Quantitative Analysis of Resource Adequacy Structures

PREPARED FOR
NYSERDA and NYSDPS

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July 1, 2020

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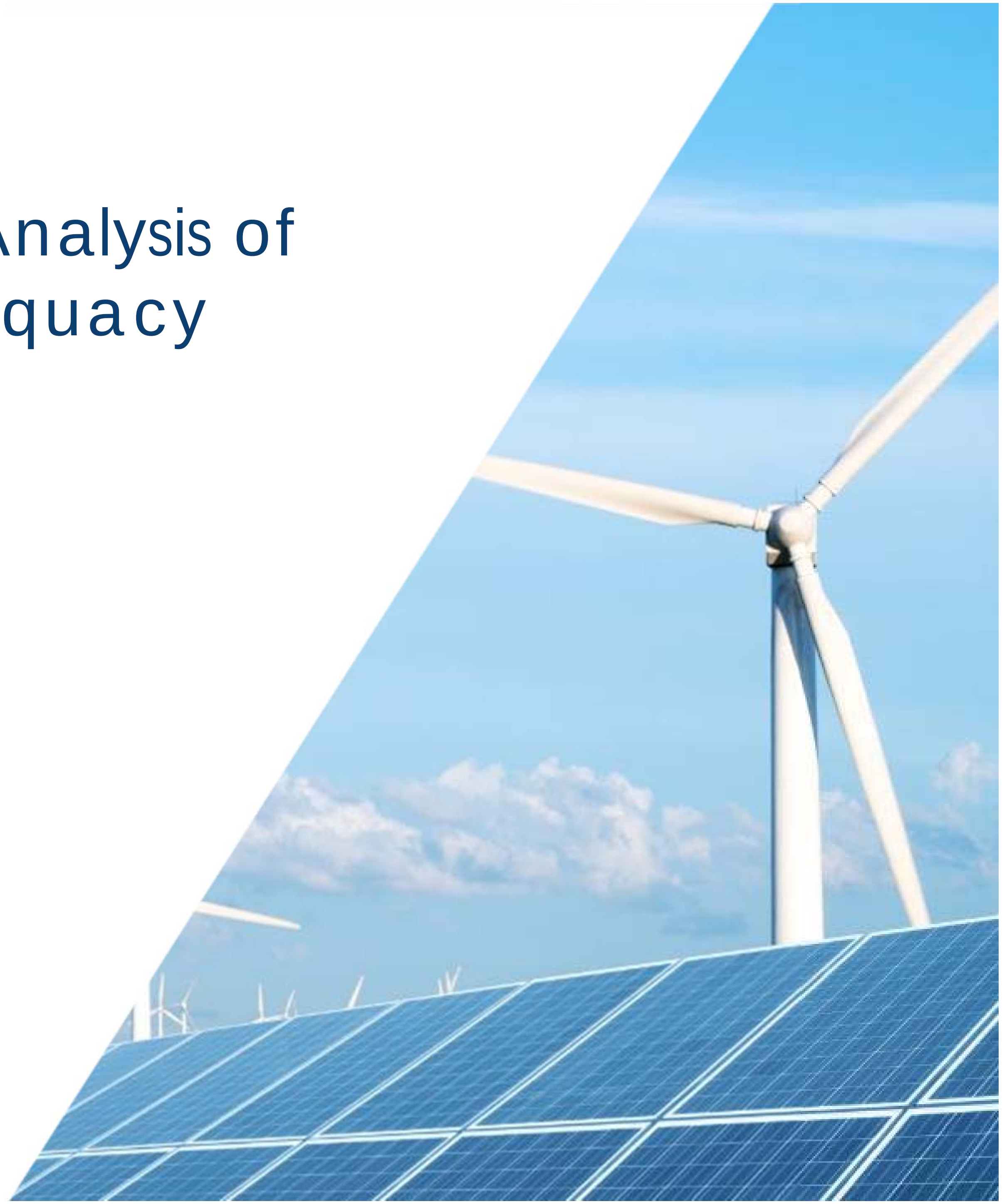


Study Scope

NYSERDA and NYDPS retained Brattle to evaluate several alternative resource adequacy constructs that differ primarily in who administers them and how Buyer-Side Mitigation (BSM) is applied; this deck presents estimates of the differences in customer costs.

Summary of RA Structures Corresponding to Brattle Qualitative Analysis Memo

	Structure	Description	Cost Evaluation
1	**ICAP Market with Status Quo BSM**	Current ICAP market with current rules	Compared to #3 to indicate costs of Status Quo BSM
2	**ICAP Market with Expanded BSM**	Same as above but with potential expansion to BSM rules corresponding to FERC's December 2019 order for PJM	Compared to #3 to indicate costs of potential Expanded BSM
3	**Centralized Market for Resource Adequacy Credits (RACs), without BSM**	Functionally similar to current ICAP market, but with rule-setting by State No BSM, except as applied by PSC to prevent the intentional introduction of uneconomic capacity to profitably suppress capacity prices	Evaluated as "No BSM"
4	**LSE Contracting for RACs**	Same as #3, but with no centralized market LSEs must procure sufficient RACs bilaterally	Similar to #3 but difficult to quantify
5	**Co-optimized Capacity and Clean Energy Procurement**	Same as #3, but a State entity would procure RACs and RECs for LSEs in a joint, co-optimized auction	Not evaluated (out of scope)

Approach and Key Assumptions

To estimate customer cost impacts, we simulated future wholesale markets (including the application of BSM) in 2030, using Brattle's GridSIM model. Key Assumptions:

