Attachment V

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER25-___-000**

AFFIDAVIT OF ZACHARY T. SMITH

Mr. Zachary T. Smith declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

2. The purpose of this Affidavit is to: (i) present the document titled *Proposed NYISO Installed Capacity Demand Curves for the 2025-2026 Capability Year and Annual Update Methodology and Inputs for the 2026-2027, 2027-2028, 2028-2029 Capability Years: Final Report (Updated)* dated October 2024, which is attached hereto as Exhibit B ("NYISO Staff Recommendations"); and (ii) provide further support for certain aspects of the filing submitted by the New York Independent System Operator, Inc. ("NYISO") in this proceeding, including: (a) the viability of a 2-hour lithium-ion battery energy storage system ("BESS") to serve as a peaking plant technology; (b) the consideration of Capacity Accreditation Factors[1] ("CAFs") in the selection of the peaking plant technology; and (c) the derating factor recommended for use in the Installed Capacity ("ICAP") to Unforced Capacity ("UCAP") translation of the ICAP Demand Curve reference point prices for BESS. This Affidavit addresses the changes directed by the NYISO Board of Directors ("Board") to the NYISO Staff Recommendations for incorporation in the NYISO's filing in this proceeding, along with updated results reflecting such changes set forth in Exhibit A. This Affidavit will also discuss the alternative peaking plant technology recommended by the Market Monitoring Unit ("MMU") and why such technology option is not viable for this reset.

I. Qualifications

3. My name is Zachary T. Smith. I am currently the Senior Manager, Capacity and New Resource Integration Market Solutions for the NYISO. My business address is 10 Krey Boulevard, Rensselaer, New York 12144. I received a Bachelor's of Science degree in Computer Engineering from Union College, and a Master's of Science degree in Engineering and Management Science from Union Graduate College (now Clarkson University).

4. I originally joined the NYISO as a Price Validation Analyst in 2009. I joined the ICAP Market Operations department in 2013 and was promoted to Supervisor of ICAP Market

[1] Capitalized terms that are not specifically defined in this Affidavit shall have the meaning set forth in the filing letter to which this Affidavit is attached or, if not defined therein, the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

Operations in 2015. I transitioned to the Manager of Capacity Market Design in 2017 and was promoted to Senior Manager of Capacity and New Resource Integration Market Solutions in 2024. As the Supervisor of the ICAP Market Operations department, I collaborated with the NYISO's Capacity Market Design team on the development and implementation of the ICAP Demand Curves for the 2017-2018 through 2020-2021 Capability Years. Additionally, in my role as the Manager of Capacity Market Design, I oversaw the internal team responsible for the development and implementation of the ICAP Demand Curves for the 2021-2022 through 2024-2025 Capability Years, as well as the NYISO's capacity accreditation framework. In my current role, I oversee the NYISO's internal team responsible for overseeing the development of capacity market designs and ensuring compliance with the ISO Tariffs and Commission orders, including the quadrennial ICAP Demand Curve reset (DCR). I am also directly involved with the DCR for the 2025-2029 period that is the subject of the NYISO's filing in this proceeding.

II. Background

5. In the first quarter of 2023, the NYISO solicited proposals from qualified consultants to develop the ICAP Demand Curve parameters for the period covering the four Capability Years beginning in May 2025 ("2025-2029 DCR"). The NYISO selected the team of the Analysis Group, Inc. ("AG") and 1898 & Co. to assist in conducting the 2025-2029 DCR. This Affidavit refers to AG and 1898 & Co., collectively, as the "Independent Consultant."

6. The Independent Consultant began its analysis in August 2023. Between August 2023 and September 2024, the Independent Consultant led discussions with stakeholders at the Installed Capacity Working Group ("ICAPWG") regarding its review of the issues impacting the ICAP Demand Curves, its analysis, and the models it developed for the 2025-2029 DCR. NYISO staff fully participated in all DCR related discussions at the ICAPWG. All interested parties had the opportunity to provide input to, and comments on, the Independent Consultant's proposed assumptions, analysis, methodology, cost estimates, and preliminary and final recommendations for the 2025-2029 DCR.

7. Based on the numerous presentations and discussions at ICAPWG meetings, as well as consideration of the additional feedback received throughout the stakeholder process, the Independent Consultant issued its draft report on June 7, 2024 (with a subsequent updated version issued on June 17, 2024) and led a discussion with stakeholders relating thereto at the June 13, 2024 ICAPWG meeting. Stakeholders were provided the opportunity to submit written comments in response to the draft report and the Independent Consultant responded to these comments at the July 23, 2024 ICAPWG meeting. After considering the additional feedback received, the Independent Consultant released an interim version of its final report on July 29, 2024. The interim version contained preliminary values for the ICAP Demand Curves for the 2025-2026 Capability Year. An updated version of the Independent Consultant's final report, including its final recommended values for the 2025-2026 Capability Year ICAP Demand Curves, was issued on October 2, 2024.

8. NYISO staff examined all issues and considered all stakeholder comments received throughout the process, including feedback from the MMU. The NYISO also reviewed

and discussed the Independent Consultant's analysis with AG, 1898 & Co., and stakeholders. NYISO staff and the Independent Consultant also held several discussions with the MMU to solicit its feedback. NYISO staff posted its initial draft recommendation for the 2025-2029 DCR on July 29, 2024 and discussed its draft recommendations with stakeholders at the August 1, 2024 ICAPWG meeting. Stakeholders were also provided an opportunity to submit written comments in response to NYISO staff's draft recommendations. After consideration of the feedback received (including the comments received from the MMU, which are included as Appendix A to the NYISO Staff Recommendations) NYISO staff issued the NYISO Staff Recommendations on October 2, 2024.

9. The NYISO Staff Recommendations generally concur with the recommendations and conclusions of the Independent Consultant, except for the derating factor recommended for use in the ICAP to UCAP translation of the ICAP Demand Curve reference point prices for BESS. As further described in Section V of this Affidavit, the NYISO proposes the use of a 2.5% derating factor as part of the ICAP to UCAP translation of the ICAP Demand Curve reference point prices for BESS.

10. Stakeholders were provided the opportunity to submit written comments to the Board in response to the NYISO Staff Recommendations. Stakeholders were also provided the opportunity for oral presentations before the Board regarding the 2025-2029 DCR on October 14, 2024. After consideration of stakeholder feedback, the Board directed NYISO staff to further assess certain key issues identified by stakeholders.

11. As further detailed in Section VII of this Affidavit, based on the its consideration of the record before it and additional due diligence, the Board approved the NYISO Staff Recommendations for filing with the Commission subject to incorporation of the following changes: (1) removing the costs associated with the interconnecting electric transmission lines (commonly referred to as the "generator leads") from the eligible basis for determining the value of the federal investment tax credit ("ITC") for BESS; (2) removing the sales tax exemption for BESS based on an assumption that the projects would qualify as capital improvements under New York sales tax law; and (3) reducing the realized level of accelerated depreciation benefits in excess of a BESS project's tax liabilities for a given year to account for the potential need to leverage a third party arrangement to monetize such excess benefits. Tables 1 and 2 below depict the resulting 2025-2026 Capability Year ICAP Demand Curves incorporating the Board-directed changes. These are the values proposed by the NYISO in this proceeding for the 2025-2026 Capability Year. Exhibit A to this Affidavit provides additional revised results reflecting the Board directed changes. Specifically, Exhibit A contains revised versions of Tables 1-3, 6, 20, 27 and 28 set forth in the NYISO Staff Recommendations, as well as a revised version of Appendix A of the Independent Consultant's October 2, 2024 final report that contains updated BESS cost and performance data.

Table 1: NYISO Staff's Recommended 2025 Summer Capability Period ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	$5.72	$6.15	$17.37	$6.80
Max Clearing Price	$21.69	$23.25	$41.30	$28.16
Zero Crossing Point	112%	115%	118%	118%

Table 2: NYISO Staff's Recommended 2025-2026 Winter Capability Period ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	$4.33	$5.29	$14.64	$8.78
Max Clearing Price	$16.39	$19.99	$34.83	$36.37
Zero Crossing Point	112%	115%	118%	118%

III. Viability Assessment of a 2-hour BESS

12. The Independent Consultant recommended the selection of 2-hour BESS as the appropriate peaking plant technology underlying each ICAP Demand Curve for the 2025-2029 reset period. Based on the results for this DCR, 2-hour BESS complies with the Market Administration and Control Area Services Tariff ("Services Tariff") requirement of being the "unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."[2]

13. The Independent Consultant assessed the economic viability of various technology options using the following screening criteria, which are consistent with the criteria applied in past DCRs: (i) availability to most market participants, (ii) operating experience sufficient to demonstrate the technology is proven, (iii) ability to be economically dispatched, (iv) ability to cycle and provide peaking service, (v) ability to be practically constructed in a particular location, and (vi) ability to meet environmental requirements and regulations. The evaluation identified simple cycle gas turbine (SCGT) technologies (as represented by the GE 7HA.02 and GE 7HA.03 frame turbine models) and BESS technologies with energy discharge durations of 2-hours, 4-hours, 6-hours, and 8-hours as economically viable peaking plant technology candidates for the 2025-2029 DCR. During the 2021-2025 DCR, the BESS technologies that were evaluated and found to be economically viable had energy discharge durations ranging from 4-hours, 6-hours, and 8-hours. For the 2025-2029 DCR, the Independent Consultant broadened the BESS duration options to include a 2-hour resource. Consistent with the other durations

[2] *See* Services Tariff, Section 5.14.1.2.2.

evaluated, the Independent Consultant determined that 2-hour BESS satisfied each of the economic viability screening criteria. The Independent Consultant also noted that, consistent with the Commission's minimum requirement for viability (*i.e.*, capability to supply capacity in the NYISO's capacity market), 2-hour BESS is an eligible capacity supply resource under the NYISO's existing capacity market rules.

14. Certain stakeholders contend that the 2-hour BESS is not a viable peaking plant technology option because it is incapable of meeting peak load needs. Like any single resource, a 2-hour BESS on its own cannot meet the system's total peak load needs. However, this does not disqualify it from being a viable peaking plant technology because it can contribute to reliability by meeting a portion of demand during peak periods as an incremental unit to the existing resource fleet. If entry of more than one unit is required to address a need, the pricing signal would be maintained to support such additional entry.

15. Certain stakeholders also claim that the 2-hour BESS is not a viable peaking plant technology option because it is incapable of meeting transmission security needs. The ICAP market and ICAP Demand Curves, however, are not currently designed to resolve (or provide price signals that fully value) transmission security. As described in the Services Tariff, the capacity market and associated auctions are designed to procure enough capacity to satisfy the established annual minimum capacity requirements.[3] The annual minimum capacity requirements are derived from an annual peak load forecast determined by the NYISO and the annual statewide installed reserve margin ("IRM") established by the New York State Reliability Council, L.L.C. ("NYSRC"). The IRM establishes an additional quantity of capacity above forecasted peak needs that is required to ensure maintenance of the resource adequacy reliability criteria to not exceed a loss of load expectation ("LOLE") of greater than 0.1 loss of load event days per year.[4]

16. The current capacity market design only indirectly considers certain aspects of transmission security. Specifically, in determining locational capacity requirements, the NYISO uses transmission security limit ("TSL") floor values as a lower limit on the allowable locational capacity requirement values.[5] The TSL floor values; however, are not intended to expressly solve for transmission security needs. Instead, the TSL floor values seek to ensure that the resource adequacy-based locational requirements are not established at levels that assume reliance on power transfer levels exceeding transmission security-based limits into a transmission-constrained locality. The current capacity market design compensates resources, on a UCAP basis, for their contributions to resource adequacy, not transmission security. Specifically, Section 5.12.14.3 of the Services Tariff establishes that the UCAP a resource is eligible to provide is based, in

[3] *See*, *e.g.*, Services Tariff, Sections 5.10 and 5.13.1.

[4] *See*, *e.g.*, NYSRC, *Reliability Rules & Compliance* Manual at Resource Adequacy Reliability Rule A1, Sections B.R.1 and B.R.1.1 (Version 47, June 14, 2024), available at: https://www.nysrc.org/wp-content/uploads/2024/07/RRC-Manual-V47-final-7-2-24.pdf; NYSRC, *Policy 5-18: Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)* at 7, Section 3.1 (June 14, 2024), available at: https://www.nysrc.org/wp-content/uploads/2024/06/NYSRC-Policy-5-18-06_14_24-Final.pdf.

[5] *See* Services Tariff, Section 5.11.4.

part, on its CAF. The Services Tariff expressly states that the CAF is a value to "reflect the marginal reliability contribution of ICAP Suppliers within each Capacity Accreditation Resource Class toward meeting NYSRC resource adequacy requirements for the upcoming Capability Year."[6]

17. The NYISO acknowledges the growing importance of transmission security and has commenced a multi-year collaborative process with its stakeholders to evaluate (and, if warranted, develop) potential enhancements to its current capacity market to more expressly value resource contributions to transmission security. It is unclear, at this time, what the results of this collaborative effort will be or the potential impact thereof on the ICAP Demand Curves. Any future enhancements resulting from this effort should be addressed in a future reset once known. Consistent with Commission precedent for the DCR, this will avoid speculating about the potential impact future unknown rules and requirements.

IV. CAF Considerations

18. CAFs were developed to capture the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class ("CARC") toward meeting NYSRC resource adequacy requirements. CAFs and derating factors are used to calculate the UCAP that an ICAP Supplier is qualified to supply to the NYCA. Because UCAP is the metric transacted in the ICAP market, the requirements and prices of the ICAP Demand Curve are converted to UCAP values for the purposes of conducting the ICAP Spot Market Auctions. The Independent Consultant's economic evaluation of peaking plant technology options focused on identifying the technology that minimizes cost on a UCAP basis, and, therefore, appropriately considered the CAFs and derating factors across technology options. Certain stakeholders and the MMU contend that the estimated costs for 2-hour BESS fail to account for future declines in CAF values over the assumed 20-year amortization period, as well as the expected precipitous decline in CAF values for 2-hour BESS in the near term.

19. The Independent Consultant considered CAF and other technology and market risks in establishing the weighted average cost of capital ("WACC") values for each technology option evaluated. For the BESS options, the Independent Consultant expressly noted its consideration of future CAF variability and uncertainty which led to 0.5% higher WACC value for the BESS options as compared to the SCGT options. In assessing the potential impact of CAFs for the BESS options, the Independent Consultant also noted that the directionality and magnitude of future CAF values will vary annually in response to numerous factors that cannot be forecasted with precision at this time, including changes in the system resource mix, the interactive relationship between BESS and different renewable resource types, and changes in load profiles.

20. NYISO staff analyzed a variety of future scenarios to assess potential changes in CAF values for 2-hour BESS over the next five years. The scenarios represented a spectrum of

[6] *See* Services Tariff, Section 2.3 (definition of "Capacity Accreditation Factor")

system conditions from current system conditions to system conditions that assume a significant increase in renewable resources to meet the requirement established by New York's Climate Leadership and Community Protection Act ("CLCPA") that 70% of energy to be supplied by renewable resources by 2030. The analysis identified a range of outcomes where CAFs either increased or decreased compared to currently effective values depending on the scenario. The scenario identifying the largest potential decrease in future CAFs continued to support the selection of the 2-hour BESS as the technology that provides UCAP at the lowest cost compared to the other technology options evaluated for this reset. This assessment also rebuts claims of certainty that: (i) CAFs for a 2-hour BESS will precipitously decline in the near-term; and (ii) CAFs for 2-hour BESS will only decline from the currently effective values. In fact, the finding that CAFs for a 2-hour BESS could increase in the near-term is further supported by the recent preliminary CAF analysis conducted for the 2025-2026 Capability Year.[7] This preliminary evaluation identified the potential for CAF values of 2-hour BESS to increase next year driven primarily by changes in the resource mix (*e.g.*, increased deployment of behind-the-meter solar resources) and modeling improvements to more accurately capture the operating characteristics of various resource types. The MMU conducted its own assessment of potential future CAF values for the 2-hour BESS. The MMU's assessment concluded that the CAFs for the 2-hour BESS could be expected to decrease significantly by 2033, but the assessment relied on specific assumptions of certain future system conditions, and it calculated CAFs using a model not used by the NYISO in actual operation. Specifically, in their assessment, the MMU assumed system conditions that included high-levels of energy storage capacity (2.3 GW), delayed deployment of renewable resource capacity, and restrictive winter fuel availability constraints for existing fossil-fired generation, which limited non-firm gas to pipeline imports and delayed oil-inventory replenishment. As demonstrated by the NYISO's analysis, future CAFs are highly dependent on the assumptions used for future system conditions. The manner in which the system will evolve over the coming decades as New York transitions to a clean energy grid is not predictable with reasonable accuracy. Therefore, attempting to forecast future CAF values is a speculative and highly influenced by the assumptions relied upon. A range of potential future outcomes are plausible with varying CAF results for 2-hour BESS.

