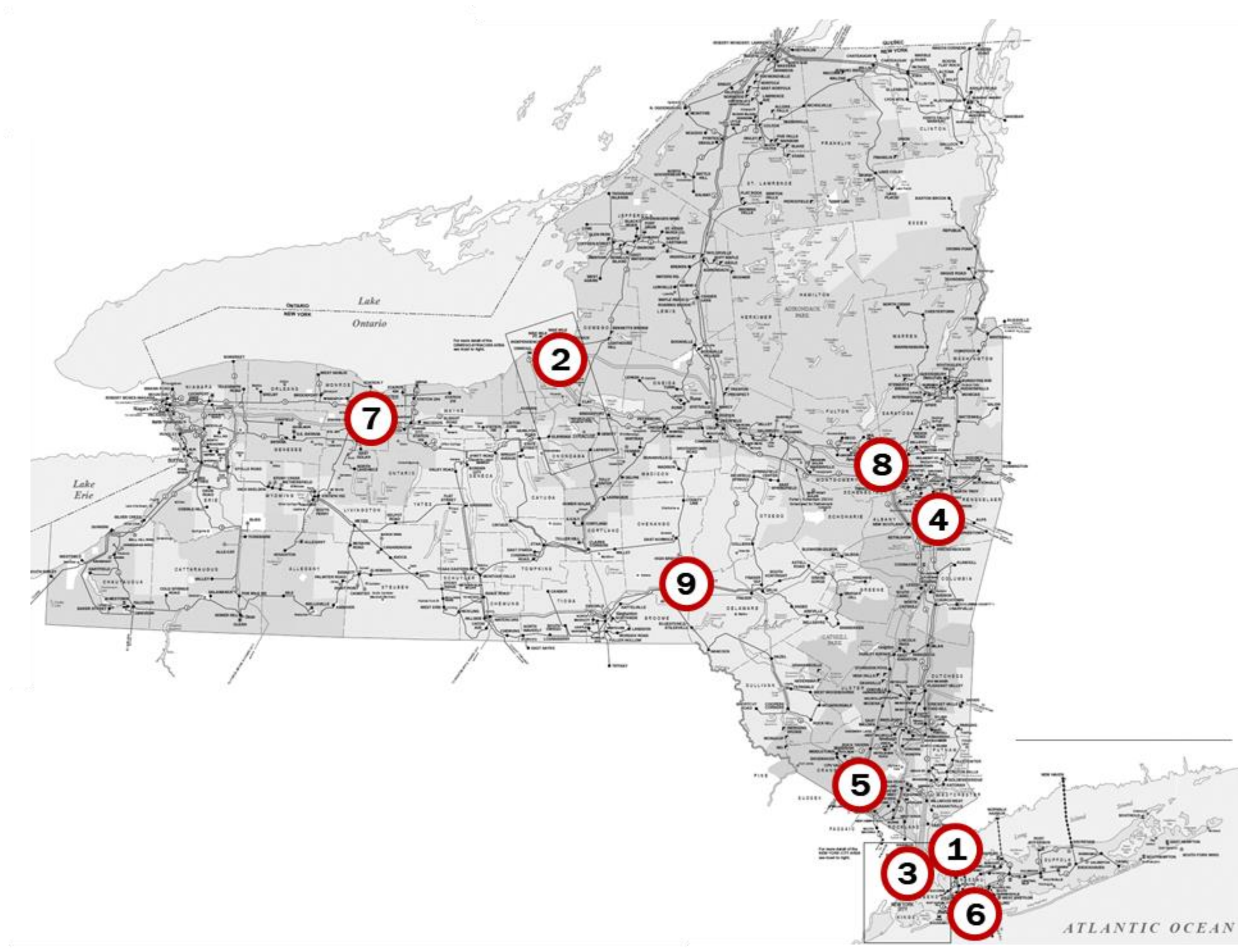
I.4. Contract Case Congestion Analysis

With additional contracted resources added to the system in the Contract Case, there is increased congestion the system both in the bulk as well as the lower kV level. The congestion analysis presented in this section analyzes some of the constrained paths in the Contract Case that are binding and may result in savings for the system if congestion on these paths is resolved. The following lines are studied in detail for the contract case.

1. Dunwoodie – Long Island 345 kV
2. Volney – Scriba 345 kV
3. Dunwoodie – Motthaven 345 kV
4. New Scotland – Knickerbocker 345 kV
5. Sugarloaf – Ramapo 138 kV
6. Barrett – Valley Stream 138 kV
7. Golah – Mortimer 115 kV
8. Stoner – Rotterdam 115 kV
9. Jennison – Sidney 115 kV

Location of each constraint is shown in the map below. Each constraint is further evaluated by relaxing the limits on the lines individually and comparing against the Contract Case flows to determine the impact of relieving congestion on the line.

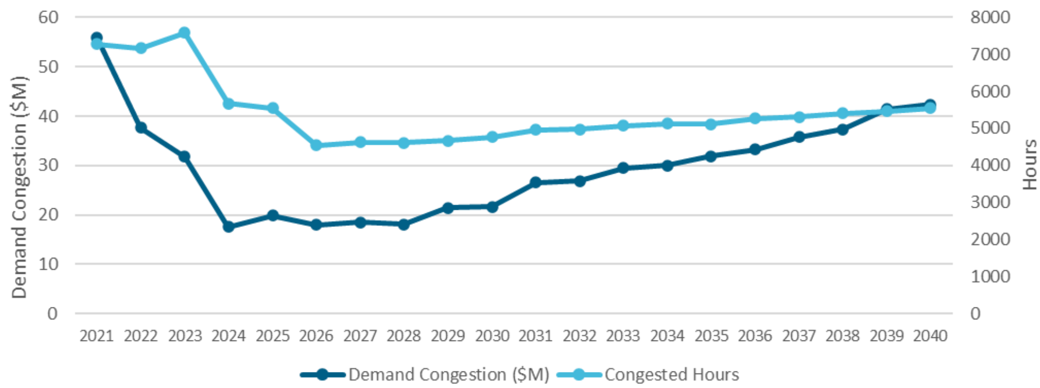
Figure 165: Locations of Contract Case constraints on New York State Map



Dunwoodie-Long Island 345 kV

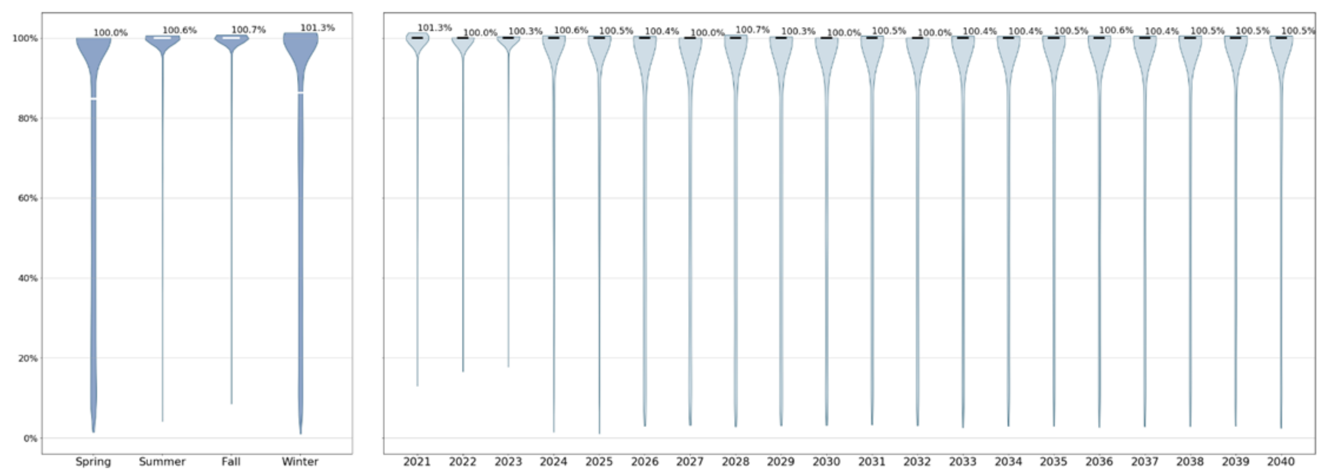
Line location, parameters and historical congestion for this line are presented in the above section for Baseline Case Congestion Analysis. The table below shows the Contract Case projected demand congestion and number of congested hours. The reason for congestion on the line is the same as the Baseline Case. Series Reactor operation during summer months on Y49 diverts more flow on Y50, increasing congestion on the line.

Figure 166: Dunwoodie-Long Island Contract Case Projected Demand Congestion and Congested Hours



The violin plots below show the flow on the lines in the Contract Case. These lines are heavily utilized throughout the year with flows reaching or nearing the limits in most hours of the year. Flows are particularly higher in the summer and fall periods.

Figure 167: Dunwoodie-Long Island Contract Case Hourly Line Utilization



Differences between the Contract Case flows and Baseline Case flows can be compared with flow duration charts shown below. The Contract Case has lower flows starting in 2024 as a result of offshore wind projects injecting power into Long Island. This pushes back on the flow on Dunwoodie-Long Island interface as it normally flows from Dunwoodie to serve load in Long Island. Flow increase compared to the Baseline Case usually occurs in the summer peak periods.

Figure 168: Dunwoodie-Long Island Flow Duration Curve

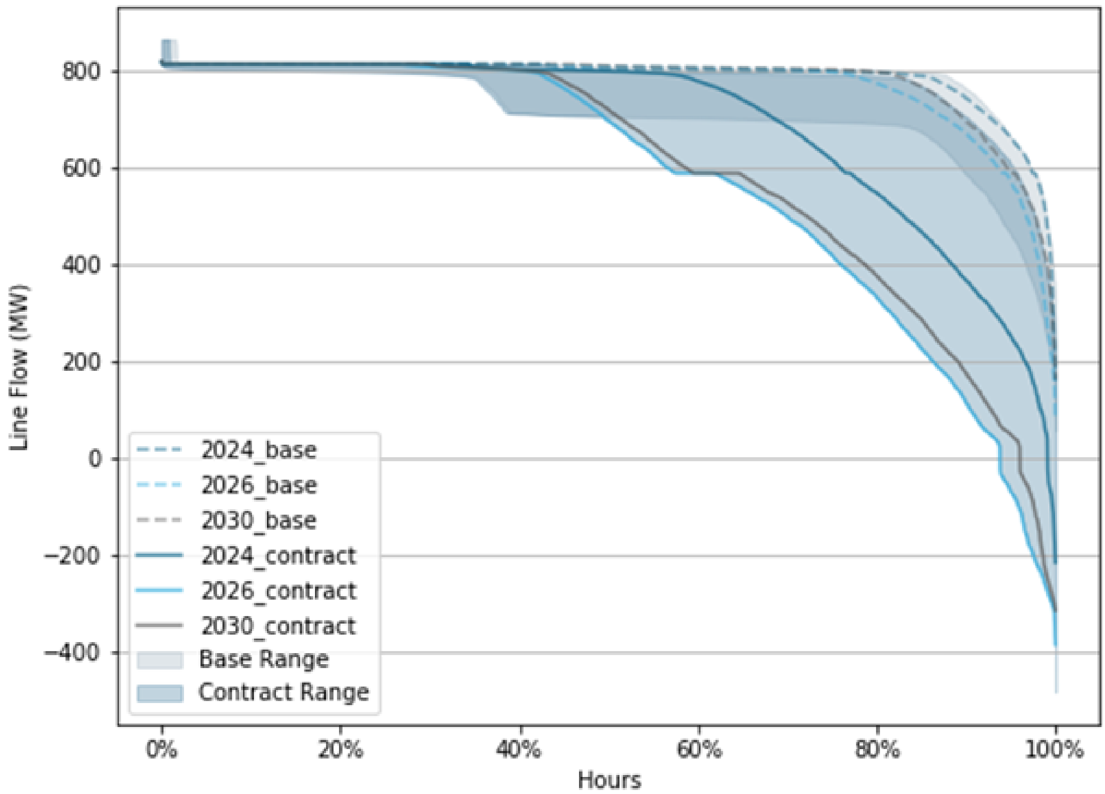
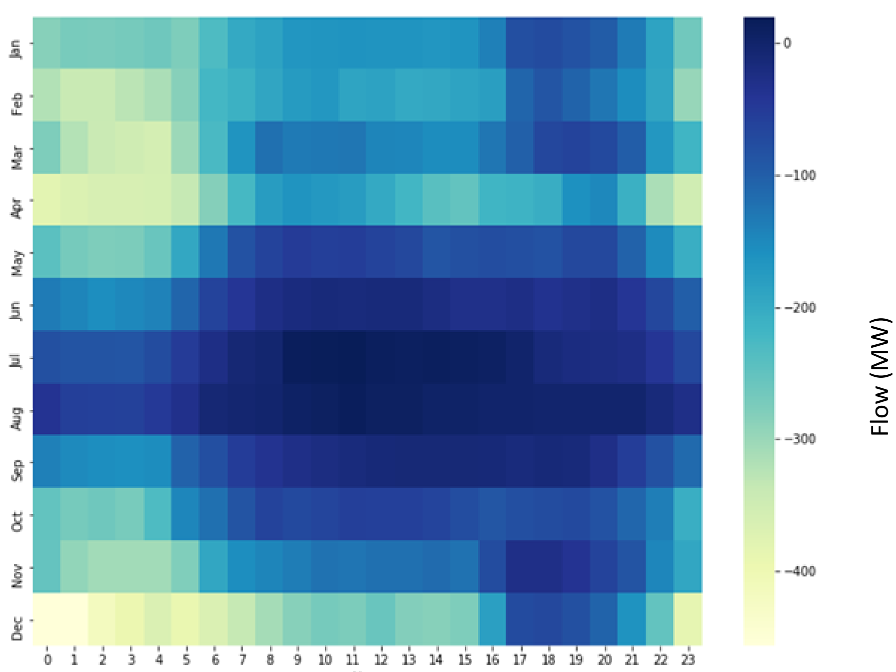


Figure 169: Dunwoodie-Long Island Average Delta Flow (Contract-Base)



A relaxation case was run for the Contract Case where the limits on Dunwoodie to Long Island interface was removed. Flows on the interface increases especially in the summer and fall season across most hours when the line was binding in the Contract Case.

Figure 170: Dunwoodie-Long Island Delta Flow Duration Curve

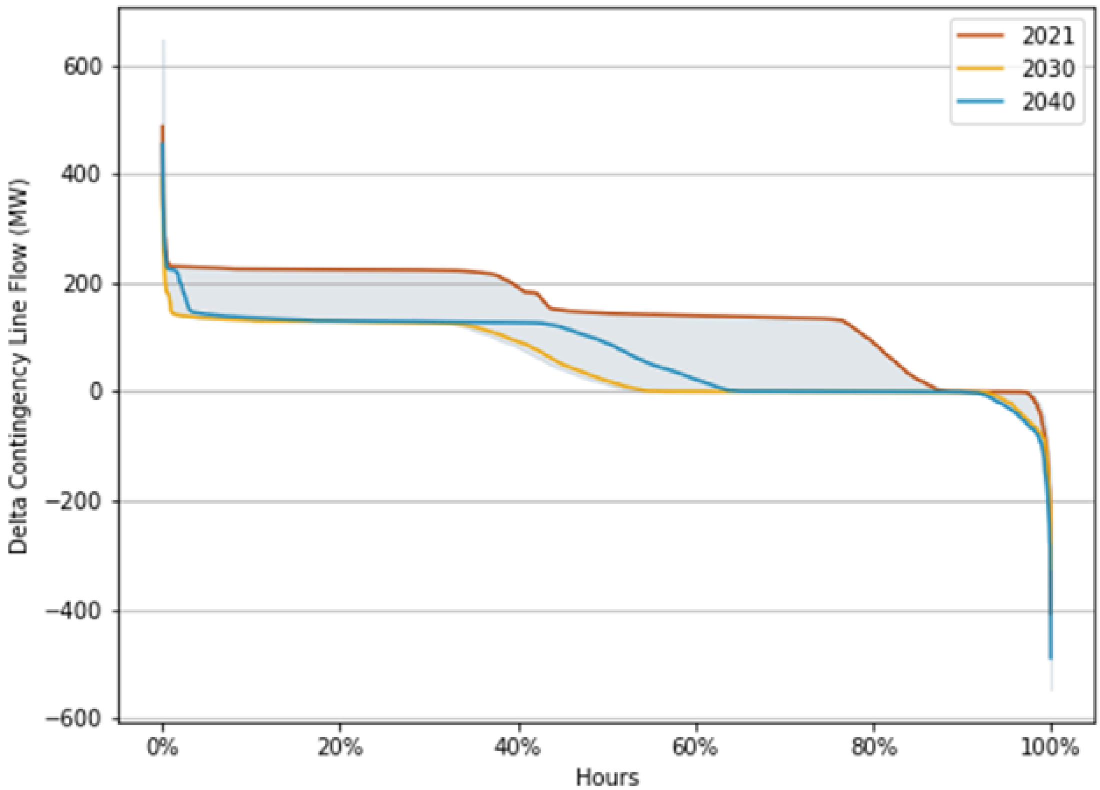
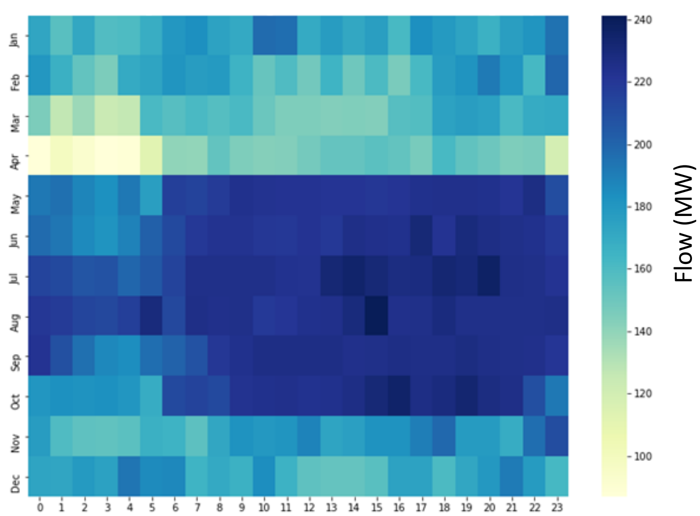
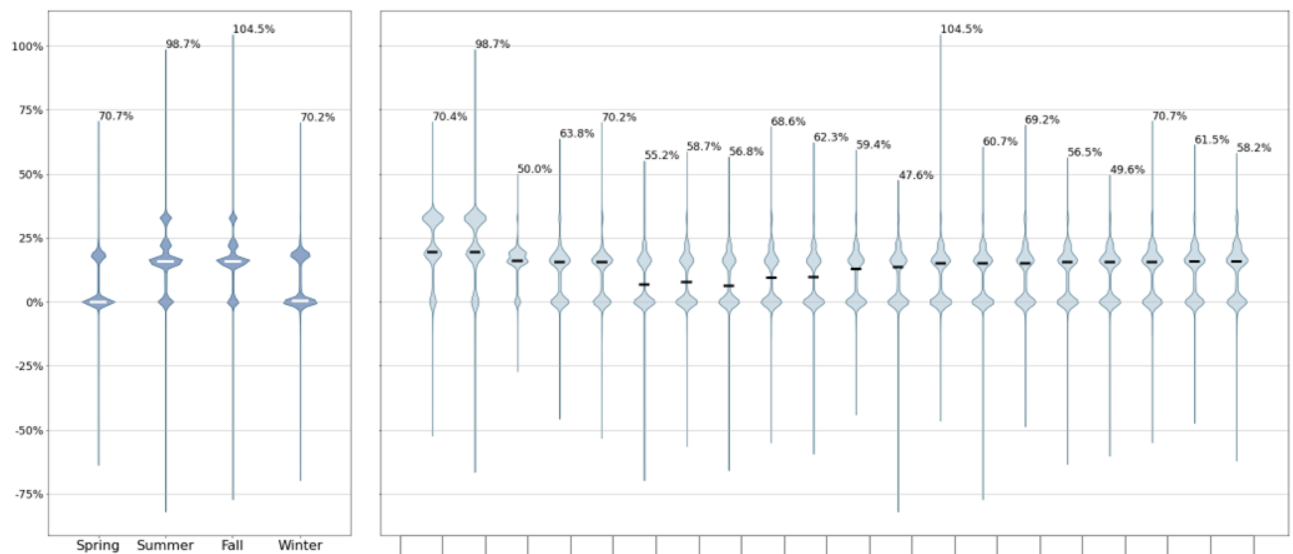


Figure 171: Dunwoodie-Long Island Average Delta Flow



Violin plots below show increase in flows for summer and fall season with higher peaks compared to winter and spring. Flow increases by about 20% overall across all years in the study period when line limits are relaxed. Even though the interface has lower overall flow compared to the Baseline Case, there is still congestion on the line in the Contract Case which is relieved when the limits are relaxed.

Figure 172: Dunwoodie-Long Island Delta Hourly Line Utilization (Relax-Contract)

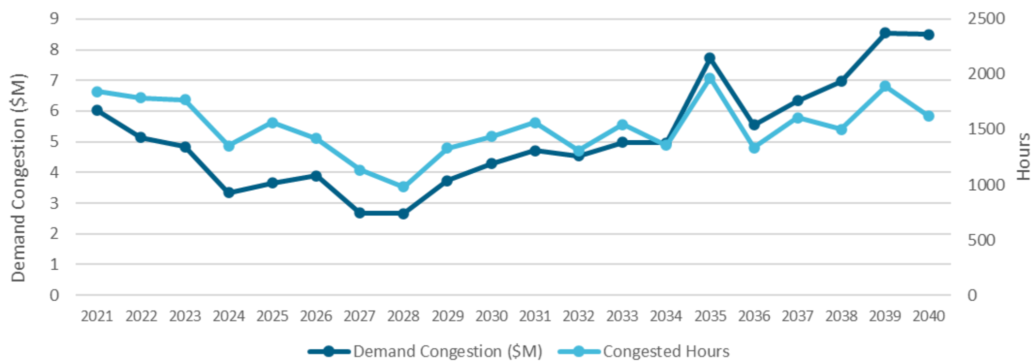


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	1294	1222	930	648	617	462	467	450	478	473	509	496	523	533	538	539	562	575	584	596

Volney-Scriba 345 kV

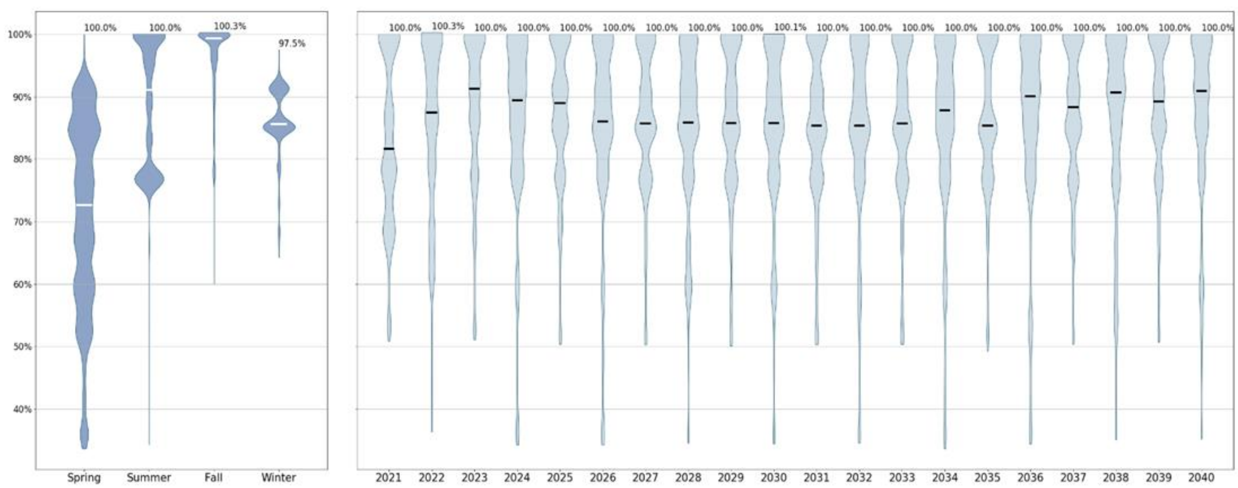
Line location, parameters and historical congestion for this line are presented in the above section for Baseline Case Congestion Analysis. The table below shows the Contract Case projected demand congestion and number of congested hours. The causes of congestion on this line are the same as the Baseline Case. The two parallel 345 kV lines have different line ratings which causes congestion when the line with lower rating is secured for the loss of the other.

Figure 173: Contract Case Projected Demand Congestion and Congested Hours



Congestion is lower overall compared to the Baseline Case as a result of additional low-cost renewable resources added to the system which causes fossil fueled generators in the Oswego complex to run less. Since this line is directly downstream of the Oswego generation, congestion and flow on this line is directly impacted by the amount of generation from these generators. The flow on the line is usually high in the summer period compared to the winter period with almost all of the congestion occurring during the summer and fall months. Line utilization of this path ranges from about 80-90% throughout the study period.

Figure 174: Volney-Scriba Contract Case Hourly Line Utilization



The flow duration curves below show that the flow on this path is lower compared to the Baseline Case flows. Flows are lower in the later years compared to the same period in the Baseline Case as more resources come online especially after 2024. The heatmap shows that flows are lower especially in the spring period and about the same during the summer peak periods when fossil fuel generator outputs are high.

