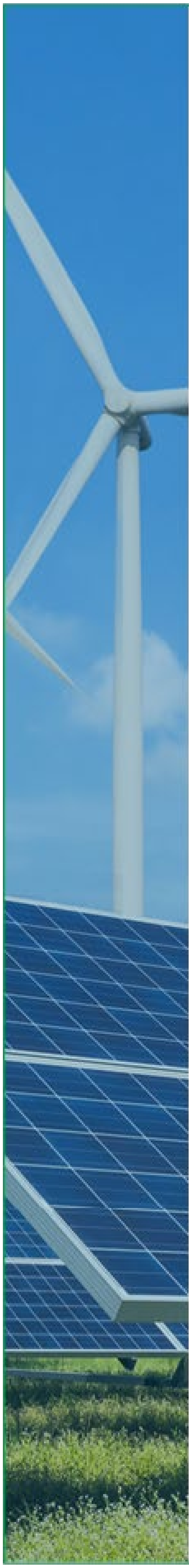

New York ISO
Independent System Operator

Appendix C: Capacity Expansion Assumptions Matrix

2023-2042 System & Resource Outlook

A Report from the New York Independent System Operator

July 22, 2024

Appendix C: Assumptions Matrix for 2023-2042 System & Resource Outlook Capacity Expansion Model

Assumption	Lower Demand Policy Scenario	Higher Demand Policy Scenario	State Scenario
Lock Down Date	11/15/2023		3/21/2024[1]
Generator Descriptions	**Base** generators are defined as generators that are currently in operation and interconnected to the NYCA or included through Base Case inclusion rules. **Awarded** generators are defined as those that have been awarded contracts and are incremental to the Base Case. **Candidate** generators are defined as the generators that the model assumes as candidates for generation expansion incremental to the existing fleet and contracted generators. These above generator categories have different characteristics and modeling assumptions, and these labels are used throughout the report and appendices to distinguish the characteristics outlined in this assumption's matrix.		
Model Framework			
Study Years	The capacity expansion model is simulated for years 2023-2042 (inclusive). Results are reported for model years 2025, 2030, 2035, 2040, and 2042. These are referred to as the "study years" for the purposes of this assessment.		
Time Representation	For each model year, several representative days are identified and selected to represent a year's variety of conditions. These days are applied and weighted across each model year to represent input renewable generation and load peaks and shapes for that year. These representative days are then solved individually and chronologically over all the model years of the capacity expansion model. This method preserves chronology, including the state-of-charge (SoC) of battery storage resources, within each representative day.		
Transmission	Nodal to zonal reduction of transmission network topology performed by PLEXOS to create a pipe-and-bubble equivalent model, where intra-zonal lines are collapsed. Transmission upgrades beyond the existing system topology included in the model include: • NYPA Northern New York Priority Transmission Project • Champlain Hudson Power Express • Clean Path New York • Joint Utilities Phase 1 & Phase 2 Projects • Long Island OSW Public Policy Project See *Appendix B: Production Cost Assumptions Matrix* for additional detail.		
			Sub zonal constraints modeled to reflect estimated transmission headroom of local transmission & distribution system and conceptual marginal upgrade costs. This information is incorporated into the model as a

[1] DPS memo on State Scenario modeling assumptions update discussed at March 21, 2024 ESPWG

Assumption	Lower Demand Policy Scenario	Higher Demand Policy Scenario	State Scenario
			headroom constraint with added cost for exceeding the constraint.
Data Inputs and Forecasting			
Energy Forecast & Peak Load	Hourly load shape for each model year. Load shape based on 2018 weather year.		
	Energy Demand and Peak Loads are based on the 2023 Load & Capacity Data Report (Gold Book) Lower Demand Policy Forecast with modifications to account for the following: • Removal of impact from energy storage resources, BTM Solar generation and electrolysis. • Energy storage resources and BTM Solar are modeled explicitly as resources. • Large loads from the Baseline forecast from the 2023 Gold Book are included in the load forecast.	Energy Demand and Peak Loads are based on the 2023 Load & Capacity Data Report (Gold Book) Higher Demand Policy Forecast with modifications to account for the following: • Removal of impact from energy storage resources, BTM Solar generation and electrolysis. • Energy storage resources and BTM Solar are modeled explicitly as resources. • Large loads from the Higher Demand Policy Scenario forecast from the 2023 Gold Book are included in the load forecast.	Energy Demand and Peak Loads are based on the "Scenario 2" forecast from the CAC Integration Analysis with modifications to account for the following: • Removal of impact of flexible loads and electrolysis. • Energy storage resources and BTM Solar are modeled explicitly • 50% of economy-wide hydrogen needs in model are met by in-state electrolysis on an annual basis. • Loads have been adjusted upward to account for transmission and distribution losses • Large loads are included in the load forecast from the Baseline forecast from the 2023 Gold Book, with adjustments per NYSERDA and DPS request.
Emissions Price Forecast	Emissions allowance price forecast is the same as that assumed in the production cost model. See *Appendix B: Production Cost Assumptions Matrix* for additional detail.		
Fuel Price Forecast	Fuel price forecast is the same as that assumed in the production cost model. See *Appendix B: Production Cost Assumptions Matrix* for additional detail.		
	Fuel price forecast for Dispatchable Emission-Free Resources is specified in the Variable O&M portion of this document.		Fuel price forecast for new and retrofit hydrogen combustion turbine technologies are specified in the Variable O&M portion of this document.
Constraints			
Capacity Reserve Margin	Capacity reserve margins (IRM and LCRs) for the 2023-2024 Capability Year are translated to the UCAP equivalent and applied to all model years, per NYISO ICAP to UCAP translation.		Capacity Reserve Margin referenced from Integration Analysis modeling, which includes a dynamic reserve margin out to 2050.