- Modeled fleet reflects the **Climate Leadership and Community Protection Act** (CLCPA) and **NYISO CARIS study**:
  - 70% of load is met by renewable resources by 2030 (does not include Nuclear generation)
  - Annual gross load, 6,100 MW of offshore wind (OSW), 3,000 MW of storage, and 7,500 MW of behind-the-meter (BTM) solar assumptions consistent with CLCPA targets and 2019 CARIS study assumptions
- Assumptions on BSM applicability were updated to align with NYISO's proposed exemption rule:
  - 1. "Status Quo" applies BSM to new renewables and storage in Zones G-J, except approximately 550 UCAP MW of policy exemptions
  - 2. "Expanded BSM" extends BSM to all zones, incl. nuclear and half of the existing hydro resources (assuming CapEx projects), with exemptions for 160 UCAP MW of OSW in Zone J, 173 UCAP MW of OSW in Zone K, and 41 UCAP MW of PV in Zones G-I
  - 3. Centralized RAC Market w/ "No BSM" does not exclude any resources from the capacity market
- Assumptions on UCAP ratings of intermittent resources affect the magnitude of BSM
  - UCAP value declines with penetration; analyzed output vs. net load to estimate effective load-carrying capability (ELCC)
  - Available output data had low CF% and output diversity, making impact estimates conservative; on the other hand, analysis does not recognize that transmission constraints could make the local J/K value fall faster with penetration
- Other key assumptions: resources' fixed and variable costs contributing to capacity prices via supply elasticity
- Sensitivity analyses: explored effects of nuclear retirements; higher load; quantity of BSM policy exemptions

The 2030 system examined here leveraged CARIS 70*30 and otherwise made necessary simplifying assumptions. While the system examined in 2030 does not represent a prediction of the future system, it is a reasonable expectation for the purpose of examining alternative RA structures

Cost estimates are thus indicative; impact will ultimately depend on the year, load, supply mix, UCAP ratings, and capacity supply elasticity, and the details of any changes to BSM rules

Updates to this Quantitative Analysis

We have updated this quantitative analysis based on stakeholder input received and to better reflect NYISO's proposed BSM rules and recent developments

- The most important changes provide a more accurate representation of likely outcomes under the "Status Quo" buyer-side mitigation approach, including:
  - Higher renewables exemption (assuming that NYISO's April 20 filing is accepted)
  - Sensitivity analysis on the quantity of public policy resource exemptions
  - Offer floor at the minimum of 0.75x mitigation Net CONE or resource offer floor
  - Updated representation of resource retirements and winter only status as per the NY DEC "Peaker Rule" Part 227-3 and 2020 Gold Book
  - Updated going-forward cost assumptions for fossil resources that are at risk of retirement (identified as a key study sensitivity)
- **Overall Impact of Updates:** Estimated customer costs imposed by Status Quo BSM are somewhat lower, but the uncertainty range remains similar at approximately \$0.4-\$0.9 billion per year; Expanded BSM scenario costs remain similar at approximately \$1.3-\$2.8 billion per year