21. Additionally, the current procedures to establish the demand curves used in the monthly ICAP Spot Market Auctions ensure continued revenue sufficiency of the 2-hour BESS during the reset period regardless of the actual changes in CAF values experienced. The translation of the ICAP Demand Curves to a UCAP basis expressly incorporates the

[7] NYISO, *2025-2026 Capability Year Informational Capacity Accreditation Factors* (presented at the October 7, 2024 ICAPWG meeting), available at: https://www.nyiso.com/documents/20142/47364758/2025-2026%20Informational%20CAFs_ICAPWG_10.07.2024_Final.pdf;

applicable CAF values of the selected peaking plant technology. As a result, any changes in the CAF values for the 2-hour BESS during the 2025-2029 reset period will be reflected in the resulting UCAP-based curves and ensure that such curves continue to provide revenue sufficiency for the 2-hour BESS under the system conditions prescribed for establishing the curves.

V. Derating factor for BESS

22. The Independent Consultant recommended the use of a 2% derating factor for the BESS options to represent their long-term expected performance capability. The recommendation, however, did not factor in current NYISO market rules (set forth in Section 4.5 of the NYISO ICAP Manual). These existing rules establish that, upon initially entering the capacity market as a new supplier, a new BESS would receive its initial derating factor based on either the North American Electric Reliability Corporation ("NERC") class average equivalent demand forced outage rate ("EFORd") of pumped hydro storage or a "NYISO class average" for BESS. However, insufficient operating history currently exists for BESS participating in the capacity market to establish a "NYISO class average" for BESS resources in New York. Until sufficient historical operating data exists to establish a "NYISO class average" value for BESS, new BESS resources will initially be assigned a derating factor based on the NERC class average EFORd for pumped hydro storage.

23. Accounting for these existing rules, the NYISO recommends use of a 2.5% derating factor for BESS. This value was calculated as a weighted average of the derating factors BESS would be expected to receive across the assumed 20-year amortization period given the currently applicable rules. Specifically, NYISO staff assumed the BESS would have a 9.19% derating factor for its first year of operation, where 9.19% is the current NERC class average EFORd of pumped hydro storage, a 5.6% derating factor for its second year of operation (average of 9.19% and the 2% expected BESS availability determined by the Independent Consultant), and a 2% derating factor for years 3-20 of its assumed economic life.[8]

VI. MMU Recommended Peaking Plant Technology

24. The MMU recommended the selection of a fossil-fired combustion turbine with an assumed 20-year amortization period as the appropriate peaking plant technology for the 2025-2029 DCR. The CLCPA imposes a requirement that 100% of electricity demand in New York be served by zero-emission resources by January 1, 2040. As a result,

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[8] The NYISO calculates derating factors for existing resources using the individual resource's performance over the two previous like-Capability Periods. For the first year of operation, a new BESS would receive the NERC class average EFORd for pumped hydro storage (or NYISO class average for BESS once there are a sufficient number of BESS operating in the NYCA). For the second year of operation, the BESS would receive a derating factor based on one year of its operating data and one year of the assumed NERC (or NYISO) class average EFORd. For the third year of operation and all remaining years, the BESS unit's derating factor would solely be based on its performance over the two previous like-Capability Periods. The NYISO used the Independent Consultant's recommended 2% derating factor as a reasonable representation of the expected actual operating performance for BESS.

consistent with the methodology accepted by the Commission for the 2021-2025 DCR, the amortization period for fossil-only resources has been set at 13 years to recognize the average length of time remaining between the start of each Capability Year covered by this reset and the 2040 zero-emission deadline established by the CLCPA. Absent the establishment of eligibility rules for what may qualify as a zero-emissions resource, the Commission determined that this approach was reasonable. The conditions for this reset remain unchanged in that rules to establish eligibility requirements for zero-emissions resources have not been promulgated.

25. The Independent Consultant assessed the viability of a zero-emission retrofit option that may allow a fossil-fired combustion turbine to comply with CLCPA requirements after 2040 using hydrogen fuel as a proxy for what might qualify as a zero-emission operating design. The Independent Consultant ultimately determined such an option is not viable due to: (i) the absence of rules to define what qualifies as an eligible zero-emission resources for compliance with the CLCPA; (ii) the absence of any commercial operating experience for a resource operating on 100% hydrogen fuel; and (iii) significant estimated operational costs that were not included in the MMUs recommended design. Based on these factors, the alternative peaking plant technology design recommended by the MMU fails multiple of the screening criteria for assessing economic viability. Because this technology design option is not economically viable, it cannot be considered for potential selection as the peaking plant in this reset.

VII. Board-Directed Changes

26. Following the issuance of NYISO staff's final recommendations, stakeholders submitted written comments for the Board's consideration. On October 14, 2024, stakeholder representatives also participated in oral presentations before the Board. After consideration of stakeholder feedback, the Board directed NYISO staff to further assess certain key issues identified by stakeholders. Upon further assessment, the Board approved NYISO staff's final recommendations subject to incorporation of the following changes: (1) removal of the BESS generator leads as eligible costs for the ITC; (2) eliminating the assumption that the BESS options will qualify as capital improvements to obtain certain sales tax exemptions; and (3) reducing the assumed level of the realized accelerated depreciation benefits to account for the costs to monetize such benefits.

27. The Independent Consultant recommended inclusion of the generator lead costs as ITC eligible, in part, because the assets would be owned by the BESS projects and located prior to the point of change in ownership between the project and interconnecting transmission owner. Certain stakeholders, however, contend that the generator lead costs for the BESS options should not be considered ITC eligible. Based on consideration of the available information and additional due diligence, the Board concluded that the generator lead costs would likely not qualify as eligible for the ITC. This determination recognized applicable guidance from the Internal Revenue Service ("IRS") and the function and purpose of the generator leads. Specifically, because the generator lead is located after the generator step-up transformer and does not involve any further adjustments to the voltage or other characteristics of the energy produced by the BESS prior to delivery to the transmission system, the IRS would likely deem the generator lead as "transmission/distribution equipment" that is not eligible for the ITC.

28. Additionally, the Independent Consultant recommended that the BESS options could potentially qualify as a capital improvement and receive an exemption from sales tax on the initial installation and labor costs to develop the facilities. Certain stakeholders, however, contend that BESS projects would be unlikely to qualify as capital improvements because they are constructed on leased property. After careful consideration of the matter, the Board determined that it would likely be difficult for the BESS projects to qualify as capital improvements under applicable New York sales tax law and guidance. This determination recognized that a BESS project would likely be subject to removal requirements and that such requirements may likely be included in a lease related to the project. Such removal requirements and lease provisions would likely prevent the BESS options from qualifying as capital improvements in New York. As a result, the BESS projects would not qualify for the assumed sales tax exemption on the initial installation and labor costs to develop the facilities.

29. Lastly, the Independent Consultant assumed that the BESS options could fully monetize the accelerated depreciation benefits in the same year such benefits arise. Certain stakeholders, however, contend that the BESS options should not be assumed to monetize the full benefit of accelerated depreciation in the same year the benefit arises, absent sufficient tax liability to absorb such benefits. Supplemental due diligence by NYISO staff identified that the BESS options were not likely to incur sufficient tax liability from their stand-alone wholesale market revenues to fully absorb the accelerated depreciation benefits during the first three years of the assumed 20-year amortization period. Thus, immediate monetization would require leveraging another option. Although various options may be available to facilitate such monetization, consistent with the stand-alone project considerations assessed in developing the applicable WACC for the BESS options, one available option would be to leverage a third party arrangement. As reflected in the assumptions for monetizing ITC benefits, leveraging such third party relationships is likely to reduce the level of realized benefits to the project. Accordingly, the Board directed the NYISO to incorporate a reduction in the realized benefits to the BESS projects consistent with the assumptions for monetizing the ITC benefit (*i.e.*, a reduction of the realized value of the excess accelerated depreciation benefits by 8%). Such reduction is intended to address the potential need for the project to leverage a third party arrangement to full monetize any accelerated depreciation benefits that exceed the project's stand-alone tax liabilities for a given year.

VIII. Conclusion

30. After consideration of the Independent Consultant's final report, NYISO staff's final recommendations, and the comments and feedback from stakeholders and the MMU, the Board directed the NYISO to file the proposed ICAP Demand Curves and methodologies and inputs for the annual updates encompassed by this reset period consistent with the NYISO Staff Recommendations as adjusted to reflect incorporation of the three changes described above. Exhibit A to this affidavit provides additional details regarding the Board-approved results for the 2025-2029 DCR.

31. This concludes my affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information, and belief.

Zachary T. Smith
November 26, 2024

Subscribed and sworn to before me this 26th day of November, 2024

Notary Public

GARRETT E. BISSELL
NOTARY PUBLIC-STATE OF NEW YORK
No. 02BI6133400
Qualified in Albany County
My Commission Expires 09-19-2025

My commission expires: 9/19/2025

Exhibit A

Exhibit A

**NYISO Staff's Recommended 2025 Summer Capability Period
ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes**

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	\$5.72	\$6.15	\$17.37	\$6.80
Max Clearing Price	\$21.69	\$23.25	\$41.30	\$28.16
Zero Crossing Point	112%	115%	118%	118%

**NYISO Staff's Recommended 2025-2026 Winter Capability Period
ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes**

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	\$4.33	\$5.29	\$14.64	\$8.78
Max Clearing Price	\$16.39	\$19.99	\$34.83	\$36.37
Zero Crossing Point	112%	115%	118%	118%

**NYISO Staff's Recommended 2025-2026 Capability Year Indicative UCAP Demand Curve
Reference Points with the Inclusion of the Board-Directed Changes**

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Summer Reference Price	\$10.64	\$11.41	\$32.23	\$13.17
Winter Reference Price	\$8.04	\$9.81	\$27.17	\$17.02

Capital Investment Costs for Battery Storage Peaking Plants Evaluated with the Inclusion of the Board-Directed Changes

	BESS 2-hour	BESS 4-hour	BESS 6-hour	BESS 8-hour
Zone C Central				
Total Capital Cost ($million)	233	360	506	652
ICAP MW	200	200	200	200
$/kW	1,170	1,800	2,530	3,260
Zone F Capital				
Total Capital Cost ($million)	235	363	509	656
ICAP MW	200	200	200	200
$/kW	1,170	1,810	2,550	3,280
Zone G Hudson Valley (Dutchess County)				
Total Capital Cost ($million)	234	362	508	654
ICAP MW	200	200	200	200
$/kW	1,170	1,810	2,540	3,270
Zone G Hudson Valley (Rockland County)				
Total Capital Cost ($million)	242	373	523	674
ICAP MW	200	200	200	200
$/kW	1,210	1,860	2,620	3,370
Zone J New York City				
Total Capital Cost ($million)	348	516	696	891
ICAP MW	200	200	200	200
$/kW	1,740	2,580	3,480	4,450
Zone K Long Island				
Total Capital Cost ($million)	250	385	540	696
ICAP MW	200	200	200	200
$/kW	1,250	1,920	2,700	3,480

2025-2026 Capability Year Indicative UCAP Demand Curve Parameters for BESS Peaking Plant Options with the Inclusion of the Board-Directed Changes

Technology	Fuel Type & Emission Control	Parameter	Central	Capital	Hudson Valley (Rockland)	Hudson Valley (Dutchess)	New York City	Long Island
BESS (200 MW)	2-hr (400 MWh)	Gross CONE	$126.73	$127.71	$131.96	$127.58	$222.73	$137.03
		Net EAS	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
		Annual Reference Value (Net CONE)	$71.35	$50.55	$55.07	$50.66	$140.47	$49.61
		Summer Reference Price	$15.01	$10.64	$12.40	$11.41	$32.23	$13.17
		Winter Reference Price	$11.34	$8.04	$10.66	$9.81	$27.17	$17.02
	4-hr (800 MWh)	Gross CONE	$194.71	$196.16	$202.29	$196.03	$328.88	$209.65
		Net EAS	$63.57	$88.64	$87.34	$87.39	$90.35	$109.40
		Annual Reference Value (Net CONE)	$131.15	$107.51	$114.95	$108.65	$238.53	$100.25
		Summer Reference Price	$22.80	$18.69	$21.44	$20.26	$44.82	$17.79
		Winter Reference Price	$17.23	$14.13	$18.43	$17.42	$37.79	$22.97
	6-hr (1200 MWh)	Gross CONE	$271.13	$273.11	$281.72	$273.00	$440.19	$292.02
		Net EAS	$65.98	$93.58	$93.60	$93.69	$94.49	$120.99
		Annual Reference Value (Net CONE)	$205.15	$179.53	$188.12	$179.30	$345.70	$171.03
		Summer Reference Price	$26.08	$22.82	$25.77	$24.56	$49.07	$26.08
		Winter Reference Price	$19.71	$17.25	$22.15	$21.12	$41.37	$33.68
	8-hr (1600 MWh)	Gross CONE	$346.57	$349.14	$360.12	$348.91	$558.63	$373.63
		Net EAS	$66.48	$93.54	$95.12	$95.24	$94.89	$124.71
		Annual Reference Value (Net CONE)	$280.09	$255.60	$265.00	$253.67	$463.73	$248.93
		Summer Reference Price	$32.75	$29.89	$33.24	$31.82	$59.58	$35.05
		Winter Reference Price	$24.75	$22.59	$28.58	$27.36	$50.23	$45.27

Note: (1) Gross CONE, Net EAS, and Annual Reference Value (Net CONE) shown as $/kw-year. Reference Points shown as $/kw-month. (2) The CAF values used in these results reflect the CAFs applicable to the 2024-2025 Winter Capability Period and will be updated to reflect the CAFs for the 2025-2026 Capability Year for the selected peaking plant

NYISO Staff's Recommended 2025-2026 Capability Year ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes

Technology		NYCA	G-J	New York City	Long Island
2-hour BESS	Gross CONE	$127.71	$127.58	$222.73	$137.03
	Net EAS	$77.15	$76.92	$82.25	$87.42
	Annual Reference Value (Net CONE)	$50.55	$50.66	$140.47	$49.61
	Summer Reference Point	$5.72	$6.15	$17.37	$6.80
	Winter Reference Point	$4.33	$5.29	$14.64	$8.78
	Summer Max Clearing Price	$21.69	$23.25	$41.30	$28.16
	Winter Max Clearing Price	$16.39	$19.99	$34.83	$36.37

NYISO Staff's Recommended 2025-2026 Capability Year ICAP Demand Curve Parameters with the Inclusion of the Board-Directed Changes

		Current Year (2025-2026)					
Parameter	**Source**	**C - Central**	**F - Capital**	**Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
Gross Cost of New Entry ($/kW-Year)	[1]	$126.73	$127.71	$131.96	$127.58	$222.73	$137.03
Net EAS Revenues ($/kW-Year)	[2]	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$71.35	$50.55	$55.07	$50.66	$140.47	$49.61
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$14,270	$10,111	$11,014	$10,132	$28,094	$9,922
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Winter to Summer DMNCs	[7]	103.30%	103.30%	105.00%	105.00%	105.70%	108.30%
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.73	$5.48	$5.97	$5.49	$15.22	$5.37
Winter ($/kW-Month)	[11]	$4.16	$2.95	$3.21	$2.96	$8.19	$2.89
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,546	$1,095	$1,193	$1,098	$3,044	$1,075
Monthly Revenue (Winter)	[13]=[11]*[9]	$832	$590	$642	$591	$1,639	$579
Seasonal Revenue (Summer)	[14]=6*[12]	$9,275	$6,572	$7,159	$6,585	$18,261	$6,450
Seasonal Revenue (Winter)	[15]=6*[13]	$4,994	$3,539	$3,855	$3,546	$9,833	$3,473
Total Annual Reference Value	[16]=[14]+[15]	$14,270	$10,111	$11,014	$10,131	$28,094	$9,922
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$8.08	$5.72	$6.69	$6.15	$17.37	$6.80
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$6.11	$4.33	$5.75	$5.29	$14.64	$8.78
Summer ICAP Maximum Clearing Price ($/kW-Month)		$21.53	$21.69	$24.04	$23.25	$41.30	$28.16
Winter ICAP Maximum Clearing Price ($/kW-Month)		$16.27	$16.39	$20.67	$19.99	$34.83	$36.37
Demand Curve Length		12%	12%	15%	15%	18%	18%