<table>
<tr><th>Assumption</th><th>Lower Demand Policy Scenario</th><th>Higher Demand Policy Scenario</th><th>State Scenario</th></tr>
<tr><td></td><td colspan="3">Model years 2030 and beyond assume adjustments to locational requirements to address major topology and system changes per TSL floor methodology.</td></tr>
<tr><td rowspan="2">Policy Targets</td><td colspan="3">CLCPA targets and other state policy mandates modeled included:

• 6 GW BTM-PV by 2025
• 10 GW BTM-PV by 2030
• 9 GW offshore wind by 2035</td></tr>
<tr><td colspan="2">• 70% renewable energy by 2030
• 3 GW energy storage by 2030
• Zero-emissions electricity by 2040</td><td>• 70% renewable energy by 2030[2]
• 6 GW energy storage by 2030
• Zero-emissions electricity by 2040; net zero imports overall from IESO, PJM, and ISONE.</td></tr>
<tr><td>Maximum Resource Potential</td><td colspan="3">Candidate renewable generator locations and availability determined by supply curve analysis undertaken by NYSERDA and consultants. Resource potential is comprised of GIS analysis to review siting and land availability, generation potential, and total MW potential per site, county, and/or zone by year.</td></tr>
<tr><td colspan="4">Generators and Generator Properties</td></tr>
<tr><td rowspan="3">Generators</td><td colspan="3">Generators assumed in the capacity expansion model are the same as those included in the Base & Contract Case production cost model (i.e., base and awarded generators). Generator specific information is assumed for these generators. See Appendix B: Production Cost Assumptions Matrix for additional detail.</td></tr>
<tr><td colspan="3">The types of generators and initial start year for expansion ("candidate generators") include the following:

• Land-based wind: 2028
• Utility PV: 2028
• Offshore wind: 2031
• Battery storage, 4- and 8-hour: 2025</td></tr>
<tr><td colspan="2">• Dispatchable Emission-Free Resource (DEFR): 2031

Generation expansion is enabled at the zonal level by generator type for candidate generators, as applicable to technology type.</td><td>• New hydrogen combustion turbine and combined cycle technology: 2031
• Retrofit hydrogen combustion turbine and combined cycle technology: 2035

Generation expansion is enabled at the county level for land-based wind and utility PV and at the zonal level by generator type for candidate generators, as applicable to technology type.</td></tr>
</table>

[2] The formula used for modeling the 70x30 mandate in the State Scenario is: $\frac{Renewable\ Generation}{Load\ forecast + Electrolysis\ load + Net\ storage\ load}$ per DPS memo on modeling assumptions update.

<table>
<tr><th>Assumption</th><th>Lower Demand Policy Scenario</th><th>Higher Demand Policy Scenario</th><th>State Scenario</th></tr>
<tr><td rowspan="2">Generator Retirements</td><td colspan="3">Known generator retirements for base generators are the same as those included in the Base & Contract Case production cost model.

Firm retirements for NYPA small gas plants in model year 2031.</td></tr>
<tr><td colspan="2">The capacity expansion model simulates optimal retirement decisions, which would include incremental generator retirements beyond those with a prescribed retirement date.</td><td>Age-based fossil retirements for existing units are assumed with phase-in of age-based retirements for fleet of generators past age-based threshold (60 years) still in operation.</td></tr>
<tr><td rowspan="2">Generator Heat Rate</td><td colspan="3">Heat rates for base generators are the same as the production cost model. Generator specific information is assumed for these generators. See Appendix B: Production Cost Assumptions Matrix for additional detail.