Figure 175: Volney-Scriba Flow Duration Curve

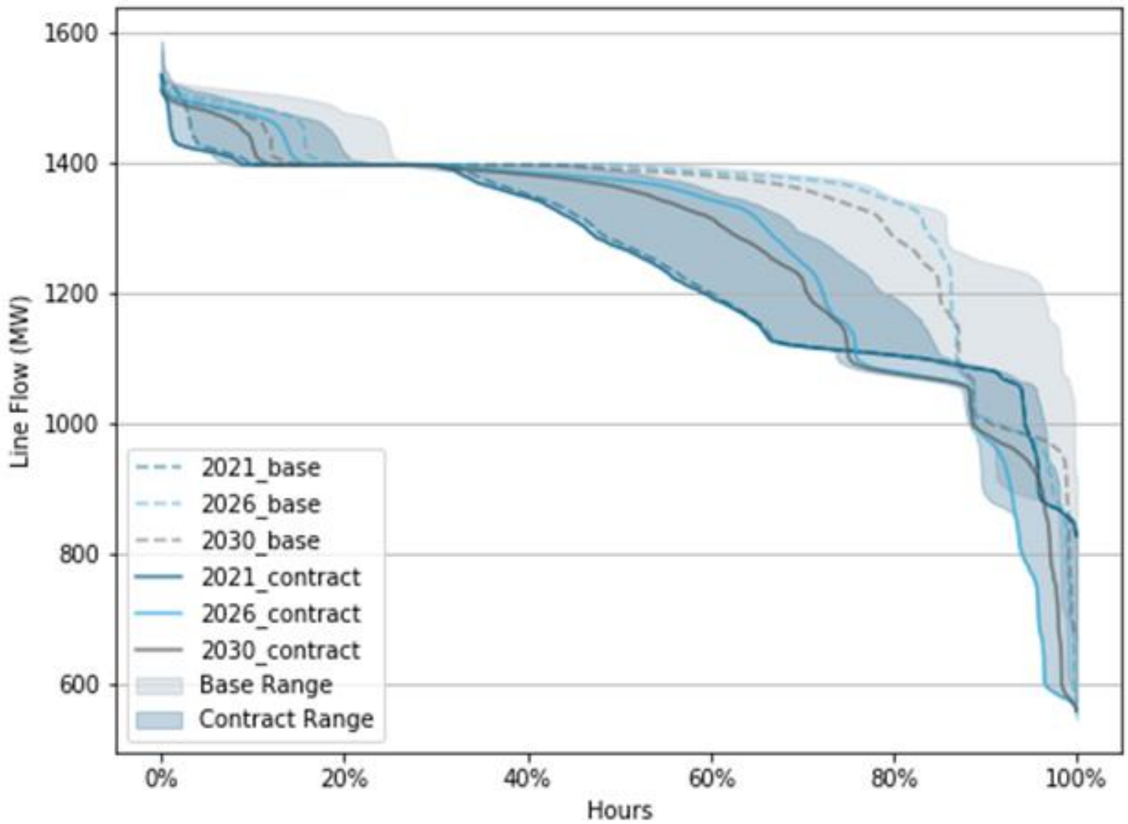
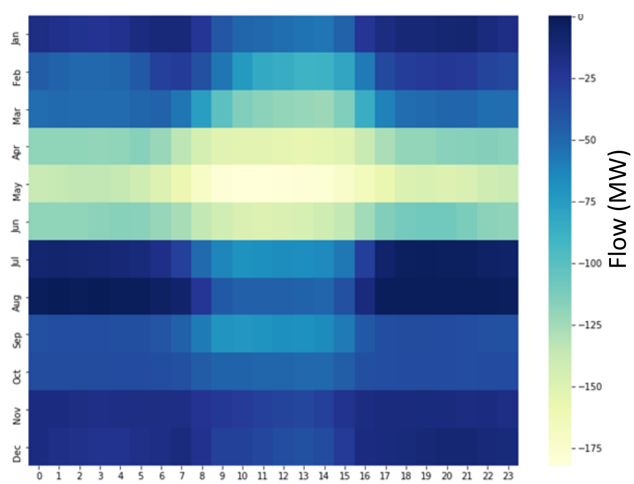


Figure 176: Volney-Scriba Average Delta Flow (Contract-Baseline)



The relaxed case flows when compared to the Contract Case flows for the path below show that the flow on the path increases for about 20-30% of the year. Flow increase in the relaxed case occurs mostly during the summer peak period in the afternoon hours when loads are highest and fossil fuel generators are operating at their peak.

Figure 177: Volney-Scriba Delta Flow Duration Curve (Relax-Contract)

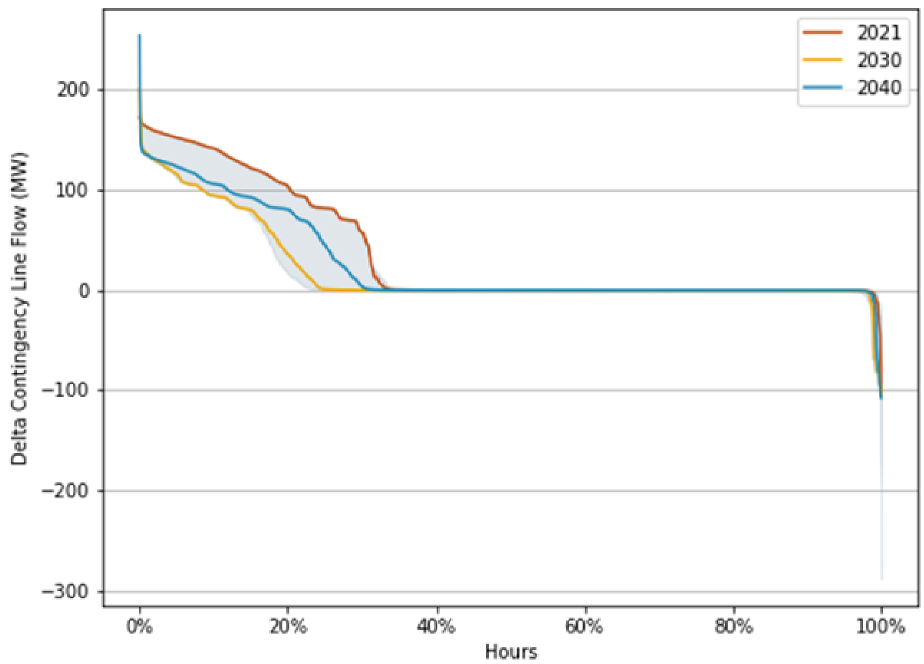
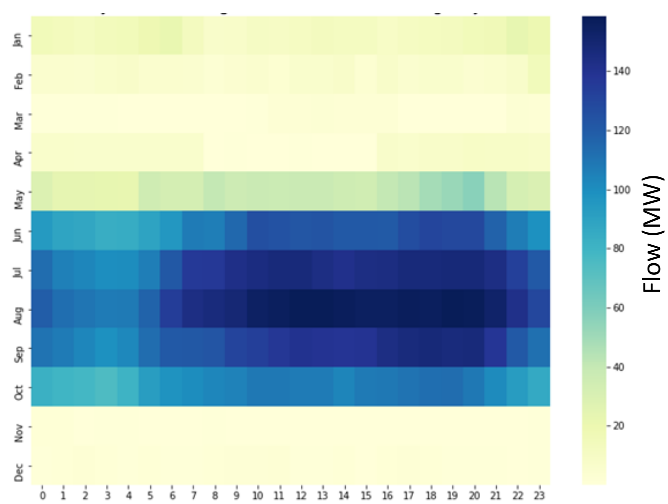
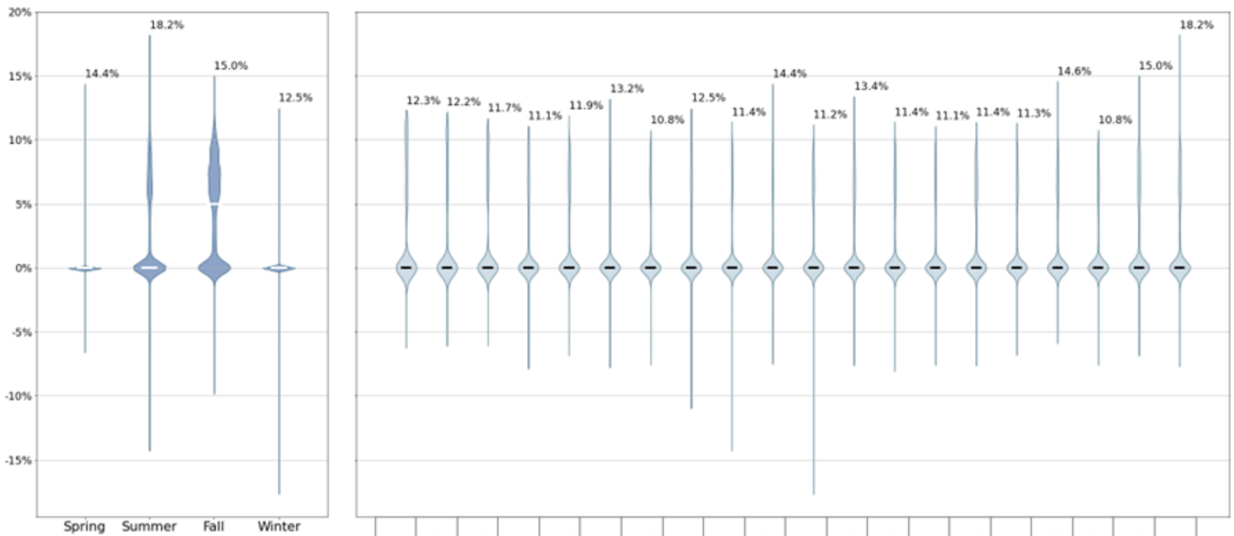


Figure 178: Volney-Scriba Average Delta Flow (Relax-Contract)



The seasonal violin plots below show increases in flows in the summer and fall season and relatively low changes during the winter and spring seasons. The freed energy as a result of relieving congestion on the line ranges from 152-316 GWh per year over the twenty-year study horizon.

Figure 179: Volney-Scriba Delta Hourly Line Utilization

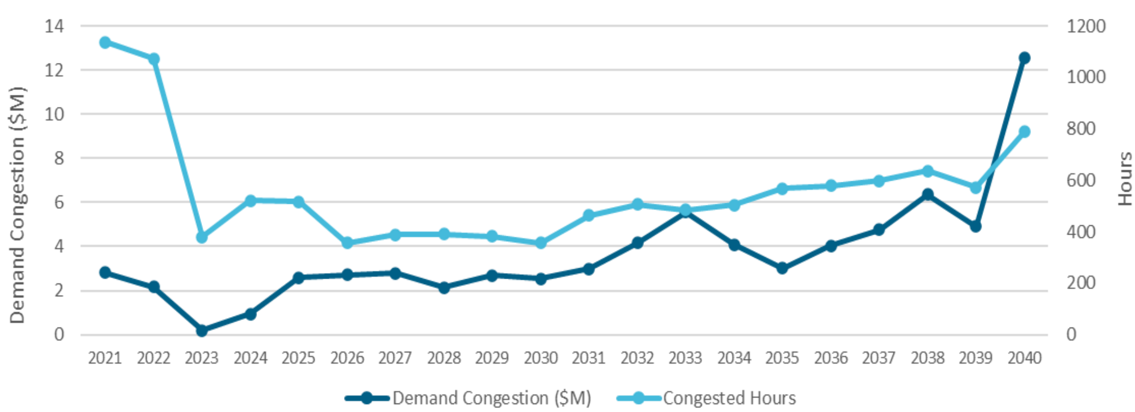


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	316	287	259	193	220	184	157	153	152	164	199	182	205	190	224	178	226	207	255	220

Dunwoodie-Motthaven 345 kV

Line location, parameters and historical congestion for this line are presented in the above section for Baseline Case Congestion Analysis. The table below shows the Contract Case projected demand congestion and number of congested hours. Congestion on Dunwoodie-Motthaven is lower overall when compared to the Baseline Case. This result is caused in part by offshore wind resources that are modeled in-service in the Contract Case. The offshore wind resources supply load in New York City and Long Island, and thereby push back on the flows on this path, reducing congestion.

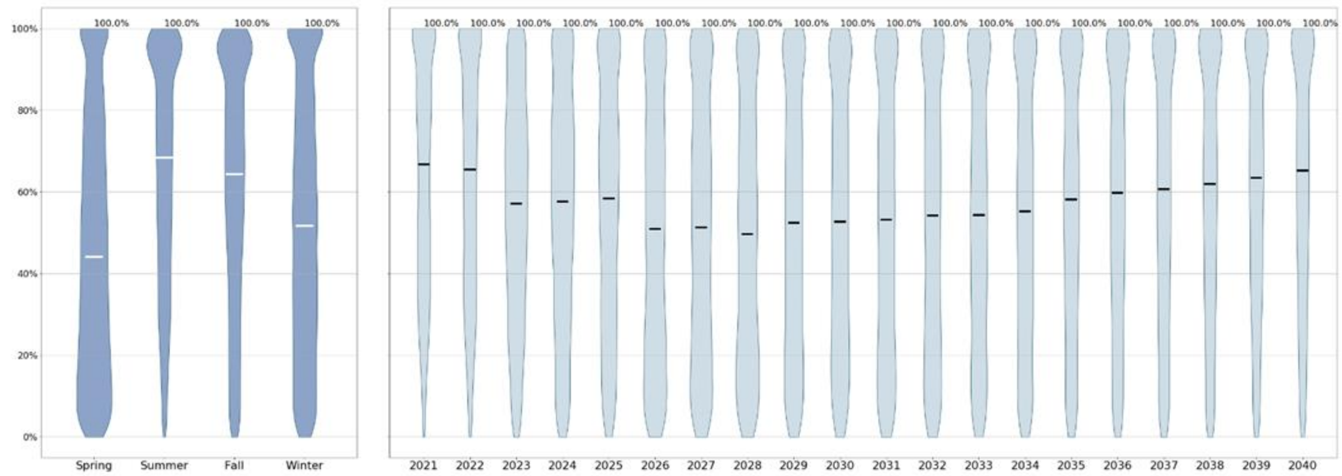
Figure 180: Dunwoodie-Motthaven Contract Case Projected Demand Congestion and Congested Hours



Line utilization on Dunwoodie-Motthaven in the Contract Case is similar to the Baseline Case.

The line utilization is spread out throughout the year and is mostly higher during the summer and fall seasons. Line utilization varies from about 50% to 70% in the study period from 2021-2040.

Figure 181: Dunwoodie-Motthaven Contract Case Hourly Line Utilization



Comparing flows on this path in the Contract Case with that in the Baseline Case shows that the flows are lower for about 50% of the year. The flow duration curve below shows the Contract Case flow range (shown in darker blue) to be lower than the Baseline Case flows (shown in lighter blue). The heatmap shows that the flows do increase in a few hours in the summer period especially during the afternoon peak load hours. Overall, there are limited hours with flows increasing in comparison to the Baseline Case.

Figure 182: Dunwoodie-Motthaven Flow Duration Curve

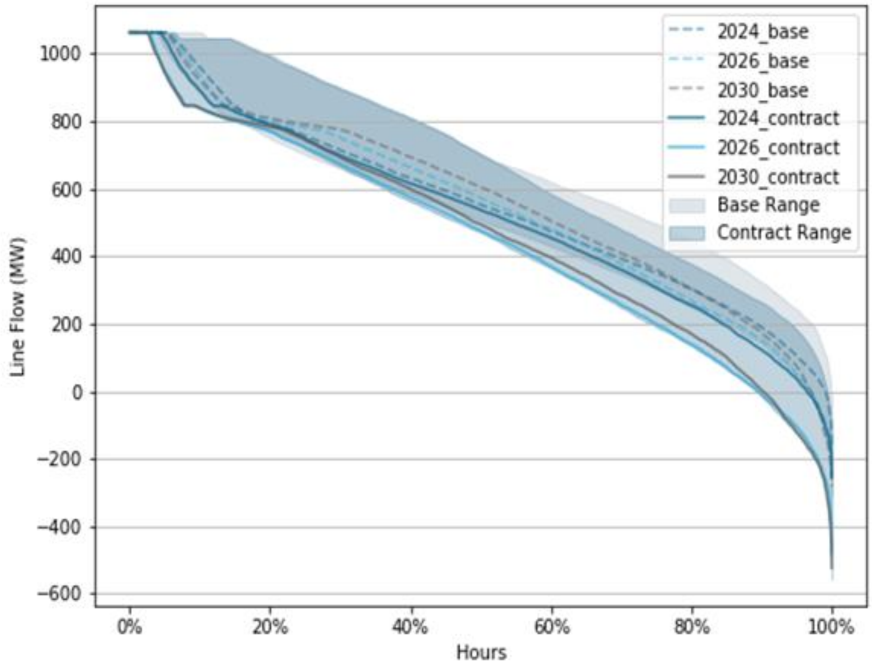
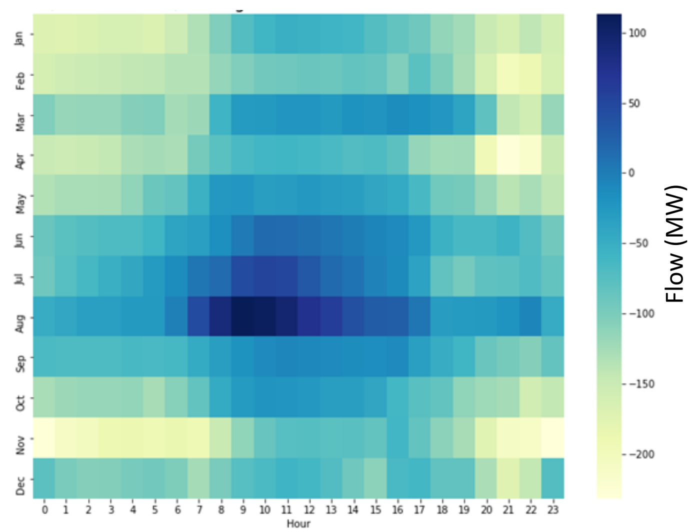


Figure 183: Dunwoodie-Motthaven Average Delta Flow (Contract-Baseline)



The relaxed case flows compared to the Contract Case shows that the flow does not have a significant increase when limits are removed from the lines in the relaxed case. Line flows increase for about 20% of the year in the relaxed case compared to the Contract Case. The heatmap shows that a large increase occurs in the peak load hours in the summer, and morning and evening hours in the winter season.

Figure 184: Dunwoodie-Motthaven Delta Flow Duration Curve (Relax-Contract)

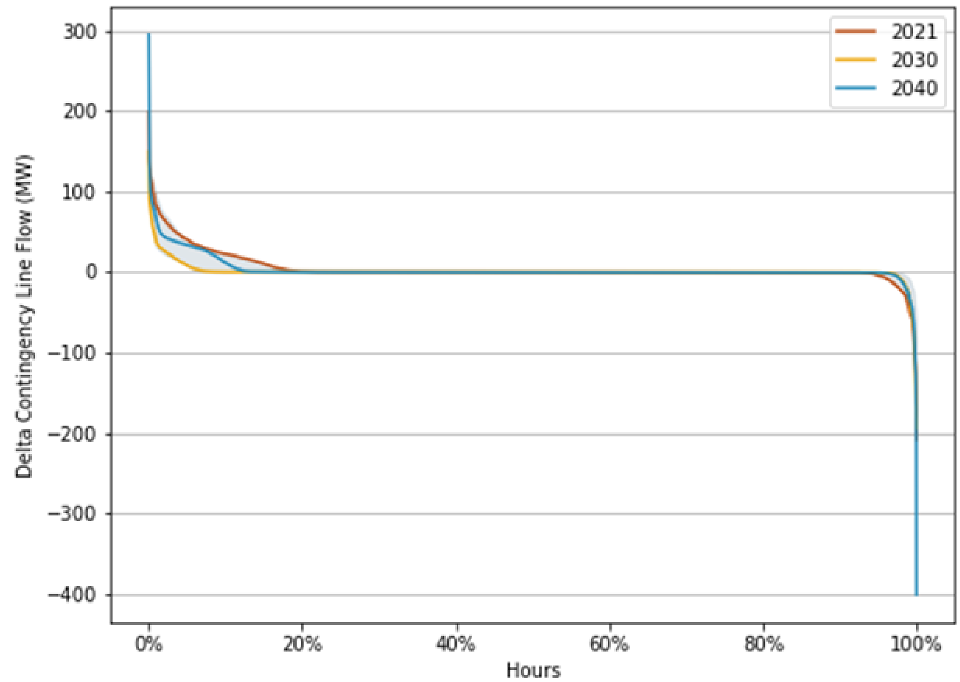
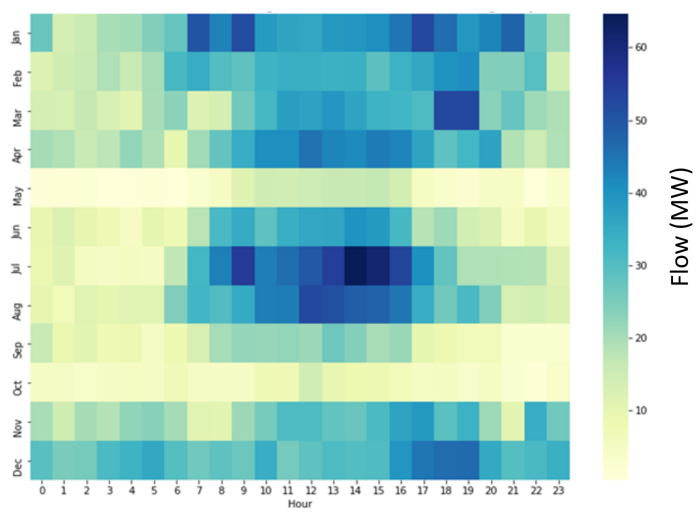
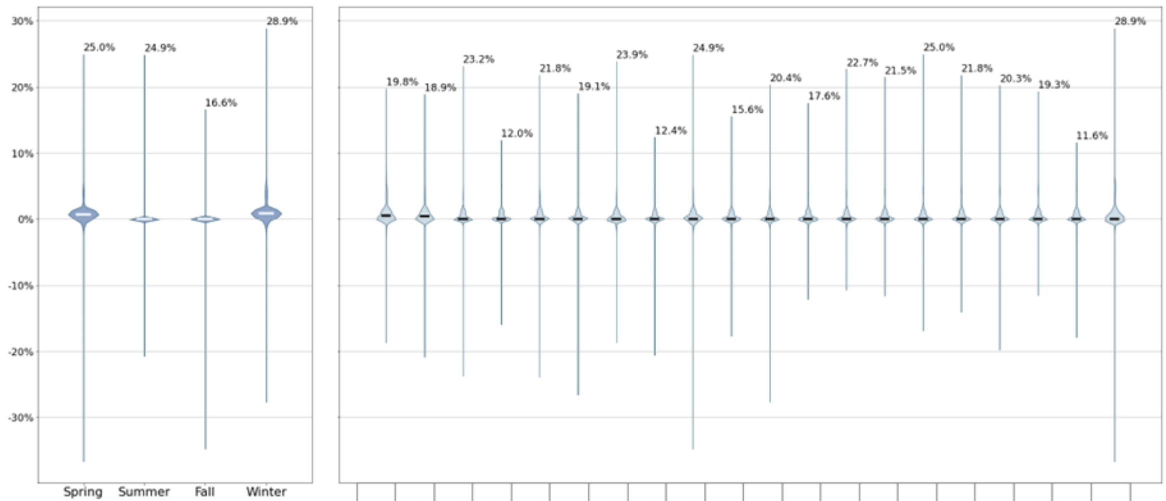


Figure 185: Dunwoodie-Motthaven Average Delta Flow (Relax-Contract)



The limited increase in line flows along this path can also be seen on the violin plots below. Slight increases during the winter and spring season flows can be observed by the bulges and higher spikes in the violin plots. Constraints downstream of this path limit the level of flows through this path in the relaxed case.

Figure 186: Dunwoodie-Motthaven Delta Hourly Line Utilization

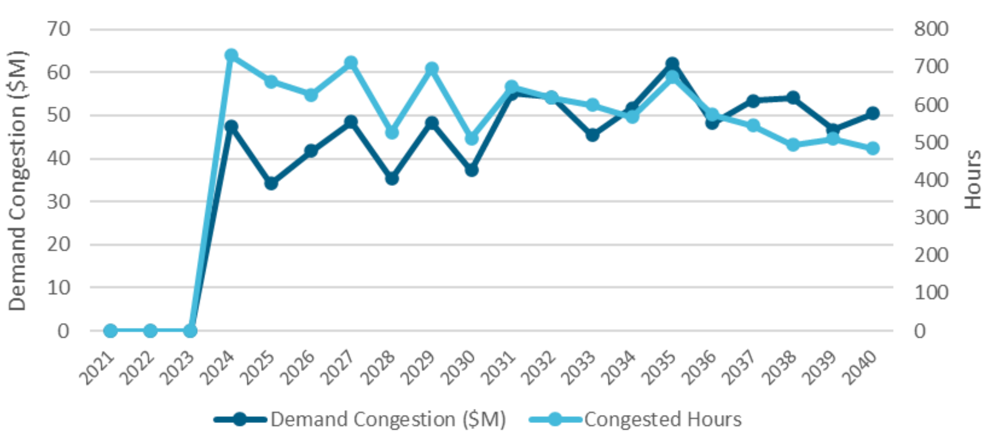


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	37	40	8	11	10	7	9	8	6	4	12	13	14	13	16	17	17	20	15	26

New Scotland-Knickerbocker 345 kV

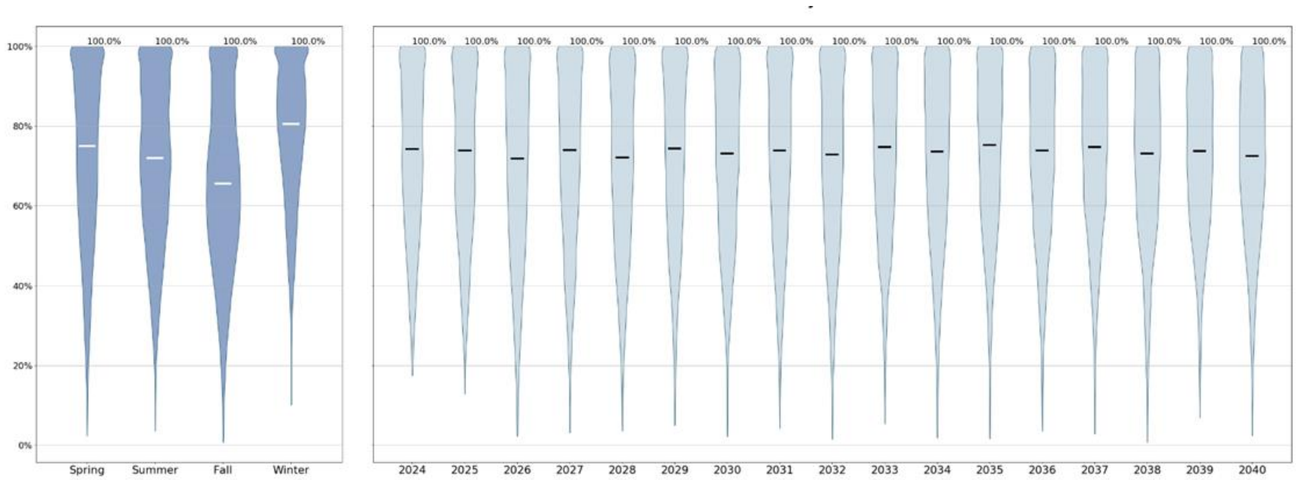
Line location and parameters for this line are presented in the above section for Baseline Case Congestion Analysis. The table below shows the Contract Case projected demand congestion and number of congested hours. Congestion on this path increases significantly with increased flow in the Contract Case compared to the Baseline Case as a result of additional resources being modeled in upstate zones.

Figure 187: New Scotland-Knickerbocker Contract Case Projected Demand Congestion and Congested Hours



Increased flow in the Contract Case can also be seen in the line utilization compared to the Baseline Case. Summer line utilization increases in the Contract Case compared to the Baseline Case. Average line utilization is about 70% across all years in the study period.