GE 7HA.03 with SCR and Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03	GE 7HA.03
Assumed Land Use, Acres	15	15	15	15	12	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NO_x Control	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR	Dry Low Nox / Water Injection / SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3	3	3
ESTIMATED PERFORMANCE (BASED ON NATURAL GAS OPERATION)						
ISO Base Load Performance						
Net Plant Output, kW	411,400	423,600	420,400	420,400	427,600	423,600
Net Plant Heat Rate, Btu/kWh (HHV)	8,930	8,920	8,920	8,920	8,920	8,920
Heat Input, MMBtu/hr	3,670	3,780	3,750	3,750	3,810	3,780
Summer Base Load Performance						
Net Plant Output, kW	400,200	411,800	408,000	408,000	413,900	417,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,000	9,000	9,000	9,000	9,000	9,000
Heat Input, MMBtu/hr	3,600	3,710	3,670	3,670	3,730	3,750
Summer DMNC Base Load Performance						
Net Plant Output, kW	396,900	405,700	403,200	403,200	409,100	408,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,020	9,050	9,020	9,020	9,030	9,030
Heat Input, MMBtu/hr	3,580	3,670	3,640	3,640	3,690	3,690
Winter Base Load Performance						
Net Plant Output, kW	417,500	429,100	426,900	426,900	434,700	438,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,850	8,870	8,850	8,850	8,830	8,830
Heat Input, MMBtu/hr	3,690	3,810	3,780	3,780	3,840	3,870
Winter DMNC Base Load Performance						
Net Plant Output, kW	419,500	433,800	432,500	432,500	439,100	433,400
Net Plant Heat Rate, Btu/kWh (HHV)	8,820	8,860	8,830	8,830	8,830	8,820
Heat Input, MMBtu/hr	3,700	3,840	3,820	3,820	3,880	3,820
ICAP Base Load Performance						
Net Plant Output, kW	389,000	400,300	397,400	397,400	404,100	404,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,070	9,060	9,070	9,070	9,060	9,060
Heat Input, MMBtu/hr	3,530	3,630	3,600	3,600	3,660	3,660

GE 7HA.03 with SCR and Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$423**	**$432**	**$435**	**$495**	**$551**	**$537**
Dual Fuel Breakout Costs, 2024 MM$ (w/o Owner's Costs)	**$26.9**	**$26.9**	**$26.9**	**Included**	**Included**	**Included**
Owner's Costs, 2024 MM$	**$150**	**$151**	**$144**	**$149**	**$209**	**$623**
Owner's Project Development	$1.2	$1.2	$1.2	$1.2	$1.6	$1.2
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Owner's Engineer	$1.6	$1.6	$1.6	$1.6	$2.0	$1.6
Owner's Project Management	$1.6	$1.6	$1.6	$1.6	$2.0	$1.6
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.8	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Construction Power and Water	$0.5	$0.5	$0.5	$0.5	$0.7	$0.5
Permitting Support	$0.7	$0.7	$0.7	$0.7	$1.0	$0.7
Switchyard	$18.19	$18.2	$18.2	$18.2	$51.0	$13.0
Transmission Line and Electrical Interconnection	$26.05	$26.0	$26.0	$26.0	$28.3	$23.0
Gas Interconnection and Reinforcement	$35.4	$35.4	$35.4	$35.4	$15.5	$36.6
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$457.5
Water Supply Infrastructure	$9.6	$9.6	$3.2	$3.2	$6.8	$1.6
Emission Reduction Credits	$0.9	$0.9	$0.9	$3.4	$3.5	$3.5
Public Outreach and Area Development	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Startup/Testing (Fuel & Consumables)	$3.2	$3.2	$3.2	$3.2	$4.1	$3.2
Initial Fuel Inventory	$6.9	$6.9	$6.9	$6.9	$6.9	$6.9
Site Security	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Operating Spare Parts	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0
Land Lease During Construction	$1.5	$1.5	$1.5	$1.5	$34.4	$1.8
Builders Risk Insurance (0.45% of Construction Costs)	$2.0	$2.1	$2.1	$2.2	$2.5	$2.4
Owner's Contingency (5% for Screening Purposes)	$28.6	$29.0	$28.9	$30.6	$36.2	$55.2
AFUDC, 2024 MM$						
EPC Portion	$41.6	$42.5	$42.7	$45.8	$50.2	$49.8
Non-EPC Portion	$13.9	$14.0	$13.4	$13.8	$19.1	$57.7
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.8	$0.8	$1.0	$1.1	$1.3	$1.9
Total Project Costs, 2024 MM$	**$656**	**$667**	**$663**	**$704**	**$831**	**$1,269**
EPC Cost Per kW, 2024 $/kW (Note 1)	**$1,156**	**$1,146**	**$1,162**	**$1,244**	**$1,363**	**$1,330**
Total Cost Per kW, 2024 $/kW (Note 1)	**$1,687**	**$1,666**	**$1,668**	**$1,771**	**$2,056**	**$3,142**

GE 7HA.03 with SCR and Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
ESTIMATED STARTUP FUEL USAGE						
Start to Base Load, MMBtu	376	376	376	376	376	376
FIXED O&M COSTS (Note 2)						
Fixed O&M Cost - LABOR, 2024$MM/Yr	$1.11	$1.22	$1.44	$1.80	$1.93	$1.93
Fixed O&M Cost - OTHER, 2024$MM/Yr	$1.61	$1.61	$1.61	$1.61	$1.61	$1.61
Property Insurance Allowance	$2.70	$2.75	$2.77	$2.97	$3.31	$3.22
Site Leasing Allowance, 2024$/MM/Yr	$0.38	$0.38	$0.38	$0.38	$8.6	$0.5
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$14.9	$14.9	$15.6	$17.0	$38.7	$17.9
LEVELIZED CAPITAL MAINTENANCE COSTS - GAS OPERATION						
Major Maintenance Cost, 2024$/GT-hr or $/engine-hr (Note 3)	$650	$650	$650	$650	$650	$650
Major Maintenance Cost, 2024$/GT-start	$23,100	$23,100	$23,100	$23,100	$23,100	$23,100
Major Maintenance Cost, 2024$/MWh	$1.57	$1.51	$1.52	$1.52	$1.49	$1.53
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - GAS OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$1.45**	**$1.45**	**$1.45**	**$1.45**	**$1.54**	**$1.50**
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00	$0.04	**$1.50**
SCR Related Costs, $/MWh	$0.55	$0.55	$0.55	$0.55	$0.60	$0.60
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - FUEL OIL OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$8.75**	**$8.55**	**$8.59**	**$8.59**	**$8.73**	**$8.49**
Water Related O&M, $/MWh	$6.98	$6.77	$6.82	$6.82	$6.99	$6.72
SCR Related Costs, $/MWh	$0.87	$0.88	$0.87	$0.87	$0.84	$0.87
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90

GE 7HA.03 with SCR and Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (Note 5)						
GT emissions prior to SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	332	341	339	339	345	341
SO2	1	1	1	1	1	1
CO	48	50	50	50	50	50
CO2	432,900	445,770	442,260	442,260	449,280	452,790
Stack emissions with SCR and CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	27	27	27	27	28	27
SO2	1	1	1	1	1	1
CO	4	4	4	4	4	4
CO2	432,900	445,770	442,260	442,260	449,280	452,790
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL (Note 7)						
GT Operating, NO SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	556	574	569	569	580	578
SO2	3	3	3	3	3	3
CO	74	77	76	76	77	77
CO2	616,470	635,909	630,818	630,818	642,369	640,557
GT with SCR and CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	79	82	81	81	83	83
SO2	3	3	3	3	3	3
CO	11	11	11	11	11	11
CO2	616,470	635,909	630,818	630,818	642,369	640,557

Notes:
[1] $/kW values based on ICAP net plant performance outputs.
[2] All gas turbine FOM costs assume 7 full time personnel for first unit.
[3] Major maintenance $/hr and $/start are NOT additive. The maintenance will be either starts or hours based depending on operating profile. If average hours/start > 35.6, then maintenance will be hours based.
[4] Gas operation only. VOM assumes the use of temporary trailers for demineralized water treatment, where applicable.
[5] Emissions estimates are shown for steady state operation at ISO conditions for natural gas, unless otherwise stated. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Emissions estimates should not be used for permitting.
[6] SO2 emissions on Natural Gas assume 0.2 gr/100 scf of sulfur in the gas.
[7] Fuel oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

GE 7HA.02 without SCR and with Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			1
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02			GE HA.02
Assumed Land Use, Acres	15	15	15			25
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)			Dual Fuel (Natural Gas and Fuel Oil)
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			Fin Fan Heat Exchanger
NO_x Control	Dry Low Nox / Water Injection	Dry Low Nox / Water Injection	Dry Low Nox / Water Injection			Dry Low NOx on Gas / Water Injection on Fuel Oil SCR Included
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			Good Combustion Practice
Technology Rating	Mature	Mature	Mature			Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3			3
ESTIMATED PERFORMANCE (BASED ON NATURAL GAS OPERATION)						
ISO Base Load Performance						
Net Plant Output, kW	342,000	352,400	349,700			375,900
Net Plant Heat Rate, Btu/kWh (HHV)	9,070	9,060	9,070			9,060
Heat Input, MMBtu/hr	3,110	3,190	3,170			3,410
Summer Base Load Performance						
Net Plant Output, kW	331,000	340,700	337,400			356,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,120	9,120	9,120			9,220
Heat Input, MMBtu/hr	3,020	3,110	3,080			3,290
Summer DMNC Base Load Performance						
Net Plant Output, kW	327,600	336,600	338,300			356,500
Net Plant Heat Rate, Btu/kWh (HHV)	9,650	9,140	8,110			9,140
Heat Input, MMBtu/hr	3,160	3,080	2,750			3,260
Winter Base Load Performance						
Net Plant Output, kW	357,000	365,000	361,000			388,500
Net Plant Heat Rate, Btu/kWh (HHV)	8,990	8,970	8,960			9,050
Heat Input, MMBtu/hr	3,210	3,280	3,240			3,520
Winter DMNC Base Load Performance						
Net Plant Output, kW	352,800	383,800	366,400			388,700
Net Plant Heat Rate, Btu/kWh (HHV)	9,470	8,960	7,960			8,990
Heat Input, MMBtu/hr	3,340	3,440	2,920			3,500
ICAP Base Load Performance						
Net Plant Output, kW	321,000	330,700	328,100			353,000
Net Plant Heat Rate, Btu/kWh (HHV)	9,180	9,170	9,170			9,240
Heat Input, MMBtu/hr	2,940	3,030	3,010			3,260

GE 7HA.02 without SCR and with Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS				[redacted]	[redacted]	
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$346.85**	**$355.06**	**$356.54**	[redacted]	[redacted]	**$422**
Dual Fuel Breakout Costs, 2024 MM$ (w/o Owner's Costs)	**$26.9**	**$26.9**	**$26.9**	[redacted]	[redacted]	**$26.9**
Owner's Costs, 2024 MM$	**$146**	**$146**	**$140**	[redacted]	[redacted]	**$137**
Owner's Project Development	$1.2	$1.2	$1.2	[redacted]	[redacted]	$1.2
Owner's Operational Personnel Prior to COD	$0.3	$0.3	$0.3	[redacted]	[redacted]	$0.3
Owner's Engineer	$1.6	$1.6	$1.6	[redacted]	[redacted]	$1.6
Owner's Project Management	$1.6	$1.6	$1.6	[redacted]	[redacted]	$1.6
Owner's Legal Costs	$0.7	$0.7	$0.7	[redacted]	[redacted]	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	[redacted]	[redacted]	$0.1
Land	$0.0	$0.0	$0.0	[redacted]	[redacted]	$0.0
Construction Power and Water	$0.5	$0.5	$0.5	[redacted]	[redacted]	$0.5
Permitting Support	$0.7	$0.7	$0.7	[redacted]	[redacted]	$0.7
Switchyard	$18.19	$18.2	$18.2	[redacted]	[redacted]	$13.0
Transmission Line and Electrical Interconnection	$26.05	$26.0	$26.0	[redacted]	[redacted]	$23.0
Gas Interconnection and Reinforcement	$35.4	$35.4	$35.4	[redacted]	[redacted]	$36.6
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	[redacted]	[redacted]	$0.0
Water Supply Infrastructure	$9.6	$9.6	$3.2	[redacted]	[redacted]	$1.6
Emission Reduction Credits	$0.5	$0.6	$0.6	[redacted]	[redacted]	$3.1
Public Outreach and Area Development	$0.6	$0.6	$0.6	[redacted]	[redacted]	$0.6
Startup/Testing (Fuel & Consumables)	$3.2	$3.2	$3.2	[redacted]	[redacted]	$3.2
Initial Fuel Inventory	$6.9	$6.9	$6.9	[redacted]	[redacted]	$6.9
Site Security	$0.7	$0.7	$0.7	[redacted]	[redacted]	$0.7
Operating Spare Parts	$10.0	$10.0	$10.0	[redacted]	[redacted]	$10.0
Land Lease During Construction	$1.5	$1.5	$1.5	[redacted]	[redacted]	$1.8
				[redacted]	[redacted]	$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$1.7	$1.7	$1.7	[redacted]	[redacted]	$2.0
Owner's Contingency (5% for Screening Purposes)	$24.7	$25.2	$24.9	[redacted]	[redacted]	$27.9
AFUDC, 2024 MM$				[redacted]	[redacted]	
EPC Portion	$34.6	$35.4	$35.5	[redacted]	[redacted]	$41.6
Non-EPC Portion	$13.5	$13.5	$12.9	[redacted]	[redacted]	$12.7
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.7	$0.7	$0.9	[redacted]	[redacted]	$1.0
Total Project Costs, 2024 MM$	**$568**	**$578**	**$572**	[redacted]	[redacted]	**$641**
EPC Cost Per kW, 2024 $/kW (Note 1)	**$1,164**	**$1,155**	**$1,169**	[redacted]	[redacted]	**$1,272**
Total Cost Per kW, 2024 $/kW (Note 1)	**$1,770**	**$1,747**	**$1,744**	[redacted]	[redacted]	**$1,816**

GE 7HA.02 without SCR and with Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED O&M COSTS						
ESTIMATED STARTUP FUEL USAGE						
Start to Base Load, MMBtu	240	240	240			240
FIXED O&M COSTS (Note 2)						
Fixed O&M Cost - LABOR, 2024$MM/Yr	$1.10	$1.20	$1.20			$1.93
Fixed O&M Cost - OTHER, 2024$MM/Yr	$1.60	$1.60	$1.60			$1.61
Property Insurance Allowance	$2.24	$2.29	$2.30			$2.69
Site Leasing Allowance, 2024$/MM/Yr	$0.38	$0.38	$0.38			$0.5
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A			N/A
Total Fixed O&M, $/kW-yr	$16.6	$16.6	$16.7			$18.7
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2024$/GT-hr or $/engine-hr (Note 3)	$620	$620	$620			$620
Major Maintenance Cost, 2024$/GT-start	$23,000	$23,000	$23,000			$23,000
Major Maintenance Cost, 2024$/MWh	$1.72	$1.70	$1.70			$1.70
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4)						
Total Variable O&M Cost, 2024$/MWh	**$0.90**	**$0.90**	**$0.90**			**$1.50**
Water Related O&M, $/MWh	$0.00	$0.00	$0.00			$0.00
SCR Related Costs, $/MWh	NA	NA	NA			$0.60
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90			$0.90
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 4) - FUEL OIL OPERATION						
Total Variable O&M Cost, 2024$/MWh	**$8.75**	**$8.55**	**$8.59**			
Water Related O&M, $/MWh	$6.98	$6.77	$6.82			6.72
SCR Related Costs, $/MWh	$0.87	$0.88	$0.87			0.88
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90			0.90

GE 7HA.02 without SCR and with Dual Fuel						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**Zone G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (Note 5)						
GT emissions prior to SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	332	341	339			341
SO2	1	1	1			1
CO	48	50	50			50
CO2	400,920	413,280	409,680			422,160
GT emissions with SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	NA	NA	NA			27
SO2	NA	NA	NA			1
CO	NA	NA	NA			11
CO2	NA	NA	NA			422,160
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL (Note 7)						
GT Operating, NO SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	556	574	569			578
SO2	3	3	3			3
CO	74	77	76			77
CO2	616,470	635,909	630,818			640,557
GT Operating, with SCR / CO Catalyst (lb/hr, HHV) (Note 6)						
NOX	NA	NA	NA			83
SO2	NA	NA	NA			3
CO	NA	NA	NA			17
CO2	NA	NA	NA			640,557

Notes:
[1] $/kW values based on ICAP net plant performance outputs.
[2] All gas turbine FOM costs assume 7 full time personnel for first unit.
[3] Major maintenance $/hr and $/start are NOT additive. The maintenance will be either starts or hours based depending on operating profile. If average hours/start > 35.6, then maintenance will be hours based.
[4] Gas operation only. VOM assumes the use of temporary trailers for demineralized water treatment, where applicable.
[5] Emissions estimates are shown for steady state operation at ISO conditions for natural gas, unless otherwise stated. Estimates account for the impacts of SCR and CO catalysts, as applicable. Emissions estimates should not be used for permitting.
[6] SO2 emissions on Natural Gas assume 0.2 gr/100 scf of sulfur in the gas.
[7] Fuel oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	2	2	2	2	2	2
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	10	10	10	10	6	9
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	2.50	2.50	2.50	2.50	2.50	2.50
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	2	2	2	2	2	2
Net Plant Energy Capacity, kWh	400,000	400,000	400,000	400,000	400,000	400,000
Energy Capacity Installed with Overbuild, kWh AC at POI	451,500	451,500	451,500	451,500	451,500	451,500