Heat rates for awarded & candidate generators are applied on a technology type basis from Table 3 of the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module.</td></tr>
<tr><td colspan="2">Heat rates for candidate DEFRs are as follows:
<table><tr><th>Candidate Generator</th><th>Heat Rate (Btu/kWh)</th></tr><tr><td>Low Capital/High Operating cost (LcHo)</td><td>9,124</td></tr><tr><td>Medium Capital/Medium Operating cost (McMo)</td><td>9,786</td></tr><tr><td>High Capital/Low Operating cost (HcLo)</td><td>10,447</td></tr></table></td><td>Heat rates for candidate hydrogen repowered units align with the Scoping Plan: Integration Analysis Annex 1 (“Thermal Op Char”).
<table><tr><th>Candidate Generator</th><th>Heat Rate (Btu/kWh)</th></tr><tr><td>New hydrogen CT</td><td>10,100</td></tr><tr><td>New hydrogen CC</td><td>6,500</td></tr></table>
*Heat rate above represents the maximum power output per Integration Analysis.</td></tr>
<tr><td>Generator Fuel Cost</td><td colspan="2">Fuel cost for candidate DEFRs are as follows:
<table><tr><th>Candidate Generator</th><th>Fuel Cost ($/MMBtu)</th></tr><tr><td>Low Capital/High Operating cost (LcHo)</td><td>40</td></tr><tr><td>Medium Capital/Medium Operating cost (McMo)</td><td>22.50</td></tr><tr><td>High Capital/Low Operating cost (HcLo)</td><td>2.5</td></tr></table></td><td>Fuel cost for candidate hydrogen repowered units are as follows:
<table><tr><th>Candidate Generator</th><th>Fuel Cost (2020 $/MMBtu)</th></tr><tr><td>New and retrofit hydrogen CT/CC</td><td>30.11</td></tr></table>
*Fuel cost above represents the cost in model year 2030; costs are projected to vary over time per Integration Analysis.</td></tr>
<tr><td rowspan="2">Generator Costs: Capital Cost</td><td colspan="3">Capital cost is only applied to candidate generators.</td></tr>
<tr><td colspan="2">The capital costs are assumed by technology type per Table 3 of the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module for land-based wind, utility PV, offshore wind, and battery storage resources to be adjusted on a zonal basis. Locational adjustments for renewable resources are based on the NYSERDA Supply Curve Analysis</td><td>The capital costs are assumed by technology type per NYSERDA Supply Curve Analysis for land-based wind, utility PV and offshore wind are adjusted on a zonal basis.</td></tr>
</table>

<table>
<tr><th>Assumption</th><th>Lower Demand Policy Scenario</th><th>Higher Demand Policy Scenario</th><th>State Scenario</th></tr>
<tr><td rowspan="1"></td><td colspan="2">and based on the 2021-2025 Demand Curve Reset for batteries.

The capital costs assumed for candidate DEFRs are as follows, and are adjusted on a zonal basis:
<table><tr><th>Candidate Generator</th><th>Capital Cost ($/kW)</th></tr><tr><td>Low Capital High Operating (LcHo)</td><td>2,000</td></tr><tr><td>Medium Capital Medium Operating (McMo)</td><td>5,000</td></tr><tr><td>High Capital Low Operating (HcLo)</td><td>8,000</td></tr></table></td><td>The capital costs for batteries are based on the Integration Analysis.

The capital costs assumed for candidate hydrogen repowered units align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Mid”), and will be adjusted on a zonal basis.
<table><tr><th>Candidate Generator</th><th>Capital Cost (2020 $/kW)</th></tr><tr><td>New hydrogen CT</td><td>1,195</td></tr><tr><td>New hydrogen CC</td><td>1,673</td></tr></table>
*Capital cost above represents the cost in model year 2031; costs are projected to vary over time per Integration Analysis.</td></tr>
<tr><td rowspan="2">Generator Costs: Fixed O&M Cost</td><td colspan="3">The Fixed O&M (FO&M) costs for base generators are provided by data from the EPA Platform v6 Documentation, Chapter 4: Generating Resources.</td></tr>
<tr><td colspan="2">The FO&M costs for awarded & candidate generators are provided by estimates in Table 3 of the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module, to be adjusted on a zonal basis based on the NYSERDA Supply Curve Analysis.

The FO&M costs for candidate DEFRs are as follows:
<table><tr><th>Candidate Generator</th><th>Fixed O&M ($/kW-yr)</th></tr><tr><td>Low Capital High Operating (LcHo)</td><td>28</td></tr><tr><td>Medium Capital Medium Operating (McMo)</td><td>75</td></tr><tr><td>High Capital Low Operating (HcLo)</td><td>122</td></tr></table></td><td>The FO&M costs for awarded & candidate generators are assumed per NYSERDA Supply Curve Analysis to be adjusted on a zonal basis.

