Assumptions Matrix for 2023-2042 System & Resource Outlook

Draft for Discussion at September 21, 2023 ESPWG

Preliminary Assumptions in Capacity Expansion Model for Policy Reference Cases

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 most accurately match the input generation and peak totals 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 the chronology, including the state-of-charge (SoC) of battery storage resources, within each 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.

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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 Forecast including Demand and Peaks 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. • BTM Solar is modeled explicitly and so should not be included in the forecast • 50% of hydrogen needs in model are met by in-state electrolysis. • Loads have been adjusted upward to account for transmission and distribution losses • Load flexibility representation TBD
Emissions Price Forecast	Emissions 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.		Capacity Reserve Margin taken from Integration Analysis modeling, which shows a dynamic reserve margin out to 2050.
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

<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"></td><td>• 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.</td></tr>
<tr><td>Maximum Resource Potential</td><td colspan="3">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.</td></tr>
<tr><td colspan="4">Generators and Generator Properties</td></tr>
<tr><td rowspan="2">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 Preliminary Assumptions in Production Cost Model for Reference Cases for additional detail.</td></tr>
<tr><td colspan="2">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)</td><td>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</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 2030.

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 applicable existing units are assumed per Climate Action Council Appendix D (ST units at 62 years, GT units at 47 years of age), including associated phase-in of age-based retirements for fleet of generators past age-based threshold still in operation.</td></tr>
<tr><td>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 the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module, pages 5-7.</td></tr>
</table>

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	Heat rates for **candidate** DEFRs are TBD.		Heat rates for **candidate** Hydrogen units align with the Scoping Plan: Integration Analysis Annex 1.
Generator Costs: Capital Cost	Capital cost is only applied to **candidate** generators.		
	The capital costs are assumed by technology type per 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 TBD.		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.
Generator Costs: Fixed O&M Cost	The Fixed O&M (FO&M) costs for **base** generators are provided by data from the EPA Platform v6 Documentation, Chapter 4: Generating Resources.		
	The FO&M costs for **awarded** & **candidate** generators are provided by estimates in the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module, pages 5-7 to be adjusted on a zonal basis based on the NYSERDA Supply Curve Analysis. The FO&M costs for **candidate** DEFRs are TBD.		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.
Generator Costs: Variable O&M Cost	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 the EIA Annual Energy Outlook 2023, Assumptions to Electricity Market Module, pages 5-7.		
	The VO&M costs for **candidate** DEFRs are TBD.		The VO&M costs for **candidate** Hydrogen units align with the Scoping Plan: Integration Analysis Annex 1.
Generator UCAP	For **base** generators, Firm Capacity (i.e., UCAP) contribution is based on 2017-2021 historic values, consistent with the 2022 RNA base case.		

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	For **awarded** & **candidate** 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 for each applicable technology type in the NYCA and for each Locality. The marginal ELCC Curves are 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 **awarded** & **candidate** 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.
External Area Properties			
External Areas: Energy Forecast	TBD		
External Areas: Generators	TBD		
External Areas: Fuel Forecast	TBD		
External Areas: Transmission	TBD		