Figure 188: New Scotland-Knickerbocker Contract Case Hourly Line Utilization



The flow duration curve below shows the clear difference in flows in the Contract Case relative to the Baseline Case. Flows increase for more than 70% of the year in the Contract Case. The heatmap shows that the flow increase occurs mostly in the early morning to afternoon hours most likely due to new UPV resources generating more upstream of the constraint.

Figure 189: New Scotland-Knickerbocker Flow Duration Curve

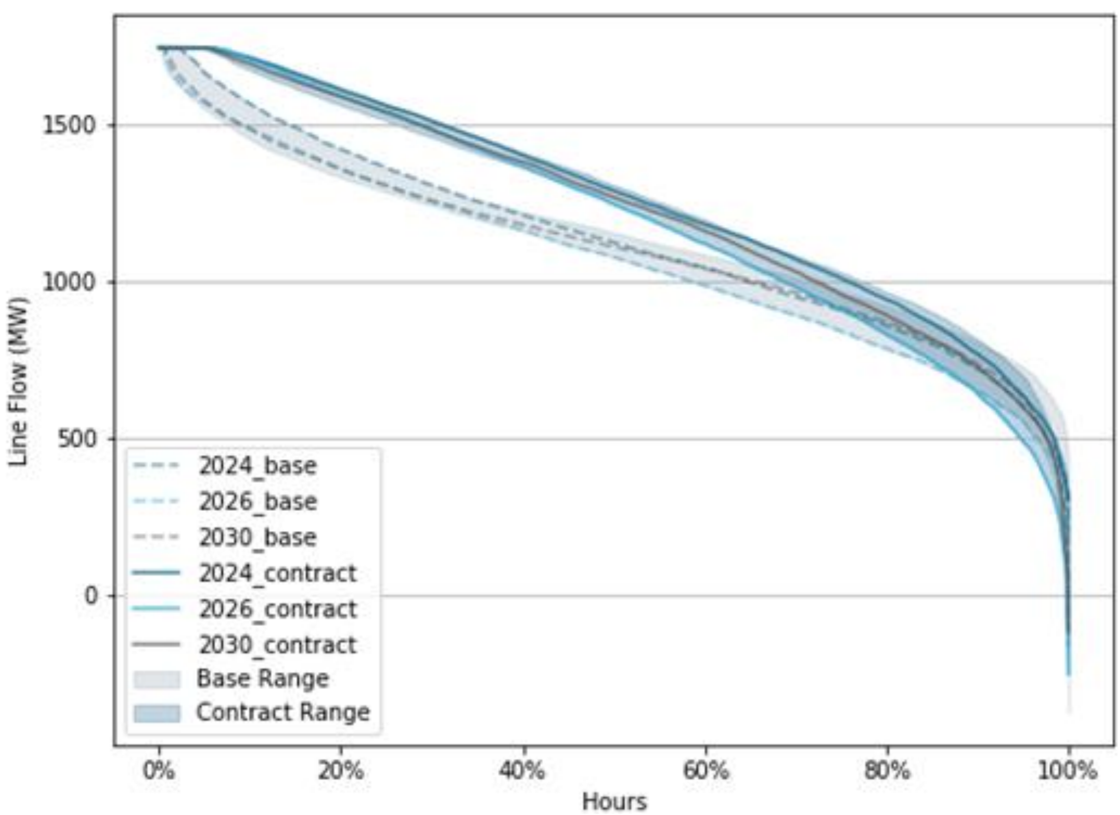
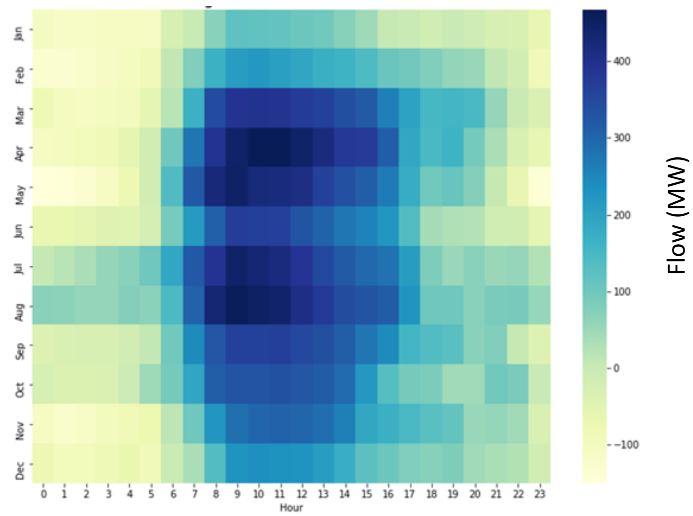


Figure 190: New Scotland-Knickerbocker Average Delta Flow



The relaxed case flows which removes limits on the line is compared to the Contract Case flows in the duration curve chart below. It shows flows increasing for about 20% of the year across the study period. The heatmap shows increase in flow occurring mostly in the winter period in January.

Figure 191: New Scotland-Knickerbocker Delta Flow Duration Curve (Relax-Contract)

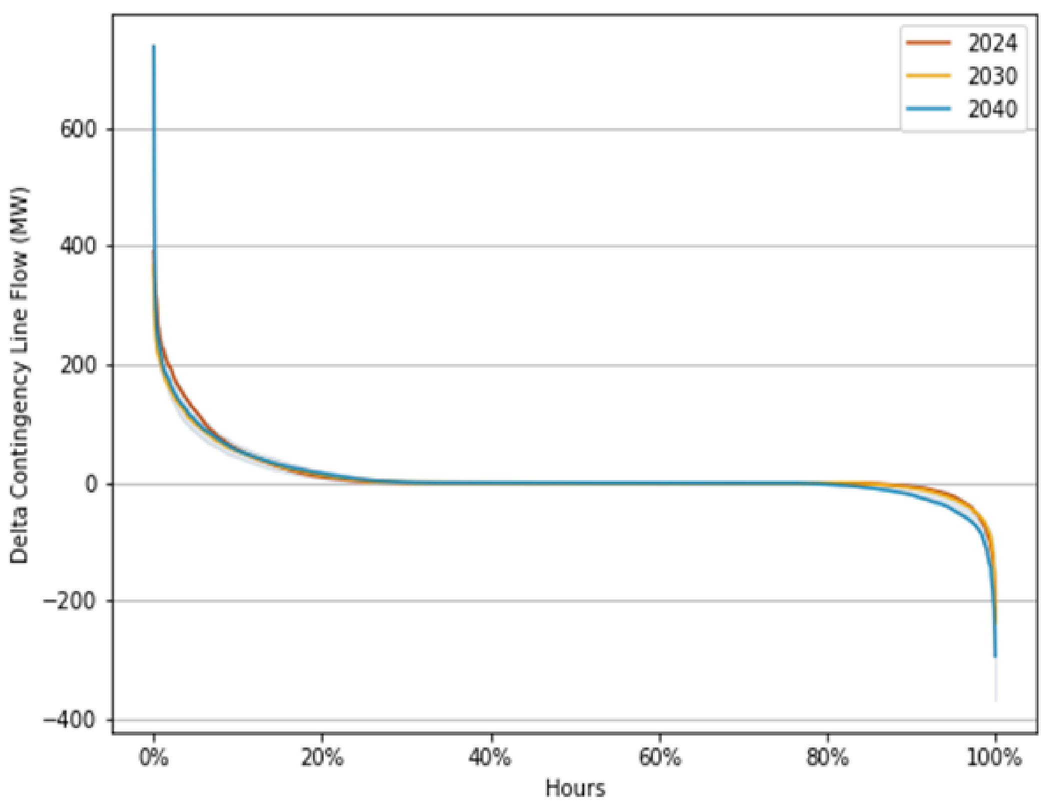
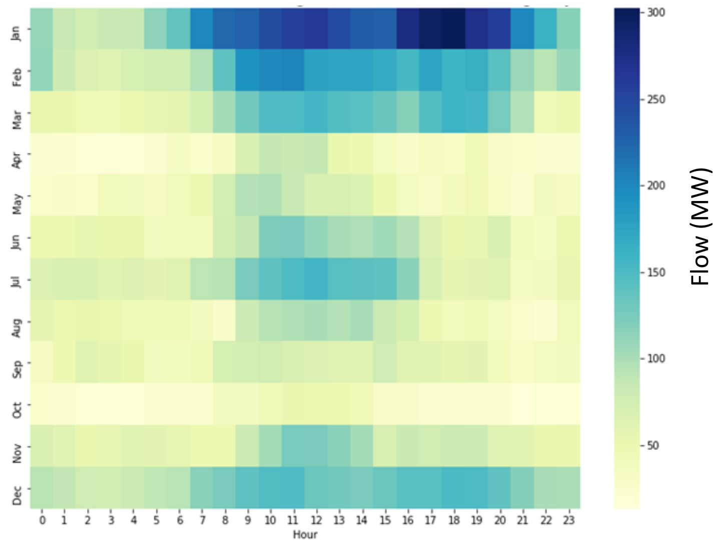
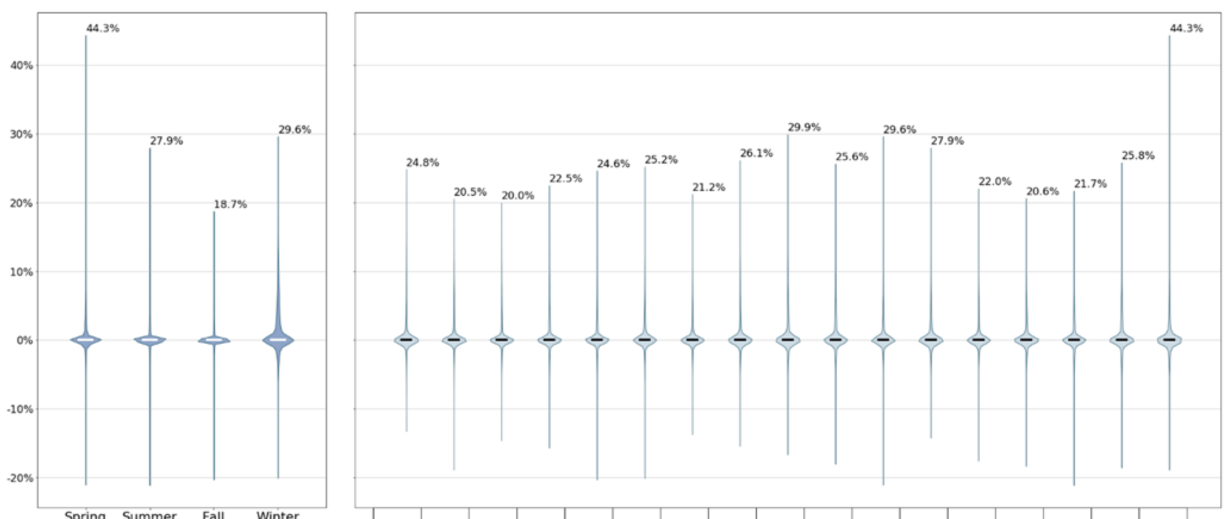


Figure 192: New Scotland-Knickerbocker Average Delta Flow (Relax-Contract)



Relaxed case flow increases in comparison to the Contract Case can be observed in the violin plots below. Freed energy from relaxing the limits on this line ranges from 60-118 GWh per year from 2024-2040. Relaxing this constraint will put more pressure back on the Central East interface and downstream constraints, which limits the flow along this path in the relaxed case.

Figure 193: New Scotland-Knickerbocker Delta Hourly Line Utilization

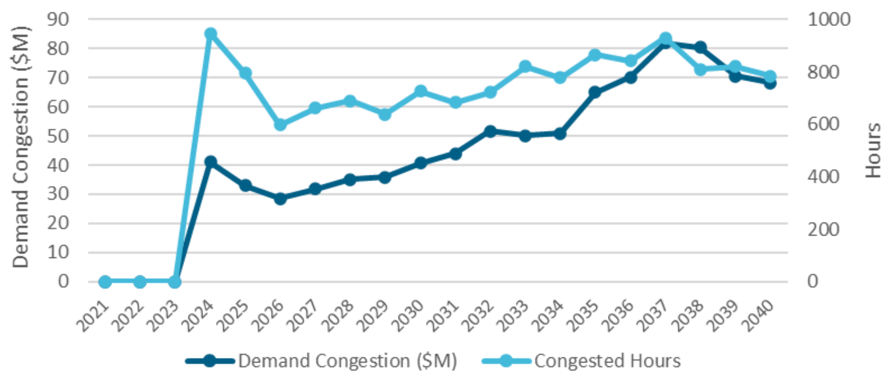


	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	113	107	79	98	77	103	95	101	119	111	100	118	93	96	60	89	80

Sugarloaf-Ramapo 138 kV

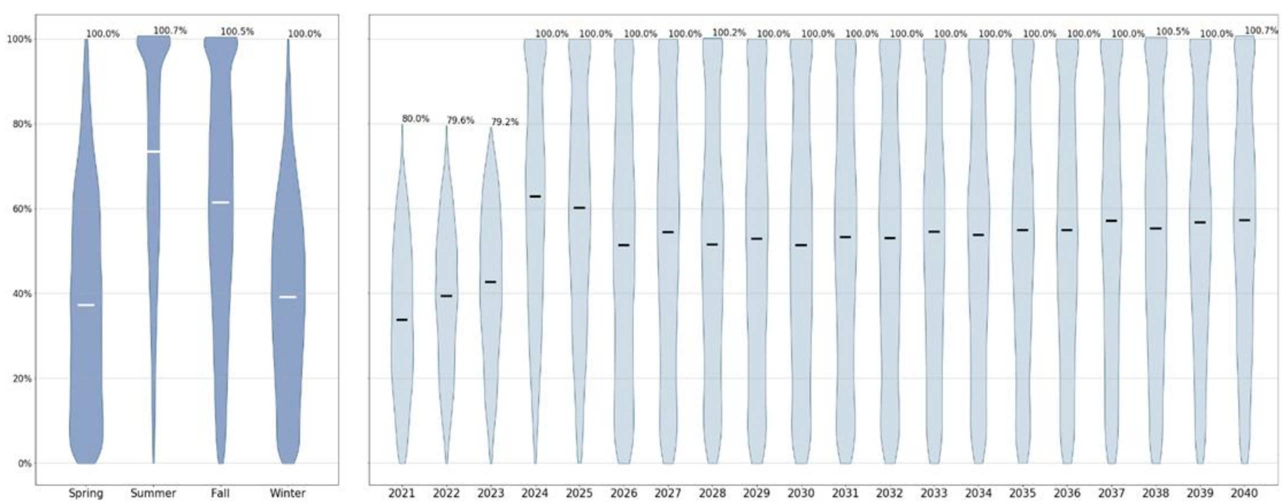
Line location and parameters for this line presented in the above section for Baseline Case Congestion Analysis. The table below shows the Contract Case projected demand congestion and number of congested hours. The congestion in the future projected years starting 2024 are primarily driven by congestion shifted to local transmission downstream of the Segment B project of AC Transmission Public Policy projects placed into service (with the addition of Rock Tavern to Sugarloaf line).

Figure 194: Sugarloaf-Ramapo Contract Case Projected Demand Congestion and Congested Hour



Line utilization on Sugarloaf-Ramapo 138 kV increases slightly during the summer period compared to the Baseline Case line utilization. The flow utilization in this path significantly increased with a portion of Segment B of the AC Transmission Public Policy project in-service in 2024. Higher flow utilization is observed in summer and fall because the seasonal rating is lower than in winter period.

Figure 195: Sugarloaf-Ramapo Contract Case Hourly Line Utilization



Compared to the Baseline Case, the flow increases slightly especially during the early morning and afternoon hours mostly occurring during the summer peak load period. Higher flows are a result of upstate renewable resources flowing to serve downstate loads.

Figure 196: Sugarloaf-Ramapo Flow Duration

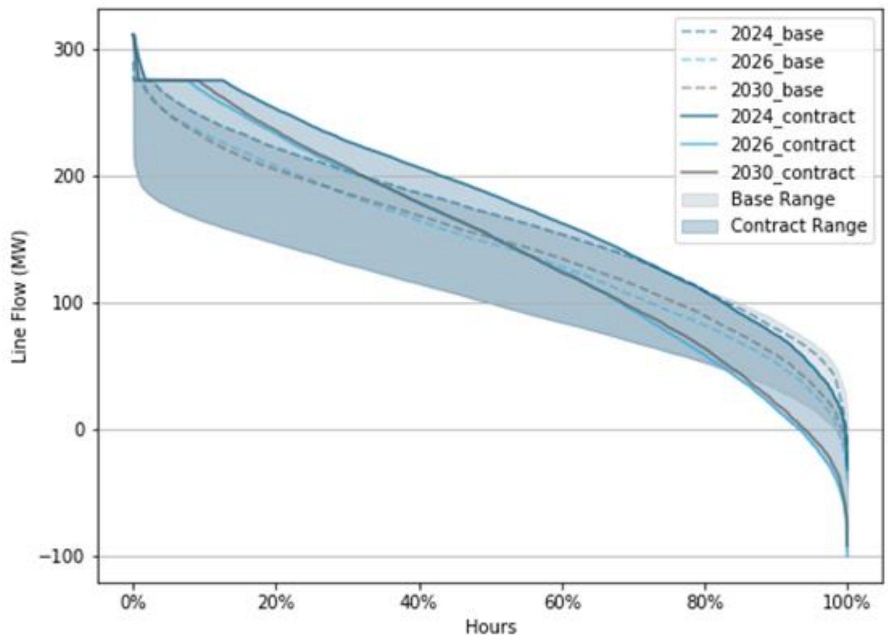
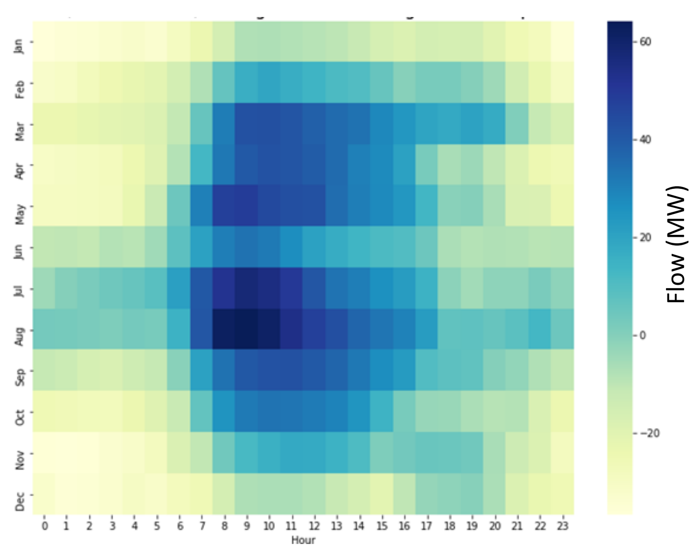


Figure 197: Sugarloaf-Ramapo Average Delta Flow (Contract-Baseline)



The relaxed case flows when compared to the Contract Case for Sugarloaf-Ramapo show an increase for about 20% of the year. Flow increases are mostly concentrated during the peak load hours in summer.

Figure 198: Sugarloaf-Ramapo Delta Flow Duration Curve (Relax-Contract)

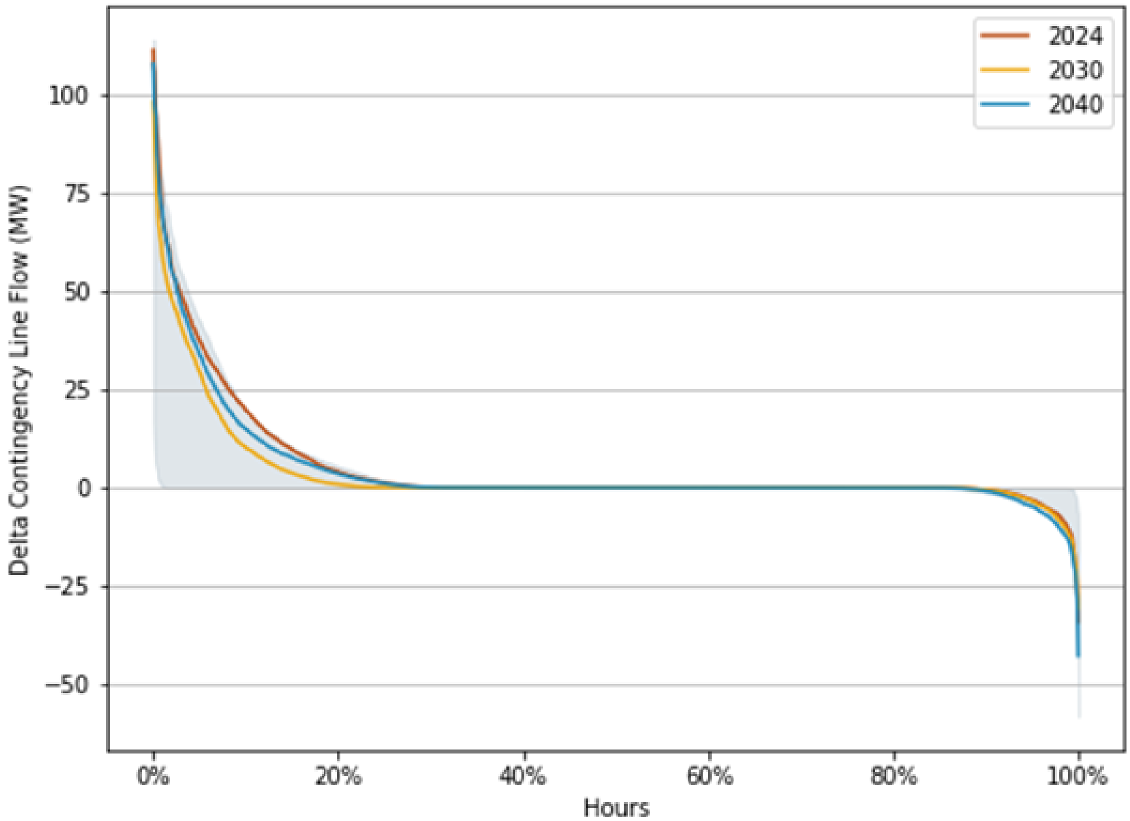
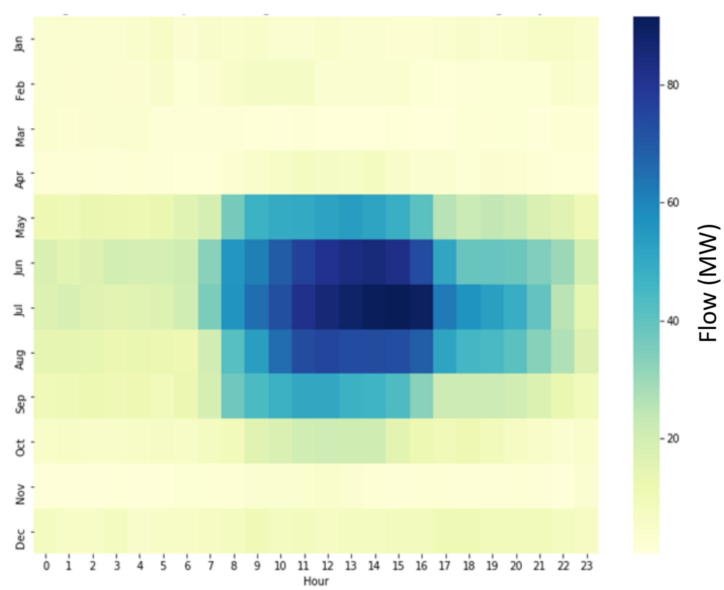
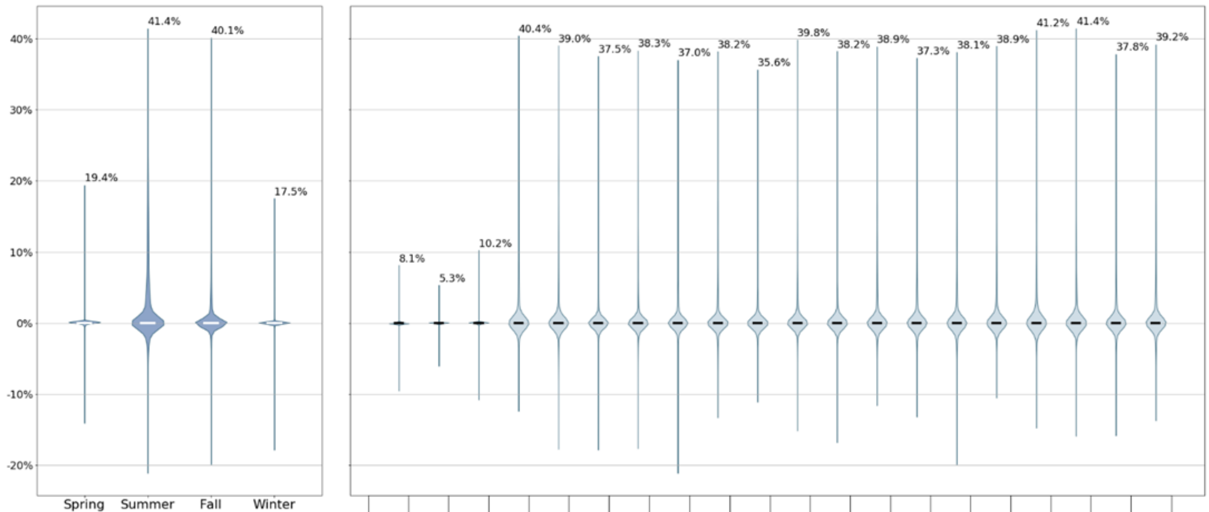


Figure 199: Sugarloaf-Ramapo Average Delta Flow (Relax-Contract)



Line utilization in relaxed case increase in the summer and fall months can be seen in the violin plots below. Freed energy ranges from 23-47 GWh from 2024-2040.