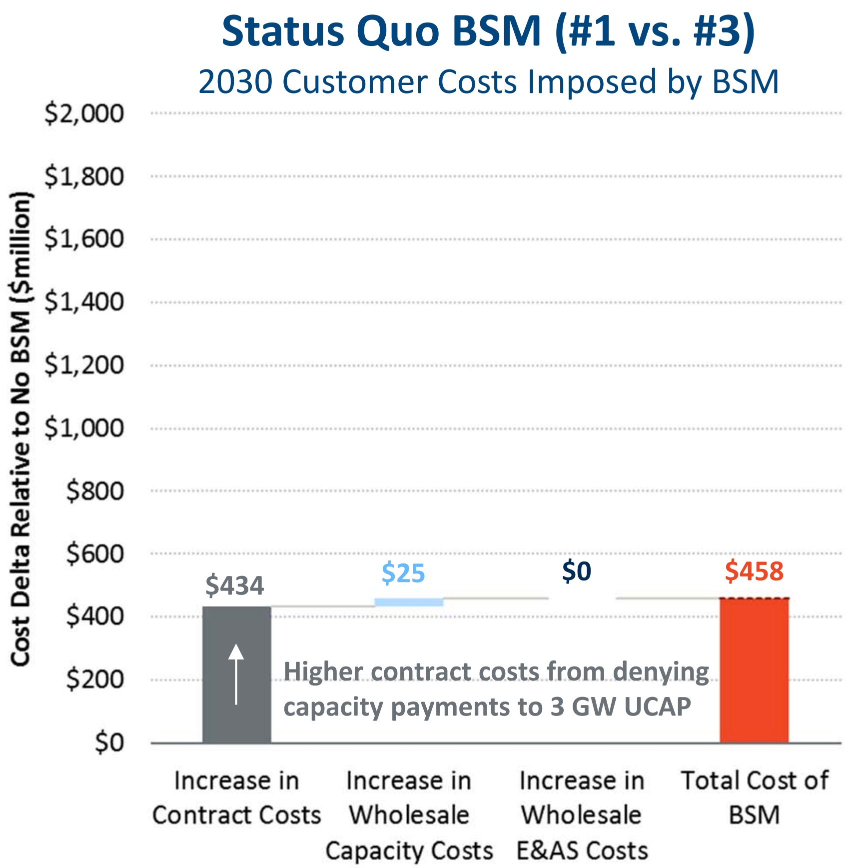
Summary of Conclusions

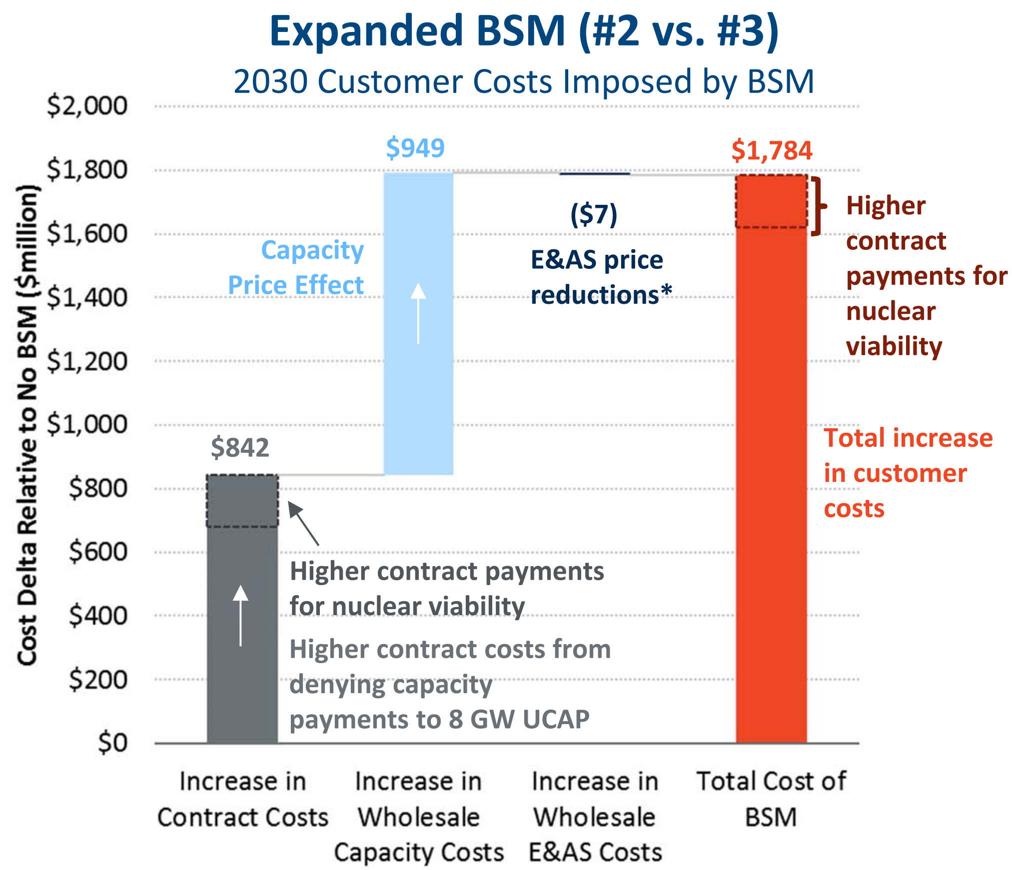
- By 2030 relative to a No-BSM scenario, estimated customer costs increase by:
  - **$0.4-0.9 billion/year** under Status Quo BSM (~12%-20% of statewide capacity costs or ~24%-34% of Zones G-J capacity costs), range depending on load growth and exemptions
  - **$1.3-2.8 billion/year** under Expanded BSM (~35%-63% of statewide capacity costs), range depending on load growth and nuclear resource retention
- This reflects costs of over-procuring capacity because mitigated policy resources would not be accounted for in the capacity market, including:
  - Contract costs increase for policy resources, since they are denied capacity payments
  - Capacity market clearing prices rise
- These estimates account for moderating long-term factors:
  - Long-term supply elasticity mitigates capacity price impacts so it is smaller than the "double-payment" quantity effect (showing up as higher contract costs)
  - Lower resource UCAP values at higher penetration of mitigated renewable resources limit the impact of BSM
  - Offsetting E&AS impacts, but these are relatively small
  - Policy resource exemptions can somewhat mitigate costs

Analytical Results

Estimated Customer Costs of BSM in 2030

Net impact of BSM on customers is $0.5 billion/yr under Status Quo; $1.8 billion/yr under Expanded BSM.