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$153.2**	**$154.5**	**$153.3**	**$159.2**	**$189.3**	**$163.2**
Owner's Cost Allowances, 2024 MM$	**$62.6**	**$62.8**	**$63.2**	**$64.4**	**$132.7**	**$68**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.7	$0.6
Owner's Project Management	$0.8	$0.8	$0.8	$0.8	$1.1	$0.8
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$10.7	$10.8	$11.2	$11.6	$14.5	$12.3
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Switchyard	$12.6	$12.6	$12.6	$12.9	$41.1	$14.1
Transmission Line and Electrical Interconnection	$22.2	$22.2	$22.2	$22.4	$40.3	$24.0
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.4	$0.4	$0.4	$0.6	$0.4
Operating Spare Parts	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Land Lease During Construction	$0.8	$0.8	$0.8	$0.8	$14.0	$0.9
Builders Risk Insurance (0.45% of Construction Costs)	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Contingency (5% for Screening Purposes)	$10.3	$10.4	$10.3	$10.7	$15.3	$11.0
AFUDC, 2024 MM$	**$17.3**	**$17.5**	**$17.5**	**$18.0**	**$25.6**	**$18.7**
EPC Portion	$12.1	$12.2	$12.1	$12.6	$14.8	$12.9
Non-EPC Portion	$4.9	$5.0	$5.0	$5.1	$10.4	$5.4
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.3	$0.3	$0.4	$0.4	$0.5	$0.4
Total Project Costs, 2024 MM$	**$233.1**	**$234.8**	**$233.9**	**$241.7**	**$347.6**	**$250.1**
EPC Cost Per kW, 2024 $/kW	**$770**	**$770**	**$770**	**$800**	**$950**	**$820**
Total Cost Per kW, 2024 $/kW	**$1,170**	**$1,170**	**$1,170**	**$1,210**	**$1,740**	**$1,250**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$340**	**$340**	**$340**	**$350**	**$420**	**$360**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$520**	**$520**	**$520**	**$540**	**$770**	**$550**

200 MW / 2-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
Investment Tax Credit Allowances/Assumptions (Note 7)						
Eligible Basis Assumption for Percent of Total Project Cost, 2024 MM$	82.5%	82.5%	82.5%	82.5%	68.0%	82.5%
Eligible Cost Basis Allowance, 2024 MM$	$192	$194	$193	$199	$236	$206
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$58	$58	$58	$60	$71	$62
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$67.2	$67.7	$67.4	$69.7	$82.4	$72.1
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$1.7	$1.7	$1.7	$1.7	$2.1	$1.8
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$2.4	$2.4	$2.4	$2.6	$2.9	$2.8
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$0.9	$0.9	$0.9	$0.9	$0.9	$0.9
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.2	$0.2	$0.2	$0.2	$0.3	$0.3
Site Leasing Allowance, 2024$/MM/Yr	$0.3	$0.3	$0.3	$0.3	$4.3	$0.3
Property Insurance Allowance, 2024$MM/Yr	$0.9	$0.9	$0.9	$1.0	$1.1	$1.0
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$23.00	$23.24	$23.50	$24.43	$48.48	$25.75
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$6.37	$6.38	$6.40	$6.46	$6.56	$6.54
Sales Tax for VOM Items Assumed to be Taxable	$0.51	$0.51	$0.54	$0.54	$0.58	$0.56

Notes:

Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.

Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.

Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, standby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).

Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.

Note 6: Estimated Costs exclude decommissioning costs and salvage values.

Note 7: ITC and sales tax allowances are based on assumptions and do not represent tax advice.

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	4	4	4	4	4	4
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	14	14	14	14	9	12
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	2.75	2.75	2.75	2.75	2.75	2.75
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	4	4	4	4	4	4
Net Plant Energy Capacity, kWh	800,000	800,000	800,000	800,000	800,000	800,000
Energy Capacity Installed with Overbuild, kWh AC at POI	903,000	903,000	903,000	903,000	903,000	903,000

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$255**	**$257**	**$255**	**$263**	**$317**	**$270**
Owner's Cost Allowances, 2024 MM$	**$76.9**	**$77.1**	**$77.8**	**$79.4**	**$159.1**	**$83.9**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Owner's Project Management	$0.9	$0.9	$0.9	$0.9	$1.2	$0.9
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$18.0	$18.1	$18.8	$19.4	$23.7	$20.5
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Switchyard	$12.6	$12.6	$12.6	$12.9	$41.1	$14.1
Transmission Line and Electrical Interconnection	$22.2	$22.2	$22.2	$22.4	$40.3	$24.0
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.4	$0.4	$0.4	$0.6	$0.4
Operating Spare Parts	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Land Lease During Construction	$1.3	$1.3	$1.3	$1.3	$22.6	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.2	$1.2	$1.2	$1.2	$1.4	$1.2
Owner's Contingency (5% for Screening Purposes)	$15.8	$15.9	$15.9	$16.3	$22.7	$16.9
AFUDC, 2024 MM$	**$29**	**$29**	**$29**	**$30**	**$41**	**$31**
EPC Portion	$21.7	$21.9	$21.7	$22.5	$26.6	$23.0
Non-EPC Portion	$6.6	$6.6	$6.6	$6.8	$13.4	$7.2
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.5	$0.5	$0.5	$0.6	$0.8	$0.6
Total Project Costs, 2024 MM$	**$360**	**$363**	**$362**	**$373**	**$516**	**$385**
EPC Cost Per kW, 2024 $/kW	**$1,270**	**$1,280**	**$1,270**	**$1,320**	**$1,580**	**$1,350**
Total Cost Per kW, 2024 $/kW	**$1,800**	**$1,810**	**$1,810**	**$1,860**	**$2,580**	**$1,920**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$280**	**$280**	**$280**	**$290**	**$350**	**$300**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$400**	**$400**	**$400**	**$410**	**$570**	**$430**

200 MW / 4-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
Investment Tax Credit Allowances/Assumptions (Note 7)						
Eligible Basis Assumption for Percent of Total Project Cost, 2024 MM$	87.5%	87.5%	87.5%	87.5%	75.0%	87.5%
Eligible Cost Basis Allowance, 2024 MM$	$315	$317	$316	$326	$387	$337
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$95	$95	$95	$98	$116	$101
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$109.7	$110.4	$110.0	$113.3	$134.5	$117.0
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$2.7	$2.8	$2.8	$2.8	$3.4	$2.9
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$3.8	$3.9	$3.9	$4.1	$4.7	$4.4
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$1.4	$1.4	$1.4	$1.4	$1.4	$1.4
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.4	$0.4	$0.4	$0.4	$0.5	$0.5
Site Leasing Allowance, 2024$/MM/Yr	$0.4	$0.4	$0.4	$0.4	$6.5	$0.4
Property Insurance Allowance, 2024$MM/Yr	$1.5	$1.5	$1.5	$1.6	$1.9	$1.6
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$37.14	$37.55	$37.90	$39.40	$75.55	$41.50
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$6.05	$6.07	$6.08	$6.14	$6.23	$6.21
Sales Tax for VOM Items Assumed to be Taxable	$0.48	$0.49	$0.51	$0.51	$0.55	$0.54

Notes:

Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.

Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.

Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, standby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).

Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.

Note 6: Estimated Costs exclude decommissioning costs and salvage values.

Note 7: ITC and sales tax allowances are based on assumptions and do not represent tax advice.

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	6	6	6	6	6	6
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	18	18	18	18	12	16
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	3.00	3.00	3.00	3.00	3.00	3.00
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	6	6	6	6	6	6
Net Plant Energy Capacity, kWh	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Energy Capacity Installed with Overbuild, kWh AC at POI	1,354,500	1,354,500	1,354,500	1,354,500	1,354,500	1,354,500

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$366**	**$369**	**$367**	**$378**	**$445**	**$389**
Owner's Cost Allowances, 2024 MM$	**$92.8**	**$93.1**	**$94.1**	**$96.1**	**$187.4**	**$101.4**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.6	$0.6	$0.6	$0.6	$0.8	$0.6
Owner's Project Management	$0.9	$0.9	$0.9	$0.9	$1.2	$0.9
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$25.9	$26.1	$27.2	$28.0	$33.3	$29.5
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Permitting Support	$1.1	$1.1	$1.1	$1.1	$1.4	$1.1
Switchyard	$12.6	$12.6	$12.6	$12.9	$41.1	$14.1
Transmission Line and Electrical Interconnection	$22.2	$22.2	$22.2	$22.4	$40.3	$24.0
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.2	$0.2	$0.2	$0.2	$0.2	$0.2
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.6	$0.6	$0.6	$0.6	$0.7	$0.6
Operating Spare Parts	$1.5	$1.5	$1.5	$1.5	$1.5	$1.5
Land Lease During Construction	$1.7	$1.7	$1.7	$1.7	$32.3	$1.8
Builders Risk Insurance (0.45% of Construction Costs)	$1.7	$1.7	$1.7	$1.7	$2.0	$1.8
Owner's Contingency (5% for Screening Purposes)	$21.9	$22.0	$21.9	$22.6	$30.1	$23.3
AFUDC, 2024 MM$	**$46.8**	**$47.1**	**$47.1**	**$48.5**	**$63.7**	**$50.1**
EPC Portion	$36.9	$37.1	$36.9	$38.1	$44.1	$39.1
Non-EPC Portion	$9.3	$9.4	$9.5	$9.7	$18.6	$10.2
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.6	$0.6	$0.8	$0.8	$1.0	$0.8
Total Project Costs, 2024 MM$	**$506**	**$509**	**$508**	**$523**	**$696**	**$540**
EPC Cost Per kW, 2024 $/kW	**$1,830**	**$1,850**	**$1,830**	**$1,890**	**$2,230**	**$1,940**
Total Cost Per kW, 2024 $/kW	**$2,530**	**$2,550**	**$2,540**	**$2,620**	**$3,480**	**$2,700**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$270**	**$270**	**$270**	**$280**	**$330**	**$290**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$370**	**$380**	**$370**	**$390**	**$510**	**$400**

200 MW / 6-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
Investment Tax Credit Allowances/Assumptions (Note 7)						
Eligible Basis Assumption for Percent of Total Project Cost, 2024 MM$	91%	91%	91%	91%	80%	91%
Eligible Cost Basis Allowance, 2024 MM$	$460	$463	$462	$476	$557	$492
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$138	$139	$139	$143	$167	$147
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$159.7	$160.8	$160.3	$165.1	$193.1	$170.5
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$4.0	$4.0	$4.0	$4.1	$4.8	$4.3
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$5.2	$5.3	$5.4	$5.7	$6.5	$6.1
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.5	$0.6	$0.6	$0.6	$0.7	$0.7
Site Leasing Allowance, 2024$/MM/Yr	$0.5	$0.5	$0.5	$0.5	$8.6	$0.5
Property Insurance Allowance, 2024$MM/Yr	$2.2	$2.2	$2.2	$2.3	$2.7	$2.3
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$52.54	$53.07	$53.60	$55.75	$103.66	$58.66
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$5.84	$5.85	$5.86	$5.92	$6.01	$5.99
Sales Tax for VOM Items Assumed to be Taxable	$0.47	$0.47	$0.49	$0.50	$0.53	$0.52

Notes:

Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.

Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.

Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, standby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).

Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.

Note 6: Estimated Costs exclude decommissioning costs and salvage values.

Note 7: ITC and sales tax allowances are based on assumptions and do not represent tax advice.

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	8	8	8	8	8	8
Assumed Useful Life / Amortization Period (years)	20	20	20	20	20	20
Equivalent Availability Factor (%)	98%	98%	98%	98%	98%	98%
Assumed Land Use During Operation, Acres (Not Construction Land Use)	22	22	22	22	15	20
Annual System Cycles	365	365	365	365	365	365
Storage System Initial Overbuild (Years)	4	4	4	4	4	4
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	115	115	115	138	138	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
EPC Schedule (Years from NTP)	3.25	3.25	3.25	3.25	3.25	3.25
ESTIMATED PERFORMANCE						
BESS Performance						
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000	200,000
Discharge Duration, hr	8	8	8	8	8	8
Net Plant Energy Capacity, kWh	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Energy Capacity Installed with Overbuild, kWh AC at POI	1,806,000	1,806,000	1,806,000	1,806,000	1,806,000	1,806,000

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
ESTIMATED CAPITAL COSTS						
EPC Project Capital Costs, 2024 MM$ (w/o Owner's Costs)	**$471**	**$474**	**$471**	**$486**	**$575**	**$500**
Owner's Cost Allowances, 2024 MM$	**$107.9**	**$108.3**	**$109.6**	**$112.0**	**$217.1**	**$118.1**
Owner's Project Development	$0.7	$0.7	$0.7	$0.7	$1.0	$0.7
Owner's Operational Personnel Prior to COD	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Project Management	$1.0	$1.0	$1.0	$1.0	$1.3	$1.0
Owner's Legal Costs	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Owner's Start-up Engineering and Commissioning	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Sales Tax	$33.4	$33.6	$35.0	$36.0	$42.9	$38.1
Construction Power and Water	$0.2	$0.2	$0.2	$0.2	$0.3	$0.2
Permitting Support	$1.1	$1.1	$1.1	$1.1	$1.5	$1.1
Switchyard	$12.6	$12.6	$12.6	$12.9	$41.1	$14.1
Transmission Line and Electrical Interconnection	$22.2	$22.2	$22.2	$22.4	$40.3	$24.0
Gas Interconnection and Reinforcement	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
System Deliverability Upgrade Costs	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Water Supply Infrastructure	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Emission Reduction Credits	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Public Outreach and Area Development	$0.3	$0.3	$0.3	$0.3	$0.4	$0.3
Startup/Testing (Fuel & Consumables)	$0.2	$0.2	$0.2	$0.2	$0.3	$0.2
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.7	$0.7	$0.7	$0.7	$0.9	$0.7
Operating Spare Parts	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0
Land Lease During Construction	$2.2	$2.2	$2.2	$2.2	$43.0	$2.4
Builders Risk Insurance (0.45% of Construction Costs)	$2.1	$2.1	$2.1	$2.2	$2.6	$2.3
Owner's Contingency (5% for Screening Purposes)	$27.6	$27.7	$27.6	$28.5	$37.7	$29.4
AFUDC, 2024 MM$	**$73**	**$74**	**$74**	**$76**	**$99**	**$78**
EPC Portion	$58.8	$59.3	$58.9	$60.7	$70.7	$62.5
Non-EPC Portion	$13.5	$13.5	$13.7	$14.0	$26.7	$14.8
Mortgage Recording Tax (Assumes 55% Debt Financing)	$0.8	$0.8	$1.0	$1.0	$1.3	$1.0
Total Project Costs, 2024 MM$	**$652**	**$656**	**$654**	**$674**	**$891**	**$696**
EPC Cost Per kW, 2024 $/kW	**$2,350**	**$2,370**	**$2,350**	**$2,430**	**$2,870**	**$2,500**
Total Cost Per kW, 2024 $/kW	**$3,260**	**$3,280**	**$3,270**	**$3,370**	**$4,450**	**$3,480**
EPC Cost Per kWh, 2024 $/kWh AC at POI	**$260**	**$260**	**$260**	**$270**	**$320**	**$280**
Total Cost Per kWh, 2024 $/kWh AC at POI	**$360**	**$360**	**$360**	**$370**	**$490**	**$390**

200 MW / 8-hr Lithium-Ion Battery Energy Storage System						
PROJECT TYPE	**ZONE C**	**ZONE F**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J**	**ZONE K**
Investment Tax Credit Allowances/Assumptions (Note 7)						
Eligible Basis Assumption for Percent of Total Project Cost, 2024 MM$	93%	93%	93%	93%	82%	93%
Eligible Cost Basis Allowance, 2024 MM$	$606	$610	$608	$627	$730	$647
ITC Percentage Assumption, %	30%	30%	30%	30%	30%	30%
ITC Value, 2024 MM$	$182	$183	$182	$188	$219	$194
ITC Legal Fees (Seller pays both sides), 2024 MM$	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Recapture Insurance Coverage Additional Coverage Assumption, %	15%	15%	15%	15%	15%	15%
Recapture Insurance Coverage Amount, 2024 MM$	$209.9	$211.3	$210.7	$217.0	$252.8	$224.2
Recapture Insurance Premium Assumption, %	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Recapture Insurance Cost, 2024 MM$	$5.2	$5.3	$5.3	$5.4	$6.3	$5.6
Assumed Value of Transferable Tax Credit (net of brokerage fees), %	92%	92%	92%	92%	92%	92%
ESTIMATED O&M COSTS						
FIXED O&M COSTS						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM, 2024$MM/Yr	$6.7	$6.8	$6.9	$7.3	$8.2	$7.9
Capacity Maintenance Agreement (Fixed Portion Levelized), 2024$MM/Yr	$2.6	$2.6	$2.6	$2.7	$2.7	$2.7
Sales Tax Allowance for FOM Items Assumed to be Taxable	$0.7	$0.7	$0.8	$0.8	$0.9	$0.9
Site Leasing Allowance, 2024$/MM/Yr	$0.6	$0.6	$0.6	$0.6	$10.8	$0.6
Property Insurance Allowance, 2024$MM/Yr	$2.8	$2.8	$2.8	$2.9	$3.4	$3.0
Underground Transmission Revocable Consent, 2024$MM/Yr	N/A	N/A	N/A	N/A	$0.2	N/A
Total Fixed O&M, $/kW-yr	$67.02	$67.72	$68.33	$71.08	$131.05	$74.99
VARIABLE O&M COSTS (Augmentation Model)						
Capacity Maintenance Agreement (Variable Portion Levelized), 2024 $/MWh	$5.95	$5.96	$5.98	$6.03	$6.12	$6.11
Sales Tax for VOM Items Assumed to be Taxable	$0.48	$0.48	$0.50	$0.51	$0.54	$0.53

Notes:

Note 1: EPC electrical scope ends at the high side of the GSU. Includes engineering, procurement, construction (EPC) contracting methodology.