Figure 200: Sugarloaf-Ramapo Delta Hourly Line Utilization



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	0	0	0	43	35	23	26	30	26	28	30	33	38	37	36	43	47	43	35	36

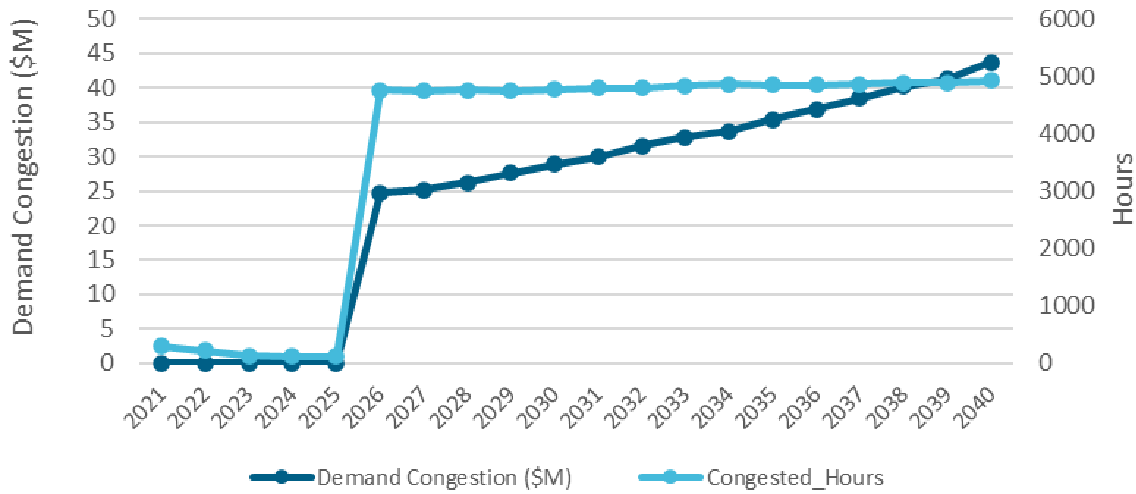
Barrett-Valley Stream 138 kV

The Barrett to Valley Stream constraint is studied in the Contract Case as a result of congestion occurring on the line due to offshore wind resources being modeled as interconnecting at the Barrett substation. Congestion is due to the contingency which secures a line with the loss of another parallel line going from Barrett to Valley Stream. Specific upgrades to the system at the point of interconnection for future offshore wind projects were not modeled as part of this study but will be studied as part of the Public Policy Transmission Project.

Figure 201: Barrett-Valley Stream Line Location and Parameters

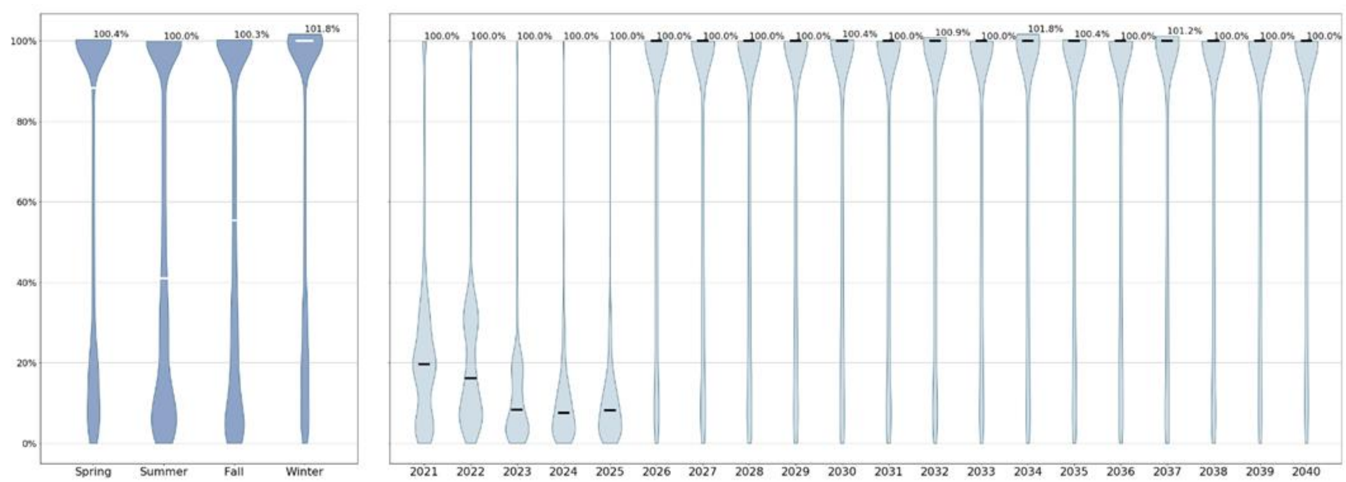
Type	Double Circuit 138 kV	
Normal Op. Rating	160/176 MW	168/184 MW
Contingency Op. Rating	261/271 MW	268/279 MW
Length	~4 Miles	
Owner	Long Island Power Authority	

Figure 202: Barrett-Valley Stream Contract Case Projected Demand Congestion and Congested Hour



This line is congested very little prior to 2026 but the congestion increases significantly after offshore wind project is modeled in-service. The unit is injecting at a lower kV bus which is not designed to handle the amount of power produced by a large project. The violin plots below show a significant increase in line utilization starting in 2026 across all seasons.

Figure 203: Barrett-Valley Stream Contract Case Hourly Line Utilization



Comparing the flows in the Contract Case to that in the Baseline Case in the plots below, it is clear that the flow increases considerably in the years after 2026. The Contract Case flow duration curve range is greater than the Baseline flow range as the early years in the Contract Case still has flows similar to the Baseline case but increases in the years after 2026. The heatmap shows that the line has increased flows on almost all hours of the year in the Contract Case when the project is modeled.

Figure 204: Barrett to Valley Stream Flow Duration Curve

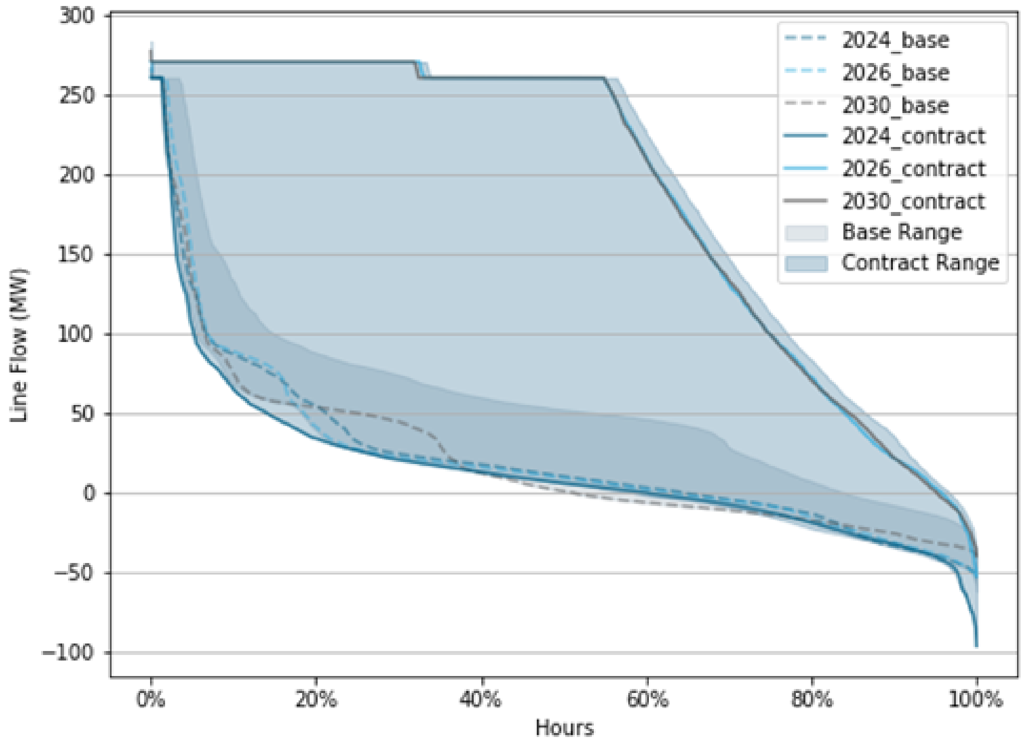
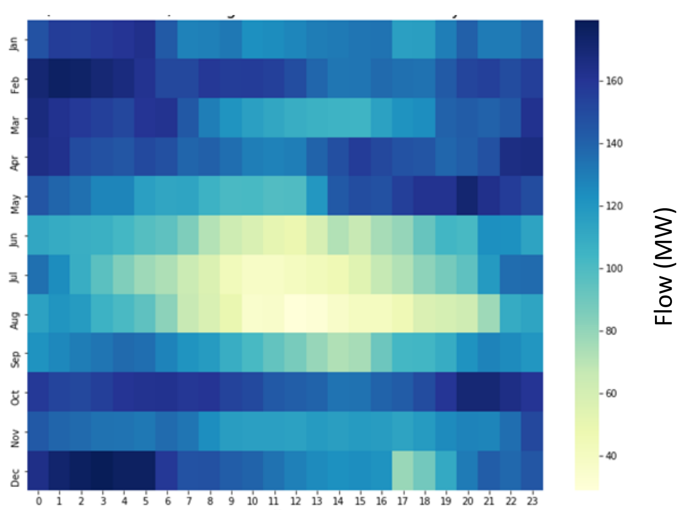


Figure 205: Barrett-Valley Stream Average Delta Flow (Contract-Baseline)



Relaxing the line limits on Barrett-Valley Stream increases the flow on the line significantly in the relaxed case compared to the Contract Case. The flow duration curves below shows a large delta in the later years compared to early years in the study period. Relaxing the limits on the line allows all of the renewable energy to export out of the interconnection point to serve load. The heatmap shows that the flow increases on almost all hours throughout the year.

Figure 206: Barrett-Valley Stream Delta Flow Duration Curve (Relax-Contract)

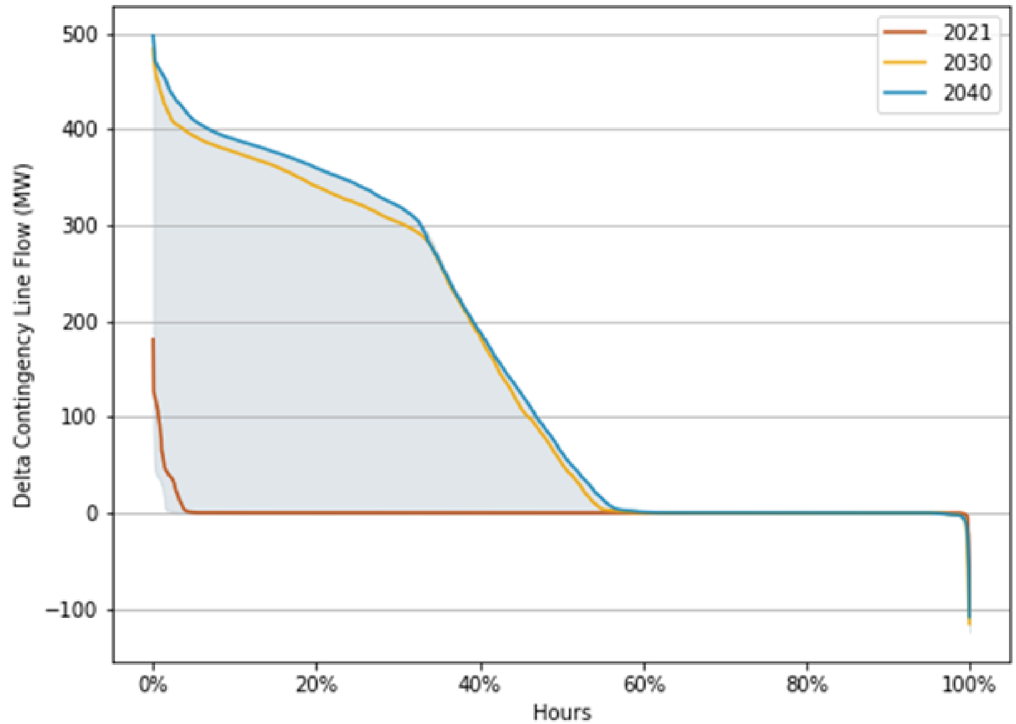
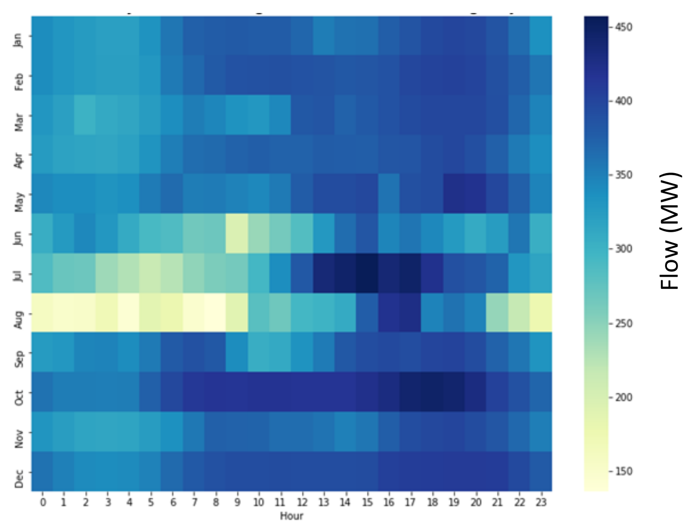
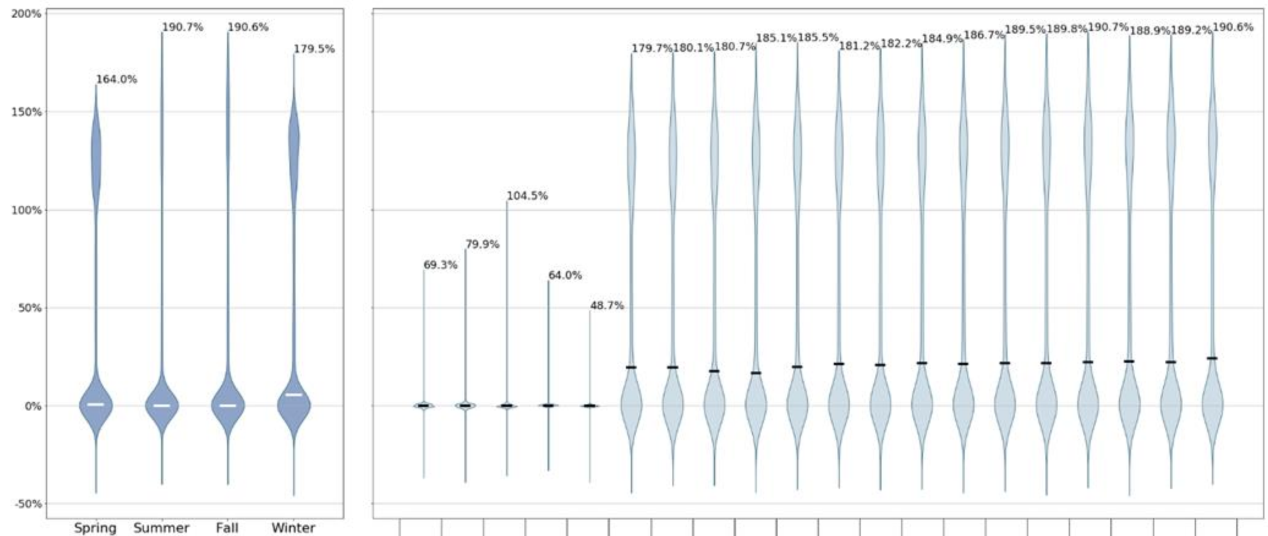


Figure 207: Barrett-Valley Stream Average Delta Flows



The violin plots below show increased flow on the path when line limits are relaxed compared to the Contract Case. Line utilization along this path is increased significantly with flows nearing four times the flow on the Contract Case after 2026. On average, line utilization increases about 25% after 2026 with very high peaks. The freed energy metric amounts to approximately 1,300 GWh per year on average after 2026 when line limits are relaxed.

Figure 208: Barrett-Valley Stream Delta Hourly Line Utilization



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	16	15	6	4	3	1274	1270	1266	1263	1279	1290	1292	1295	1298	1308	1316	1324	1333	1335	1348

Golah-Mortimer 115 kV

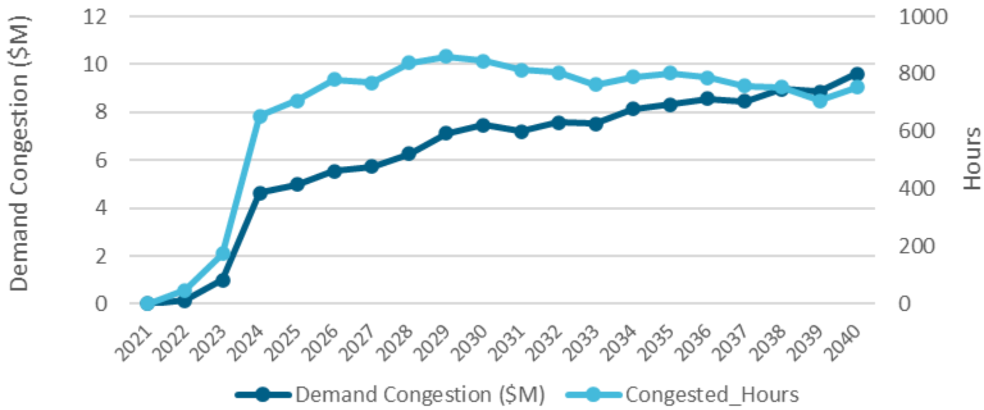
This constraint lies in pocket W1 in the Contract and Policy Cases. Additional analysis on the pockets is presented in Appendix J. This line is located in western New York closer to Rochester. This is a single circuit 115 kV line which flows power from the Golah 115 kV bus to the Mortimer 115 kV bus. The line location and parameters are shown below.

Figure 209: Golah-Mortimer Line Location and Parameters

Type	Single Circuit 115 kV
Normal Op. Rating	120/148 MW
Contingency Op. Rating	
Length	~10 Miles
Owner	National Grid

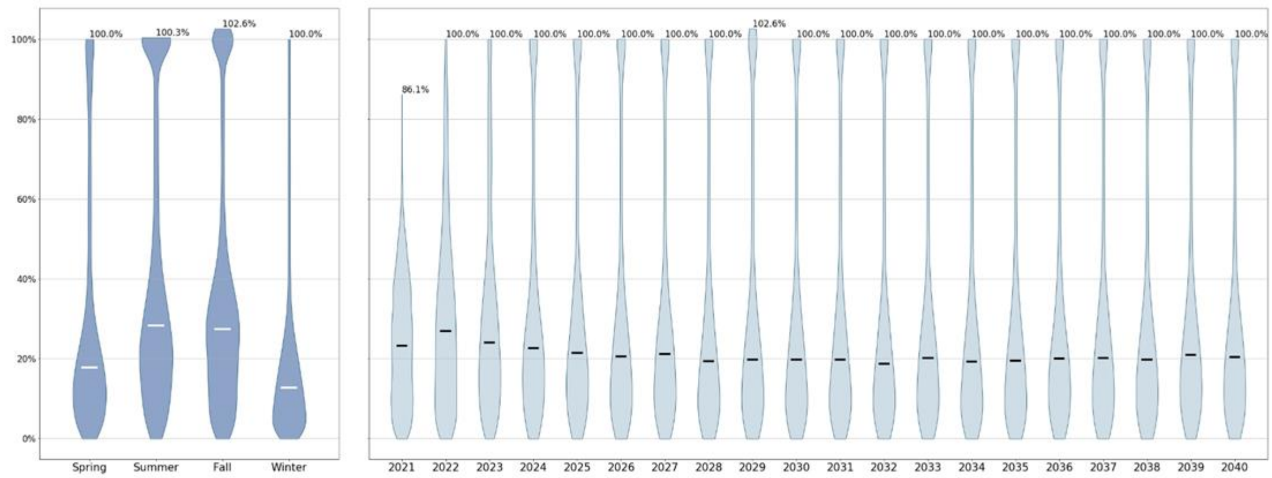
Congestion on this path is primarily due to UPV resources sited upstream of constraints that flow into load centers in zone B. The congestion increases on the line as more resources are added upstream of the constraint along the 115 kV corridor.

Figure 210: Golah-Mortimer Contract Case Projected Demand Congestion and Congested Hours



The line is mostly congested during the summer and fall period. Line utilization is on average around 20% across all years in the study period with peak periods showing full line utilization. Gradual increases in line flow and utilization result from upstate resources coming online.

Figure 211: Golah-Mortimer Contract Case Hourly Line Utilization



When compared to the Baseline Case, flows along this path are higher in the Contract Case on almost all hours of the year as seen on the flow duration curve below. The heatmap shows that the flow increase is highest during the afternoon and morning hours, indicating that the flow is mostly from UPV resources upstream of the constraint.

Figure 212: Golah-Mortimer Flow Duration Curve

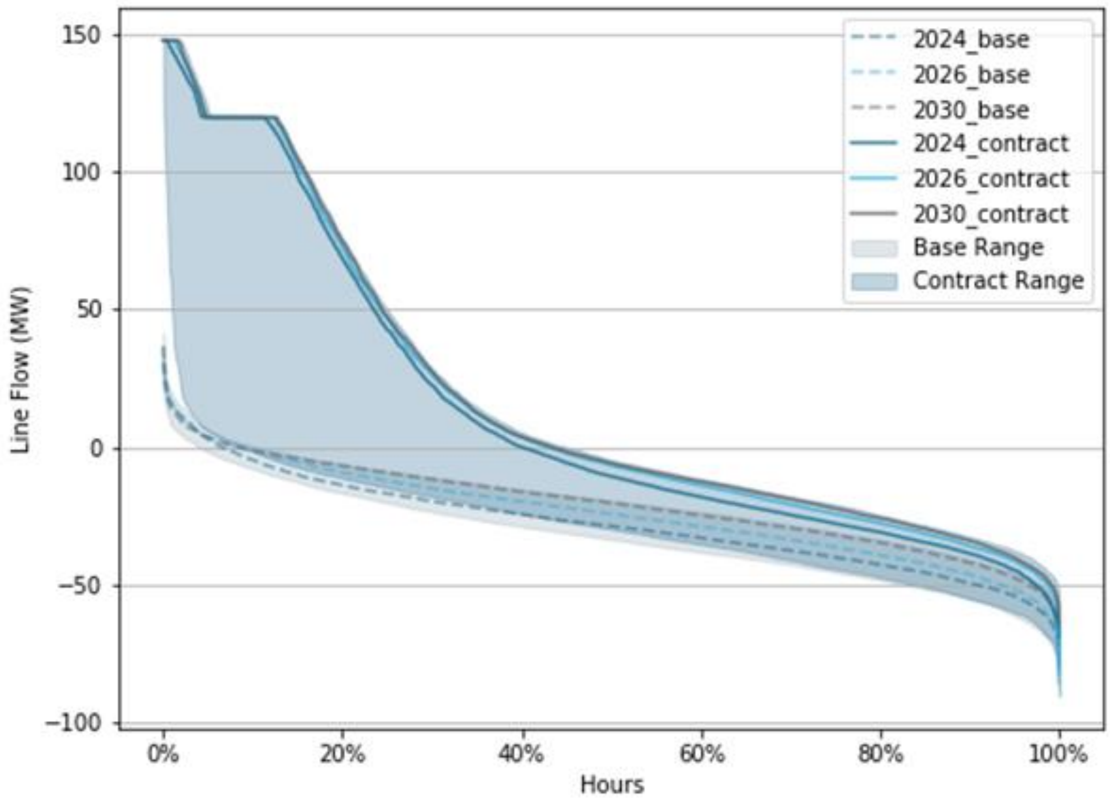
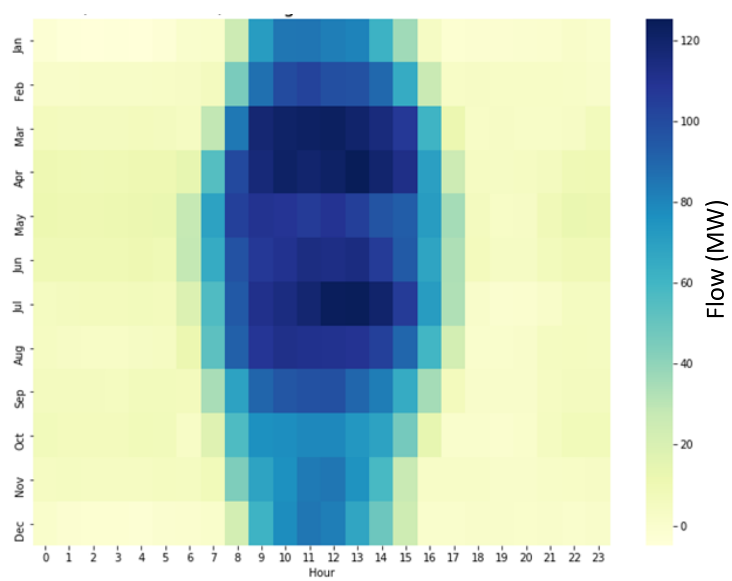


Figure 213: Golah-Mortimer Average Delta Flow



The relaxed case flows are marginally higher with about 10% of the hours showing increased flows compared to the Contract Case. Flow increase occurs during the afternoon hours in the summer months.

