New York ISO
Independent System Operator

Appendix D

2021-2040 System & Resource Outlook (The Outlook)

A Report from the New York Independent System Operator

September 22, 2022

Appendix D: Policy Case Capacity Expansion Assumptions Matrix

	Scenario #1 (S1)	Scenario #2 (S2)
Scenario Description	*S1 utilizes industry data and NYISO load forecasts, representing a future with high demand (57,144 MW winter peak and 208,679 GWh energy demand in 2040) and assumes less restrictions in renewable generation buildout options.*	*S2 utilizes various assumptions more closely aligned with the Climate Action Council Integration Analysis and represents a future with a moderate peak but a higher overall energy demand (42,301 MW winter peak and 235,731 GWh energy demand in 2040).*
Existing Generation	Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.	Consistent with Policy Case production cost simulation database, noting that the model simulates optimal retirement decisions which may differ from production cost database.
Existing Generation FOM Costs	Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources.	Fixed O&M costs for existing generators assumed per 2018 documentation for EPA Platform. Chapter 4: Generating Resources.
Existing Generation Properties	Firm capacity (*i.e.*, UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.	Firm capacity (*i.e.*, UCAP) values based on 2016-2020 historic values, as used in 2020 RNA base case.
Chronological Representation	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.	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.

Energy Demand & Profile

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.

Annual Energy in the following table represents net load.

Outlook Scenario S1: Annual Energy Forecast (GWh)

Year	Base Shape	BTM PV	EV	Electrification	Annual Energy
2025	139,863	-7,483	1,922	10,402	144,704
2030	133,856	-11,068	5,488	22,633	150,909
2035	130,775	-11,983	10,322	43,452	172,566
2040	129,178	-12,454	16,361	75,594	208,679

Outlook Scenario S1: Peak Forecasts (MW)

Year	Summer Peak	Winter Peak
2025	31,679	26,491
2030	34,416	31,717
2035	40,033	41,681
2040	48,253	57,144

Outlook Scenario S1: BTM-PV Capacity (MW)

Year	BTM PV
2025	6,834
2030	10,055
2035	10,828
2040	11,198

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.

Annual Energy in the following table represents gross load.

Outlook Scenario S2: Annual Energy Forecast (GWh)

Year	BTM PV	Annual Energy
2025	-7,631	150,047
2030	-14,461	164,256
2035	-17,223	204,702
2040	-23,220	235,731

Outlook Scenario S2: Peak Forecasts (MW)

Year	Summer Peak	Winter Peak
2025	29,612	21,758
2030	30,070	25,892
2035	34,402	35,093
2040	38,332	42,301

Outlook Scenario S2: BTM-PV Capacity (MW)

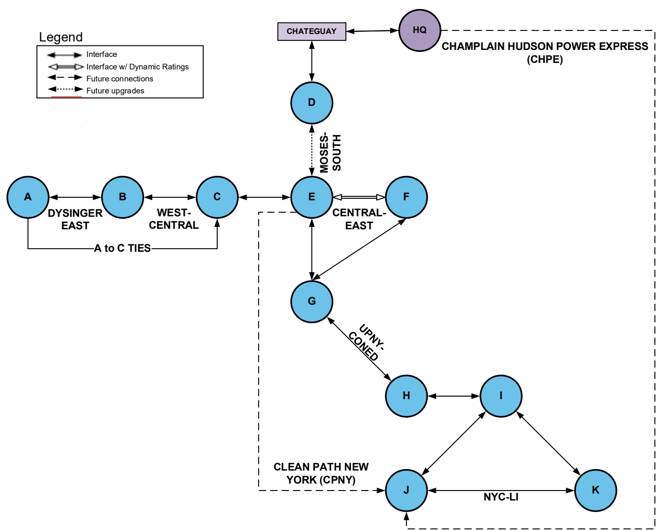
Year	BTM PV
2025	6,000
2030	9,523
2035	11,601
2040	15,764

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	0	Tier 4 contracts [4]
2025-2040	CHAMPLAIN HUDSON POWER EXPRESS	1,250	0	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.

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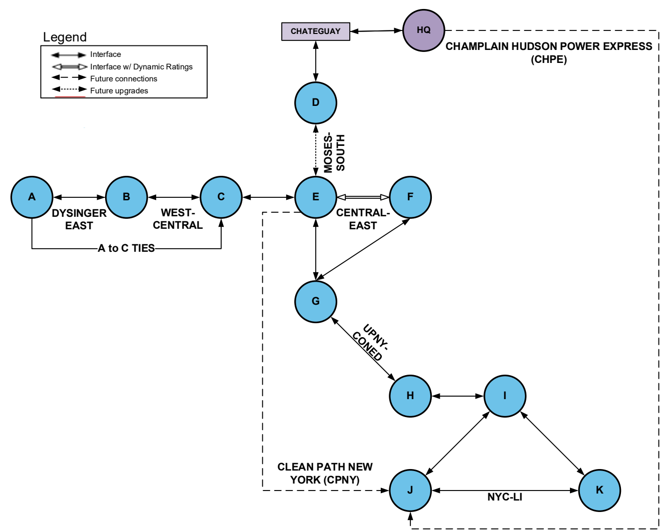

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New Transmission

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

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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 is assumed as firm builds 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 is assumed as firm builds 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 Capital	Zonal Multiplier for Capital Costs										
		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.

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Medium Operating/Medium Capital	4,500	9	23	6.37

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Candidate Technology	Base Capital	Zonal Multiplier for Capital Costs										
		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
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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

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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 New York's Evolution to a Zero Emission Power System "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 New York's Evolution to a Zero Emission Power System "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. The G-J and J Localities assume a 650 MW reduction in LCR requirements due to the Clean Path New York HVDC project. 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. The G-J and J Localities assume a 650 MW reduction in LCR requirements due to the Clean Path New York HVDC project. 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 grid 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 grid 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.