Assumptions Matrix for 2023-2042 System & Resource Outlook

Draft for Discussion at November 2, 2023 ESPWG

Preliminary Assumptions for Policy Reference Cases in Capacity Expansion Model

Assumption	"Lower Demand Policy Scenario"	"Higher Demand Policy Scenario"	"State Scenario"
Generator Descriptions	**Base** generators are defined as generators that are currently in operation in the NYISO system 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 generator categories have different characteristics and model assumptions, and so these labels are used to distinguish the characteristics outlined in this assumption's matrix.		
Model Framework			
Study Years	The capacity expansion model is run for years 2023-2042 (inclusive). Results will be 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, a number of representative days will be identified and selected to represent a year's variety of conditions. These days will be applied and weighted across each model year to represent input renewable generation and load peaks and shapes for that year. These representative days will then be 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 are as follows: • 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 *Preliminary Assumptions in Production Cost Model for Reference Cases* for additional detail.		
			Subzonal constraints modeled to reflect estimated transmission headroom of local transmission & distribution system and conceptual marginal upgrade costs. This information will be incorporated into the model as a

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			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) Low Policy Forecast with modifications to account for the following: • Removal of impact from energy storage resources, BTM Solar generation, electrolysis, and large loads. • Energy storage resources, BTM Solar, and large loads are modeled explicitly as resources.	Energy Demand and Peak Loads are based on the 2023 Load & Capacity Data Report (Gold Book) High Policy Forecast with modifications to account for the following: • Removal of impact from energy storage resources, BTM Solar generation, electrolysis, and large loads. • Energy storage resources, BTM Solar, and large loads are modeled explicitly as resources.	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, BTM Solar, and large loads 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
Emissions Price Forecast	Emissions allowance price forecast is the same as that assumed in the production cost model. See *Preliminary Assumptions in Production Cost Model for Reference Cases* for additional detail.		
Fuel Price Forecast	Fuel price forecast is the same as that assumed in the production cost model. See *Preliminary Assumptions in Production Cost Model for Reference Cases* for additional detail.		
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. Model years 2030 and beyond will assume adjustments to LCR requirements to address major topology and system changes per TSL floor methodology.		Capacity Reserve Margin taken from Integration Analysis modeling, which shows a dynamic reserve margin out to 2050. Model years 2030 and beyond will assume adjustments to LCR requirements to address major topology and system changes per TSL floor methodology.

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Policy Targets	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 • Zero carbon electricity by 2040		CLCPA targets and other state policy mandates modeled include: • 6 GW BTM-PV by 2025 • 70% renewable energy by 2030 • Consistent with Integration Analysis, CHPE is incremental to 70x30 while generation associated with CPNY will count towards 70x30 • 6 GW energy storage by 2030 • 10 GW BTM-PV by 2030 • 9 GW offshore wind by 2035 • Zero carbon electricity by 2040; net zero imports overall from IESO, PJM and ISONE.
Maximum Resource Potential	**Candidate** 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.		
Generators and Generator Properties			
Generators	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 *Preliminary Assumptions in Production Cost Model for Reference Cases* for additional detail.		
	The types of generators available for expansion ("**candidate** generators") include the following: • Land-based wind • Utility PV • Offshore wind • Battery storage, 4- and 8-hour • Dispatchable Emission-Free Resource (DEFR) Generation expansion will be enabled at the zonal level by generator type for **candidate** generators, as applicable to technology type. Initial start year for **candidate** generators to build are as follows: • Land-based wind: 2028 • Utility PV: 2028 • Offshore wind: 2031		The types of generators available for expansion ("**candidate** generators") include the following: • Land-based wind • Utility PV • Offshore wind • Battery storage, 4- and 8-hour • New and retrofit Hydrogen combustion turbine technology Generation expansion will be enabled at the county level by generator type for **candidate** generators, as applicable as applicable to technology type. Initial start year for **candidate** generators to build are as follows: • Land-based wind: 2028 • Utility PV: 2028 • Offshore wind: 2031

<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="2">• Battery storage, 4- and 8-hour: 2024
• Dispatchable Emission Free Resource (DEFR): 2031</td><td>• Battery storage, 4- and 8-hour: 2024
• New and retrofit Hydrogen combustion turbine technology:</td></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.

The capacity expansion model simulates optimal retirement decisions, which would include incremental generator retirements beyond those with a prescribed retirement date.</td></tr>
<tr><td colspan="2"></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 Preliminary Assumptions in Production Cost Model for Reference Cases 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 (LcHo)</td><td>9,124</td></tr><tr><td>Medium Capital Medium Operating (McMo)</td><td>9,786</td></tr><tr><td>High Capital Low Operating (HcLo)</td><td>10,447</td></tr></table></td><td>Heat rates for candidate Hydrogen units align with the Scoping Plan: Integration Analysis Annex 1 (“Thermal Op Char”).</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 based on the NYSERDA Supply Curve Analysis.

The capital costs assumed for candidate DEFRs are as follows, and will be 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 are assumed by technology type per NYSERDA Supply Curve Analysis for land-based wind, Utility PV and offshore wind to be adjusted on a zonal basis.

The capital costs assumed for candidate Hydrogen units align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Mid”).</td></tr>
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<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 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”).</td></tr>
<tr><td rowspan="2">Generator Costs: Variable O&M Cost</td><td colspan="3">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 Preliminary Assumptions in Production Cost Model for Reference Cases 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 colspan="2">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 units align with the Scoping Plan: Integration Analysis Annex 1 (“Hydrogen Costs”).</td></tr>
<tr><td>Generator UCAP Ratings and Marginal ELCC Curves</td><td colspan="2">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 applicable technology type in the NYCA and for each Locality for summer and winter seasons for each scenario.</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).</td></tr>
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	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.		
External Area Properties			
External Areas: Energy Forecast	Neighboring regions peak and energy forecast 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 for neighboring regions updated for PJM, ISO-NE, and IESO to represent "policy futures" based on publicly available reports. Generation expansion will not be enabled in the capacity expansion model for neighboring regions.		
External Areas: Fuel Forecast	Fuel price forecast is the same as that assumed in the production cost model for External World Model. See *Preliminary Assumptions in Production Cost Model for Reference Cases* 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 *Preliminary Assumptions in Production Cost Model for Reference Cases* for additional detail.		
External Areas: System Representation	HQ imports modeled with a fixed hourly schedule. Historic level of imports will be 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 system.		