Figure 214: Golah-Mortimer Delta Flow Duration Curve (Relax-Contract)

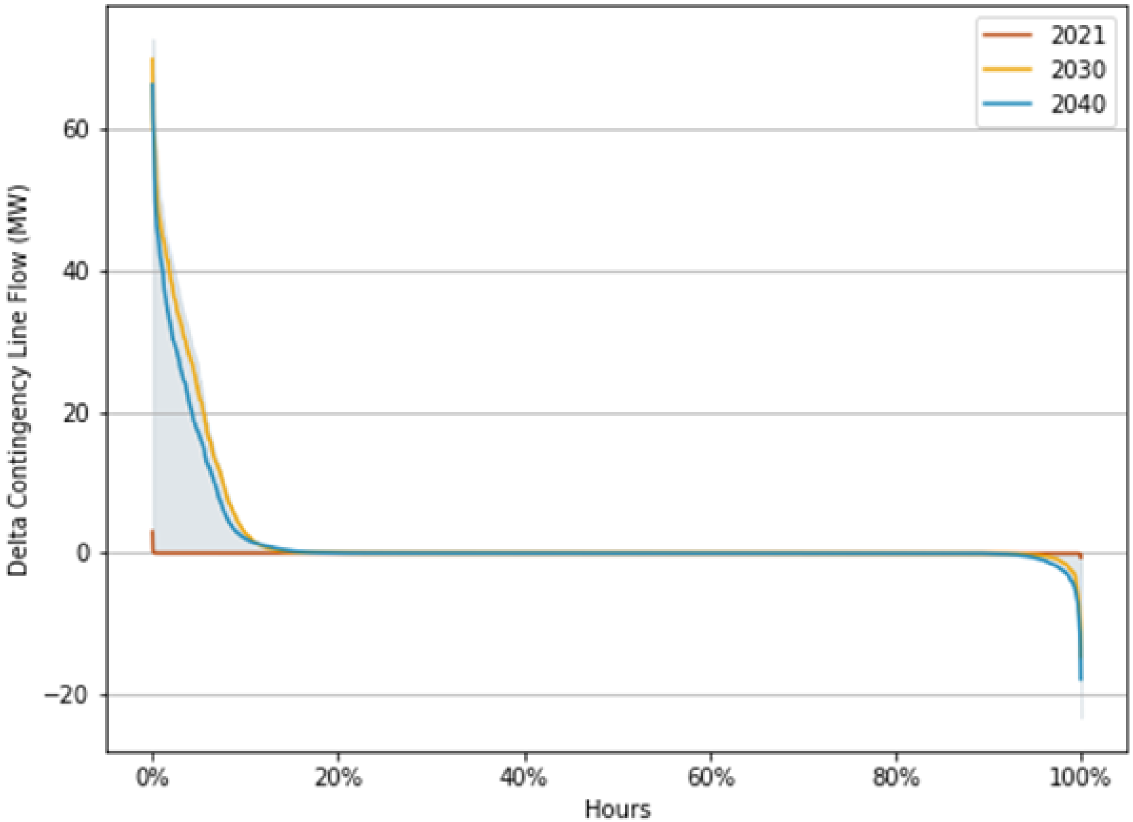
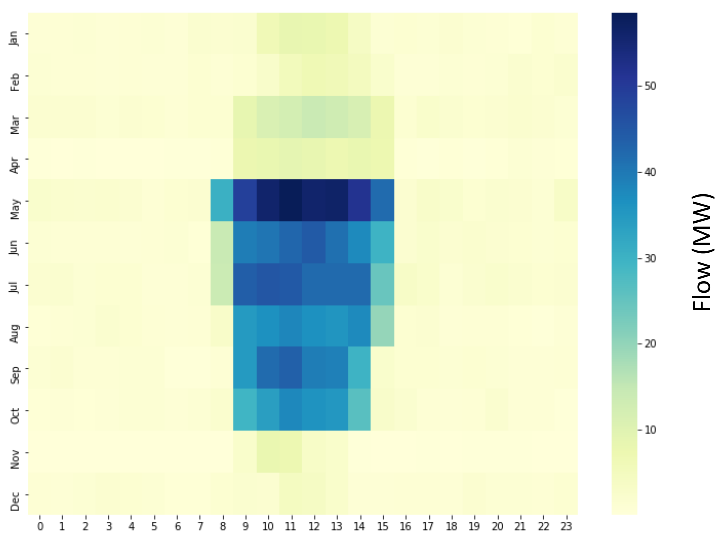
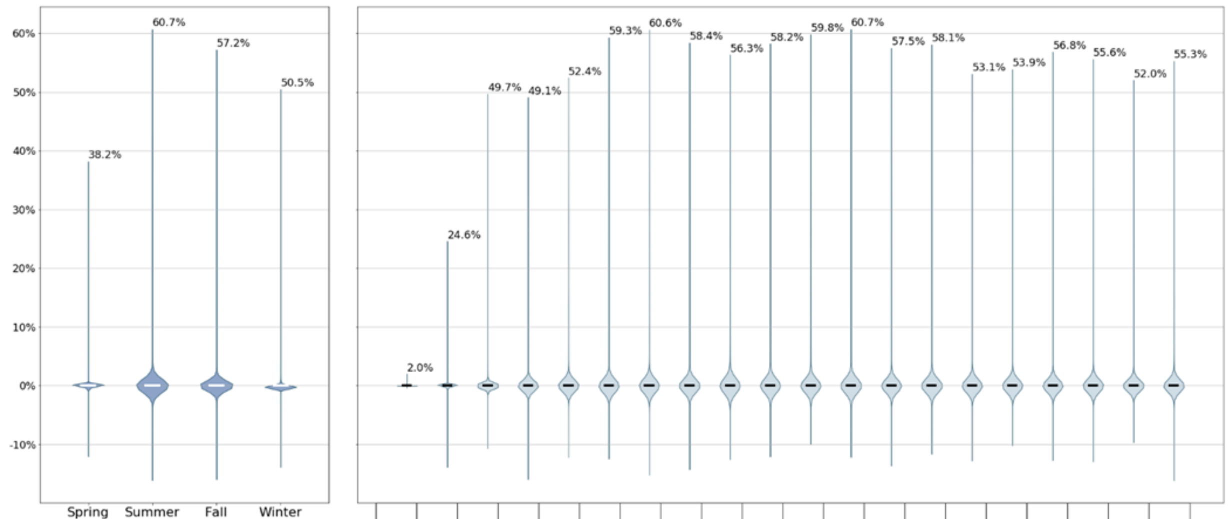


Figure 215: Golah-Mortimer Average Delta Flow (Relax-Contract)



Marginal increase in flow under relaxed case can be seen in the violin plots below. Higher peaks in the delta violin plots for individual years are observed with increasing renewable energy injections.

Figure 216: Golah-Mortimer Delta Hourly Line Utilization

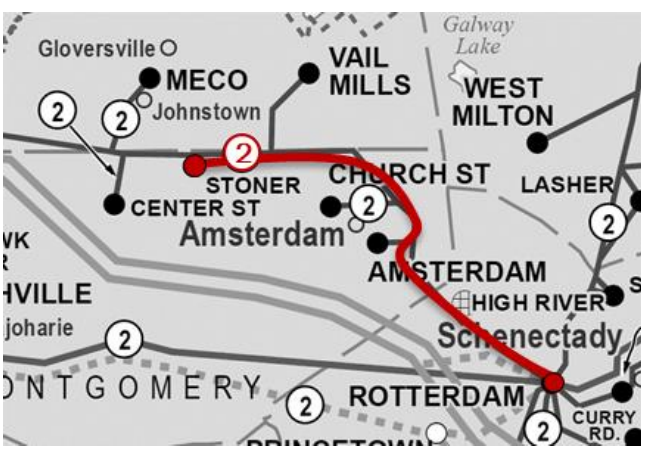


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	0	0	2	13	15	18	19	19	22	20	19	20	17	18	18	18	16	17	15	16

Stoner-Rotterdam 115 kV

Stoner to Rotterdam is a 115 kV double circuit line along the 115 kV corridor from the Inghams 115 kV to the Rotterdam 115 kV substation, which is directly downstream of the Central East interface. This constraint lies in Pocket Y1 in the Contract and Policy Cases. A lot of contracted UPV resources are modeled along this corridor in Montgomery County looking to interconnect at various tap buses along this path. The line location and parameters are shown below.

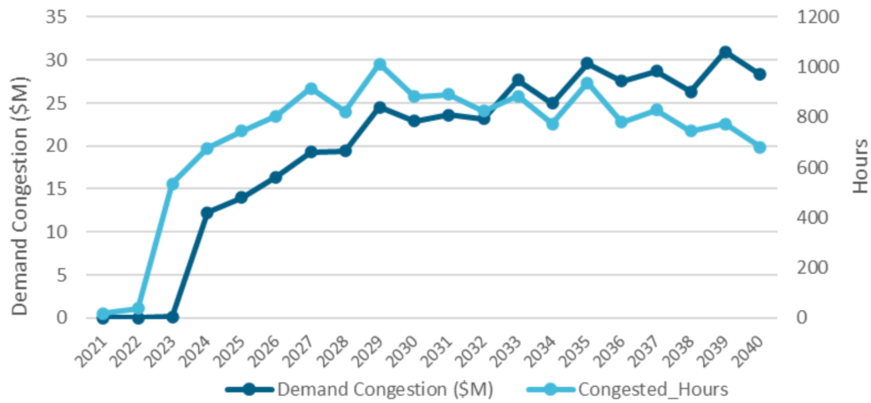
Figure 217: Stoner-Rotterdam Line Location and Parameters



Type	Double Circuit 115 kV
Normal Op. Rating	74/74 MW
Contingency Op. Rating	74/ 111 MW
Length	~23 miles
Owner	National Grid

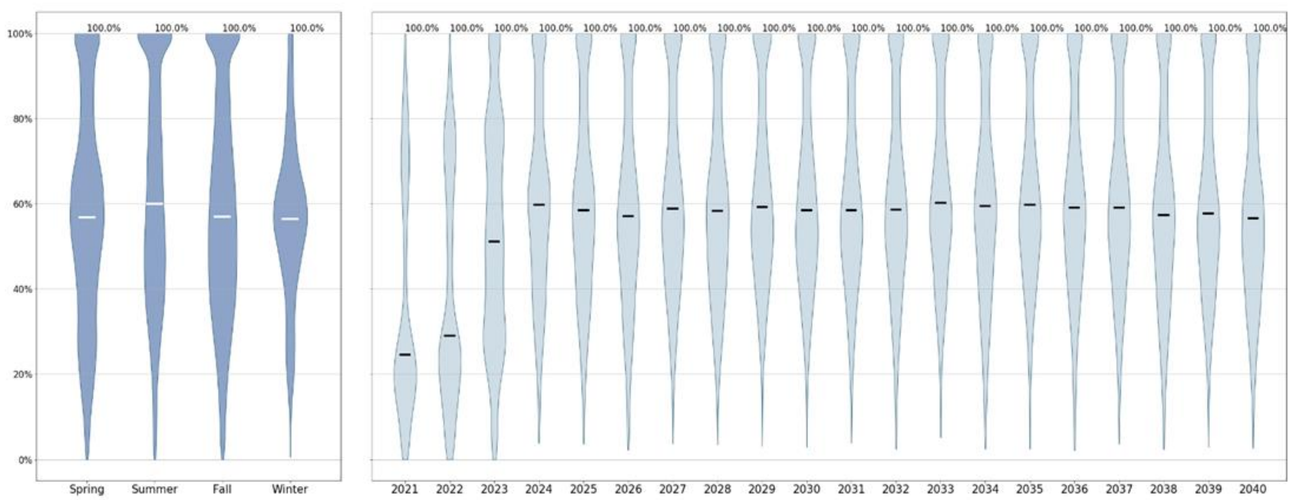
Congestion on this path in the Contract Case is projected to increase as more resources are added upstream of the line. The demand congestion and congested hour chart below shows increasing amounts of congestion as the study progresses due to modeling additional resources in-service in the Contract Case.

Figure 218: Stoner-Rotterdam Contract Case Projected Demand Congestion and Congested Hour



The violin plots for line utilization show a gradual increase in average line utilization in successive study years. Line utilization is slightly higher in the summer and fall periods due to increased output from UPV resources. On average, the line utilization is about 60%.

Figure 219: Stoner-Rotterdam Contract Case Hourly Line Utilization



Compared to Baseline Case flows, flows in the Contract Case along this path is larger for most hours in the year as shown in the flow duration curve below. The heatmap shows that the highest flow increase occurs during the late morning and afternoon hours with shape similar to a solar PV curve. This indicates that the flow on the line increases due to new contracted UPV resources injecting energy along this path during these hours.

Figure 220: Stoner-Rotterdam Flow Duration Curve

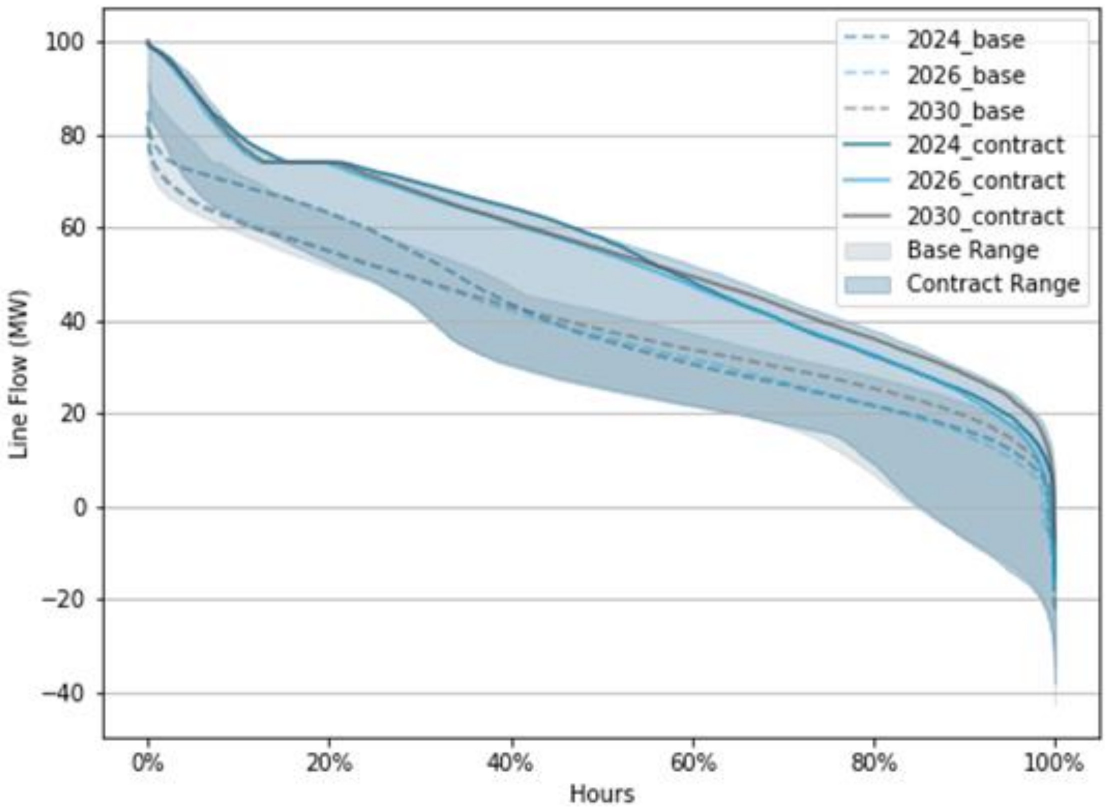
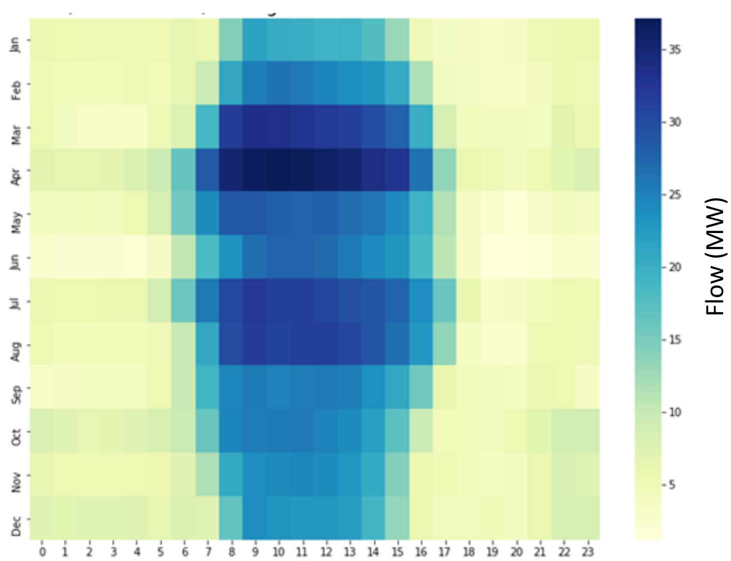


Figure 221: Stoner-Rotterdam Average Delta Flow (Contract-Baseline)



Relaxing the constraint by removing line limits along the path does not significantly change the flow on the line. The flow duration curve below shows the delta change in flow in the relaxed case as compared to the flow in the Contract Case. The relaxed case has higher flows in about 20% of the year in years after 2024. The heatmap shows that the increase in flow in the relaxed case occurs when UPV output is expected to be high and when more flow is expected flowing across the Central

East interface.

Figure 222: Stoner-Rotterdam Delta Flow Duration Curve (Relax-Contract)

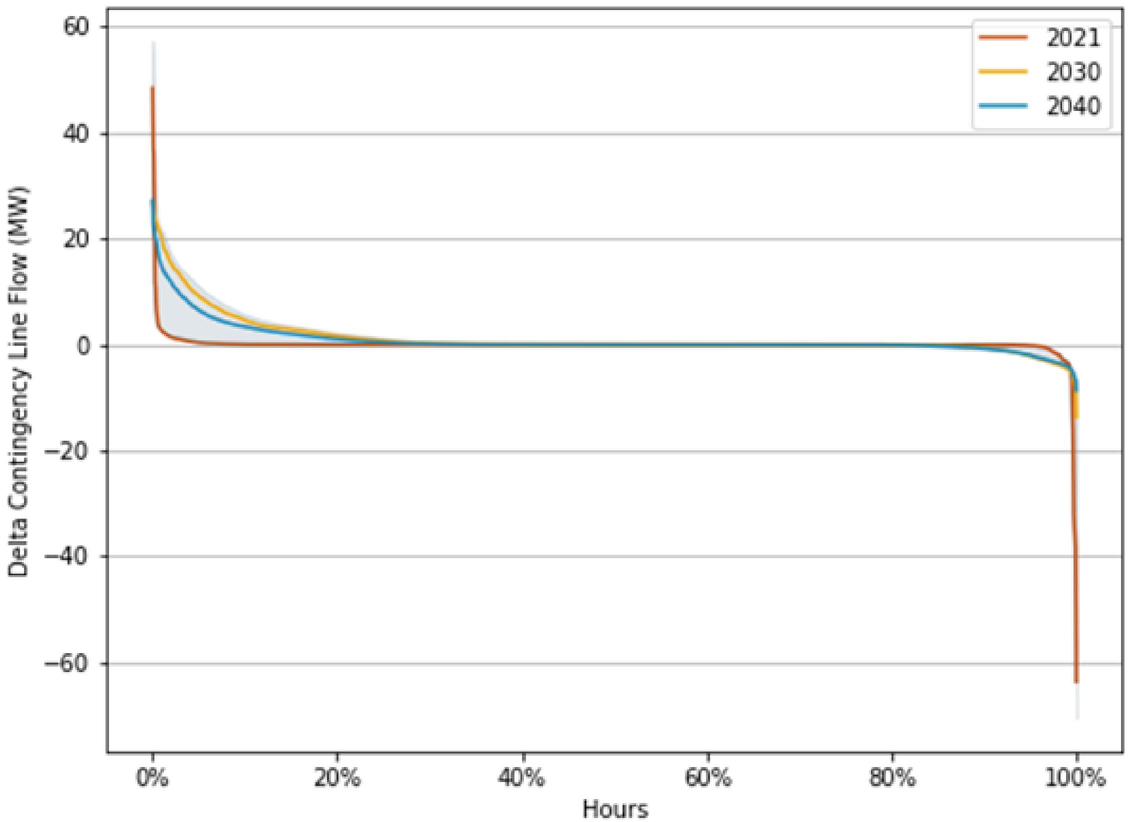
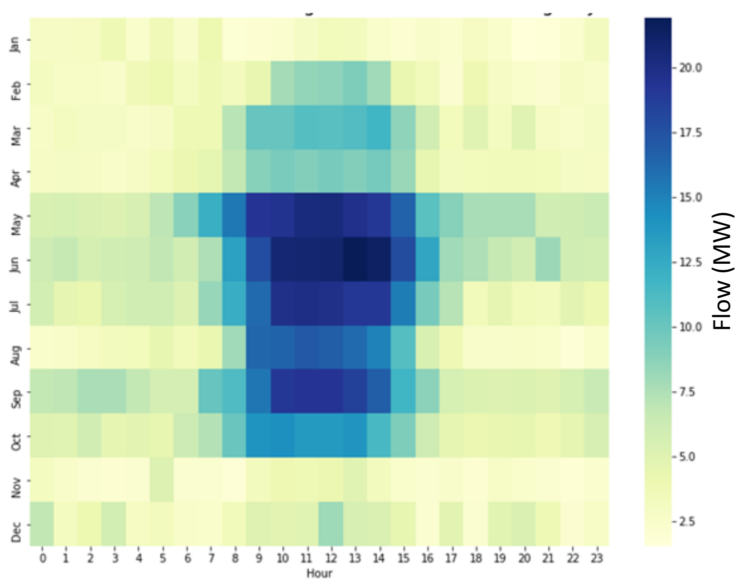
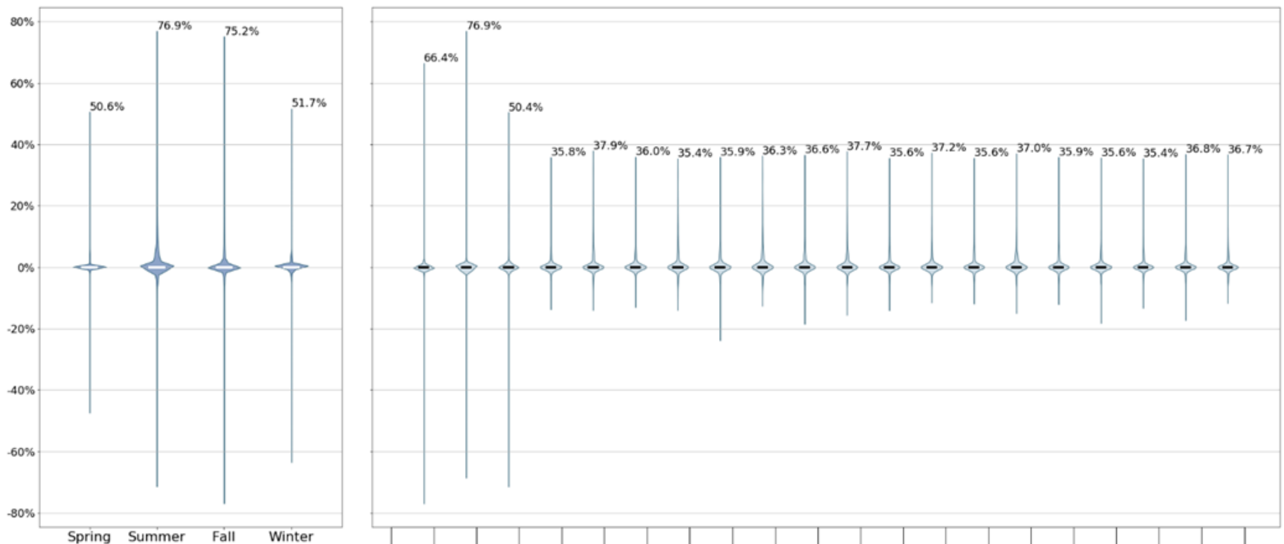


Figure 223: Stoner-Rotterdam Average Delta Flow (Relax-Contract)



Relaxing line limits along this path allows for additional UPV resources to inject energy into the system and reduces curtailment. Increased utilization in the relaxed case can be seen in the violin plots below. Overall line utilization increase remains low but there are periods with high peaks indicating additional injection of power through this path in limited hours.

Figure 224: Stoner-Rotterdam Delta Hourly Line Utilization

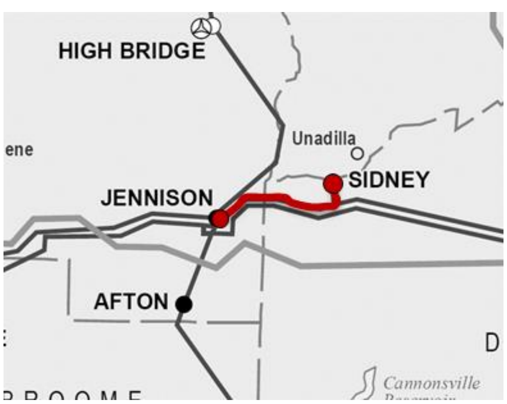


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	0	0	4	8	9	10	10	9	13	10	11	9	10	8	11	8	9	7	8	6

Jennison-Sidney 115 kV

The Jennison-Sidney line is located in pocket Z2 in the Contract and Policy Cases. This line is directly downstream of paths that connect to contracted resources in the Southern Tier comprising of LBW and UPV resources. The line location and parameters are as shown below:

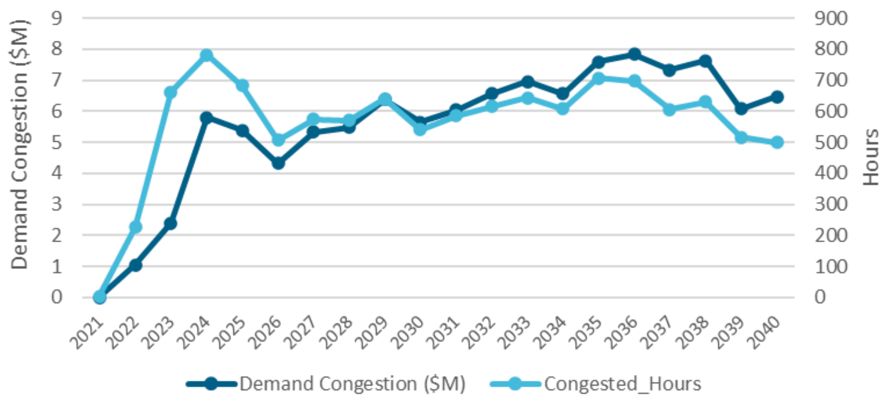
Figure 225: Jennison-Sidney Line Location and Parameters



Type	Single Circuit 115kV
Normal Op. Rating	70/ 107 MW
Contingency Op. Rating	110/ 110 MW
Length	~10 Miles
Owner	NYSEG

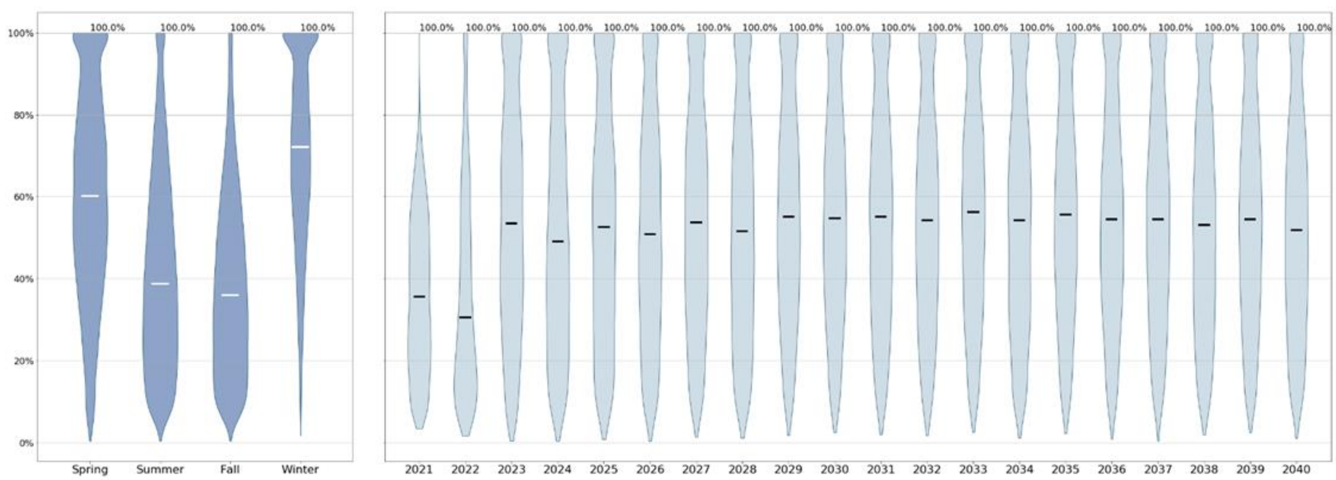
Congestion on this line increases as more resources are added in the upstate region in the Contract case. The congested hours and demand congestion metrics for this line are shown below.