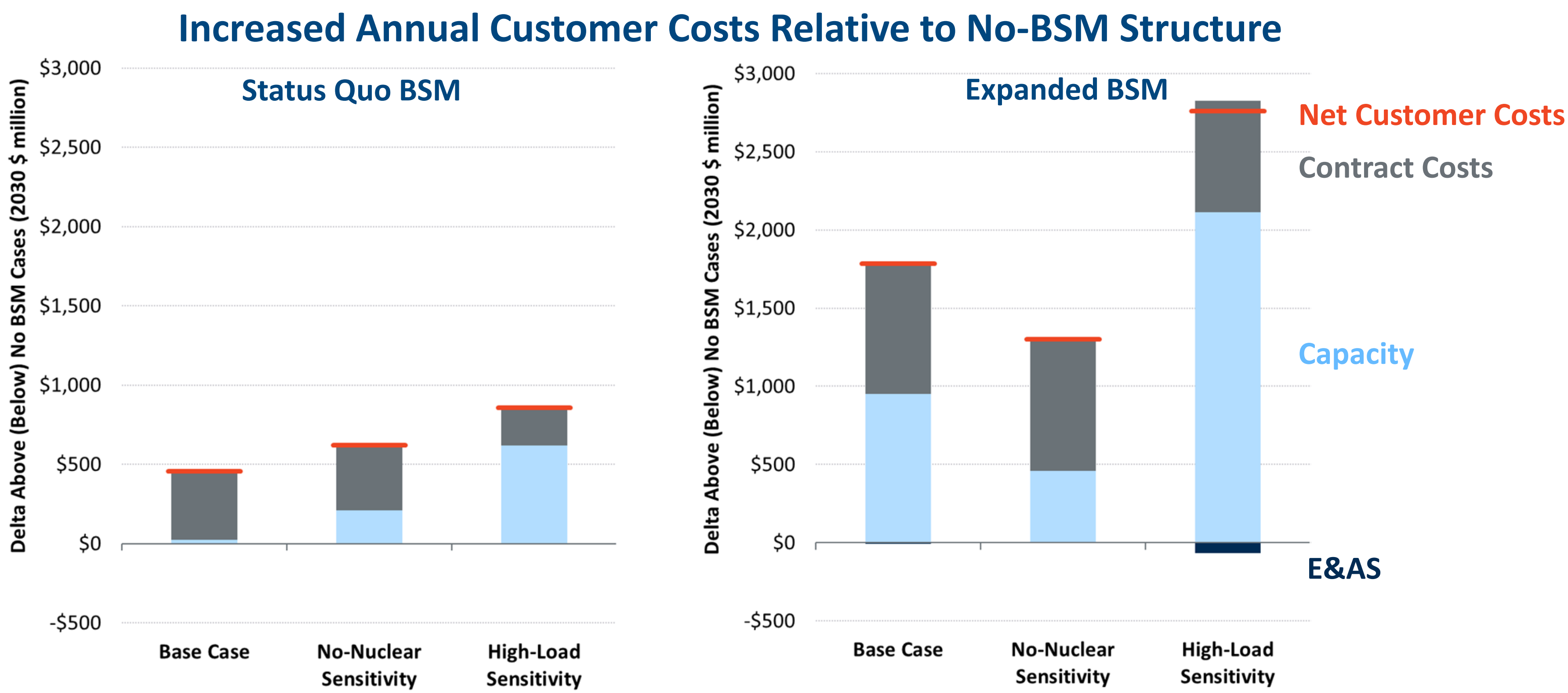




* Energy and AS prices decrease in some cases because excess capacity depresses prices in tight hours; and because higher contract payments (due to lack of capacity payments) cause energy prices to be more negative in over-generation hours.

Sensitivity of BSM Costs to Supply-Demand Balance

Customer costs of BSM are sensitive to peak load (higher load driving higher costs)



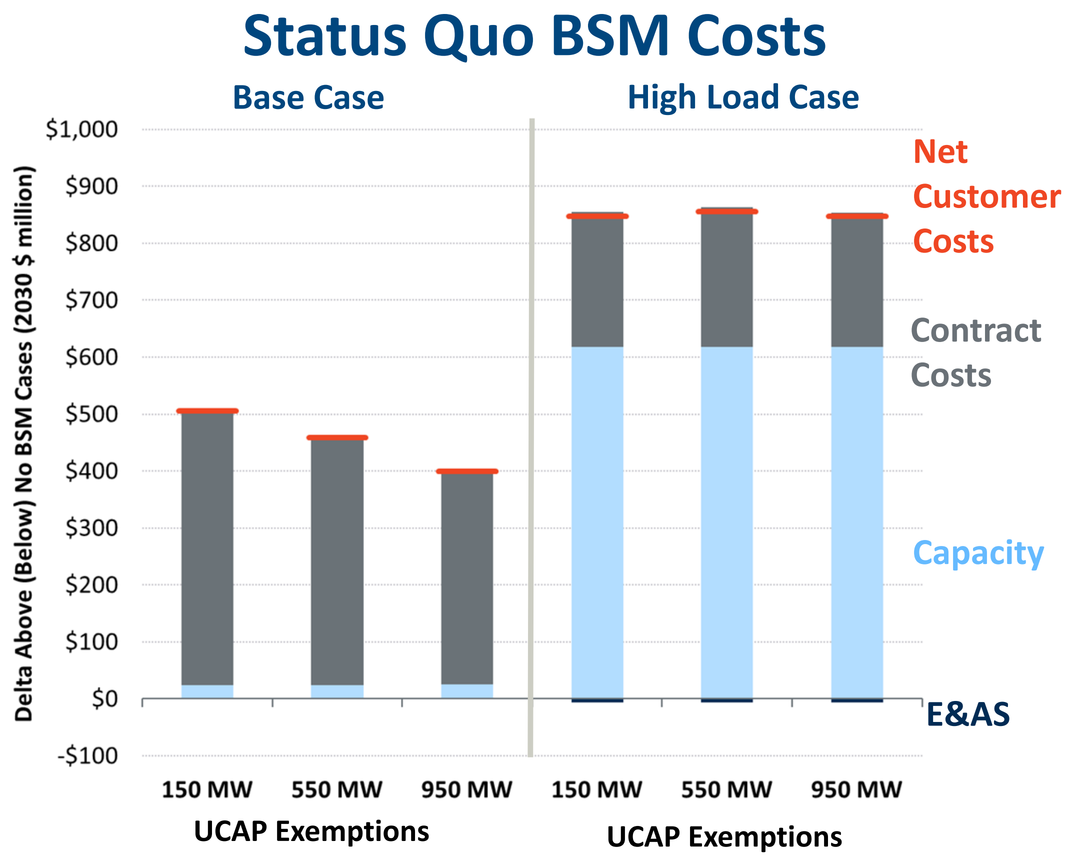
Notes: "**No-Nuclear Sensitivity**" loses all >3 GW of upstate nuclear, largely replaced by retaining gas CCs, so fewer resources to mitigate.
"**High-Load Sensitivity**" results in additions of onshore wind to meet 70% target.

Sensitivity of Status Quo BSM Costs to Policy Resource Exemptions

We evaluated the sensitivity of Status Quo costs to +/- 400 MW of policy resource exemptions

Costs remain similar because:

