Assumptions Matrix for 2021-2040 System & Resource Outlook

Draft for Discussion at April 26, 2022 ESPWG

Preliminary Assumptions in Capacity Expansion Model for Policy Reference Cases

<table>
<tr><th></th><th>Baseline Scenario #1 (S1)</th><th>Baseline Scenario #2 (S2)</th></tr>
<tr><td>Existing Generation</td><td>Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.</td><td>Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.</td></tr>
<tr><td>Existing Generation FOM Costs</td><td>Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources</td><td>Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources</td></tr>
<tr><td>Existing Generation Properties</td><td>Firm capacity (i.e., UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.</td><td>Firm capacity (i.e., UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.</td></tr>
<tr><td>Chronological Representation</td><td>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.</td><td>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.</td></tr>
<tr><td>Energy Demand & Profile</td><td>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.

Outlook CLCPA Case Annual Energy Forecast - GWh
<table>
<tr><th>Year</th><th>Base Shape</th><th>BTM PV</th><th>EV</th><th>Electrification</th><th>Annual Energy</th></tr>
<tr><td>2025</td><td>139,863</td><td>-7,483</td><td>1,922</td><td>10,402</td><td>144,704</td></tr>
<tr><td>2030</td><td>133,856</td><td>-11,068</td><td>5,488</td><td>22,633</td><td>150,909</td></tr>
<tr><td>2035</td><td>130,775</td><td>-11,983</td><td>10,322</td><td>43,452</td><td>172,566</td></tr>
<tr><td>2040</td><td>129,178</td><td>-12,454</td><td>16,361</td><td>75,594</td><td>208,679</td></tr>
</table>
Outlook CLCPA Case Peak Forecasts - MW
<table>
<tr><th>Year</th><th>Summer Peak</th><th>Winter Peak</th></tr>
<tr><td>2025</td><td>31,679</td><td>26,491</td></tr>
<tr><td>2030</td><td>34,416</td><td>31,717</td></tr>
<tr><td>2035</td><td>40,033</td><td>41,681</td></tr>
<tr><td>2040</td><td>48,253</td><td>57,144</td></tr>
</table>
</td><td>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.

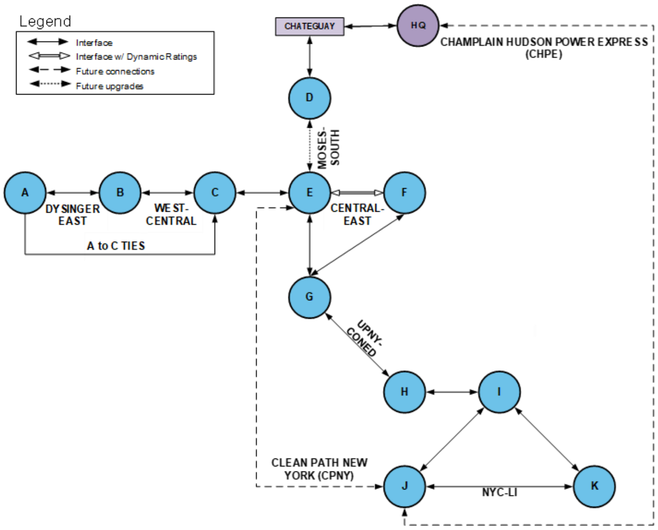
Outlook Alternative Forecast Scenario Annual Energy Forecast - GWh
<table>
<tr><th>Year</th><th>BTM PV</th><th>Annual Energy</th></tr>
<tr><td>2025</td><td>-7,631</td><td>150,047</td></tr>
<tr><td>2030</td><td>-14,461</td><td>164,256</td></tr>
<tr><td>2035</td><td>-17,223</td><td>204,702</td></tr>
<tr><td>2040</td><td>-23,220</td><td>235,731</td></tr>
</table>
Outlook Alternative Forecast Scenario Peak Forecasts - MW
<table>
<tr><th>Year</th><th>Summer Peak</th><th>Winter Peak</th></tr>
<tr><td>2025</td><td>29,612</td><td>21,758</td></tr>
<tr><td>2030</td><td>30,070</td><td>25,892</td></tr>
<tr><td>2035</td><td>34,402</td><td>35,093</td></tr>
<tr><td>2040</td><td>38,332</td><td>42,301</td></tr>
</table>
</td></tr>
</table>

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.

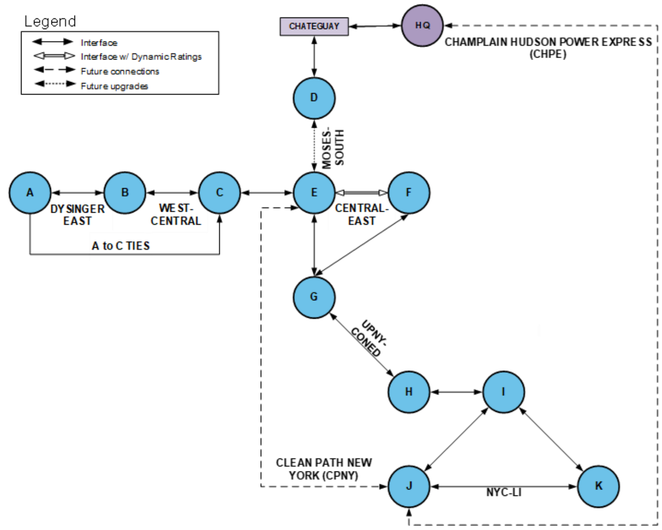


Years	Interface/Interzonal Pipes	+ Limit (MW)	- Limit (MW)	Source
All	DYSINGER EAST	2,700	*	2020 ATR
All	A to C Ties	550	0	2021 CRP limit
All	WEST-CENTRAL	1,475	*	2020 ATR
2021-2024	MOSES-SOUTH	3,050	-1,500	1/2015 Ops study stability limit [1]
2025-2040	MOSES-SOUTH	4,050	-1,500	Tier 4 contract [2]
2021-2023	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	-1,300	Tier 4 contracts [4]
2025-2040	CHAMPLAIN HUDSON POWER EXPRESS	1,250	-1,250	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]
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	-1,300	Tier 4 contracts [4]
2025-2040	CHAMPLAIN HUDSON POWER EXPRESS	1,250	-1,250	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 was assumed firm build 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 was assumed firm build 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	Zonal Multiplier for Capital Costs										
	Capital	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	Zonal Multiplier for Capital Costs										
	Capital	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. 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. 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

Policy Targets and Other Model Constraints	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 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.	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 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.