Figure 226: Jennison-Sidney Projected Contract Case Demand Congestion and Congested Hour



Line utilization for this line in the Contract case increases in 2023 to about 50% as more resources are modeled in-service. Line utilization is higher in the winter and spring time period compared to summer and fall.

Figure 227: Jennison-Sidney Contract Case Hourly Line Utilization



A comparison of flows with the Baseline Case shows that the flows in the Contract Case is higher for most hours of the year. In the flow duration curve below, the darker blue region represents the Contract Case flow range whereas the lighter shade represents Baseline flows. The heatmap shows that the flow increase is spread throughout the year. Increased flow in the Contract case results from nearby wind resources being modeled in the Contract Case.

Figure 228: Jennison-Sidney Flow Duration Curve

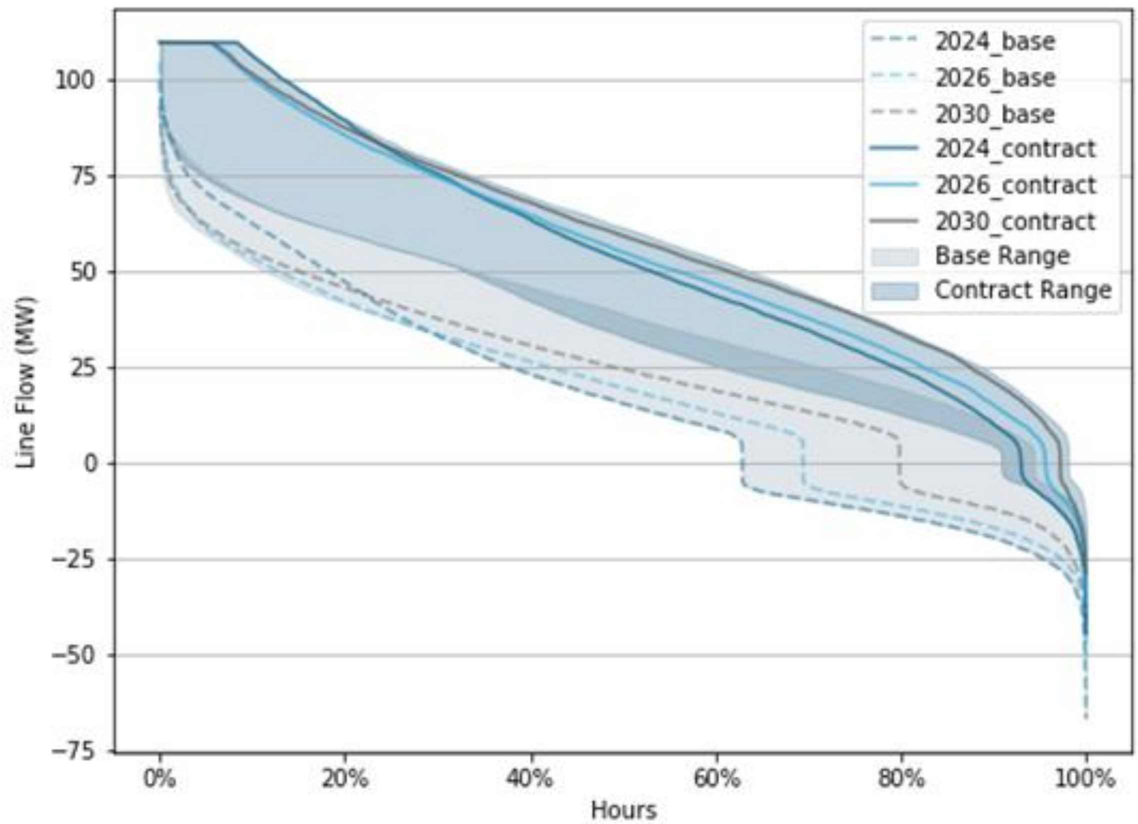
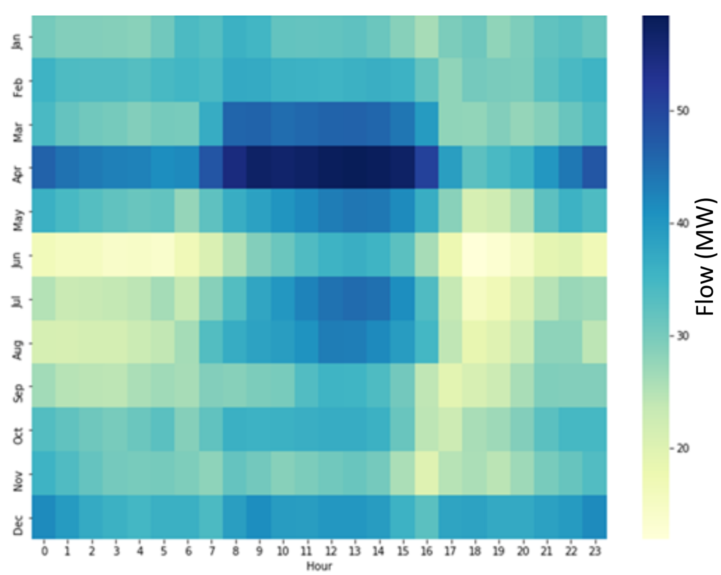


Figure 229: Jennison-Sidney Average Delta Flow (Contract-Baseline)



The relaxed case flows are marginally higher compared to the Contract Case flows. Flows on the line increases for about 20% of the year. Higher flows in the relaxed case usually occurs during the winter and spring period. Higher line flows are most likely due to nearby wind resources injecting additional energy on the line due to relieving congestion on the line.

Figure 230: Jennison-Sidney Delta Flow Duration Curve (Relax-Contract)

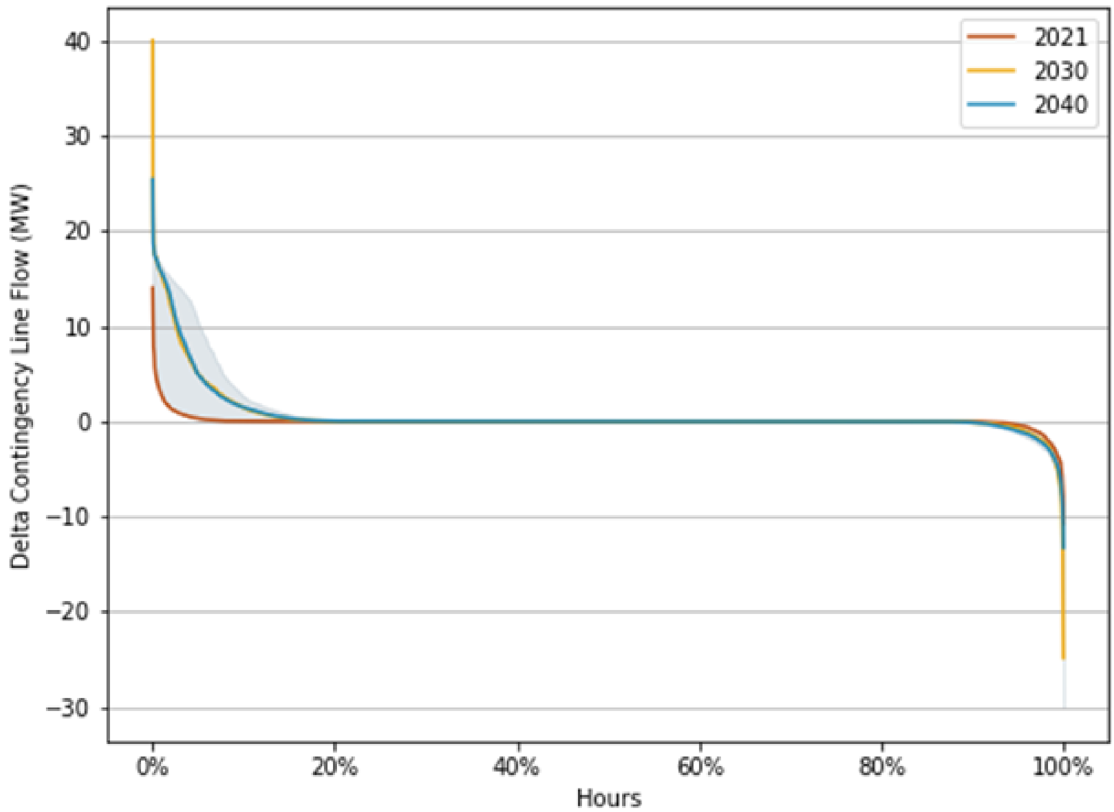
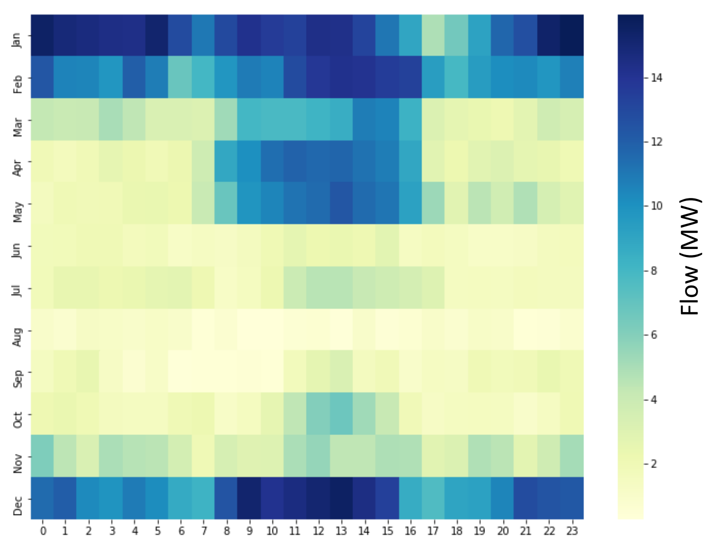


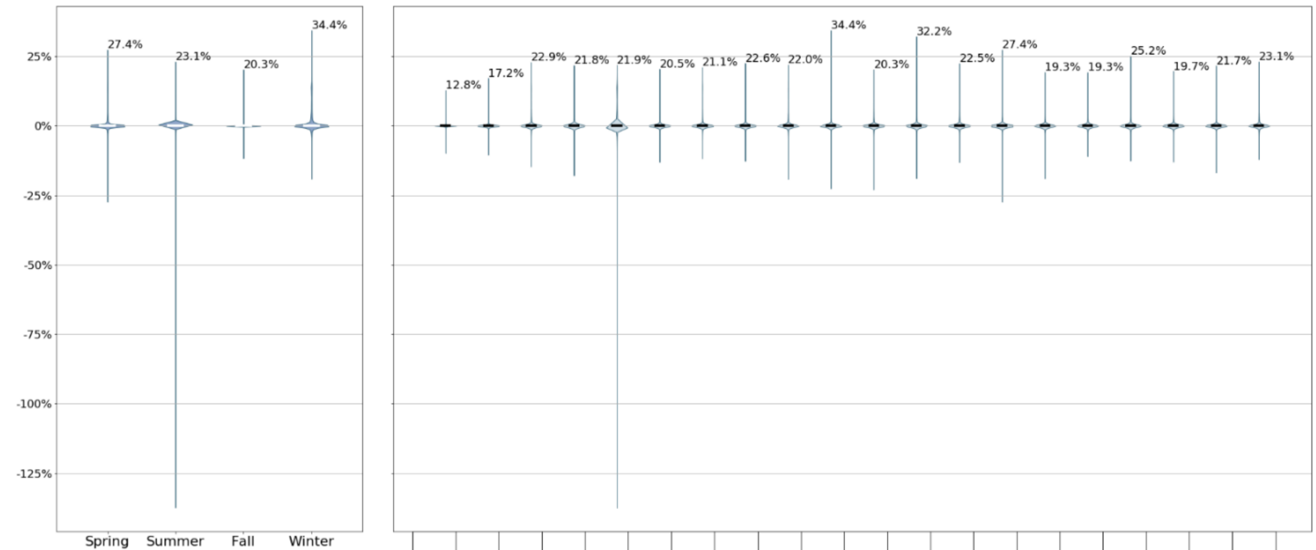
Figure 231: Jennison-Sidney Average Delta Flow



Line utilization in the relaxed case increases only marginally compared to the Contract Case as seen below in the delta line utilization plots. Relaxing line limits along this path only adds about 5

GWh per year of flow on the line.

Figure 232: Jennison-Sidney Delta Hourly Line Utilization



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Freed Energy (GWh)	0	2	6	8	7	5	5	5	5	5	5	6	6	6	6	6	6	5	5	5

Appendix J: Detailed Renewable Generation Pockets

This appendix section discusses in detail the congested hours for transmission constraints and deliverability of energy from renewable resources from the pockets identified in the Contract and Policy Cases for simulation years 2030 and 2035. Previous pocket analysis performed for the 2019 CARIS 1 70x30 study focused on the 2030 year as it represents the year by which set policy goals for 70% renewable generation are to be achieved. Since the Outlook expands the study horizon and includes additional policy goals that allow for different buildouts of renewable resources over different years, 2035 was also studied for Policy Case scenarios S1 and S2 to examine the effects of expanded large-scale renewables on localized transmission networks.

The sections below describe each individual pocket and sub-pockets identified for both 2030 and 2035 study years and provide metrics for comparing congestion and energy deliverability across three different cases – Contract Case, Policy Case Scenario S1 and Scenario S2. These pocket locations were identified as part of the 2019 CARIS 1 70x30 study. Naming conventions of pockets and sub-pockets are consistent with the prior CARIS study.

Western New York (Pocket W)

The Western New York pocket contains large existing hydro units as well as a mix of new utility-scale solar (UPV) and Land Based Wind (LBW) units. UPV units, which are mostly derived from the Contract Case, are located in this region, particularly in sub-pocket W1 along the Dysinger-Rochester path. There is also a considerable amount of LBW resources built in this area with about 36% of the total contracted wind capacity located in this pocket. With lower amounts of imports from IESO, as identified in both the Baseline and Contract Cases, this region shows less congestion than that observed in prior studies.

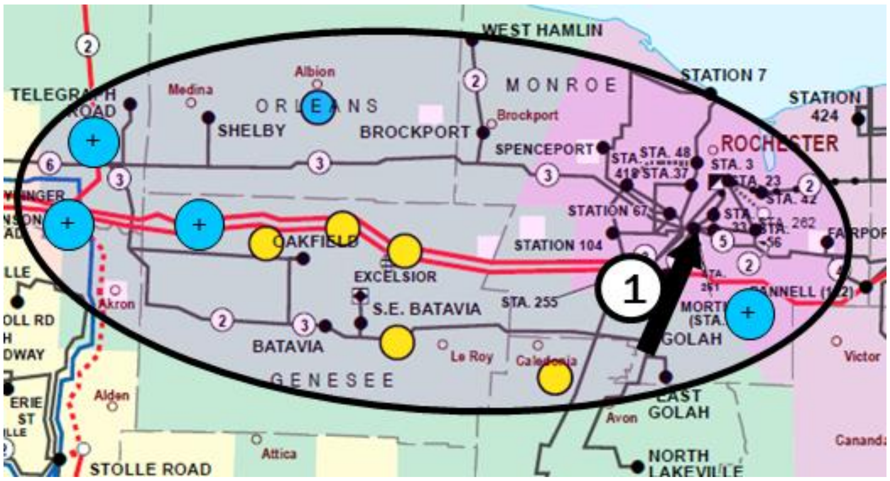
Pocket W1

W1 - 2030 Pocket Analysis

Pocket W1 is located in Niagara-Orleans-Rochester area. For year 2030, UPV units in this sub-pocket are all contracted units which experience minimal curtailment in all three Cases. LBW units, which are mostly connected to higher kV buses, experience no curtailment.

The only congested element which meets a threshold of greater than 100 hours congested[50] to be included in the pocket is 'Golah 115-Mortimer 115' which is a 115 kV line feeding power into the Rochester area. This line is congested for about 800-1000 hours in 2030 in all three cases.

Figure 233: Pocket W1 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	GOLAH 115-MORTIMER 115	845	979	983

Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	200	1,543	735	100%	100%	100%
Solar	1,130	1,130	1,130	99%	98%	99%

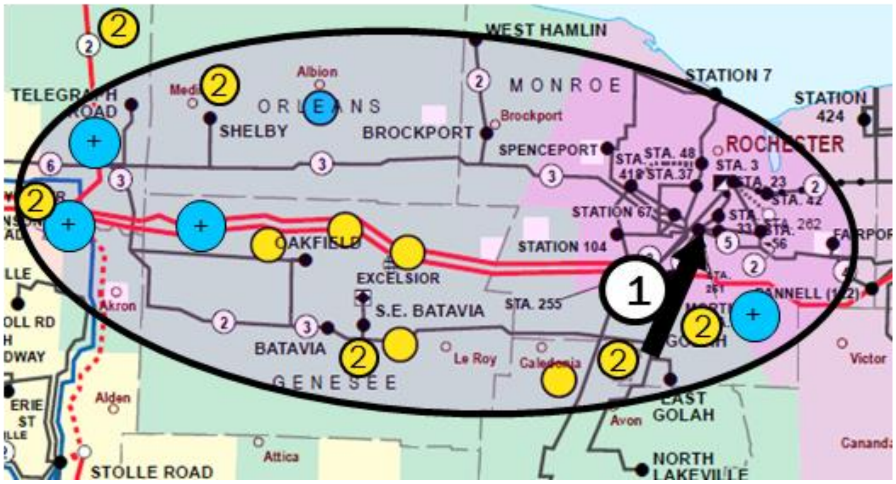
W1 - 2035 Pocket Analysis

W1 contains additional UPV units built in S2 compared to S1 which does not have any additional UPV units other than the contracted units. These new UPV units are indicated in the pocket map below by the yellow circle with '2' inside indicating this unit is only included in the S2 case. The number of congested hours decreases in 2035 compared to 2030 as UPV resources are added downstream of the constraint. Load increases elsewhere in the system might also divert flows away from congested paths.

[50] A threshold of 100 constrained hours per year per transmission path, in any of the three cases evaluated, was used to filter results to be reported in the pocket analysis. All additional transmission constraints with less than 100 hours of transmission congestion were not reported for simplification purposes.

With the addition of UPV units in S2 in 2035 in the 115 kV and 345 kV system, the curtailment increases for pocket W1. Additional wind units in 2035 are still deliverable in both cases.

Figure 234: Pocket W1 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	GOLAH 115-MORTIMER 115	793	458

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	1,130	2,092	95%	98%
Wind	1,621	1,375	100%	100%

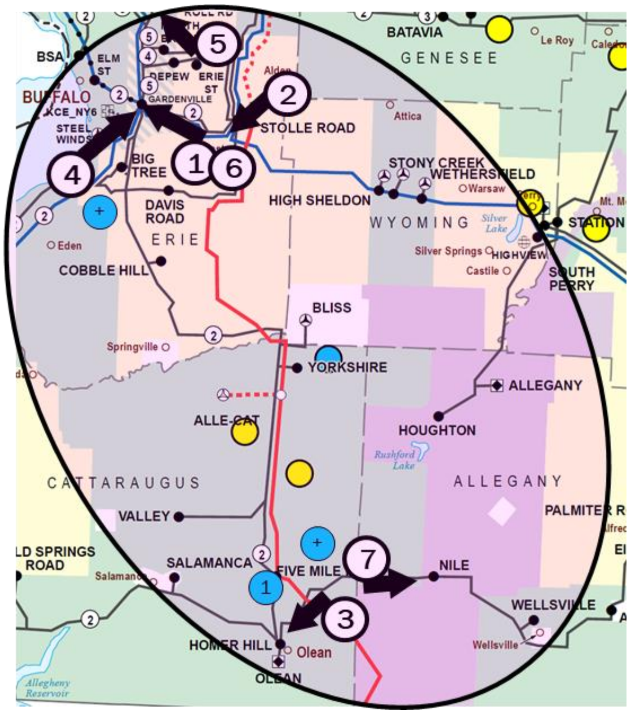
Pocket W2

W2 - 2030 Pocket Analysis

Pocket W2 is located in the Buffalo-Erie area which contains mostly LBW resources along the 345 kV corridor from Stolle Road to Five Mile substation. Most binding constraints are on the 115 kV level within Buffalo around Stolle 115 kV Bus.

Contracted UPV units within the pocket are curtailed slightly in 2030 in both the policy cases but the magnitude of curtailment is small. LBW resources have lower energy deliverability (higher curtailment) in S1 compared to S2 due to larger buildout in the same region.

Figure 235: Pocket W2 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	STOLE 115-GIRD 115	3,816	1,442	2,975
2	STOLE 115-STOLE 345	2,040	1,215	1,885
3	DUGN-157 115-HOMERHIL 115	8	2,833	722
4	BETH-149 115-GRDNVL1 115	0	827	0
5	CLSP-181 115-URBN-922 115	12	199	34
6	GARDV 115-GIRD 115	0	158	24
7	DUGN-157 115-NILE 115	0	116	2

Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	813	1,491	1,074	100%	94%	99%
Solar	60	60	60	100%	89%	96%

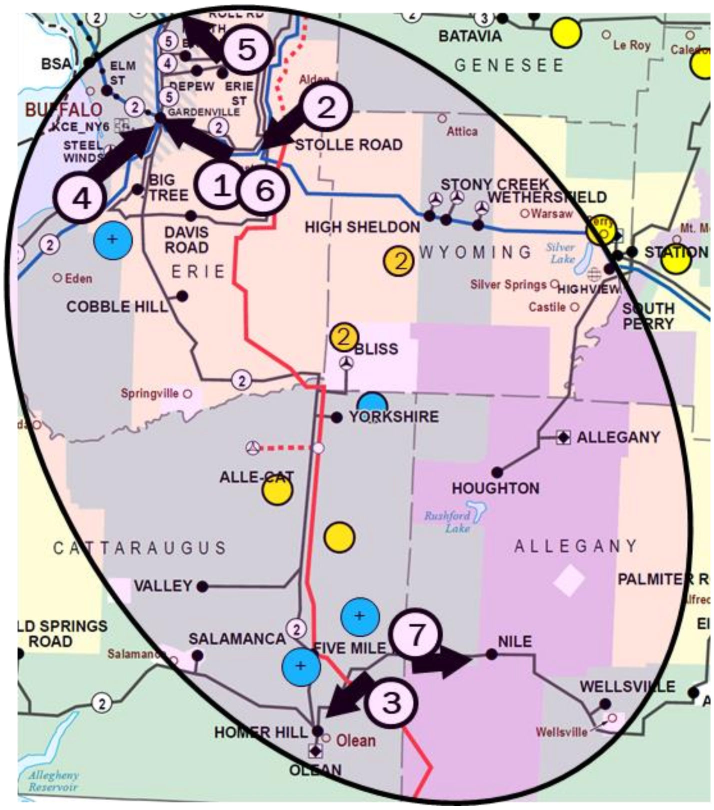
W2 - 2035 Pocket Analysis

Additions of incremental UPV and LBW resources in 2035 cause congestion to increase in the elements within the pocket as seen in the congested hour by constraint table below. The Dugan

Road 115 kV to Homerhill 115 kV line congestion increases significantly in both cases as additional resources are added upstream of this constraint.

Increased congestion on lines due to incremental resources in the same area causes the energy deliverability metric of the resources within the pocket to reduce. LBW energy deliverability is lower compared to 2030 as incremental additions are placed at the same locations.

Figure 236: Pocket W2 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	STOLE 115-GIRD 115	1,642	1,438
2	STOLE 115-STOLE 345	1,266	2,456
3	DUGN-157 115-HOMERHIL 115	3,634	3,933
4	BETH-149 115-GRDNVL1 115	1,340	1,330
5	CLSP-181 115-URBN-922 115	461	396
6	GARDV 115-GIRD 115	83	183
7	DUGN-157 115-NILE 115	110	304

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	60	349	83%	95%
Wind	1,633	1,633	88%	88%

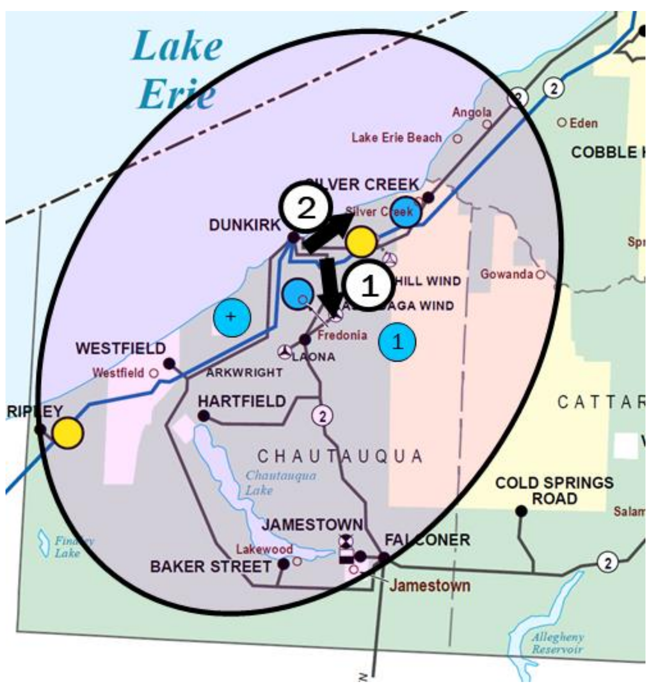
Pocket W3

W3-2030 Pocket Analysis

Pocket W3 is located in Chautauqua County along the 230 kV line from Silver Creek- Dunkirk-Ripley. This pocket contains significant LBW resources connected to the 115 kV and 230 kV circuits around the Dunkirk 230 kV substation, which supply power to load centers further north in the Buffalo area. The 115 kV path from Dunkirk to Silver Creek is highly congested in S1 compared to the other two cases due to increased LBW capacity buildout upstream of the constraint.

The energy deliverability metric results shows that higher amounts of renewable energy resources built within this sub-pocket in S1 causes increased curtailments.