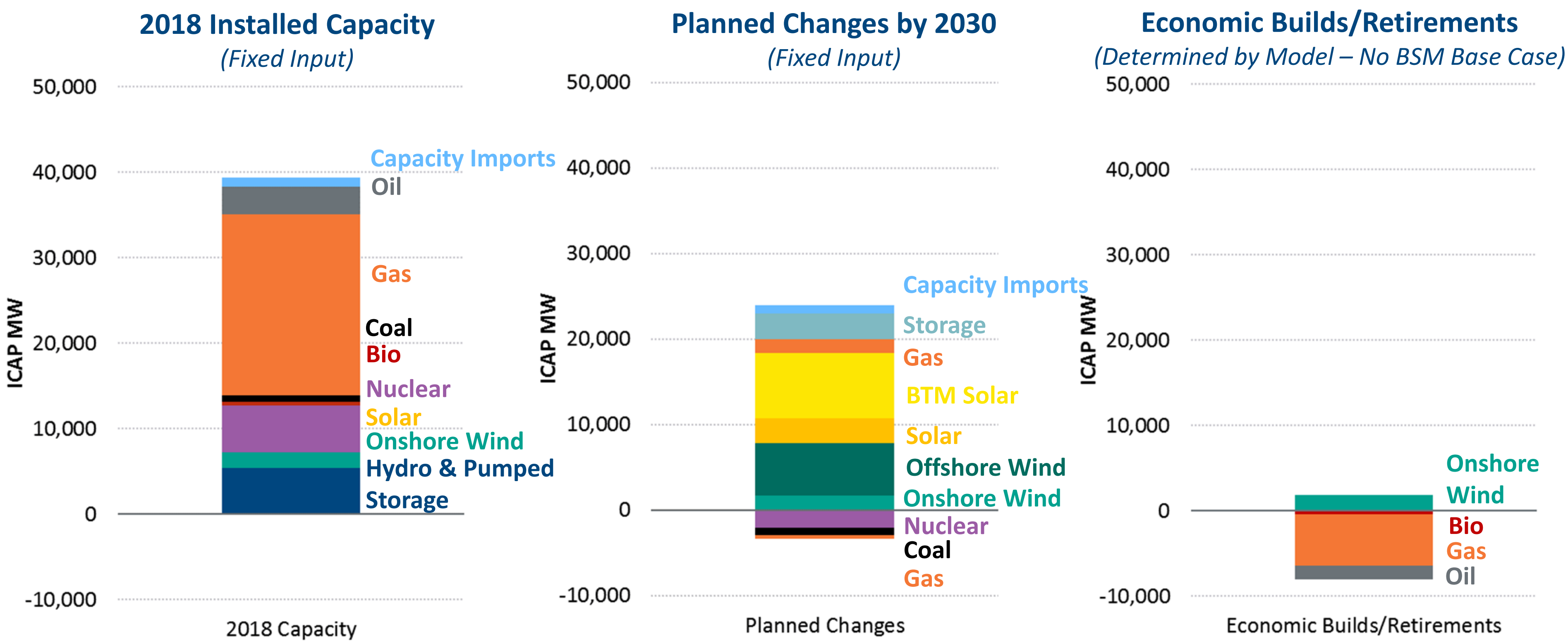
- **Base Case:** Gas ST is marginal, so 400 MW policy exemptions displaces 400 MW of gas ST retention
- **High Load Case:** Generic offer floor is marginal in all cases, so 400 MW exemptions results in +400 MW generic offer floor resources (and vice versa)



Base Case Detailed Results

Base Case Supply Mix

Existing generation is consistent with the 2019 Gold Book, and planned capacity changes are based on signed CES contracts and CARIS study assumptions. The model economically retires old plants and builds new clean ones to meet any remaining gap to reach CLCPA 70% target



Note: Model determines if 2018 existing supply resources will retire by 2030.

Note: Model determines economic resource builds needed to reach CLCPA targets (incremental to planned changes).

Capacity Subject to Mitigation
before considering exemptions or clearing

Mitigated Non-Emitting Capacity by Zone (ICAP MW)

Blue shading subject to Status Quo BSM

Expanded BSM applies to blue and teal

	2018 Capacity	Planned/Assumed 2019-2030 Additions/Retirements (Fixed Input)					Economic Additions (Determined by Model)		Total Capacity by 2030
		Zone A-E	Zone F	Zone G-I	Zone J	Zone K	Zone A-E	Zone F-K	
Hydro & PS	5,436	0	0	0	0	0	0	0	5,436 **
Onshore Wind	1,739	1,710	0	0	0	0	1,814	0	5,263
Offshore Wind	0	0	0	0	4,320*	1,778	0	0	6,098
Solar	77	2,677	0	284*	0	0	0	0	3,038
Storage	0	660	240	270	1,350	480	0	0	3,000
Nuclear	5,399	0	0	(2,054)	0	0	0	0	3,345
Capacity Import	1,100	0	0	0	1,000	0	0	0	2,100
Total	**13,751**	**5,047**	**240**	**(1,500)**	**6,670**	**2,258**	**1,814**	**0**	**28,280**

Notes: 2018 installed capacity informed by 2019 Gold Book. Planned/assumed builds are informed by 2019 CARIS study assumptions and signed CES contracts based on 2018-2019 CES contract summary document and recent 2019 Tier 1 solicitation.

* 816 ICAP MW OSW in Zone J and 880 ICAP MW OSW in Zone K procured in 2018 solicitation and 284 MW solar in Zone GHI exempt in both Status Quo and Expanded BSM. See the following slide for assumptions regarding status quo renewable exemptions as assumed consistent with the April 20 NYISO filing.

** Half of existing hydro fleet assumed to be mitigated under Expanded BSM.

Status Quo Exemptions

The quantity of possible public policy resource exemptions under the NYISO's April 20 proposed approach is subject to considerable uncertainty. Our updated analysis assumes ~550 UCAP MW of exemptions (with a sensitivity analysis of +/-400 UCAP MW)

- Given the large uncertainties, our assumed quantity of exemptions is intentionally abstracted from specific predictions such as which resources may be deemed "policy-driven" retirements
- Overall quantity is consistent with outlook for load growth, retirements, and demand curve width
- In "high exemptions" scenario, we further assume that some storage becomes exempt through other means (such as via Part A or Part B tests)

