Assumptions Matrix for Capacity Expansion Model[1]

Comparison of 2023-2042 System & Resource Outlook and Coordinated Grid Planning Process Scenarios

<table>
<tr><th rowspan="2">Assumption</th><th colspan="2">System & Resource Outlook</th><th>Both</th><th colspan="2">Coordinated Grid Planning Process</th></tr>
<tr><th>Lower Demand Policy Scenario</th><th>Higher Demand Policy Scenario</th><th>State Scenario</th><th>Low Transmission Impact</th><th>High Transmission Impact</th></tr>
<tr><td>Lock Down Date</td><td colspan="2">11/15/2023</td><td>3/21/2024[2]</td><td colspan="2">4/22/2024</td></tr>
<tr><td>Generator Descriptions</td><td colspan="5">Base generators are defined as generators that are currently in operation and interconnected to the NYCA or included by satisfying the 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.

A list of the awarded generators in the base and contract cases was presented to NYISO stakeholders at the April 4, 2024, LFTF/ESPWG.</td></tr>
<tr><td colspan="6">Model Framework</td></tr>
<tr><td>Study Years</td><td colspan="5">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 these assessments.</td></tr>
<tr><td>Time Representation</td><td colspan="5">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.</td></tr>
<tr><td rowspan="2">Transmission</td><td colspan="5">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 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 2023-2042 System & Resource Outlook Appendix B: Production Cost Assumptions Matrix for additional detail (here).</td></tr>
<tr><td colspan="2"></td><td colspan="3">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 headroom constraint with added cost for exceeding the constraint.</td></tr>
</table>

[1] Additional details on capacity expansion assumptions, as well as modeling and methodologies, are provided in the 2023-2042 System & Resource Outlook, Appendices C and D, respectively

[2] DPS memo on State Scenario modeling assumptions update discussed at March 21, 2024 ESPWG and March 25, 2024 EPPAC

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<tr><td colspan="6">Data Inputs and Forecasting</td></tr>
<tr><td rowspan="2">Energy Forecast & Peak Load</td><td colspan="5">Hourly load shape for each model year. Load shape based on 2018 weather year.</td></tr>
<tr><td>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.</td><td>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.</td><td>Energy Demand and Peak Loads are based on the "Scenario 2" forecast from the CAC Integration Analysis[3] with modifications to account for the following:

• Removal of impact of flexible loads and electrolysis.
• Flexible loads are modeled explicitly according to Medium End-Use Flexibility data from IA Scenario 2.
• 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.</td><td>Same as the State Scenario with the following modifications:

• Removal of impact of flexible loads and electrolysis.
• Flexible loads are modeled explicitly according to High End-Use Flexibility data from IA Scenario 2.
• Higher statewide BTM Solar forecast based on NYSERDA Distributed Solar Roadmap.</td><td>Energy Demand and Peak Loads are based on the "Scenario 3" forecast from the CAC Integration Analysis. The following assumptions are also modified as compared to the State Scenario:

• No inclusion of the impact of flexible loads.</td></tr>
<tr><td>Emissions Price Forecast</td><td colspan="5">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.</td></tr>
<tr><td rowspan="2">Fuel Price Forecast</td><td colspan="5">Fuel price forecast is the same as that assumed in the production cost model. See Appendix B: Production Cost Assumptions Matrix for additional detail.</td></tr>
<tr><td colspan="2">Fuel price forecast for Dispatchable Emission-Free Resources is specified in the Variable O&M portion of this document.</td><td colspan="3">Fuel price forecast for new and retrofit hydrogen combustion turbine technologies are specified in the Variable O&M portion of this document.</td></tr>
<tr><td colspan="6">Constraints</td></tr>
<tr><td rowspan="2">Capacity Reserve Margin</td><td colspan="2">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.</td><td colspan="3">Capacity reserve margin referenced from Integration Analysis modeling, which includes a dynamic reserve margin out to 2050.</td></tr>
<tr><td colspan="5">Model years 2030 and beyond assume adjustments to locational requirements to address major topology and system changes per TSL floor methodology.</td></tr>
</table>

[3] The Integration Analysis is included as part of New York's Scoping Plan. Additional details on Integration Analysis inputs and outputs are available in IA Annex 1 & 2.