Figure 237: Pocket W3 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	EDNK-161 115-ARKWRIGH 115	297	106	139
2	SLVRC141 115-DUNKIRK1 115	13	2,270	387

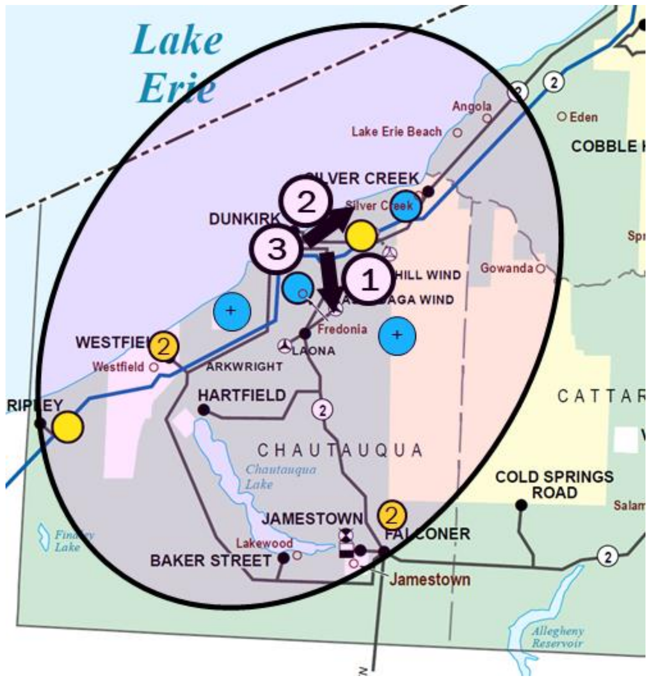
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	305	916	576	100%	93%	99%
Solar	290	290	290	100%	94%	100%

W3-2035 Pocket Analysis

W3 pocket congestion increases in year 2035 because of resource additions in both cases. S2 has additional UPV units added in 2035 which increases congestion on the 115 kV path from Dunkirk to Silver Creek. However, due to an additional unit added downstream of East Dunkirk 115 kV to Arkwright 115 kV line on Falconer 115 kV bus, the congestion on this line decreases in 2035. This new unit might still experience some curtailment due to congestion on lines outside of this pocket. A new constraint ('DUNKIRK 230-DUNKIRK1 115') meets the threshold of greater than 100 hours congested in 2035 due to additional LBW capacity added on the Dunkirk 230 kV bus.

As a result of limited transmission paths and large renewable capacity within pocket W3, energy deliverability is lowest for both LBW and UPV in Pocket W.

Figure 238: Pocket W3 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	EDNK-161 115-ARKWRIGH 115*	92	64
2	SLVRC141 115-DUNKIRK1 115	2,757	3,060
3	DUNKIRK 230-DUNKIRK1 115	289	187

*met >100 hours threshold in 2030

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	290	574	87%	83%
Wind	1,012	1,012	88%	89%

Northern New York (Pocket X)

Northern New York Pocket located in Zone D (North) and Zone E (Mohawk Valley) consists of large-scale LBW units, Hydro, few UPV units in the Contract and S1 cases and some large UPV additions which are in-service in 2035 in S2. With existing scheduled imports from HQ into Zone D (HQ-Chateaugay and HQ-Cedars), which are assumed to count as qualified renewable energy injections, Pocket X is one of the most resource rich areas in terms of renewable energy in the system.

The Policy Cases include upgrades to the existing Adirondack-Chases Lake and Adirondack-Porter 230 kV path as well as upgrades to Moses-Willis-Patnode and Willis-Ryan 230 kV circuits as part of the Northern New York Priority Transmission project ('Smart Path Connect Project', a priority transmission project approved by the New York Public Service Commission under New York's Accelerated Renewable Energy Growth and Community Benefit Act). Upgrades to the transmission system along this path increases transfer capability by approximately 1,000 MW.

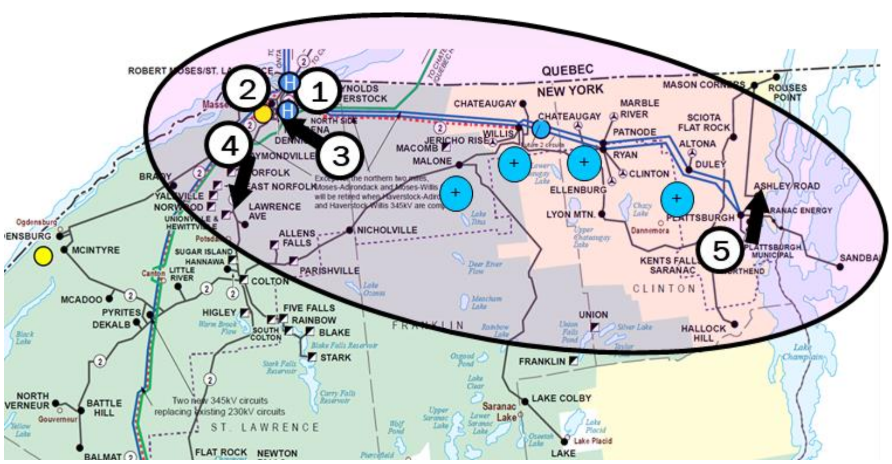
Pocket X1

X1 – 2030 Pocket Analysis

Pocket X1 is located in Zone D along the 230 kV path from Moses to Plattsburgh. This region contains existing LBW resources and incremental LBW resources in the Policy Cases in year 2030. The primary transmission constraints in the area are on the 115 kV system including the Phase Angle Regulators (PARs) connecting NY to the Ontario system. This path is highly utilized to transact power from New York into Ontario and is congested almost all hours of the year. The Dennison-Alcoa 115 kV path is congested around 10% of the year which serves load at the Alcoa bus.

There is slight curtailment of LBW resources. However, due to upgrades to the bulk system in the area energy deliverability from resources in this pocket is high in 2030.

Figure 239: Pocket X1 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	North Tie: OH-NY	7,678	8,098	7,978
2	ALCOA-NM 115-ALCOA N 115	926	967	847
3	ALCOA-NM 115-DENNISON 115	782	859	805
4	LWRNCE-B 115-SANDST-5 115	0	146	158
5	NOEND115 115-PLAT 115	128	94	64

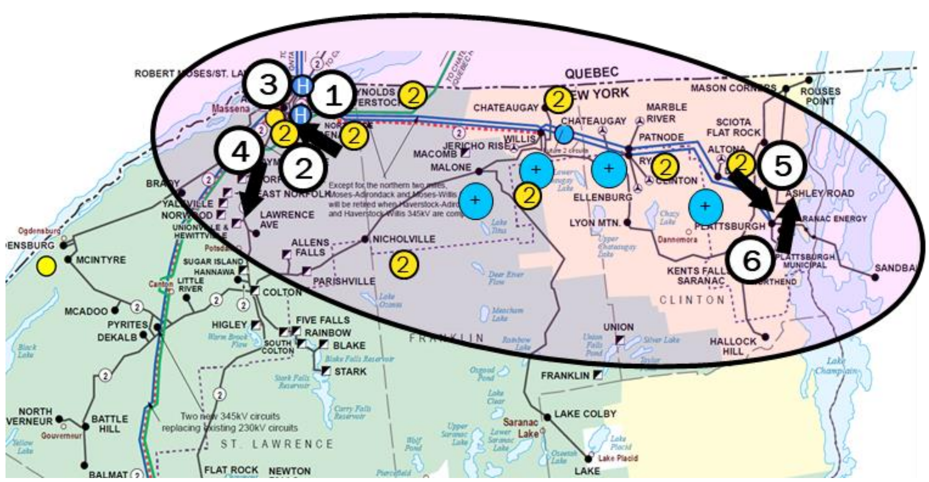
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Hydro	1,049	1,049	1,007	100%	100%	100%
HQImport	1,930	1,930	1,930	100%	98%	99%
Wind	678	876	778	100%	98%	99%
Solar	180	180	180	100%	100%	100%

X1 – 2035 Pocket Analysis

Congestion patterns in 2035 remain similar to those seen in 2030 for pocket X1. There are UPV additions in S2 which are primarily on the 230 kV level. The Duley 230 kV to Plattsburgh 230 kV constraint meets the threshold for inclusion due to increased wind and solar penetration along the 230 kV corridor from West to East towards Plattsburgh. Congestion around the Alcoa substation is slightly lower due to additional resources connecting upstream of congested paths around the Moses 230 kV bus.

Energy deliverability of resources from within the pocket decreases slightly due to increased resource capacity in the system in 2035. Additional constraints outside of the pocket may also cause curtailment of resources in the pocket if local constraints are not encountered.

Figure 240: Pocket X1 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	North Tie: OH-NY	8,024	7,972
2	ALCOA-NM 115-DENNISON 115	738	696
3	ALCOA-NM 115-ALCOA N 115	591	444
4	LWRNCE-B 115-SANDST-5 115	137	120
5	DULEY 230-PLAT T#1 230	4	176
6	NOEND115 115-PLAT 115	113	50

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Hydro	1,068	1,068	94%	97%
HQImport	1,930	1,930	92%	95%
Solar	180	355	97%	99%
Wind	1,274	1,274	93%	96%

Pocket X2

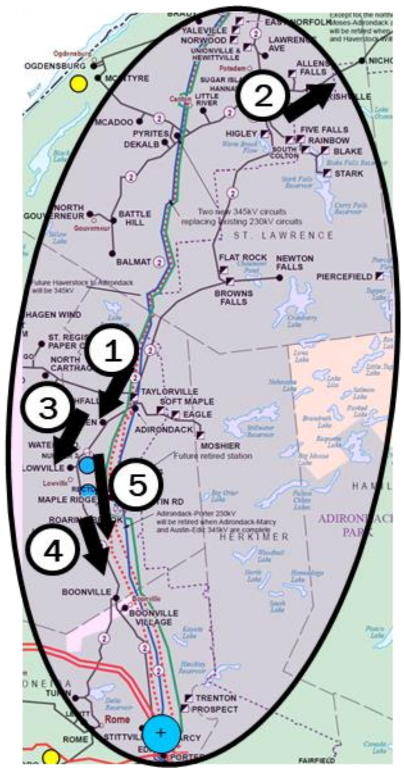
X2 – 2030 Pocket Analysis

Pocket X2 is located in Zones D and E along the Moses-Adirondack-Porter path that connects upstream of Central East interface. A parallel 115 kV path also runs alongside the higher kV system from Colton - Browns Falls – Taylorville – Lowville – Boonville – Stittville. This pocket contains primarily hydro and LBW resources connected along the 115 kV path in 2030.

The most binding constraint in this pocket is the line from Q531 POI 115 kV to Burrows 115 kV bus which is binding for about 15-25% of the year. This constraint is directly downstream of Number 3 Wind interconnection point that is serving load at the Burrows 115 kV bus. The contingency securing this line with loss of parallel path on Q531 – Lowville 115 kV causes congestion for a high number of hours.

Policy S1 case resources have slightly less energy deliverability compared to the S2 and Contract cases owing to an assumed higher resource buildout in pocket X.

Figure 241: Pocket X2 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	BREMEN 115-Q531_POI 115	182	24	7
2	NICHOLVL 115-PARISHVL 115	515	183	664
3	LOWVILLE 115-Q531_POI 115	434	132	92
4	BOONVL 115-LOWVILLE 115	96	0	0
5	Q531_POI 115-BU+LY+MO 115	0	1,994	1,262

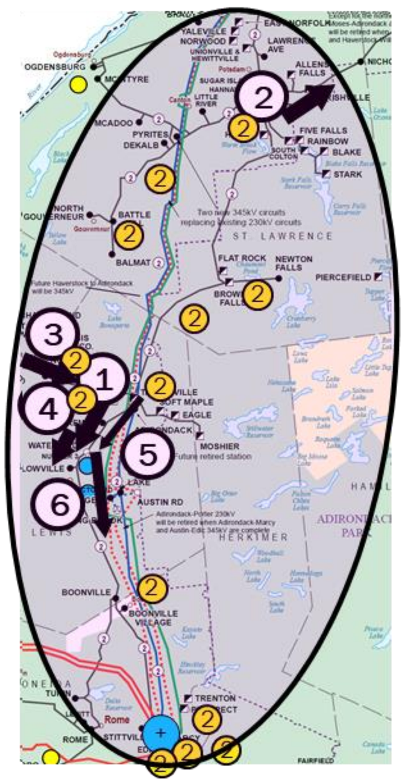
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Hydro	250	250	240	100%	95%	99%
Wind	505	598	552	100%	99%	99%
Solar	35	35	35	96%	84%	91%

X2 -2035 Pocket Analysis

Pocket X2 contains additional UPV units in S2 in 2035 that are upstream of most constraints within the pocket. This leads to the number of hours congested for constraints to increase compared to the 2030 case. Some additional constraints such as the Deferiet to Taylorville 115 kv line meet the threshold for inclusion in 2035. This line is connected to sub-pocket X3 which has increased resource additions in 2035.

Energy deliverability from resources in X2 in the S1 case is lower than 2030 as a result of incremental resource additions in the pocket and the system. Existing hydro resources, which are mostly upstream of the constrained paths, are curtailed about 13% of the year. Even though S2 has very high capacity of UPV resources added to this pocket, energy deliverability from these units remains high at around 98%. Most of the larger UPV projects are connected to the higher kV bulk system with few smaller UPV projects with interconnections to 115 kV level circuits.

Figure 242: Pocket X2 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	BREMEN 115-Q531_POI 115	17	161
2	NICHOLVL 115-PARISHVL 115	163	489
3	DEFERIET 115-TAYLORVL 115	195	178
4	LOWVILLE 115-Q531_POI 115	178	287
5	TAYLORVL-Q531_POI_115	951	816
6	Q531_POI 115-BU+LY+MO 115	2,099	2,546

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Hydro	249	249	87%	89%
Solar	35	1,043	75%	98%
Wind	785	785	95%	98%

Pocket X3

X3-2030 Pocket Analysis

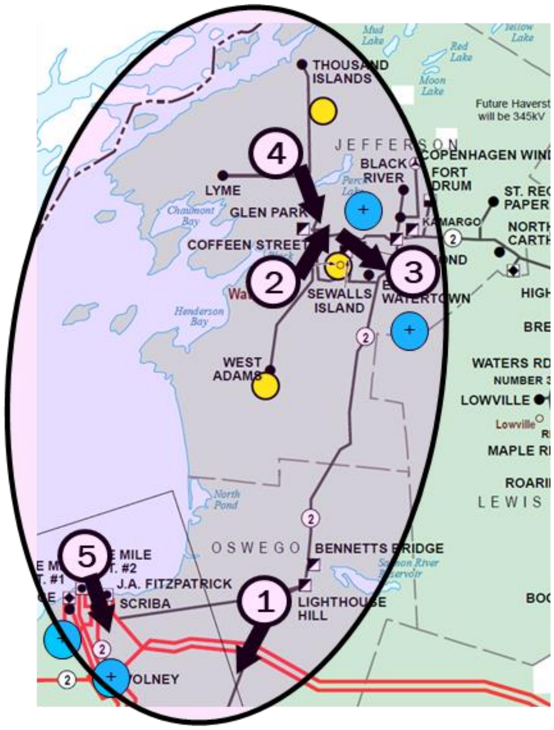
Pocket X3 is located in Jefferson and Oswego counties in Zone C and E. It consists of a mostly 115 kV system around Watertown and a 115 kV path down from Watertown to Lighthouse Hill 115 kV substation. Some constraints are also observed in the Oswego area on the 115 kV system.

2030-year resources consist of existing wind and hydro resources along with contracted UPV in the Contract Case. Policy Cases S1 and S2 include new LBW projects with S1 having a larger buildout of capacity at the same locations compared to S2.

Contracted UPV resources in the pocket experience curtailment due to local congestion on 115 kV lines flowing out of the pocket. The 115 kV line from Lighthouse Hill to Mallory, which is exporting power out of the pocket, is consistently congested across the cases and is proportional to the magnitude of resource capacity in each case.

Energy deliverability from UPV and hydro resources are impacted by congestion on the lower kV circuits. LBW units connected further downstream of congested elements are less impacted and have high energy deliverability across all cases.

Figure 243: Pocket X3 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	HTHSE HL 115-MALLORY 115	591	2,495	1,217
2	COFFEEN 115-GLEN PRK 115	1,119	1,152	1,168
3	COFFEEN 115-E WTRTWN 115	748	223	376
4	COFFEEN 115-LYMETP 115	0	117	115
5	HMMRMILL 115-WINE CRK 115	0	190	0

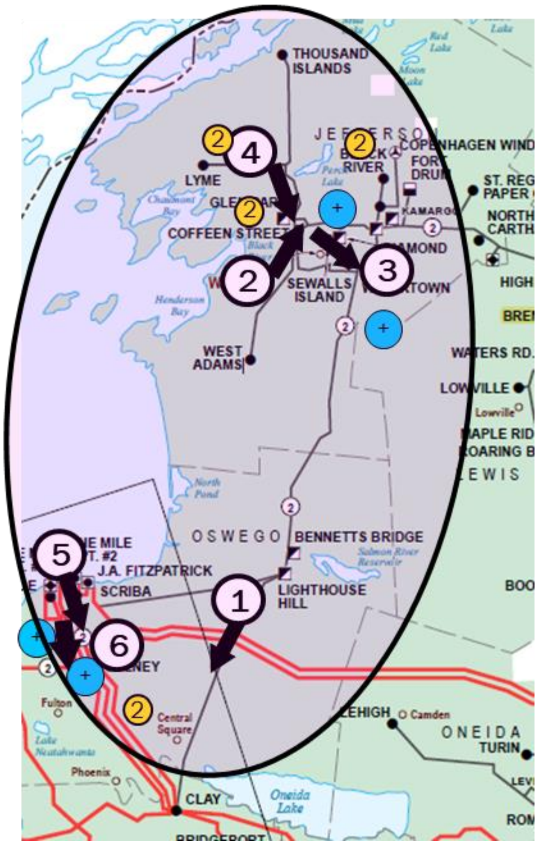
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Hydro	155	155	152	99%	85%	94%
Wind	80	790	417	100%	98%	99%
Solar	369	369	369	90%	75%	81%

X3-2035 Pocket Analysis

Constraints identified in 2030 have increased congested hours in 2035 in Pocket X3 with addition of UPV and LBW resources. Some constraints, such as on the Coffeen to Lyme 115 kV line, may experience less congestion due to resources being added downstream of the constraint. The 115 kV line from Lighthouse Hill to Mallory remains the most congested element as it exports power out of the pocket towards the Clay 115 kV bus. Constraints in the Oswego area also experience increased congestion as a result of incremental resource additions.

Due to higher congestion on lines and increased renewable capacity in the pocket, curtailment rates are higher in 2035 for all resources across all cases.

Figure 244: Pocket X3 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	HTHSE HL 115-MALLORY 115	3,497	3,290
2	COFFEEN 115-GLEN PRK 115	1,047	1,686
3	COFFEEN 115-E WTRTWN 115	352	154
4	COFFEEN 115-LYMETP 115*	36	0
5	HMMRMILL 115-WINE CRK 115	1,469	1,512
6	SCRIBA 345-VOLNEY 345	859	879

*met >100 hours threshold in 2030

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Hydro	156	156	67%	70%
Solar	369	686	64%	59%
Wind	1,313	1,313	94%	94%

Capital Region (Pocket Y)

The Capital Region pocket (Pocket Y) includes areas in the Mohawk Valley and upper Hudson

Valley regions and is centered around the Albany metropolitan area. Large amounts of UPV generation are modeled in this pocket mainly on the 115 kV path in Montgomery and Herkimer counties. Bulk level transmission constraints such as Central East and New Scotland-Knickerbocker, which are historically congested paths, are also within this pocket. Since this area is downstream of major interfaces carrying power from upstate to downstate, this pocket experiences high levels of congestion with the addition of resources in the upstate region.

Pocket Y1

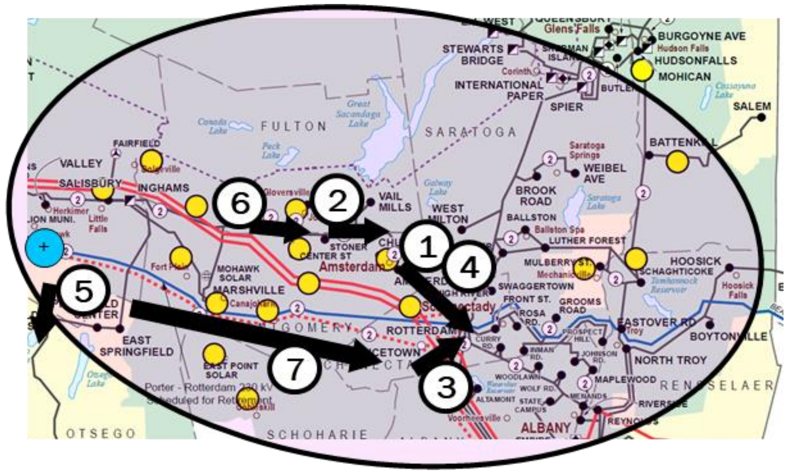
Y1-2030 Pocket Analysis

Pocket Y1 contains mostly contracted UPV units in the 2030 case. Policy Case S1 and S2 have one LBW resource that is within the pocket boundaries. The primary congested transmission corridor is from West to East along the 115 kV path from Inghams 115 kV bus, which is directly downstream of Central East, to the Rotterdam 115 kV bus in the Capital Region. There is significant amount of contracted UPV capacity along this corridor which is injecting power into the Albany metropolitan area down to pocket Y2 in the Hudson Valley region. Central East, which is historically one of the most congested bulk transmission interfaces in the New York system, runs directly through this pocket. Central East carries much of the power from upstate zones to downstate loads and is heavily congested in Policy Case scenarios with high renewable penetration.

Congestion on the bulk as well as the lower kV system can be seen in the Contract Case. Some new constrained elements are identified in the S1 and S2 cases with added resources in the pocket and in upstate zones. Existing constrained paths have more congested hours due to added pressure on lines from increased resource capacity upstream of the path.

Energy deliverability numbers are proportional to the capacity of resources added to each case with higher resource additions causing greater congestion and hence greater amounts of curtailment. Competition between resource types may cause differences in curtailment owing to differences in REC prices assigned to each unit or unit type.

Figure 245: Pocket Y1 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	RTRDM1 115-Q638POI 115	1,200	1,265	1,424
2	STONER 115-VAIL TAP 115	882	1,666	1,275
3	ROTTERDA 345-ROTRDM.2 230	61	1,299	967
4	AMST 115-Q638POI 115	302	604	730
5	COLER 115-RICHF 115	0	278	205
6	CENTER-N 115-MECO 115	0	210	0
7	CENTRAL EAST	234	2480	2281

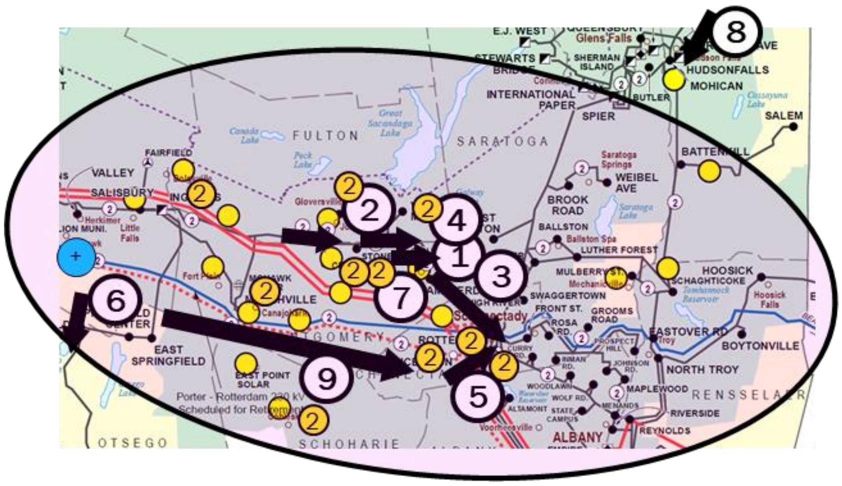
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Hydro	30	30	30	100%	98%	99%
Wind	74	101	86	97%	90%	94%
Solar	961	961	961	96%	91%	93%

Y1 – 2035 Pocket Analysis

An increased amount of congestion is seen in the 2035 case in both Policy Cases with the addition of renewable energy resources upstream of the constraints identified in 2030. Additional constraints along the 115 kV path that meet the inclusion criteria are also included in the congested hour table below. The S2 case has higher number of congested hours for the same constrained element compared to S1 due to increased UPV capacity additions along the 115 kV corridor. Bulk level constraints such as Rotterdam 345 kV-Rotterdam 230 kV transformer and Central East have increased congestion hours in both S1 and S2.

Energy deliverability numbers reflect that incremental capacity additions, such as those for UPV in S2, cause increases in curtailment rates due to excess congestion around interconnection points.

Figure 246: Pocket Y1 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	RTRDM1 115-Q638POI 115	1,216	2,014
2	STONER 115-VAIL TAP 115	1,503	2,533
3	AMST 115-Q638POI 115	546	1,583
4	CHURCH-E 115-MAPLEAV1 115	0	154
5	ROTTERDA 345-ROTRDM.2 230	2,107	2,208
6	COLER 115-RICHF 115	316	277
7	CHURCH-W 115-VAIL TAP 115	17	1,992
8	COMSTOCK 115-MOHICAN 115	24	283
9	CENTRAL EAST	2,280	2,064

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Hydro	30	30	94%	97%
Solar	961	2,162	88%	77%
Wind	120	120	88%	88%

Pocket Y2

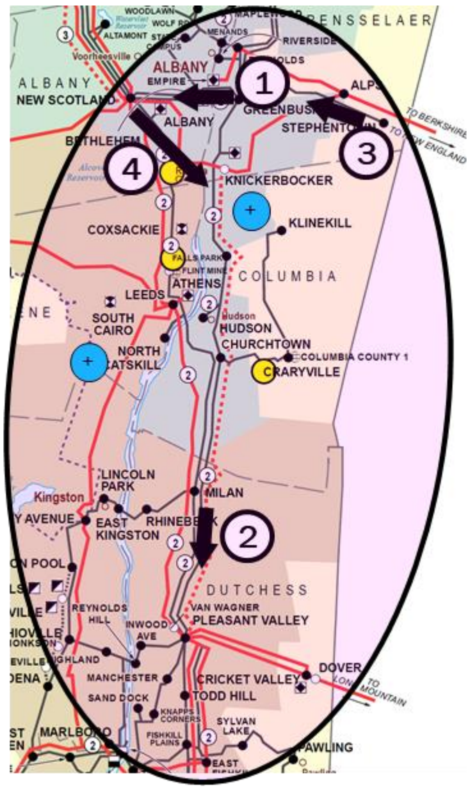
Y2-2030 Pocket Analysis

Pocket Y2 is located south of the Albany metro area in the upper Hudson Valley. This pocket is primarily composed of high capacity 345 kV lines carrying power from the Capital Region into the Hudson Valley and eventually down to load centers in New York City and Long Island.

There are several constraints on the 115 kV level system that experience congestion in all three cases but the numbers of hours limited are low. Due to assumed retirements of fossil resources in the Capital Region, congestion is affected on the bulk as well as the 115 kV system is affected.

Energy deliverability of resources within this pocket remains high due to limited capacity built within the pocket and low congestion on transmission paths.