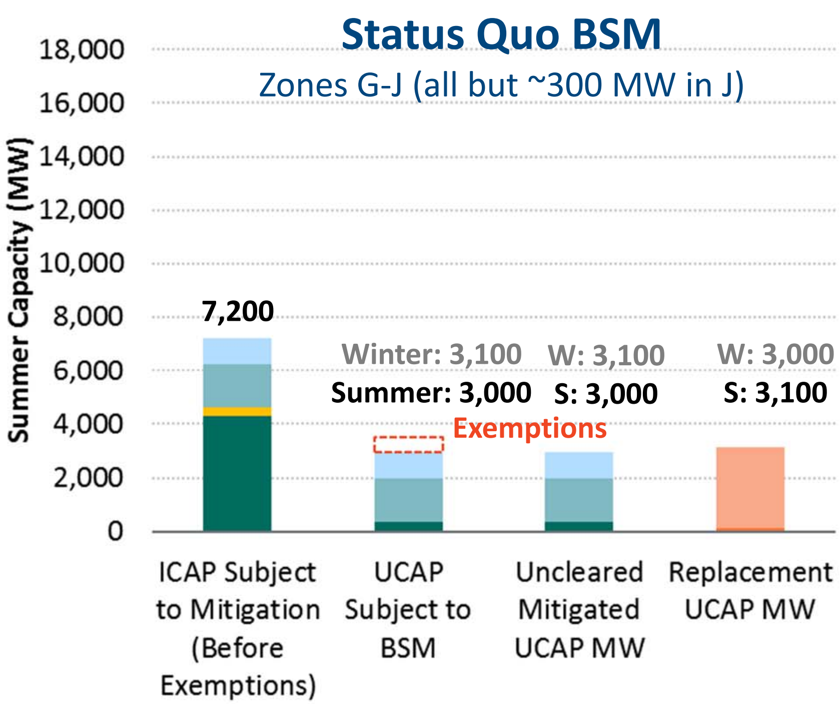
Status Quo Exemptions by Zone

	Zones G-I	Zone J	Zones G-J
Summer UCAP Supply (UCAP MW)			
Offshore Wind	0	848	848
Storage	270	1,350	1,620
Solar	41	0	41
Capacity Imports	0	1,000	1,000
Exemptions (UCAP MW)			
Public Policy Resources	41	507	548
Remaining Mitigated Resources (UCAP MW)			
Offshore Wind	0	341	341
Storage	270	1,350	1,620
Solar	0	0	0
Capacity Imports	0	1,000	1,000

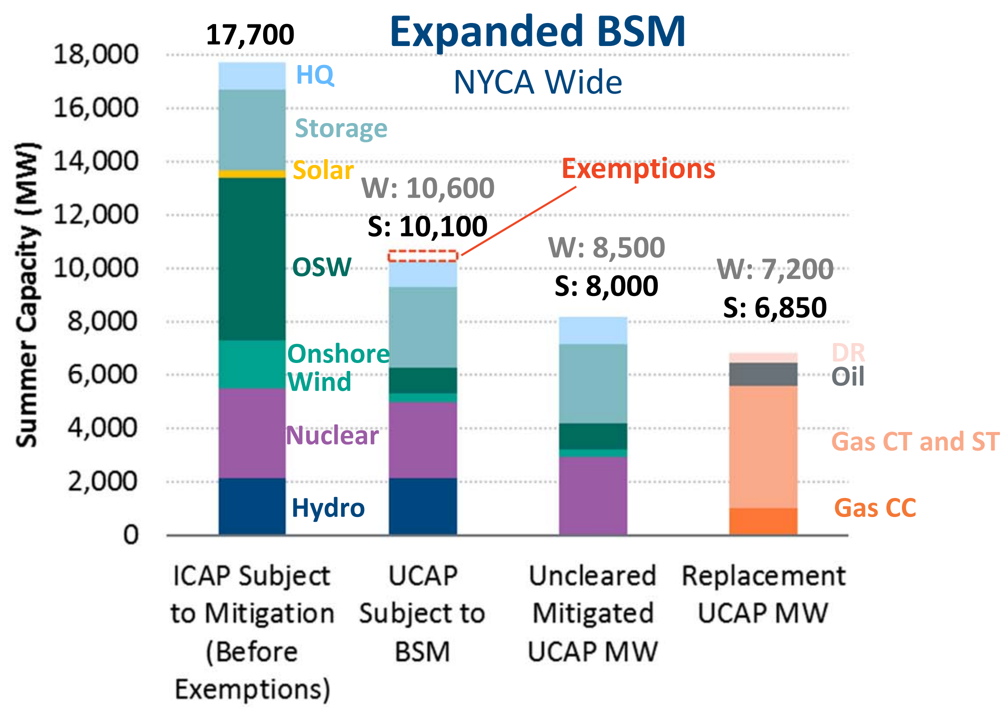
Summary of Mitigation and Market Response Quantities (NYCA-Wide)

In Status Quo BSM, essentially all of the ~3,000 summer UCAP MW uncleared mitigated capacity is replaced by retained gas ST

In Expanded BSM, ~1,150 summer UCAP MW of the 8,000 summer UCAP MW uncleared mitigated capacity is *not* replaced (mostly Upstate), resulting in a higher capacity prices and costs



Mitigated capacity in Zones G-J only under Status Quo, mostly OSW and storage in Zone J that is replaced by retained gas ST plants. UCAP values reflect average ELCC. Capacity numbers are approximate.



Mitigated capacity in all zones. Mitigated OSW and storage in Zones J and K largely offset by retained gas resources. All UCAP values shown reflect average ELCC. Capacity numbers are approximate.

Prices and Customer Costs

Zone J Capacity prices remain similar across all structures as retiring gas ST resources are marginal. Capacity prices in A-F increase significantly in Expanded BSM as more renewables and nuclear resources are mitigated, thus retaining more thermal plants that would otherwise retire

Wholesale Market Prices

	Capacity Market Prices (2030 $/kW-month)			Delta Above (Below) No BSM (2030 $/kW-month)	
Zone	1. Status Quo	2. Expanded BSM	3. No BSM	1. Status Quo	2. Expanded BSM
A-E	$3.65	$8.13	$3.69	($0.04)	$4.44
F	$3.65	$8.13	$3.69	($0.04)	$4.44
G-I	$6.05	$8.13	$6.05	($0.00)	$2.08
J (NYC)	$12.33	$12.32	$12.34	($0.01)	($0.02)
K (LI)	$13.05	$13.88	$13.05	$0.00	$0.83

	Energy Market Prices (2030 $/MWh)			Delta Above (Below) No BSM (2030 $/MWh)	
A-E	$28.02	$27.99	$28.02	$0.00	($0.03)
F	$30.28	$30.23	$30.28	$0.00	($0.05)
G-I	$30.36	$30.33	$30.36	$0.00	($0.03)
J (NYC)	$30.36	$30.33	$30.36	$0.00	($0.03)
K (LI)	$32.19	$32.19	$32.19	$0.00	($0.00)