Note 2: EPC cost accounts for BESS sizing that accommodates system losses, equipment efficiencies, minimum state of charge, aux load, degradation during shipping/construction, and 4 years of overbuild.

Note 3: Battery FOM accounts for routine BESS and PCS maintenance, BOP maintenance, remote monitoring, asset management, performance guarantees, extended warranties, standby/idle aux loads, and an inverter replacement allowance.

Note 4: Augmentation typically occurs in milestone events, but the total lifetime augmentation estimates are levelized here, intended to account for maintaining rated energy capacity for 20-year life. Augmentation estimates are modeled in fixed and variable components to allow for cycle adjustments in DCR (both components together make up the augmentation estimate).

Note 5: Availability and outage rate assumptions are based on vendor correspondence and industry publications.

Note 6: Estimated Costs exclude decommissioning costs and salvage values.

Note 7: ITC and sales tax allowances are based on assumptions and do not represent tax advice.

Exhibit B

Proposed NYISO Installed Capacity Demand Curves for the 2025-2026 Capability Year and Annual Update Methodology and Inputs for the 2026-2027, 2027-2028, 2028-2029 Capability Years

A Report by the
New York Independent System Operator

FINAL REPORT (Updated): October 2024

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Executive Summary

As required under the Market Administration and Control Area Services Tariff (Services Tariff), the New York Independent System Operator, Inc. (NYISO) has conducted its periodic review of the ICAP Demand Curves (commonly referred to as the "ICAP Demand Curve reset" or "DCR"). This review addresses the ICAP Demand Curves that would be effective for Capability Years 2025-2026, 2026-2027, 2027-2028, and 2028-2029. This report covers the NYISO staff's recommendations for the proposed ICAP Demand Curves, which has been informed by the work performed by the independent consultants, Analysis Group Inc. and 1898 & Co. (collectively identified herein as the "Consultant"), as well as stakeholder and Market Monitoring Unit (MMU) feedback provided through multiple stakeholder meetings and written comments.

The NYISO staff generally accepts the conclusions, assumptions and recommendations of the Consultant including the recommended selection of a two-hour, lithium-ion battery energy storage system (BESS) as the appropriate peaking plant technology underlying each ICAP Demand Curve for the 2025-2029 reset period.

Certain stakeholders and the MMU have expressed concerns that the risk of potential future declines in the Capacity Accreditation Factor (CAF) values for a 2-hour BESS may result in such technology failing to remain the appropriate peaking plant technology in future resets. These parties contend that the potential to select alternative technology options in future resets undermines the ability for a 2-hour BESS to recover its costs over the amortization period assumed for this reset. The risk that an alternative technology could be selected to anchor the demand curves in a future reset exists for any technology selected as the peaking plant in a reset and is a risk presented by the nature of the tariff-required periodic reviews of the ICAP Demand Curves. The requirement to comprehensively review technology options and identify the lowest fixed and highest variable cost technology option among economically viable candidates for each curve during each reset presents the risk that technological innovation and other changes may produce changes in the peaking plant technology from one reset to the next. In fact, this has occurred in multiple past instances, including the last reset when the H-class frame turbine was selected to replace the F-class frame turbine that served as basis for the peaking plant designs in the preceding reset. Accordingly, this risk, which is inherent to the periodic review process required by the Services Tariff does not provide a reasonable justification for rejecting the consideration of any particular technology option. For purposes of this reset, analyses, based on the information available at this time associated with potential future CAF values, suggest that the 2-hour BESS will remain economically favorable for the four-year reset period compared to the other alternatives evaluated for the 2025-2029

DCR.

A summary of NYISO staff's recommendations for each ICAP Demand Curve, including the 2025-2026 Capability Year ICAP Demand Curve reference point prices associated with such recommendations, is listed below.

Table 1: NYISO Staff's Recommended 2025-2026 Capability Year Indicative UCAP Demand Curve Reference Points (for Informational Purposes Only) ($2025)

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Summer Reference Price	$9.61	$10.30	$29.99	$11.66
Winter Reference Price	$7.26	$8.86	$25.29	$15.07

Note: The CAF values used in these results reflect the CAFs applicable to the 2024-2025 Winter Capability Period and will be updated to reflect the CAFs applicable to the 2025-2026 Capability Year for the selected peaking plant technology.

Table 2: NYISO Staff's Recommended 2025-2026 Capability Year Summer ICAP Demand Curve Parameters and Reference Points ($2025)

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	$5.17	$5.56	$16.16	$6.02
Max Clearing Price	$20.86	$22.35	$39.50	$26.99
Zero Crossing Point	112%	115%	118%	118%

Table 3: NYISO Staff's Recommended 2025-2026 Capability Year Winter ICAP Demand Curve Parameters and Reference Points ($2025)

	NYCA	G-J	New York City	Long Island
Technology	2-hour BESS	2-hour BESS	2-hour BESS	2-hour BESS
Load Zone	F	G (Dutchess)	J	K
Reference Price	$3.91	$4.78	$13.63	$7.77
Max Clearing Price	$15.76	$19.22	$33.30	$34.86
Zero Crossing Point	112%	115%	118%	118%

Introduction

Section 5.14.1.2.2 of the Services Tariff requires the NYISO to conduct periodic reviews of the ICAP Demand Curves. This process is the seventh such review since the initial implementation of the ICAP Demand Curves. Analysis Group, Inc. (AGI), together with its engineering consultant subcontractor 1898 & Co., were selected by the NYISO to serve as the independent demand curve consultant (i.e., the Consultant) to lead market participants through the DCR process.

As set forth in the Services Tariff, this periodic review assesses (i) the current localized, levelized, embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, along with (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant, net of the costs of producing such Energy and Ancillary Services. For purposes of this periodic review, a peaking unit is defined by the Services Tariff as "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."

As part of the last reset, modifications were made to the process for performing annual updates and how the monthly value of the gross cost of new entry was determined for use in the calculation of the maximum clearing price for each ICAP Demand Curve. The changes regarding the annual updates modified the procedures for annually adjusting capital costs to construct each peaking plant and calculating the composite escalation factor. The changes regarding translation of annual gross cost of new entry values to the monthly values provided for improved alignment with the translation of annual net cost of new entry values to monthly values by accounting for seasonal differences in capacity availability and the percent of capacity at tariff-prescribed level of excess conditions.

During the current reset, enhancements were made to the calculation of the reference point price and maximum allowable clearing price of the ICAP Demand Curves. The enhancements will produce separate ICAP Demand Curves for the Summer and Winter Capability Periods and incorporate the relative share of reliability risk between the seasons in the ICAP Demand Curves. The enhancements were filed with the Federal Energy Regulatory Commission (FERC) on December 19, 2023. FERC issued an order accepting the enhancements on February 15, 2024. In addition, enhancements were made to allow consideration of real-time interval pricing in determining the net EAS revenues used to establish ICAP Demand Curves. These enhancements were filed with FERC on May 15, 2024, and FERC issued an order accepting the enhancements on July 11, 2024.

This report contains: (i) the NYISO staff's response to the Consultant's work; and (ii) the NYISO staff's recommendations for: (a) the ICAP Demand Curves applicable for the 2025-2026 Capability Year (CY), and

(b) the methodologies and inputs to be used in the annual update process for the three succeeding Capability Years (CY 2026-2027, CY2027-2028 and CY 2028-2029). In preparing these recommendations, NYISO staff has considered the Consultant's work as well as feedback provided by stakeholders and the MMU.

This report sets forth the NYISO staff's recommendations for adjusting the current ICAP Demand Curve parameters and the underlying assumptions leading to those recommendations. The MMU has been involved in reviewing the Consultant's work product and provided feedback at various stages throughout the process. The DCR schedule (see the *Timeline* section of this report) identifies the timing for the remaining steps of this reset, culminating in the NYISO's filing with FERC on or before November 30, 2024 of the results of the DCR, as approved by the NYISO Board of Directors (Board).

Specific Technologies Evaluated by the Consultant

The ICAP Demand Curve reset assesses "…the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements." The peaking unit is referred to as the unit with technology that results in the lowest fixed costs and highest variable costs among economically viable technology options. For this DCR, the Consultant reviewed the following technology types:

1. Simple cycle gas turbine (SCGT) having one or more combustion turbines that are fueled by either natural gas, liquid fossil fuels (ultra-low sulfur diesel or "ULSD"), or both.
2. Battery energy storage system (BESS) having duration capabilities of 2-hours, 4-hours, 6-hours, or 8-hours.
3. A SCGT retrofitted to operate using hydrogen as a proxy for a potential zero-emission fuel option that could potentially comply with the 2040 zero-emission requirement for electricity generation specified in New York's Climate Leadership and Community Protection Act (CLCPA). This technology option was analyzed in this review for informational purposes only.

The technology options were evaluated for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K.

Economic Viability Assessment Criteria

The Consultant used criteria consistent with the past DCRs to assess whether various technology options were economically viable to be considered as a potential peaking plant technology option. The criteria included the following: availability of the technology to most market participants; operating experience sufficient to demonstrate that the technology is proven; unit characteristics that can be economically dispatched; ability to cycle and provide peaking service; ability to be practically constructed in a particular location; and ability to meet environmental requirements and regulations.

Discussion of Units Evaluated

The Consultant selected specific representative units for each evaluated technology. Based on its initial economic viability assessment, the Consultant recommended that the following technology options be evaluated for the 2025-2029 DCR:

1. H-class fossil-fired frame turbine (~325 MW)
2. J-class fossil-fired frame turbine (~400 MW)
3. 2-hour lithium-ion battery storage (200 MW, 400 MWh of discharge capability)
4. 4-hour lithium-ion battery storage (200 MW, 800 MWh of discharge capability)
5. 6-hour lithium-ion battery storage (200 MW, 1,200 MWh of discharge capability)
6. 8-hour lithium-ion battery storage (200 MW, 1,600 MWh of discharge capability)

NYISO staff agrees with the technology options recommended by the Consultant for evaluation as potential peaking plants for this reset.

Battery Energy Storage Systems

For the BESS options, the Consultant evaluated units with lithium-ion battery technology. Other storage technologies initially considered included pumped hydro and flow batteries. However, pumped hydro presents siting and location requirements which could result in the option being incapable of construction in certain locations. Flow batteries reflected higher capital costs than lithium-ion batteries through the initial screening as well as limited operating experience. The Consultant ultimately elected to utilize lithium-ion batteries as the representative technology option for energy storage for this DCR.[1]

The Consultant also considered different potential chemistries for the lithium-ion battery storage options. The market currently has multiple different chemistries for lithium-ion batteries. Rather than selecting a single chemistry, the costs developed by the Consultant are intended to be representative of the following three commonly utilized options: lithium nickel manganese cobalt oxide (NMC), lithium iron phosphate (LFP), and lithium nickel cobalt aluminum oxide (NCA). The Consultant chose to evaluate 200 MW storage units with the following discharge durations: 2-hour (400 MWh of energy storage capability), 4-hour (800 MWh of energy storage capability), 6-hour (1,200 MWh of energy storage capability), and 8-

[1] *See* Consultant Final Report (Updated Version) at 7.

hour (1,600 MWh of energy storage capability).

With respect to the assessment criteria, lithium-ion battery storage was found to be economically viable because the technology is widely available to developers. The Consultant also identified that more than 10,000 MWh of lithium-ion battery storage capability is currently operating in the U.S. with varying energy discharge durations ranging from 1-hour to 8-hours. The Consultant noted that lithium-ion battery storage is a highly flexible technology that can be economically dispatched. The Consultant further noted that battery storage has the technical capability to be cycled to permit the discharge of stored energy during peak periods.

The Consultant's findings with respect to the economic viability of lithium-ion batteries are consistent with the last reset. Lithium-ion batteries were similarly found to be economically viable and fully evaluated as a potential peaking plant technology option during the 2021-2025 DCR. Energy storage was not selected as the peaking plant technology for any ICAP Demand Curve because, at that time, the economic evaluation of potential technology options determined that frame turbines were the appropriate technology selection for each ICAP Demand Curve. For this reset, the Consultant proposed broadening the battery storage durations to include a 2-hour option. Based on the economic viability assessment described above, the Consultant confirmed that a 2-hour battery storage option was also economically viable. The Consultant's recommendation to consider 2-hour energy storage was, in part, based on concerns that the other storage duration options and frame turbines may not appropriately represent the "lowest fixed cost" technology option among all other economically viable options. The Consultant also acknowledged that, consistent with the other battery storage duration options considered, the NYISO's current capacity market rules establish that a 2-hour resource is an eligible capacity supplier.

Certain stakeholders and the MMU have noted potential concerns regarding the appropriateness of evaluating 2-hour battery storage as a peaking plant technology option. Initial concerns include the ability of 2-hour battery storage to serve longer-term system reliability needs as the transition to a clean energy grid continues to unfold. Concerns have also been expressed regarding the capability of a 2-hour resource to address nearer-term transmission security needs that have been identified in capacity regions such as Load Zone J. The ICAP market and ICAP Demand Curves are not currently designed to resolve (or provide price signals that fully value) all potential reliability needs or concerns on the system. The ICAP market (including the use of ICAP Demand Curves in the monthly spot auctions) is designed to provide price signals to attract and retain the capacity needed to maintain resource adequacy as reflected in the requirements established by the installed reserve margin (IRM) and Locational Minimum Installed Capacity Requirements (LCRs). The inclusion of Capacity Accreditation Factors, which explicitly account for the value of a resource in meeting resource adequacy needs, ensures that the ICAP market appropriately compensates resources for their contribution to meeting such resource adequacy-based reliability needs.

The NYISO has proposed future efforts to reassess the current ICAP market design, including the consideration of transmission security-based reliability needs. However, the potential outcomes of any such future efforts are unknown at this time. Consistent with precedent for the DCR, any such future outcomes should be reviewed in a future reset once known. The assessment of information available at this time for the four year period covered by this reset indicates that a 2-hour BESS provides value to the grid in assisting to maintain reliability and meet system needs. Additional information regarding the viability of 2-hour energy storage to serve as a potential peaking plant technology are addressed in the "NYISO Staff Recommendations" section below.

Simple Cycle Gas Turbines

For the simple cycle technologies, the Consultant initially considered three different types: aeroderivative combustion turbines, frame combustion turbines, and reciprocating internal combustion engines (RICE). These technologies have been found to be economically viable in past resets with one or more types being selected in each reset to serve as the appropriate peaking plant technology for the ICAP Demand Curves. Based on a preliminary, high-level cost screening, the Consultant eliminated aeroderivative units and reciprocating engines because their fixed costs significantly exceed the fixed costs of frame turbines and, therefore, would not satisfy the overarching requirement to have the "lowest fixed costs" in comparison to other viable generation options.

For the frame combustion turbine, the Consultant considered nine different units for potential evaluation representing a range of units from both the G/H/J-class and the F-class.[2] The G/H/J-class options included the following: GE 7HA.03, GE 7HA.02, Siemens SGT6-9000HL, Mitsubishi Hitachi 501JAC, GE 7HA.01, Mitsubishi Hitachi MHPS 501GAC, and Siemens SGT6-8000H. The F-class units identified as potential options were as follows: GE 7F.05, and Siemens SGT6-5000F. Of the nine potential options, the Consultant compared operating experience, initial high-level screening costs, and heat rates. Initial screening indicated G/H/J-class frame turbines have lower costs per kW and better heat rates as compared to F-class frame turbines. For the G/H/J-class frame turbines, two options were identified as representative technology candidates: a GE 7HA.03 unit with selective catalytic reduction (SCR) emissions controls and a GE 7HA.02 unit with or without SCR emissions controls. The 7HA.02 design option without

[2] *See* Consultant Final Report (Updated Version) at 17.

SCR emissions controls was evaluated for Load Zones C, F, and G (Dutchess County) only. The Consultant used these representative technology options for purposes of developing detailed designs and cost estimates for the SCGT options.

Informational Hydrogen Fueled Turbine Retrofit Option

The Consultant also conducted a limited review of the potential costs to retrofit a frame turbine to a zero-emissions operating design for compliance with the CLCPA's requirement that 100% of load be served by "zero-emissions" resources by 2040. To conduct this assessment, the Consultant evaluated the cost to convert to burning hydrogen starting in 2040 as a proxy for a potential zero-emissions fuel option.