Figure 247: Pocket Y2 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	JMC2+9TP 115-OC W +MG 115	702	0	0
2	MILAN 115-BL STR E 115	11	119	15
3	STEPH 115-GBSH+LGE 115	1	134	139
4	NEW SCOTLAND 345-KNICKB 345	511	303	249

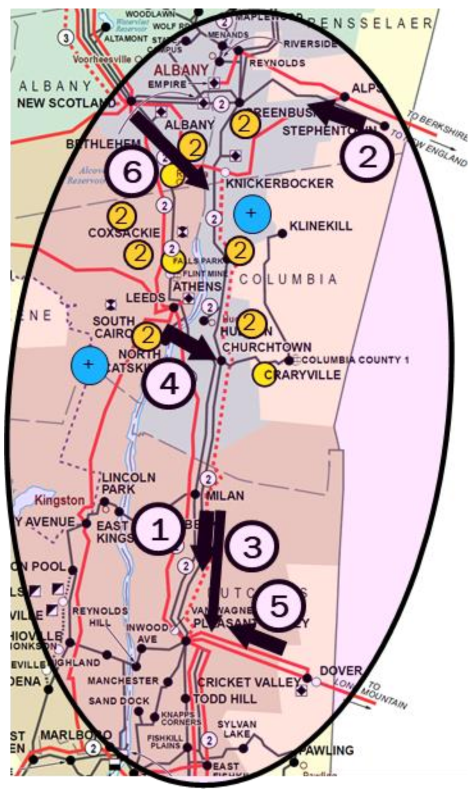
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind		255	123		100%	100%
Solar	250	250	250	100%	99%	99%

Y2-2035 Pocket Analysis

2035-year case includes UPV and LBW additions to pocket Y2 in S1 and S2. UPV additions in S2 are concentrated on the 115 kV path along Bethlehem to Leeds west of the Hudson River and along Greenbush to Churchtown to the east. This introduces additional elements to congest which did not meet the threshold of greater than 100 hours congested in 2030. Of note is North Catskill 115 kV to Churchtown 115 kV line which is downstream of new UPV units in S2. There is also congestion on the Tie-lines which connect to the New-England ISO (NEISO) system – constraints '2' and '5' below.

S2 with higher UPV capacity has lower energy deliverability compared to S1. Overall, energy deliverability from resources within this pocket remains high compared to other pockets.

Figure 248: Pocket Y2 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	MILAN 115-BLSTR E 115	322	1,255
2	STEPH 115-GBSH+LGE 115	636	564
3	MILAN 115-PLVAL 1 115	6	159
4	N.CAT. 1 115-CHURCHTO 115	1,939	1,992
5	PLTVLLEY 345-CRICKET 345	186	131
6	NEW SCOTLAND 345-KNICKB 345	169	439

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	250	626	93%	88%
Wind	618	618	94%	96%

Southern Tier (Pocket Z)

Pocket Z is located along the southern NY border in zones C and E. Large amounts of LBW and UPV resources are located within the three sub-pockets in Pocket Z. This pocket contains both bulk level and lower kV transmission network connecting resources in Western NY and the Finger Lakes region to bulk level transmission that connect to other major interfaces such as Central East and Marcy-South that deliver power to the rest of the state.

Pocket Z1

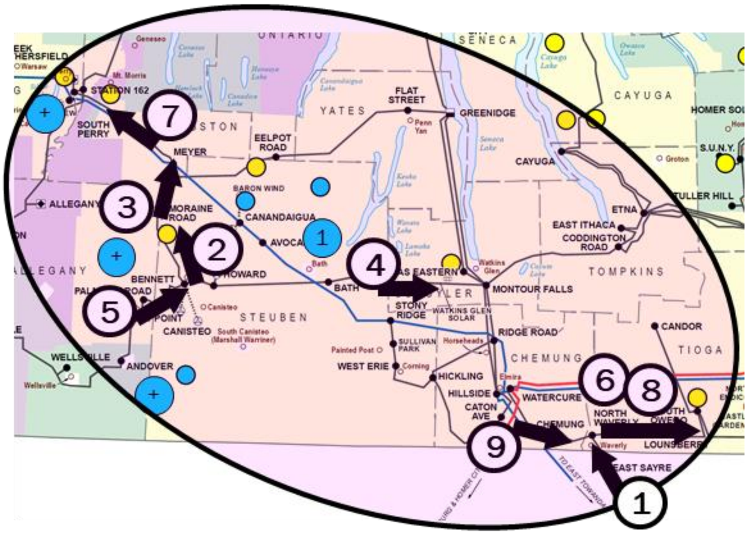
Z1-2030 Pocket Analysis

Pocket Z1 is located along the 230 kV path from South Perry to Hillside, the 115 kV circuits around Bennett substation, 115 kV circuit from Hillside to North Waverly, and the Watercure 345 kV bus. This large sub-pocket includes multiple counties and includes varied transmission paths for resources to interconnect.

The 115 kV lines around Bennet are heavily congested due to large scale LBW projects connected to transmission lines with saturated flows. Addition of Policy Case LBW resources in S1 and S2 to areas with already large capacity of contracted resources causes additional pressure on lines that are not designed to handle so much capacity. Addition of resources with Pocket Z1 pushes back on import flows from PJM along the East Sayre-North Waverly 115 kV tie line, hence the congestion is less in the Policy S1 and S2 cases compared to the Contract Case.

Policy Case S1, which has significant LBW capacity added to Pocket Z1 in 2030, has the low energy deliverability for wind resources compared to other cases. S2, which adds some LBW capacity to Pocket Z1 is closer in energy deliverability metric to the Contract Case.

Figure 249: Pocket Z1 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	N.WAV 115-26E.SAYR 115	3,225	1,249	1,276
2	MORAINE 115-BENET 115	0	2,246	925
3	MEYER 115-MORAINE 115	0	1,825	1,045
4	BATH 115-MONTR 115	5	1,986	572
5	BENET 115-PALMT 115	0	1,906	159
6	LOUNS 115-STAGECOA 115	170	366	201
7	MEYER 115-S.PER 115	12	179	176
8	N.WAV 115-LOUNS 115	95	84	91
9	N.WAV 115-CHEMUNG 115	0	147	26

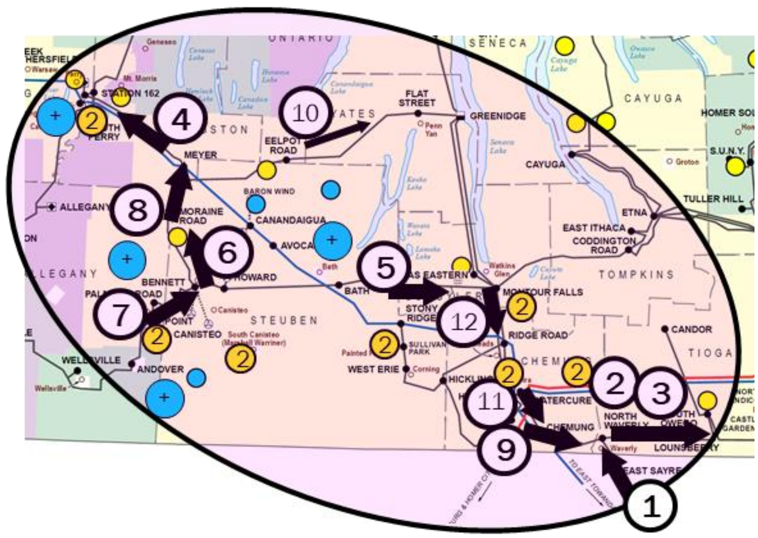
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	720	1,495	1,119	100%	83%	96%
Solar	405	405	405	100%	93%	97%

Z1-2035 Pocket Analysis

With the addition of incremental resources in both Policy Cases, additional constrained paths are identified in the 2035 case. All constraints are on the 115 kV level and restrict power to flow into the bulk system. Policy Case S2 has UPV builds which are more than twice the capacity of contracted UPV in the pocket in S1 and the Contract Case. This leads to increased congestion in S2 compared to S1.

Energy deliverability of LBW units are lower in both S1 and S2 cases compared to 2030 as incremental capacity is built on the same locations as 2030 where curtailments were occurring. UPV builds in S2 are more spread out across the pocket and some units connect to higher kV buses. Hence energy deliverability numbers are comparable between S1 and S2 for UPV resources.

Figure 250: Pocket Z1 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	N.WAV 115-26E.SAYR 115	1,100	855
2	LOUNS 115-STAGECOA 115	212	216
3	N.WAV 115-LOUNS 115	41	201
4	MEYER 115-S.PER 115	668	650
5	BATH 115-MONTR 115	1,811	1,422
6	MORAINE 115-BENET 115	6	3,542
7	BENET 115-PALMT 115	1,814	1,785
8	MEYER 115-MORAI 115	2,062	1,746
9	N.WAV 115-CHEMUNG 115	196	413
10	EELPO 115-FLATS 115	554	629
11	HILLSIDE 115-CHEMUNG 115	43	231
12	MONTR 115-RIDGT 115	6	247

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	405	1,037	85%	87%
Wind	2,160	2,160	74%	74%

Pocket Z2

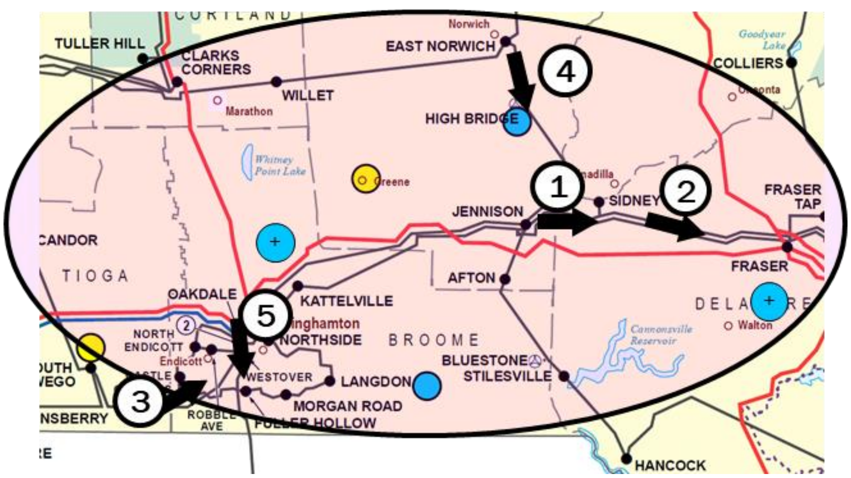
Z2-2030 Pocket Analysis

Pocket Z2 is located along the 345/115 kV corridor from Oakdale to Fraser substation. It also contains the 115 kV section from East Norwich to Jennison. This sub-pocket contains mostly contracted LBW and UPV resources with the Policy Case containing additional LBW resources connecting at the 345 kV and 230 kV buses at Fraser and Oakdale, respectively.

In 2030, constrained elements within the pocket are more congested in the Policy Cases S1 and S2 compared to the Contract Case. These constrained paths are downstream of sub-pockets Z1 and Z3, so resources added in the Policy Case in surrounding sub-pockets affect the congestion in Z2. The Jennison-Sidney-Delhi 115 kV path remains consistently congested across the three cases studied with the number of congested hours increasing in the Policy Case scenarios.

Energy deliverability for resources are relatively high for Contract and S2 cases but S1 experiences increased curtailment of contracted UPV resources in the sub-pocket due to increased congestion on 115 kV paths.

Figure 251: Pocket Z2 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	JENNISON 115-SIDNEY 115	542	3,459	1,357
2	FRASER 115-SIDNEY 115	0	242	155
3	S.OWEGO 115-GOUDEY8- 115	0	167	169
4	E.NORWICH 115-JENNISON 115	0	193	58
5	OAKDALE 230-OAKDALE 115	0	119	0

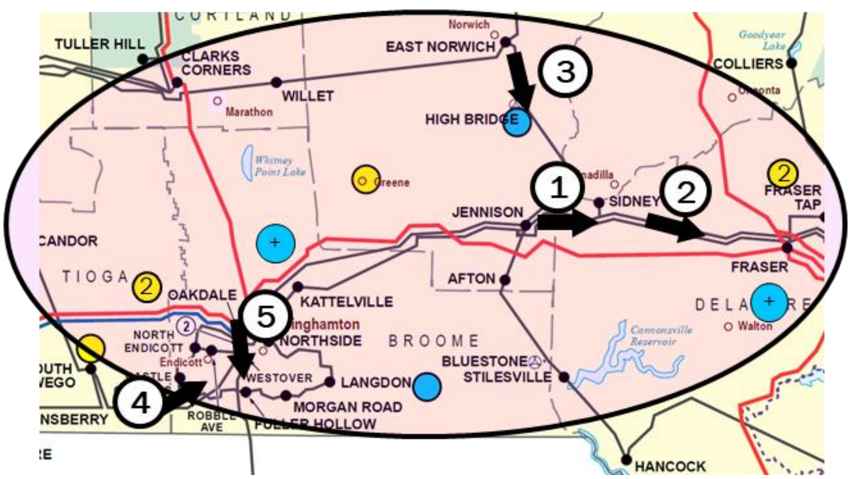
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	213	803	512	99%	92%	97%
Solar	60	60	60	100%	78%	91%

Z2-2035 Pocket Analysis

As a result of additional resources being added to the cases, 115 kV lines that are downstream of resources within the sub-pocket or downstream of neighboring sub-pockets experience increased congestion in 2035. The Jennison-Sidney 115 kV line remains one of the most binding elements in Z2 as it connects the 115 kV lines to 345 kV system at Fraser substation. The East Norwich-Jennison 115 kV path also gets congested more as additional resources are added to pocket Z3 which is directly upstream of the constraint.

Energy deliverability of resources within the pocket is lower overall as a result of increased congestion. S2 has additional UPV resources that connect to higher kV buses and have higher energy deliverability compared to S1.

Figure 252: Pocket Z2 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	JENNISON 115-SIDNEY 115	3,768	4,015
2	FRASER 115-SIDNEY 115	169	49
3	E.NORWICH 115-JENNISON 115	1,240	705
4	S.OWEGO 115-GOUDEY8- 115	92	307
5	OAKDALE 230-OAKDALE 115	1,056	1,419

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	60	443	74%	87%
Wind	1,257	1,257	91%	91%

Pocket Z3

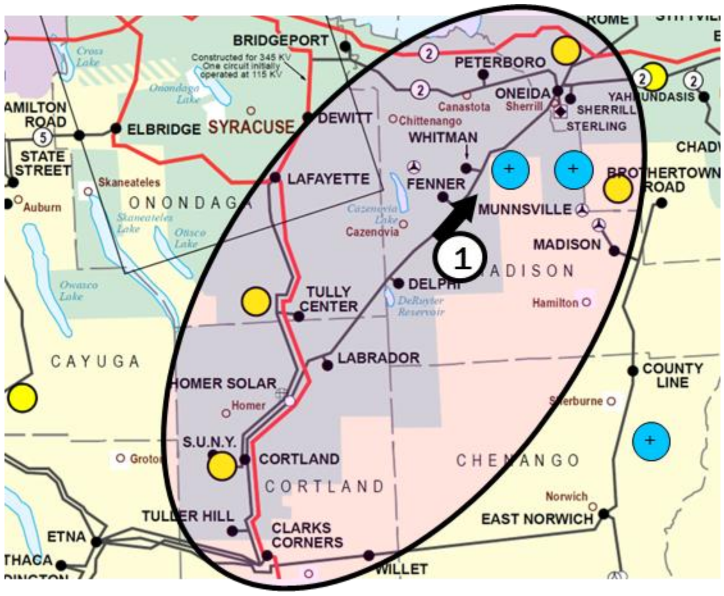
Z3-2030 Pocket Analysis

Pocket Z3 is located along the 345/115 kV corridor from Lafayette-Clarks Corners substation and 115 kV circuit from Clarks Corners to Oneida substation. Resources in this pocket are mostly contracted UPV and LBW units with few LBW additions in the Policy Cases.

In 2030, the 115 kV line from Fenner-Whitman substation is the only element identified as a constraining element within the pocket. This constraint meets the criteria for inclusion only in the Policy S1 Case.

Energy deliverability is high from resources within this pocket with only LBW units experiencing some curtailment in the Policy Cases.

Figure 253: Pocket Z3 Congestion and Energy Deliverability Summary (2030)



ID	Constraint	Contract	Policy S1	Policy S2
1	WHITMAN 115-FEN-WIND 115	0	128	7

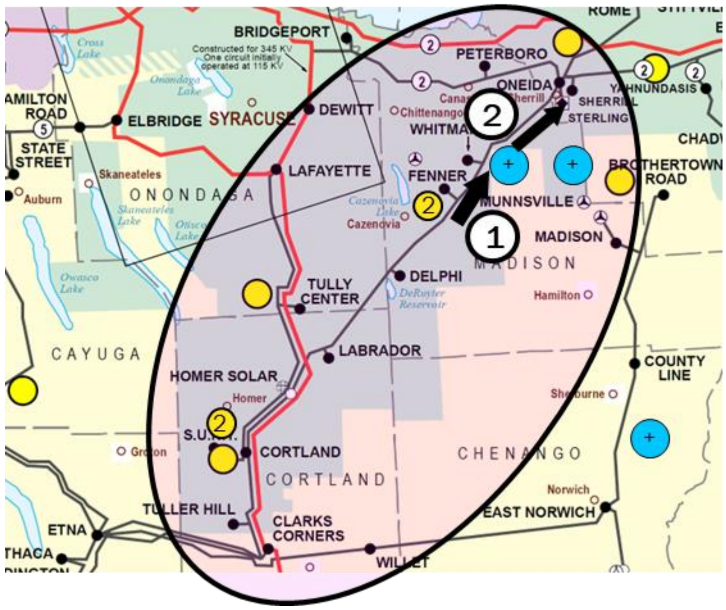
Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Wind	76	265	173	100%	95%	99%
Solar	150	150	150	100%	96%	99%

Z3-2035 Pocket Analysis

An additional constraint from Whitman-Sterling 115 kV is identified for the 2035 Policy Cases as additional resources are added on the 115 kV path upstream of the constraints. Congested hours for S2 increased as the capacity of resources added in S2 is greater than that in S1.

Energy deliverability of resources decreases in 2035 in both S1 and S2 Cases as a result of increased congestion on constraints within the pocket and further downstream in adjacent pockets.

Figure 254: Pocket Z3 Congestion and Energy Deliverability Summary (2035)



ID	Constraint	Policy S1	Policy S2
1	WHITMAN 115-FEN-WIND 115	530	783
2	WHITMAN 115-STERLING 115	1,142	1,862

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Solar	150	303	87%	81%
Wind	413	413	92%	91%

Offshore Wind Zone J Pocket (OSW J)

Offshore Wind Zone J Pocket consists of almost all of Zone J with OSW injections at higher kV buses throughout the zone. The Contract Case consists of two OSW projects injecting at Gowanus 345 kV and Astoria East 138 kV bus. The Policy Cases S1 and S2 have additional OSW projects modeled and interconnected to buses identified from the current interconnection queue. These new interconnections are all on the higher kV buses spread across the city. The Champlain-Hudson Power Express ("CHPE") Project is modeled as a fixed injection of 1,250 MW at Astoria 345 kV substation only in the Policy Cases. Due to retirement of older fossil units and addition of new resources within the pocket, congestion patterns on lines may change and new constrained elements might show up.

OSW J - 2030 Pocket Analysis

Constraints identified in the 2030 pocket analysis for OSW J are mostly on the 138 kV level and are downstream of OSW interconnection points. Congestion in the Contract Case is primarily due to existing system conditions and generation. These paths do get congested more in the Policy Case with additional OSW resources modeled in the system.

The Zone J bulk level system allows all of the OSW energy to be dispatched in 2030 when interconnected to 345 kV buses as modeled in the Contract and Policy Cases. Even with increased congestion in the 138 kV system, there exists alternate routes and enough generation redispatch capability to accommodate all of the OSW energy.

Figure 255: Pocket OSW J Congestion and Energy Deliverability Summary (2030)

ID	Constraint	Contract	Policy S1	Policy S2
1	E179 ST 138-HG 4 138	4,726	5,519	5,775
2	ASTE-ERG 138-CORONA-S 138	1,327	1,888	1,418
3	ASTANNEX 345 E13ST 345	786	6,724	5,555
4	FRESH KI 138-WILOWBK1 138	339	343	229
5	RAINEY8W 138-VERNON-W 138	299	3,044	4,202
6	HG 5 138-ASTORIA 138	210	222	2
7	GOWNUSR1 138-GRENWOOD 138	105	225	840
8	RAINEY8E 138-VERNON-E 138	16	661	610

Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Offshore Wind	2,046	2,046	5,166	100%	100%	100%
HQImport		1,250	1,250		100%	100%

OSW J - 2035 Pocket Analysis

Additional constrained paths are identified for both Policy Cases in 2035 as a result of resources being added and assumed fossil capacity retirements. Overall, an increase in congested hours for constrained elements is observed, which indicates that added pressure on the 138 kV system can be expected with a new resource mix in Zone J.

OSW units are still highly deliverable with the system redispatching capacity to accommodate all of the OSW energy into the system. This can also be attributed to the high REC price received by OSW projects relative to other types of renewable resources. The import from HQ through the CHPE line does experience slight curtailment in 2035 but is still highly deliverable.

Figure 256: Pocket OSW J Congestion and Energy Deliverability Summary (2035)

ID	Constraint	Policy S1	Policy S2
1	E179 ST 138-HG 4 138	5,368	5,716
2	ASTE-ERG 138-CORONA-S 138	1,545	1,974
3	ASTANNEX 345 E13ST 345	6,193	7,038
4	FRESH KI 138-WILOWBK1 138	1,002	163
5	RAINEY8W 138-VERNON-W 138	4,633	7,270
6	HG 5 138-ASTORIA 138	240	0
7	GOWNUSR1 138-GRENWOOD 138	228	1,806
8	RAINEY8E 138-VERNON-E 138	409	499
9	DUNWOODI 345-MOTTHAVEN 345	116	148
10	GREENWOOD 138 - VERNON 138	20	233
11	MOTTHAVN 345-RAINEY 345	190	296

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Offshore Wind	4,571	5,166	100%	100%
HQ Import	1,250	1,250	96%	98%

Offshore Wind Zone K Pocket (OSW K)

The Long Island electric system is primarily comprised of 138 kV lines with local distribution at 69 kV and lower voltage levels. With considerable amounts of OSW projects looking to interconnect into the Long Island system, large amounts of congestion can be expected on lines that are not designed to handle large injections of power. Local constraints that are directly downstream of interconnection points or radial lines that connect the interconnection bus to the rest of the system may limit the amount of energy that can be utilized based on the thermal limits of the line.

The NYISO is currently evaluating the viable and sufficient project proposals to the Long Island Offshore Wind Export Public Policy Transmission Need ("Long Island PPTN"), based on the Order issued by the New York Public Service Commission ("PSC") on March 19, 2021. If a more efficient or cost-effective solution is selected to meet the Long Island PPTN, the observed congestion is expected to be reduced significantly.

OSW K - 2030 Pocket Analysis

The 2030 case includes contracted OSW projects interconnecting at Barrett 138 kV, Holbrook 138 kV, and East Hampton 69 kV buses. Policy Case S1 includes additional OSW units that are placed at seven additional locations indicated in the map below. The most binding constraint in all three cases that directly impacts the energy deliverability of a particular OSW project is the line from Barrett 138 kV to Valley Stream 138 kV. This constraint is consistently binding in all three cases for more than 50% of the year. Other bulk level constraints also impact energy deliverability of resources within the pocket or ability of resources outside of the pocket to serve load in Zone K.

Due to high congestion on the Barrett-Valley Stream 138 kV line and other surrounding constraints, the energy deliverability of OSW projects is highly impacted.

Figure 257: Pocket OSW K Congestion and Energy Deliverability Summary (2030)

ID	Constraint	Contract	Policy S1	Policy S2
1	Cross Sound Cable	6,305	6,049	6,166
2	BARRETT2 138-VLYSTRM 138	4,768	4,922	4,741
3	DUNWOODI 345-SHORE RD 345 (Y50)	3,991	4,362	5,347
4	REACBUS 345-DVNPT NK 345 (Y49)	3,278	2,909	3,559
5	HAUPAGUE 138-C.ISLIP 138	3,066	3,223	3,271
6	Neptune HVDC	2,472	3,125	3,655
7	NRTHPRT1 138-NRTHPRT2 138	1,776	2,114	1,839
8	HOLBROOK 138-RONKONK 138	681	248	754
9	CARLE PL 138-E.G.C. 138	477	680	245
10	NEWBRGE 138-RULND RD 138	436	630	802
11	E.G.C.-2 138-NEWBRGE 138	269	370	292
12	VLY STRM 138-E.G.C.-2 138	264	248	230
13	HAUPAGUE 138-PILGRM P 138	224	190	191
14	BUELL 69-EHAMP 69	158	186	160
15	L SUCS 138-SHORE RD 138	0	207	2

Type	Capacity (MW)			Energy Deliverability (%)		
	Contract	Policy S1	Policy S2	Contract	Policy S1	Policy S2
Offshore Wind	2,270	2,990	2,270	77%	83%	77%
Solar	99	99	99	100%	96%	93%

OSW K - 2035 Pocket Analysis

Additional constrained paths are identified in the 2035 case for both S1 and S2. Overall, the congested hours for constrained paths increase in comparison to 2030. In 2035, both S1 and S2 have additional OSW units added with slightly more capacity in S1. These new OSW additions introduce congestion of lines within the pocket and also on tie lines connecting Zone K to other areas.

Energy deliverability for resources in the pocket is lower in comparison to the 2030 case due to increased congestion on lines and additional capacity added to the system.

Figure 258: Pocket OSW K Congestion and Energy Deliverability Summary (2035)

ID	Constraint	Policy S1	Policy S2
1	Cross Sound Cable	5,756	5,687
2	BARRETT2 138-VLY STRM 138	4,955	4,925
3	DUNWOODI 345-SHORE RD 345 (Y50)	4,090	4,798
4	REACBUS 345-DVNPT NK 345 (Y49)	2,610	2,192
5	HAUPAGUE 138-C.ISLIP 138	2,382	2,518
6	Neptune HVDC	3,748	3,392
7	NRTHPRT1 138-NRTHPRT2 138	2,206	1,977
8	HOLBROOK 138-RONKONK 138	351	944
9	CARLE PL 138-E.G.C. 138	1,344	714
10	NEWBRGE 138-RULND RD 138	380	710
11	E.G.C.-2 138-NEWBRGE 138	1,186	390
12	VLY STRM 138-E.G.C.-2 138	637	410
13	HAUPAGUE 138-PILGRM P 138	403	125
14	BUELL 69-EHAMP 69*	84	18
15	L SUCS 138-SHORE RD 138	1,037	655
16	HOLBROOK 138-HOLBRK2 69	862	299

*met >100 hours threshold in 2030

Type	Capacity (MW)		Energy Deliverability (%)	
	Policy S1	Policy S2	Policy S1	Policy S2
Offshore Wind	4,430	3,835	88%	87%
Solar	99	99	85%	94%