Cost of BSM

	Customer Costs Delta Above (Below) No BSM (2030 $ million)	
Category	1. Status Quo	2. Expanded BSM
Wholesale Market Cost	**$25**	**$941**
Energy	$0	($7)
Ancillary Services	$0	($0)
Capacity	$25	$949
Contract Costs	**$434**	**$842**
Total Customer Cost	**$458**	**$1,784**
Excluding Nuclear Make-Whole	$457	$1,622

Modeling Approach and Assumptions

Brattle GridSIM Model

Inputs

Supply

Existing resources
Fuel prices
Investment/fixed costs
Variable costs

Demand

Representative day hourly demand
Capacity needs

Transmission

Zonal limits
Intertie limits

Regulations, Policies, Market Design

Capacity market
Carbon pricing
Procurement mandates

GridSIM Optimization Engine

Objective Function

Minimize NPV of Investment & Operational Costs

gridSIM

Constraints

- Market Design and Co-Optimized Operations
  - *Capacity*
  - *Energy*
  - *Ancillary Services*
- Regulatory & Policy Constraints
- Resource Operational Constraints
- Transmission Constraints

Outputs

Annual Investments and Retirements

Hourly Operations

System and Customer Costs

Supplier Revenues

Emissions and Clean Energy Additions

Market Prices

Demand Assumptions

- "Base Load" load assumptions align with 2019 CARIS study input assumptions for 2030
- "Base Load" assumes lower demand than 2019 (156 TWh gross load)
- Modeled "High Load" based on State Team input that assumes greater load than 2019

2030 Demand Assumptions

	Base Load	High Load
Scenarios	Base Case No-Nuclear	High-Load
Annual Gross Load	145 TWh	169 TWh
Gross Peak Load	30 GW	35 GW
Net Peak Load	28 GW	33 GW

Sources and Notes:

"Base Load" annual gross load assumptions are based on 2019 CARIS study. Used ratio of 2019 annual gross load and CARIS annual gross load to convert 2019 gross peak loads to 2030 gross peak loads on zonal level.

"High Load" annual gross load assumptions based on State Team's input. Calculated peak loads based on annual gross load ratio as described above.

Netted out assumed 7,542 MW of solar BTM (based on 2019 CARIS study) valued at ~27% summer capacity value from gross peak load to calculate net peak load (similar to Gold Book assumptions).

2019 load data taken from NYISO OASIS data.

Supply Cost Characteristics

- **Resources' fixed O&M costs** affect supply elasticity and BSM price impacts. Sources:
  - *New Gas CCs, CTs*: 2020 costs from Demand Curve Reset (DCR); 2.2% cost inflation rate
  - *New Gas STs*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -1%/year real)
  - *New wind, solar, storage*: 2019 costs and cost decline rate from 2019 NREL ATB (0% to -7% /year real)
  - *Existing Nuclear*: 2019 costs from NEI (constant real), plus assumed $280/kW-year refurbishment cost adder in 2030
  - *Existing CTs, STs*: FOM from NYISO 2018 SOM Report
  - *Other existing thermal:* FOM assumed 2x new units
  - *All other existing:* Same FOM as new resources
  - *Zone J and K*: FOM assumed 1.3 – 2.7x higher than upstate based on DCR zonal cost ratios
- **Offshore wind** tied to either zone J or K
- **Utility-scale PV and onshore wind** cannot be built in zones J or K

2030 Resource Cost Assumptions

	Upstate New Resource Capital Cost *2030$/kW*	Upstate New Resource FOM *2030$/kW-yr*	Upstate Existing Resource FOM + Refurb Costs *2030$/kW-yr*	Variable O&M *2030$/MWh*
Natural Gas				
Combined cycle	$2,300	$27	$54	$2
Combustion turbine	$1,200	$14	$25	$7
Steam turbine	$5,000	$43	$72	$11
Battery Storage				
4-hour duration	$1,100	$26	$26	$6
Solar PV				
Utility scale	$1,100	$13	$13	$0
Wind				
Offshore (downstate)	$4,600	$107	$107	$0
Onshore	$1,600	$50	$50	$0
Nuclear				
Single-unit	N/A	N/A	$602	$3
Multi-unit	N/A	N/A	$491	$3

Sources and Notes:

Includes interconnection and network upgrade costs. NREL 2019 ATB, NYISO DCR Model 2019-2020 and 2020-2021 , and NEI Nuclear Costs in Context.
VOM for storage resources reflect efficiency losses. Existing FOM for nuclear includes refurbishment costs.
FOM costs for existing STs and CTs were based on average GFC shown in Figure 16 of the 2018 State of the Market Report; FOM costs for existing Gas CTs upstate assumed to be half of those for existing Gas CTs in Zone K.
FOM costs for other existing thermal resources were assumed to be 2x that of comparable new ones, informed by EPA Integrated Planning Model document.
Nuclear refurbishment costs informed by refurbishment costs for nuclear plants in Ontario.