For informational purposes, capital cost estimates were prepared for converting the 7HA.03 simple cycle facility to combust carbon free hydrogen beginning in 2040. However, the Consultant did not conduct any further evaluation of a hydrogen fueled frame turbine as a potential peaking plant technology option for this study because this technology option was not found to be economically viable for the 2025-2029 DCR due to failing multiple assessment criteria. For example, there is currently no commercial operating experience for a frame turbine operating on 100% hydrogen fuel. Additionally, such a design cannot demonstrate compliance with existing requirements because the New York State Public Service Commission has not established whether operation on hydrogen qualifies as a zero-emissions resource pursuant to the CLCPA. In addition, the Consultant noted that, at this time, such a technology would not represent the lowest fixed cost option for any ICAP Demand Curve due to the identified capital costs for this technology option, including the costs of assumed onsite hydrogen storage. Figure 3 of the Consultant's report shows the estimated capital costs for onsite hydrogen storage and compression to exceed $2 billion.[3]

Relevant Environmental Regulations

Environmental regulations can significantly influence the capital costs, fixed and variable operation and maintenance (O&M) costs, and operating restrictions for the SCGT peaking plants evaluated during the DCR. The following section reviews the applicable environmental regulations and state policies that would likely impact a SCGT peaking plant constructed during the reset window.

Climate Leadership and Community Protection Act (CLCPA)

In July 2019, the CLCPA became effective, codifying into law many of New York's clean energy goals. In

[3] *See* Consultant Final Report (Updated Version) at 21-22.

addition to establishing clean energy requirements for the state's energy sector, the CLCPA outlines various targets for specific procurement of certain clean energy resources in New York. The CLCPA also requires that New York's electric demand be served 100% by zero-emission resources by 2040.[4] Given this legislation, it is reasonable to expect that development of fossil units may be affected in the coming years, specifically in regard to the amortization period assumed for recovering the costs to construct new fossil units as part of this DCR.

New Source Performance Standards (NSPS)

All newly constructed combustion turbines evaluated by the Consultant are subject to NSPS emissions rules as set forth in 40 CFR Part 60, specifically Subpart KKKK – Stationary Combustion Turbines and Subpart TTTT – Standards for Performance for Greenhouse Gas Emissions for Electric Generating Units. NSPS rules apply to specific unit technologies, and do not vary based on where the unit is located.

Subpart KKKK requires combustion turbines to abide by specific limits for nitrogen oxides (NO_x) emissions based on whether their heat inputs are above or below 850 MMBtu/hour. For units with heat inputs greater than 850 MMBtu/hour, such as the GE 7HA.03 and GE 7HA.02, NO_x, emissions must be less than 15 ppm @ 15% O_2 when firing on natural gas and less than 42 ppm @ 15% O_2 when firing on oil (USLD). The GE 7HA.02 and GE 7HA.03 units both have NO_x emissions of 25 ppm @ 15% O_2. Therefore, the 25 ppm GE 7HA.02 and GE 7HA.03 unit would require SCR emissions controls for compliance with Subpart KKKK.

However, GE also offers a 7HA.02 unit tuned to emit 15 ppm NO_x @ 15% O_2, allowing it to operate in compliance with Subpart KKKK without back-end emissions controls. The 15 ppm GE 7HA.02 unit has the same hardware but fires at a lower combustion temperature to reduce NO_x emissions. Due to the reduced firing temperature, there is approximately a 5% reduction in output compared to the base 25 ppm GE 7HA.02 unit.

Subpart TTTT sets CO_2 emission limits for new stationary combustion turbines that start construction after May 23, 2023, and can generate over 25 MW of electricity. These turbines are divided into three categories: low load, intermediate load, and base load. Each category is defined based on a 3-year rolling average capacity factor where the capacity factor measures the amount of energy produced by the turbine with respect to its maximum output. New stationary combustion turbines with a capacity factor below 20% fall under the low load category. Those with a capacity factor between 20% and 40% are considered intermediate load, while turbines with a capacity factor above 40% are classified as base load. Subpart

[4] Chapter 106 of the Laws of the State of New York of 2019.

TTTT assigns each category a CO_2 emission limit as defined in Table 8 of the Consultant's report.[5] The 7HA.02 and 7HA.03 units are anticipated to satisfy the intermediate load CO_2 emission limit without requiring any additional controls. However, they would only be able to satisfy the base load CO_2 emission limit with post combustion carbon capture controls. The Consultant concluded that this approach is impractical and therefore the fossil peaking plant would need to limit its capacity factor to less than 40% to avoid being subject to the base load NSPS standard. Accordingly, the Consultant recommended that each of the SCGT peaking plant technology options be subject to an annual operating limit of 3,504 hours . This annual operating limit is applied in the modeling to estimate the annual net EAS revenues that could be earned by the SCGT options from participation in the NYISO-administered markets.

New York State also has rules for CO_2 emissions in the New York Codes, Rules, and Regulations (NYCRR) Part 251. A new SCGT in NYS must comply with NYCRR Part 251 as well as Subpart TTTT. In general, the NYCRR Part 251 limits that apply to simple cycle units are less stringent than the limits set forth in Subpart TTTT[6], and the 7HA.02 and 7HA.03 units are anticipated to satisfy NYCRR Part 251 without requiring any additional controls.

New Source Review (NSR)

In addition to the NSPS requirements noted above, the NSR program established by the U.S. Environmental Protection Agency (EPA) considers the impact of air quality from new generation resources. The NSR program subjects new units to an evaluation of the air quality in the surrounding area. Depending on the National Ambient Air Quality Standard (NAAQS) in each location, the area is either an "attainment" or "nonattainment" area based on its criteria for pollutant concentration. A geographic area where a criteria pollutant's concentration is below its respective NAAQS is classified as an attainment area for that pollutant. Conversely, an area where the concentration of a particular pollutant is above the applicable NAAQS is classified as nonattainment area for that pollutant. Additionally, there are varying degrees of nonattainment, such as moderate or severe nonattainment classifications.

There are two pathways to pursue an air permit under the NSR program: Prevention of Significant Deterioration (PSD) and Nonattainment New Resource Review (NNSR). The applicable pathway is dependent upon the classification of the area where a new or modified source is located. The preconstruction review process for new or modified sources located in an attainment area is subject to the PSD requirements. The corresponding process for new or modified sources located in nonattainment

[5] *See* Consultant Final Report (Updated Version) at 24.

[6] Please refer to Table 8 on page 24 of the Consultant Final Report (Updated Version) for additional details regarding the applicable CO_2 limits under both Subpart TTTTa and NYCRR Part 251.

areas is performed under the NNSR process.

Nonattainment areas have more stringent requirements, permitting thresholds, and analyses than attainment areas in an effort to improve the location's air quality. To qualify for a permit in an attainment area, a source would have to perform a Best Available Control Technology (BACT) analysis for the pollutant(s) at issue. For nonattainment areas, a source would have to perform a Lowest Achievable Emissions Rate (LAER) analysis for the applicable pollutant(s). LAER typically results in more stringent requirements than BACT.

However, under applicable environmental regulations, it is possible for a unit to "synthetically limit" its operation by accepting an annual emissions cap to adhere to the PSD thresholds for applicable pollutants. A unit that synthetically limits its operation will be considered a "synthetic minor source" and will subject to less stringent permitting analyses. This approach has been utilized in prior resets to potentially avoid a requirement to install SCR emissions controls to reduce NO_x emissions for certain gas-only simple cycle combustion turbines located in areas of New York subject to less restrictive emissions limits, such as Load Zones C, F and G (Dutchess County). Due to the more stringent emissions limits that apply in severe non-attainment areas, such as Load Zones G (Rockland County), J, and K, the restrictive nature of the operating limitations that would apply to a synthetic minor source undermine the viability of this approach in such areas.

The PSD major source threshold for NO_x emissions for new simple cycle combustion turbines is 250 tons/year and is typically based on the potential to emit (PTE) at 8,760 hours/year of operation. Compared to the PSD thresholds, the emission limitations under the NNSR are more stringent. The NNSR thresholds for Volatile Organic Compounds (VOC) and Nitrogen oxides (NO_x) are 50 tons/year and 100 tons/year, respectively, for marginal, moderate, or Ozone Transport Regions and 25 tons/year for both VOC and NO_x in severe non-attainment areas. Since all of New York is in the Ozone Transport Region (OTR), the NNSR applies for all locations for precursors of ozone (VOC and NO_x).[7] As a result, new sources in Load Zones C, F, and G (Dutchess County) are subject to the NO_x emissions limit of 100 tons/year. New sources in Load Zones G (Rockland County), J, and K are subject to the 25 tons/year NO_x emissions limit.

Emissions Cap and Trade Programs

Stationary combustion sources in New York State are subject to three different cap-and-trade programs. The aim of these programs is to limit the emissions of CO_2, NOx, and SO_2. The three programs

[7] *See* Table 11 on page 28 of the Consultant Final Report (Updated Version) for further details regarding the New Source Review requirements and applicable emissions limits for this DCR.

are the following: Cross State Air Pollution Rule (CSAPR), the CO_2 Budget Trading Program (i.e., the Regional Greenhouse Gas Initiative), and the SO_2 Acid Rain Program. All of these programs apply to the SCGT peaking plant technologies evaluated as part of this DCR. Consequently, the costs of CO_2, NOx, and SO_2 allowances were included in the development of net EAS revenue estimates for the SCGT peaking plants.

CSAPR is implemented in New York State by creating three different budgets of tradable allowances: an annual NO_x budget (6 NYCRR 244), an annual SO_2 budget (6 NYCRR 245), and a seasonal (May 1 to September 30) NO_x budget (6 NYCRR 243).

The CO_2 Budget Trading Program (6 NYCRR Part 242) implements New York's participation in the Regional Greenhouse Gas Initiative (RGGI). RGGI seeks to reduce CO_2 emissions from the fossil-fuel fired electric generation facilities in the participating states through placement of a cap on annual CO_2 emissions from affected generators. CO_2 allowances are primarily distributed through quarterly auctions.

The SO_2 Acid Rain Program (40 CFR Parts 72-78) similarly limits the amount of SO_2 and NO_x emitted from electric generation facilities. While this program was first implemented in 1995, it still applies to generators in New York State and has not been superseded by the implementation of CSAPR.

DEC Peaker Rule

In 2020, the New York State Department of Environmental Conservation (DEC) enacted a rule placing incremental restrictions on the allowable level of NO_x emissions during the higher ozone level season (commonly referred to as the "peaker rule"). The rule applies to "owners and operators of simple cycle and regenerative turbines (SCCTs) that are electric generating units with a nameplate capacity of 15 megawatts (MW) or greater and that inject power into the transmission or distribution systems." Both the combustion turbine technologies evaluated as part of this DCR satisfy the applicable emissions requirements established by the DEC's peaker rule.

Recommendations on SCR Emissions Controls

The Consultant recommends including SCR emissions controls for the SCGT peaking plant option in all Load Zones due to economic considerations and emission restrictions described below.[8]

First, there is a potential for future increases to demand for operating the SCGT peaking plant options compared to past evaluations. This anticipated increase in demand is driven by higher renewable energy levels and the possible retirement of downstate gas turbines in compliance with the DEC peaker rule over

[8] *See* Consultant Final Report (Updated Version) at 30-31.

the coming years along with the ongoing transition of the resource fleet in response to energy and environmental policies, such as the CLCPA, as well as economic and other factors. Implementing SCR emissions controls offers the peaking plant flexibility to exceed the synthetic minor operating limit, potentially adding financial value to meet potential greater operational future operating demands.

Additionally, the SCGT 7HA.02 without SCR emissions controls is similar in cost to SCGT 7HA.03 with SCR emissions controls. Due to higher efficiency and operating limits, however, the SCGT 7HA.03 with SCR emissions controls is anticipated to have higher net EAS revenues in all applicable locations,[9] and therefore, has lower annual net costs in all applicable locations except Load Zone K. In Load Zone K, the SCGT 7HA.02 with SCR represents a lower fixed cost SCGT technology due to reasons specified in the Interconnection Costs section of this report.

With respect to the G-J Locality, the lower Hudson Valley region consists of areas classified as part of the Ozone Transport Region (i.e., subject to NO_x emissions limit of 100 tons/year), as well as areas classified as severe non-attainment areas (i.e., subject to NO_x emissions limit of 25 tons/year). Installing SCR emissions control could reduce permitting and siting risks linked to constructing a new dual fuel unit in the lower Hudson Valley without back-end emissions control technology.

NYISO staff concurs with the Consultant's recommendation to have the SCGT peaking plant option implement SCR emissions controls in all Load Zones.

Dual-Fuel Capability

In the last DCR, dual-fuel capability for the SCGT peaking plant options was evaluated in all locations. Ultimately, the SCGT peaking plants with dual-fuel capability were used in Load Zones G, J, and K and gas only SCGT peaking plants were used in Load Zones C and F. For this DCR, dual-fuel capability for the SCGT peaking plant options was evaluated again in all locations. Consistent with the evaluation conducted for the 2021-2025 DCR, run time requirements based on applicable emissions limitations associated with NSPS requirements, as previously described, for dual-fuel units and the relative economics associated with such operation were considered for the various technologies. Specifically, the Consultant's evaluation considered the economic tradeoffs between the additional costs associated with units with dual-fuel capability and the potential for additional revenues associated with having dual-fuel capability. The Consultant's evaluation also considered the potential impact of fuel availability capacity accreditation rules to be implemented beginning with the 2026-2027 Capability Year affecting revenue opportunities

[9] *See* Table 15 of the Consultant Final Report (Updated Version) at 31.

for units with gas-only capability.

Dual-fuel capability is required in Load Zones J and K, and although it is not mandated in other Load Zones, various factors support the inclusion of dual-fuel capability for the SCGT peaking plant options in the lower Hudson Valley. Considerations such as the cost of dual-fuel capability versus gas-only capability, flexibility of siting, and current level of reliance on natural gas for electric generation have been noted in past resets in support of a peaking plant with dual-fuel capability in Load Zone G. For this reset, due to the new fuel availability capacity accreditation rules, risks associated with a gas-only design and opportunities for additional revenues for plants with dual fuel capability, the Consultant recommends dual fuel capability in Load Zones C and F as well.

NYISO staff concurs with the Consultant's recommendations to include dual-fuel capability for SCGT peaking plant options for all locations.

Interconnection Costs

The NYISO's interconnection process offers two types of interconnection services. New projects seeking to participate in the NYISO markets must request one or both types of interconnection services, as applicable to the project. Energy Resource Interconnection Service (ERIS) allows a new project to participate in the NYISO's energy market and Capacity Resource Interconnection Service (CRIS) allows a new project to participate in the NYISO's ICAP market.

As required by FERC, a deliverability assessment was conducted to determine whether the peaking plant technology options being considered may require any System Deliverability Upgrades (SDUs) to obtain CRIS under the tariff prescribed level of excess[10] conditions required for the DCR.

[10] Services Tariff Section 5.14.1.2.2 defines this as conditions in which the available capacity is equal to the sum of (a) the applicable minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues.

Table 4: List of Interconnection Points Evaluated for Deliverability Analysis

Zone	Location
C	Sithe, Wright Avenue - Milliken
F	Rotterdam
G	Ladentown, Shoemaker, Shenandoah
H	East Fishkill
J	Rainey, East 179th St.
K	Ruland Road, Holbrook, Riverhead

Note: Only the 200 MW BESS was tested at the Shenandoah and Wright Avenue - Miliken interconnection points

Deliverability Study

NYISO planning staff conducted a deliverability analysis for the various peaking plant technologies utilizing the deliverability methodology consistent with the NYISO's Class Year deliverability study process and the case developed for the 2023-2024 New Capacity Zone (NCZ) study.[11] Consistent with FERC's directives, the deliverability analysis for the DCR is conducted under the level of excess conditions prescribed for use in the reset instead of using the "as found" summer peak system conditions used for the NCZ study.

The deliverability analysis indicated that all SCGT and BESS peaking plant options under consideration were fully deliverable in all locations, except for the 7HA.03 unit in Load Zone K. The 7HA.02 unit, however, was deliverable in Load Zone K. Due to the significantly high additional costs of SDUs for the 7HA.03 unit in Load Zone K, NYISO staff concurs with the Consultant's recommendation to use the 7HA.02 unit as the SCGT peaking technology option in Load Zone K.

Capital Investment and Other Plant Costs (Overnight Capital Costs)

The Consultant developed capital cost estimates for the various SCGT and BESS technologies evaluated for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K.

[11] The assumptions for the NCZ study were presented at the September 18, 2023 Installed Capacity working group (ICAPWG) meeting and the results of the study were presented to the ICAPWG on January 4, 2024. The New Capacity Zone study report was filed with FERC on February 23, 2024. *See* Docket No. ER24-1325-000, *New York Independent System Operator*, *Inc.*, 2023-2024 New Capacity Zone Study Report (February 23, 2024).

These cost estimates include the costs associated with a developer's engineering, procurement, and construction (EPC) contract, owner's costs (including electric and gas interconnection, fuel inventory (for dual-fuel units) and configurations), and construction financing costs and are summarized in the tables below. Section II.E and Appendix A of the Consultant's report includes additional detail on these cost estimates.