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<tr><th>Lower Demand
Policy Scenario</th><th>Higher Demand
Policy Scenario</th><th>State Scenario</th><th>Low Transmission Impact</th><th>High Transmission Impact</th></tr>
<tr><td rowspan="2">Policy Targets</td><td colspan="5">CLCPA targets and other state policy mandates modeled include:

• 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 electric grid by 2040</td><td colspan="3">• 70% renewable energy by 2030[4]
• 6 GW energy storage by 2030
• Zero-emissions electric grid by 2040; net zero imports overall from IESO, PJM, and ISONE.</td></tr>
<tr><td>Maximum Resource Potential</td><td colspan="5">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="6">Generators and Generator Properties</td></tr>
<tr><td rowspan="3">Generators</td><td colspan="5">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="5">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 colspan="2">• 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><td>New hydrogen fuel cell technology: 2031</td></tr>
<tr><td rowspan="2">Generator Retirements</td><td colspan="5">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 colspan="3">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>
</table>

[4] 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.

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Policy Scenario</th><th>State Scenario</th><th>Low Transmission Impact</th><th>High Transmission Impact</th></tr>
<tr><td rowspan="2">Generator Heat Rate</td><td colspan="5">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 colspan="2">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><td>Heat rate for candidate hydrogen fuel units align with data from PNNL.[5]
<table><tr><th>Candidate Generator</th><th>Heat Rate (Btu/kWh)</th></tr><tr><td>New hydrogen fuel cell</td><td>6,730</td></tr></table></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 colspan="2">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><td>Fuel cost for candidate hydrogen fuel cell units are as follows:
<table><tr><th>Candidate Generator</th><th>Fuel Cost (2020 $/MMBtu)</th></tr><tr><td>New hydrogen fuel cell</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="5">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 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:</td><td>The capital costs are assumed by technology type per NYSERDA Supply Curve Analysis for land-based wind, utility PV, and offshore wind and are adjusted on a zonal basis.

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. Retrofit generation is assumed as $0/MW.</td><td>Unless otherwise noted the capital costs are the same as the state scenario.

The capital costs assumed for candidate batteries align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Low”) and will be adjusted on a zonal basis.</td><td>Unless otherwise noted the capital costs are the same as the state scenario.

The capital costs assumed for candidate fuel cell units align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Mid”) and will be adjusted on a zonal basis. Assumes no retrofit generation.
<table><tr><th>Candidate Generator</th><th>Capital Cost (2020 $/kW)</th></tr><tr><td>New hydrogen Fuel Cell</td><td>1,290</td></tr></table></td></tr>
</table>

[5] Pacific Northwest National Laboratory

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<td colspan="2"><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><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>
<td><table><tr><th>Candidate Generator</th><th>Capital Cost (2020 $/kW)</th></tr><tr><td>4-hr Battery</td><td>1,009</td></tr><tr><td>8-hr Battery</td><td>1,921</td></tr></table>
Retrofit generation is assumed as $0/MW.

*Capital cost above represents the cost in model year 2025; costs are projected to vary over time per Integration Analysis.</td>
<td>*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="5">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>
<td>Unless otherwise noted the FO&M costs are the same as the State Scenario.

The FO&M costs for candidate batteries align with the Scoping Plan: Integration Analysis Annex 1 (“Resource Costs – Low”).
<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></table></td>
<td>Unless otherwise noted the FO&M costs are the same as the State Scenario.

The FO&M costs for candidate hydrogen fuel cell 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 fuel cell</td><td>30</td></tr></table></td></tr>
</table>