ELCC Modeling Approach

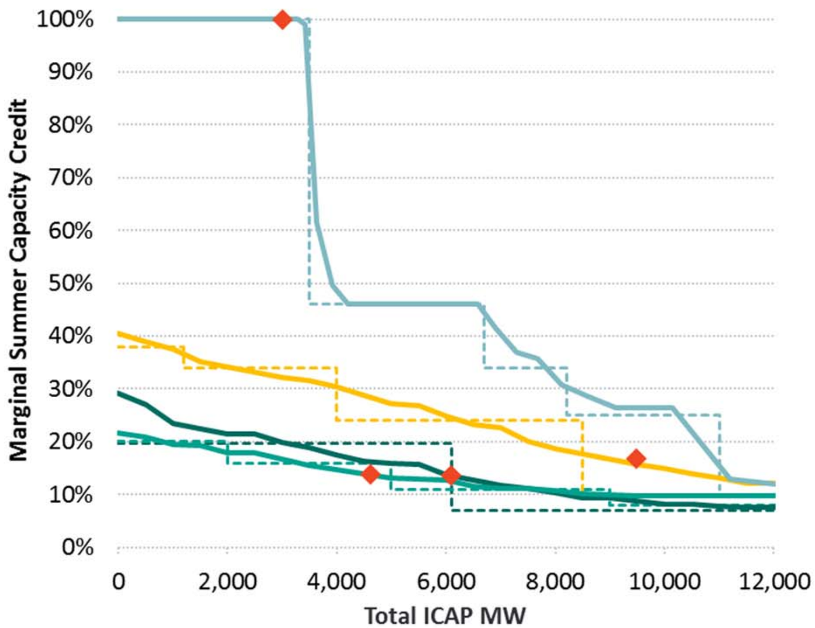
Supply Resource	Concept	Methodology
Wind and Solar Resources	Generation of new wind and solar additions is correlated with previously deployed resources. New resources therefore provide less marginal capacity value than previously added resources.	1. Across 8760 hours, identify 100 top NYCA net load hours 2. Calculate wind UCAP value as avg. output in those hours 3. Repeatedly change the MW of wind installed, all else equal 4. Each time, find top 100 net load hours and the avg. output 5. Repeat process for offshore wind and solar; for each one, hold other variable technologies at likely 2030 levels
Storage Resources	Energy storage can change the "shape" of peak net load periods, flattening and elongating peak periods. As more storage is deployed, longer discharge durations are therefore required to provide the same capacity value.	1. Across 8760 hours, analyze MW of storage required to reduce NYCA net peak load by 1 MW 2. Calculate UCAP value as 1 MW peak reduction / MW storage required 3. Increase amount of storage assumed, holding all else equal. Simulate effect of increased storage on net peak load 4. Repeat steps 1 – 3 across many storage deployment levels 5. Repeat process for storage of different durations

Base Case UCAP Value Curves
modeled based on NYCA-wide net load

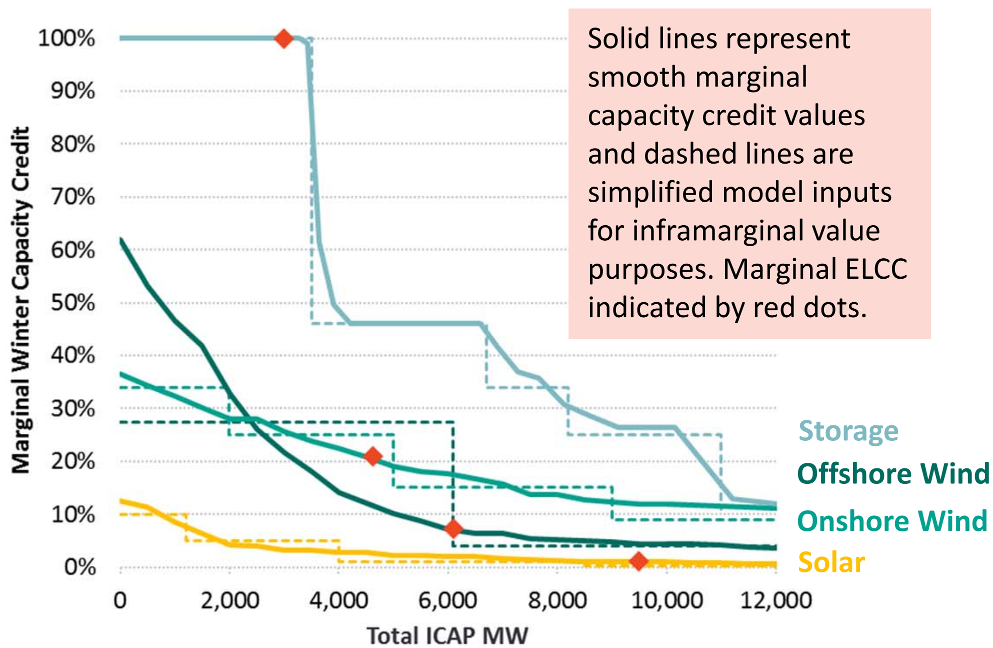
As the penetration increases, marginal effective load-carrying capability (ELCC) decreases.

Note: this analysis may have conservatively low ELCCs for renewables, based on hourly data with lower output than future installations are likely to achieve (and that does not capture diversity across sites for OSW); on the other hand, this analysis uses NYCA-wide net load without considering how transmission constraints could reduce value more quickly.

Summer UCAP Value



Winter Capacity Value



Note: solar capacity credit curves include assumed 7,542 MW of solar BTM already on the grid (based on CARIS study assumption).

Assumptions on BSM Applicability

Resource Type	BSM in Structure 1. Status Quo		BSM in Structure 2. Expanded BSM	
	Zones G-J	Rest of System	Zones G-J	Rest of System
Nuclear	N/A	N/A	N/A	3,345 ICAP MW
OSW	1,740 ICAP MW (assumed 507 UCAP MW exemption in Zone J applies to OSW)		3,504 ICAP MW (assume 816 ICAP MW of already signed contracts exempt)	898 ICAP MW (assume 880 ICAP MW of already signed contracts exempt)
Existing Solar and Onshore Wind	No		No	No
New Utility Scale Solar and Wind	Any new utility scale solar or onshore wind in Zones G-J		All new utility scale solar and onshore wind	
Bulk Storage	1,620 ICAP MW		1,620 ICAP MW	1,380 ICAP MW
Existing Hydro	No		50 ICAP MW	2,085 ICAP MW
Tier 2 Renewables	No		No	No
New HQ Imports	1,000 MW in Zone J		1,000 MW in Zone J	N/A
Demand Response	No		No	No
Fossil Resources	No		No	No

Source: Assumptions on applicability provided by NYSERDA/DPS staff.

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