The EPC cost estimates are based on a generic site for each peaking plant and include the direct costs to construct the facility as well as indirect costs associated with the construction. In addition to the costs associated with equipment, materials, and labor for each peaking plant, the development of the cost estimates for the BESS include additional factors. Given the dynamic nature of the market for various BESS, the Consultant developed cost estimates for BESS technology options based on current market pricing for lithium-ion battery storage, rather than a specific battery chemistry or manufacturer.

The cost estimates for all locations, excluding Load Zone J, are based on a greenfield site. Load Zone J assumes a brownfield site. For Load Zone J, the costs include an assumed need to increase the existing site elevation by 4 feet for all technologies to accommodate the floodplain zoning requirements to prevent flooding damage to facilities, similar to the aftermath of Hurricane Sandy. Additionally, the Consultant assumed that interconnecting electric transmission lines (i.e., generator leads) in Load Zone J would be underground and that the switchyard would include gas insulated switchgear (GIS) technology, as compared to overhead transmission and air insulated switchgear (AIS) in all other locations. Based on construction of projects in New York City in recent years, considerations for constructing electric generation resources in highly dense urban areas such as New York City, as well as existing interconnection requirements and guidelines for new interconnections within Load Zone J, NYISO staff concurs with the Consultant's recommended assumptions for interconnection design within New York City.

The Consultant's recommended estimates for owner's costs as described in Section II.E and further detailed in Appendix A of the Consultant's report represent reasonable estimates. The Consultant initially developed electrical interconnection costs for the BESS assuming interconnection to the 345 kV system in all locations outside of Load Zone K. For Load Zone K, the Consultant assumed interconnection to the 138 kV system for all peaking plant technology options. However, interconnection to the 115 kV or 138 kV system (depending on location) is available for the 200 MW BESS in the other locations and, based on interconnection request data for similarly sized battery storage projects, is more representative of the interconnection voltage likely to be pursued for a 200 MW BESS. Supplemental deliverability analysis, consistent with the requirements for the DCR, was conducted by NYISO planning staff for lower voltage interconnections of the BESS option in Load Zones C, F, G (Dutchess County), G (Rockland County) and J. The supplemental analysis determined that all BESS peaking plant options under consideration were fully deliverable at the lower kV interconnections in all locations. NYISO staff recommended updated electrical interconnection cost estimates as shown in Table 5 to reflect assumed interconnection to the 115 kV or 138 kV system (depending on location) for the BESS options, which have since been adopted by the Consultant.

Table 5: Electrical Interconnection Assumptions for BESS Peaking Plant Technologies

Zone	Transmission Line (kV)	Cost (2024 MM$)
C	115	33.8
F	115	33.8
G (Rockland)	138	34.3
G (Dutchess)	115	33.8
J	138	78.3
K	138	36.9

Note: The costs in Table 5 reflect transmission line costs and switchyard interconnection costs

The owner's costs are divided into subcategories, including but not limited to categories such as development, engineering, interconnection and deliverability, and vary by technology type and location. The way costs are categorized by the Consultant in this DCR is similar to the last DCR. However, compared to the last reset, capital costs for both SCGT and BESS technologies have increased significantly. Factors contributing to the increase include higher labor costs, commodity and material prices, and equipment costs that have persisted following the COVID-19 pandemic and conflicts in Ukraine and the Middle East.

Considerations such as building and container designs, enclosures, overbuild, and augmentation were evaluated for the BESS options. The evaluation of the BESS options includes costs for battery storage installation in modular purpose-built enclosures (PBEs). Accounting for the known performance degradation of battery storage over time, the analysis assumed overbuild and future augmentation for the battery storage technology to account for losses and degradation of the unit's capacity over time.

For Load Zone J, the BESS options must meet the fire safety requirements set by the New York City Fire Department (FDNY), including the requirement to obtain a Certificate of Approval (i.e., Application for Certification of Approval Form TM-2 or "Form TM-2"). The BESS designs and equipment costs are compliant with the FDNY requirements.

Additionally, the analysis assumed the availability of a 30% Investment Tax Credit (ITC) for the BESS units in all locations.[12] The Consultant's application of the ITC for BESS required determining the percentage of total capital costs eligible for the ITC in each location evaluated, the costs of legal fees and recapture insurance, and an assumed discount to the credit to account for the market value of the transferable ITC. The Consultant developed these assumptions based on its consideration of stakeholder feedback, the Consultant's experience and knowledge of confidential project-specific information, correspondence with tax consultants and developers, and related research.

Considerations such as dual-fuel capability, inlet cooling, and emissions controls were evaluated for the SCGT technologies. The Consultant developed cost estimates for dual-fuel SCGT units with SCR emissions controls in all locations, as well as estimates for gas-only and dual fuel SCGT units without SCR emissions controls in Load Zones C, F, and G (Dutchess County). Inlet evaporative coolers were included in the estimates for all SCGT options in all locations.

Table 6: Capital Investment Costs for Battery Storage Peaking Plants Evaluated ($2024)

	BESS 2-hour	BESS 4-hour	BESS 6-hour	BESS 8-hour
Zone C Central				
Total Capital Cost ($million)	229	355	499	643
ICAP MW	200	200	200	200
$/kW	1,150	1,780	2,500	3,220
Zone F Capital				
Total Capital Cost ($million)	231	358	502	647
ICAP MW	200	200	200	200
$/kW	1,160	1,790	2,510	3,240
Zone G Hudson Valley (Dutchess County)				
Total Capital Cost ($million)	230	356	501	645
ICAP MW	200	200	200	200
$/kW	1,150	1,780	2,500	3,230
Zone G Hudson Valley (Rockland County)				
Total Capital Cost ($million)	237	367	515	664
ICAP MW	200	200	200	200
$/kW	1,190	1,830	2,580	3,320
Zone J New York City				
Total Capital Cost ($million)	339	505	682	873
ICAP MW	200	200	200	200
$/kW	1,690	2,530	3,410	4,360
Zone K Long Island				
Total Capital Cost ($million)	245	378	531	684
ICAP MW	200	200	200	200
$/kW	1,230	1,890	2,650	3,420

[12] *See* Table 22 of the Consultant Final Report (Updated Version).

Table 7: Capital Investment Costs for SCGT Peaking Plant Options with Dual Fuel ($2024)

	1x0 GE 7HA.03 (with SCR)	1x0 GE 7HA.02 (without SCR)	1x0 GE 7HA.02 (with SCR)
Zone C Central			
Total Capital Cost ($million)	656	568	-
ICAP MW	389	321	
$/kW	1,687	1,770	
Zone F Capital			
Total Capital Cost ($million)	667	578	-
ICAP MW	400.3	330.7	
$/kW	1,666	1,747	
Zone G Hudson Valley (Dutchess County)			
Total Capital Cost ($million)	663	572	-
ICAP MW	397.4	328.1	
$/kW	1,668	1,744	
Zone G Hudson Valley (Rockland County)			
Total Capital Cost ($million)	704	-	-
ICAP MW	397.4		
$/kW	1,771		
Zone J New York City			
Total Capital Cost ($million)	831	-	-
ICAP MW	404.1		
$/kW	2,056		
Zone K Long Island			
Total Capital Cost ($million)	1,269	-	641
ICAP MW	404		353
$/kW	3,142		1,816

Performance Characteristics and Fixed and Variable Operating & Maintenance Costs

For each peaking plant technology option evaluated, the Consultant developed performance characteristics (e.g., plant capacity, heat rates, and reserve capability) and fixed and variable O&M costs for each location.

Performance Characteristics and Variable O&M Costs

Due to technological differences, the evaluation of performance characteristics and variable O&M costs for the BESS options differed from the SCGT options but aim to capture the same types of costs. As previously noted, the variable O&M costs for the BESS include costs for capacity augmentation, as performance of batteries is known to degrade over time due to the unit's chemistry, discharge duration, and cycling behavior. Additionally, fixed O&M costs related to augmentation also exist for the BESS options and vary by duration.

Additional information on the performance characteristics and variable O&M costs are included in Sections II.G and II.F, as well as Appendix A of the Consultant's report. For ease of review, the characteristics and variable O&M costs are averaged across all locations for each peaking plant and are summarized in the tables below.

Table 8: Performance Characteristics and Variable Operating and Maintenance Costs for Battery Storage Peaking Plants Evaluated ($2024)

	BESS 2-hr	BESS 4-hr	BESS 6-hr	BESS 8-hr
Net Plant Output (Average ICAP, MW)	200	200	200	200
Discharge Duration, hr	2	4	6	8
Net Plant Energy Capacity, kWh	400,000	800,000	1,200,000	1,600,000
Spin Reserves	10min	10min	10min	10min
Capacity Augmentation as Variable O&M Costs (Average $/MWh)	6.99	6.64	6.41	6.53
Note: 'Capacity Augmentation as Variable O&M Costs' is the average of BESS Capacity Augmentation and includes Sales Tax for Variable O&M items assumed to be taxable for all identified locations reported in the Consultant's Report Table 31				

Table 9: Performance Characteristics and Variable Operating and Maintenance Costs for Fossil Fuel Peaking Plants Evaluated ($2024)

	1x0 GE 7HA.03 (with SCR)	1x0 GE 7HA.02 (without SCR)	1x0 GE 7HA.02 (with SCR)
Configuration	1x0	1x0	1x0
Net Plant Output (Average ICAP, MW)	398.7	326.6	353
Net Plant Output - Summer (Average MW)	409.8	336.4	356.5
Net Plant Output - Winter (Average MW)	428.9	361	388.5
Net Plant Heat Rate - Summer (Average BTU/kWh, HHV)	9,000	9,120	9,220
Net Plant Heat Rate - Winter (Average BTU/kWh, HHV)	8,847	8,973	9,050
Non-Spin Reserves	10 min	10 min	10 min
Post Combustion Controls	SCR	None	SCR
Natural Gas Variable O&M Costs (Average $/MWh)	1.47	0.9	1.5
ULSD Variable O&M Costs (Average $/MWh)	8.62	8.63	6.72
Fuel Required per Start (Average MMBtu/Start)	376	240	240
Variable Cost per Start (Average $/Start)	23,100	23,000	23,000

Fixed O&M Costs

The fixed O&M costs developed by the Consultant generally capture the fixed plant expenses, site leasing costs, and property taxes and insurance. The Consultant conducted a full evaluation of these costs, based on industry experience, review of various data sources, and propriety tools to ensure the reasonableness of its assumed costs. The Consultant estimated site leasing costs by escalating values from the 2021-2025 DCR by the cumulative change in the Gross Domestic Product (GDP) implicit price deflator from Q1 2019 to Q1 2024 for all locations except Load Zone J. In Load Zone J, property values have outpaced the GDP-based escalation,[13] so the Consultant used average sales prices from JLL report data to

[13] The Consultant compared the GDP-based escalation values to transaction data for all locations and determined the escalated values to be reasonable considering the range of market data for all locations outside of Load Zone J.

estimate site leasing costs in Load Zone J. The assumed land lease costs are intended to account for property taxes on the underlying property without consideration of the additions related to each peaking plant technology option. Additional information on the fixed O&M costs are included in Section II.F and Appendix A of the Consultant's report. NYISO staff concurs with the overall fixed O&M estimates, including the Consultant's adoption of updated estimates reflecting land lease payments during the full construction period assumed for each peaking plant technology option, shown in Table 10, and the inclusion of sales taxes on applicable BESS O&M expenses.

Table 10: Land Lease During Construction Costs for Peaking Plants Evaluated (2024 MM$)

Technology	Central	Capital	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	New York City	Long Island
1x0 GE 7HA.03	1.5	1.5	1.5	1.5	34.4	1.8
1x0 GE 7HA.02	1.5	1.5	-	1.5	-	1.8
BESS 2-hr	0.8	0.8	0.8	0.8	14.0	0.9
BESS 4-hr	1.3	1.3	1.3	1.3	22.6	1.3
BESS 6-hr	1.7	1.7	1.7	1.7	32.3	1.8
BESS 8-hr	2.2	2.2	2.2	2.2	43.0	2.4

Development of Levelized Carrying Charges

A new capacity resource requires an upfront capital investment for its development and construction that must be recovered. Therefore, the peaking plant's gross cost, or gross cost of new entry (Gross CONE), must consider financing costs in addition to the upfront capital costs described above. The financial parameters used in the DCR translate the upfront technology and development capital costs into an annualized value that represents the Gross CONE underlying each ICAP Demand Curve. Starting this DCR cycle, the NYISO will convert annualized gross CONE values and annual reference values (ARVs) into the monthly values used to set seasonal ICAP Demand Curves. These "levelized fixed charges" account for all payments made by a merchant investor to develop and finance construction of each peaking plant technology option and recover those payments over a reasonable term. This includes the recovery of capital costs, return on equity, debt service costs, applicable property and sales tax payments, and tax depreciation among other items.

The financial parameters that affect the levelized fixed charge are described in detail in Section III of the Consultant's report and are addressed below.

Financial Parameters

The Consultant recommended different financial parameters for SCGT peaking plant technology options and BESS peaking plant technology options for this DCR. They are as follows:

- BESS: 10.49% weighted average cost of capital (WACC) derived from:
        - 14.5% return on equity (ROE)
        - 7.20% cost of debt (COD)
        - 55/45 debt to equity ratio
    - 9.45% (NYCA, LI, G-J Locality) and 9.17% (NYC) after-tax WACC (ATWACC)
- SCGT: 9.99% weighted average cost of capital (WACC) derived from:
        - 14.00% return on equity (ROE)
        - 6.70% cost of debt (COD)
        - 55/45 debt to equity ratio
    - 9.02% (NYCA, LI, G-J Locality) and 8.76% (NYC) after-tax WACC (ATWACC)
- 20-year amortization period for the BESS options, and a 13-year amortization period for SCGT units

Weighted Average Cost of Capital

The Consultant's recommendation on the WACC used for the DCR is derived from analyzing metrics from publicly traded companies, independent assessments performed by the Consultant, professional judgement and past experience, conversations with developers and market participants, and considerations for current and future expected market conditions over the period covered by this reset. The recommended values for the ROE, COD and debt to equity ratio are all considered in tandem to develop a WACC that reflects the specific financial, regulatory, and policy risks attributed to a new peaking plant technology seeking to enter the NYISO markets during the study period for the current DCR under the capacity supply excess conditions specified by the tariff for use in determining the ICAP Demand Curves. Given that the BESS and SCGT peaking plant technology options each have a unique set of risks, the Consultant recommended a different WACC be developed for each category of peaking plant technology option (i.e., BESS and SCGT).

The Consultant noted multiple risks to consider for the BESS option when developing its WACC. The Consultant noted that uncertainties exist affecting the expected economic and physical lifetime of new battery units, including the potential for cell degradation, wear and tear on balance-of-system components, uncertain market dispatch outcomes, and potential variations in operational modes and uses in system operations. The Consultant partially captures this risk by including augmentation costs in its

O&M costs and an assumption of overbuild in its up-front capital costs. The Consultant further noted that battery storage faces market performance risks. Given that lithium-ion batteries are an early-stage technology, current battery storage plants may be less competitive than ones that are built later with more efficient technologies. This potential outcome could translate into lower net revenues over time. Moreover, battery storage is vulnerable to potential changes in CAFs. Future CAF values would depend largely on the timing, magnitude, and types of future resource additions. Although the financial risk of potential CAF changes for BESS as a peaking plant technology are mitigated during the upcoming four-year reset period through the incorporation of the actual CAFs applicable to BESS as part of the annual translation of the ICAP Demand Curves to UCAP terms, potential future reductions in CAFs for a BESS option could potentially result in an alternative technology being selected as the technology option to anchor the demand curves in a future reset. Such a potential outcome presents a risk to future revenues for a BESS option over the course of its assumed amortization period. Additional information related to the consideration of future changes in CAFs is provided in the “NYISO Recommendations” section below.

The SCGT options have their own unique financial risks. The SCGT options face regulatory constraints from the CLCPA that limit future operations for fossil-fired resources, as well as the potential for additional policies to be enacted that make fossil-fired technologies less competitive to alternatives during the period before the CLCPA requires 100% of electricity demand to be served by zero-emission resources.

The ROE values recommended by the Consultant are based on estimated ROEs for publicly traded independent power producers (IPPs), the ROEs used in neighboring markets that have similar capacity market constructs, and estimated ROEs for stand-alone project finance developments. Ultimately, the Consultant’s recommendation reflects the consideration of all of the above-described factors and the observed changes to the risk-free rate since the last reset. The Consultant recommended an ROE of 14.5% for the BESS options and 14.0% for the SCGT options. This recommendation was made to reflect the balance between IPP values and project specific considerations, including a difference in ROE for the SCGT relative to the BESS. NYISO staff concurs with the recommended ROE values for the BESS and SCGT peaking plant options.