The FO&M costs for candidate hydrogen repowered units align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Mid”).
<table><tr><th>Candidate Generator</th><th>Fixed O&M (2020 $/kW-yr)</th></tr><tr><td>New hydrogen CT</td><td>16.3</td></tr><tr><td>New hydrogen CC</td><td>24.2</td></tr><tr><td>Retrofit hydrogen CT</td><td>28.6</td></tr><tr><td>Retrofit hydrogen CC</td><td>43.2</td></tr></table></td></tr>
</table>

<table>
<tr>
<td rowspan="2">Generator Costs: Variable O&M Cost</td>
<td colspan="2">The Variable O&M (VO&M) costs of base generators are the same as the production cost model. Generator specific information is assumed for these generators. See Appendix B: Production Cost Assumptions Matrix for additional detail.

The VO&M costs for awarded & candidate renewable and battery storage resources are provided by estimates in Table 3 of the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module.</td>
</tr>
<tr>
<td>The VO&M costs for candidate DEFRs are as follows:

<table>
<tr><th>Candidate Generator</th><th>Variable O&M ($/MWh)</th></tr>
<tr><td>Low Capital High Operating (LcHo)</td><td>16</td></tr>
<tr><td>Medium Capital Medium Operating (McMo)</td><td>9</td></tr>
<tr><td>High Capital Low Operating (HcLo)</td><td>2</td></tr>
</table>
</td>
<td>The VO&M costs for candidate hydrogen repowered units align with the Scoping Plan: Integration Analysis Annex 1 (“Hydrogen Costs”).

<table>
<tr><th>Candidate Generator</th><th>Variable O&M (2020 $/MWh)</th></tr>
<tr><td>New hydrogen CT</td><td>4.9</td></tr>
<tr><td>New hydrogen CC</td><td>4.9</td></tr>
</table>
</td>
</tr>
<tr>
<td rowspan="2">Generator UCAP Ratings and Marginal ELCC Curves</td>
<td>For renewable resources (e.g., land-based wind, utility PV, offshore wind) and battery storage resources, a resource's Firm Capacity contribution is based on marginal ELCC curves. The marginal ELCC curves are calculated for each applicable technology type in the NYCA and for each Locality. The marginal ELCC Curves for renewable resources are calculated based on the new resource’s average output during top 1% (P99) of peak net load hours (i.e., marginal contribution during top net load hours). The marginal ELCC curves for battery storage resources are calculated based on the new resource’s peak demand reduction during the top peak net load hour. Variables considered in the marginal ELCC curve calculation specific to each technology type include hourly load, resource contribution (average output or peak demand reduction for renewables and battery storage resources respectively), and hourly load net of resource evaluated.

Marginal ELCC curves are calculated for each scenario, for each applicable technology type in the NYCA, and for each Locality for summer and winter seasons.

The Firm Capacity ratings for DEFRs align with the default derating factor value for combined cycle units from the NERC GADS database.</td>
<td>For renewable resources (e.g., land-based wind, utility PV, offshore wind) and battery storage resources, a resource's Firm Capacity contribution is based on marginal (incremental) ELCC curves. ELCC curves are calculated for each applicable technology type in the NYCA and for each Locality. The specific curves will be leveraged from the Integration Analysis (pg. 119-125).

The Firm Capacity ratings for hydrogen powered units align with fleet derating factor value for existing combustion turbine and combined cycle units as applicable.</td>
</tr>
<tr>
<td colspan="2">For all other base generators, Firm Capacity (i.e., UCAP) contribution is based on 2017-2021 historic values, consistent with the 2022 RNA base case.</td>
</tr>
</table>

External Area Properties	
External Areas: Energy Forecast	Neighboring systems' peak and energy forecasts updated utilizing load forecast data from PJM, ISO-NE, and IESO to represent "policy futures" based on publicly available reports.
External Areas: Generators	Generation fleet evolution for neighboring systems updated for PJM, ISO-NE, and IESO to represent "policy futures" based on publicly available reports. Generation expansion is not enabled in the capacity expansion model for neighboring systems.
External Areas: Fuel Forecast	Fuel price forecast is the same as that assumed in the production cost model for External World Model. See *Appendix B: Production Cost Assumptions Matrix* for additional detail.
External Areas: Emissions Price Forecast	Emissions price forecast is the same as that assumed in the production cost model for External World Model. See *Appendix B: Production Cost Assumptions Matrix* for additional detail.
External Areas: System Representation	HQ imports modeled with a fixed hourly schedule. Historic level of imports is assumed and adjusted accordingly to account for firm contracts (e.g., CHPE and NECEC). Transmission network for PJM, ISO-NE, and IESO regions included in pipe-and-bubble equivalent model to link external regions to NYCA.