The COD values recommended by the Consultant are derived from consideration of similar data and information utilized in determining the recommended ROE, such as publicly available information on recent debt offerings from public companies and rates on recent debt offerings for other public companies with similar credit ratings (typically BBB to B). The Consultant recommended a 7.20% COD for the BESS options reflecting risks consistent with B-rated debt issues, recent corporate debt costs, differences between COD to IPPs relative to generic debt indices and differences between corporate and project-specific risks. The Consultant recommended a 6.70% COD for the SCGT options for similar reasons but with the assumption of slightly lower technology risks and the yield of debt issues with ratings between BB- and B-ratings.[14] NYISO staff agrees with the Consultant's recommended COD values for the BESS and SCGT peaking plant options.

The Consultant's recommendation for a 55/45 debt to equity ratio is consistent with the prior DCR. This recommendation takes into account the relationship between capital structure, cost of debt, return on equity, and different project development approaches (e.g., balance sheet and project finance). It also implicitly considers various indirect financing costs, such as financial hedges. A corporate-level capital structure may not directly reflect the appropriate capital structure for a specific project; however, it provides relevant insights for assets in the industry and new project capital structures. Given that, the average corporate capital structure of the proxy group companies is aligned with the recommended debt-to-equity ratio. The Consultant's recommendation is also in line with recent studies for ISO-NE and PJM, which have adopted similar capital structure values.

Amortization Period

In the context of the DCR, the amortization period is the term (in years) over which a merchant investor expects to recover upfront capital costs and generate a reasonable return on its investment. This term reflects considerations for the associated financial risks of investing in a new peaking plant in New York, such as perceived risks to changes in market structures, technology, regulations, and underlying electricity demand. Due to these perceived risks, investors generally seek to recover their capital costs (and return on investment) over a term that is shorter than the asset's expected physical life. The Consultant proposed to use an amortization period of 20 years for the BESS technologies and 13 years for SCGT technologies, reflecting the different risks associated with each resource type.

The Consultant recommended a 20-year amortization period for the BESS options based on consideration of a range of factors. Unlike fossil plants, battery storage plants do not face the same regulatory constraints from the CLCPA that would limit future operations. Thus, it is appropriate to select a 20-year amortization period to reflect the expected operating lifetime of a utility-scale lithium-ion battery under current industry trends. The fixed and variable O&M costs developed for the BESS options also account for future augmentations that would maintain the plant's capability over the recommended 20-year amortization period. Additionally, the Consultant noted that 20-year warranties for battery performance are common. The Consultant also observed that since the 2021-2025 DCR there has been a

[14] *See* Consultant Final Report (Updated Version) at 65-66.

significant growth in BESS development and operation in the U.S.[15] This mitigates the performance concerns which drove the recommended 15-year amortization period for BESS technology options in the last DCR, and it makes a 20-year amortization more appropriate for this DCR.

The Consultant's recommended amortization period of 13 years for thermal units reflects consideration of the CLCPA requirement to serve electricity demand in New York with 100% zero-emission resources by January 1, 2040. This is consistent with the approach in the last DCR and is described in detail in Section III.A.1 of the Consultant's report. A fossil fuel-powered unit that enters the markets at any time between May 1, 2025, and April 30, 2029, (the period covered by the DCR) may not be able to continue to operate under New York State law as of January 1, 2040. This could impair the unit's ability to recover its upfront capital costs and generate a reasonable return on its investment. Table 11 shows the derivation of average amortization period of 13 years and is thus recommended as the appropriate assumption for fossil fuel peaking plant options in all locations

Table 11: Potential Economic Operating Life

Capability Year	Potential Operating Life of Fossil Unit	Average Operating Life of Fossil Unit Operating Over 4 Capability Years
2025-2026	14.7 Years	13.2 Years
2026-2027	13.7 Years	
2027-2028	12.7 Years	
2028-2029	11.7 Years	

Note: The potential commercial operating life was calculated using the number of years between May 1 of each Capability Year and January 1, 2040

Property Taxes

New York City Tax Abatement

Under RPTL Section 487, energy storage plants statewide are eligible to receive a 15-year tax abatement. For this study, it is assumed that all BESS plants in all locations will benefit from this 15-year property tax exemption. For any remaining years of the assumed amortization period that extend beyond this 15-year period (i.e., years 16-20 of the assumed amortization period for the BESS options in Load Zone J), the BESS options will be subject to property taxes at an assumed rate of 4.77%.

Title 2-F of the New York State Real Property Tax law (RPTL) provides property tax abatements to certain electric generating facilities located in New York City as set forth in RPTL § 489-BBBBBB(3)(b-1). Section 489 defines a "peaking unit" as "a generating unit that: (a) is determined by the New York

[15] *See* Consultant Final Report (Updated Version) at 61-62.

independent system operator or a federal or New York state energy regulatory commission to constitute a peaking unit as set forth in section 5.14.1.2 of the New York independent system operator's market administration and control area services, as such term existed as of April first, two thousand eleven … it may be comprised of a single turbine and generator or multiple turbines and generators located at the same site."[16] This tax abatement is applicable to SCGT peaking plant options for the New York City ICAP Demand Curve . Although this tax abatement is currently scheduled to expire for construction activities occurring after April 1, 2025, the New York State Legislature recently passed a bill (NYS Senate Bill No. S9822) that would extend the abatement to cover construction activities commencing before April 1, 2029. NYISO staff is continuing to monitor this bill for action by the New York State Governor. If enacted, this abatement will apply to the SCGT technologies in Load Zone J. If the extender bill is not enacted, the SCGT technologies in Load Zone J will be subject to property taxes at an assumed rate of 4.77%.

Locations Outside New York City

As described above, for the BESS options, RPTL Section 487 provides a 15-year abatement. NYISO staff agrees with the Consultant's conclusion that a 15-year property tax abatement would apply to BESS plants in all locations evaluated.

The Consultant estimated a 0.6% property tax rate for SCGT peaking plant technologies outside of New York City and any remaining years of the assumed BESS options beyond the 15-year abatement described above under the assumption that the peaking plant technology options will enter into a Payment in Lieu of Taxes (PILOT) agreement that is effective for: (a) the full amortization period assumed for this DCR in the case of the SCGT options outside Load Zone J; and (b) years 16 through 20 of the assumed amortization period for the BESS options outside Load Zone J. The assumed rate was developed by the Consultant based on a review of PILOT data available from the New York State Comptroller's office. Based on their review of ten natural gas plants and four battery storage projects located outside New York City and after adjustments for inflation to determine the effective PILOT rates as of the time the plants at issue became operational, the Consultant observed effective, adjusted PILOT rates for the natural gas plants ranging from 0.15% to 5.63% with a median rate of 0.67%, and a range of 0.03% to 1.92% with a median value of 0.21% for the battery storage projects. NYISO staff agrees that 0.6% is a reasonable assumption for the property tax rate applicable to SCGT options locations outside New York City for their entire assumed amortization period and for the portion of the assumed amortization period for BESS options located outside New York City that is not covered by the 15-year tax abatement provided by RPTL

[16] RPTL § 489-AAAAAA (17).

Section 487 (i.e., years 16 through 20 of the assumed amortization period for BESS options).

Mortgage Recording Tax

The Consultant assumed that each peaking plant technology option would avail itself of certain economic development benefits available from tax-exempt industrial development agencies/authorities and obtain exemptions from any otherwise applicable mortgage recording taxes. Such exemptions, however, do not apply for the mortgage recording tax component assessed pursuant to Section 253(2) of the New York State Tax Law within transportation districts. As a result, the Consultant assumed that each peaking plant technology option located within Load Zones G (Dutchess County), G (Rockland County), J and K would incur the applicable mortgage recording tax of $0.30 per $100 of mortgage debt related to the Metropolitan Commuter Transportation District. Additionally, the Consultant assumed that each peaking plant technology option located within Load Zones C and F would incur the applicable mortgage recording tax of $0.25 per $100 of mortgage debt associated with the Central New York Regional Transportation District and Capital District Transportation Authority, respectively. The NYISO concurs with the Consultant's assessment of mortgage recording taxes applicable to peaking plant technology options.

Net EAS Revenue

The reference point price for each ICAP Demand Curve is based on estimated Gross CONE less an estimate of expected net revenues the peaking plant could earn in NYISO's Energy and Ancillary Services markets. These revenues reflect the prices paid for supplying Energy and Ancillary Services, net of the variable costs of production. The DCR estimates net EAS revenues using expected supply excess conditions consistent with the requirements prescribed by the tariff ("LOE conditions").[17]

Net EAS revenues are estimated based on the modeled dispatch of each peaking plant technology option using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions). The approach in this DCR, consistent with the last reset, assumes that annual average net revenues earned over the prior three years provide a reasonable estimate of forward-looking expectations, particularly considering the annual updating mechanism, which ensures that the ICAP Demand Curves evolve over time by incorporating updated market outcomes.

The net EAS revenue models developed by the Consultant estimate the net EAS revenues of the peaking plant technologies for the historical 3-year period based on maximum possible revenues earned

[17] *See* Services Tariff Section 5.14.1.2.2. The Services Tariff refers to the supply conditions assumed for purposes of the DCR as the "prescribed level of excess."

by supplying energy and/or reserves in either the Day-Ahead Market (DAM) or Real-Time Market (RTM). Each year after the first year of the reset, as part of an annual updating of the ICAP Demand Curves, net EAS revenues are recalculated using the same models, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges, as applicable for the peaking plant technology.

Energy Storage Net EAS Model Logic

Energy storage resources participate in the NYISO markets and earn revenue in a way that is fundamentally different from thermal resources. First, the variable cost to produce electricity for a thermal unit is primarily determined by the cost of procuring fuel and the cost of emissions produced from combustion; the cost of fuel for a storage unit is based on the energy cost at the time of charging. Second, a thermal unit could theoretically operate continuously, subject to constraints for fuel availability and environmental regulations; a storage unit is theoretically not subject to these constraints but has a limited amount of energy that can be injected into the grid before it is depleted, and it must charge again. The storage units under study for this DCR have assumed duration limits of 2, 4, 6, or 8 hours, meaning they can inject electricity into the grid at full power (determined by the inverter) for the stated amount of time before the unit is depleted.

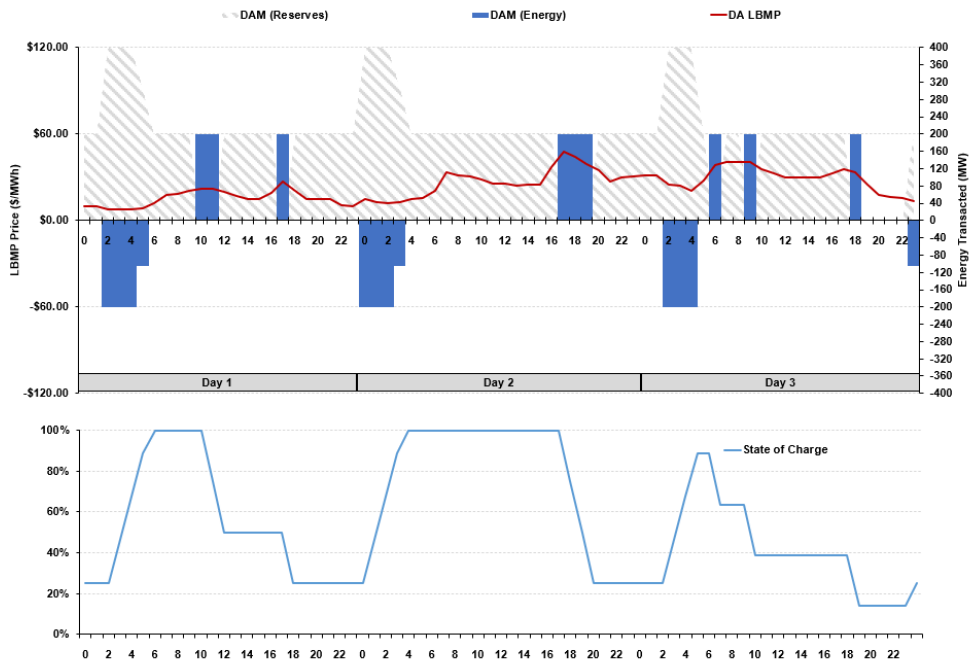
Due to the fundamental differences in how the different resource types operate and participate in the NYISO markets, the Consultant developed separate net EAS revenue models for the BESS and SCGT options evaluated in this study. The BESS model uses many of the same inputs as the SCGT (or thermal) model, such as historical energy and reserve prices, to maximize the net EAS revenue that a theoretical storage unit could earn in the various locations under study at the tariff prescribed LOE conditions. For this reset, the Consultant developed and recommends an updated BESS net EAS model that utilizes Real-Time Dispatch (RTD) pricing to evaluate deviations from a BESS option's day-ahead schedule on a real-time interval basis. The new model considers possible revenues that were not accounted for in the BESS model from the prior DCR that evaluated real-time dispatch on an hourly basis using time-weighted hourly real-time prices. The energy storage resource net EAS revenues model schedules daily DAM commitments using "hour-pairs," where charging and discharging intervals are assigned simultaneously. For example, over the course of a 24-hour day, the model will assign the unit to discharge energy (inject) during hours when energy prices are highest and charge the unit when energy prices are the lowest; assigning both a charge and discharge constitutes an hour-pair. Throughout each 24-hour period, the model will assign hour-pairs starting with the most profitable pair (assigning dispatch during the interval with the highest LBMP and charging during the hour with the lowest LBMP) and continue assigning hour-pairs until there are no more hour-pairs that are profitable or if the unit receives an infeasible schedule. The model builds on this logic by considering the size of the battery in MWh, the amount of energy left in the unit at the end of each cycle-day, as well as round trip efficiency losses and cell degradation over time.

Like thermal resources, storage resources can provide both energy and reserves. Energy dispatch assignments are based entirely on economics, as described above. Reserves are also assigned based on economics, but do not require hour-pairs to be assigned. The battery can receive reserve revenue if it has at least one hour of stored energy (or charge) and does not have an energy discharge assigned for that hour. Additionally, a storage unit that is charging can receive reserves on its charging schedule, where it can forgo charging to “provide” reserves. As a result, the unit can provide reserves for both the amount of stored energy available (assuming it has at least one hour of charge) as well as if it is actively charging.

The storage model logic is split into two steps: (1) daily DAM commitments and (2) daily RTM dispatch. The first step determines the daily DAM positions by assigning hour-pairs that maximize net revenue earned through providing energy and reserves for each “cycle-day,” defined as a 24-hour period between from HB 0 (12:00 AM) through HB 23 the following day (11:59 PM). The model first identifies every feasible day-ahead hour-pair given the state of charge at the beginning of each cycle-day, before ranking each hour-pair by profitability (net revenue). Since the model aims to maximize net revenue, hour-pairs that increase the unit’s profitability are assigned for commitment, while those that do not are dropped. Figure 1 below provides an example of hour-pairs assigned for a 4-hour BESS during step one over three cycle-days (November 30-December 2, 2022).[18]

[18] Figures 1 and 2 included herein are replications of Figures 11 and 12, respectively in the Consultant Final Report (Updated Version).

Figure 1: AGI Battery Model Step 1 Example: Load Zone C, November 30-December 2, 2022, 4-Hour BESS



In Figure 1 above, the left y-axis of the upper figure shows the LBMP ($/MWh), and the right y-axis of such figure shows the energy transaction amount (MW) for energy and reserves; the x-axis shows time elapsed over the three cycle-day period. DAM energy positions (charge and discharge) are shown in blue, with DAM reserve positions shown in gray. Three hour-pairs are assigned for the first cycle-day (i.e., from 11/30/2022 00:00 to 11/30/2022 23:59), three hour-pairs are assigned for the second cycle-day (i.e., from 12/1/2022 00:00 to 12/1/2022 23:59) and three-hour pairs are assigned for the third cycle-day (i.e., from 12/2/2022 00:00 to 12/2/2022 23:59). The additional charging shown at 11/30/2022 05:00, 12/1/2022 03:00 and 12/2/2022 23:00 show the additional charge required to account for round-trip efficiency losses.

DAM reserves can be provided if the unit has at least one hour of energy stored, and if the unit has a charging schedule. The model logic operates to achieve at least 200 MW of energy charge at the end of each cycle-day to ensure that the BESS is capable of providing reserves overnight at its nameplate capacity. Once the unit has charged for at least one hour, it can continue selling reserves based on the energy stored as well as the charging position, as shown by the higher blue bars, since the unit can forgo charging in order to provide reserves, and also inject to provide reserves, using the energy stored.

The second step evaluates additional RTM positions that capture arbitrage opportunities presented by RTM LBMPs. In the previous reset, the BESS net EAS model used hourly DAM LBMPs when looking forward in time to decide whether to assign an RTM energy position in the form of an hour-pair. In this reset, however, the Consultant recommends using RTD interval pricing (which are nominally 5-minute prices) to select RTM positions. The reasoning for this included the fact that batteries can charge and discharge rapidly. Given the operating capability of batteries, 5-minute pricing intervals offer improved accuracy in assessing the potential for energy arbitrage revenues compared to hourly pricing intervals.

To evaluate potentially profitable RTM positions using RTD pricing, the Consultant developed charge and discharge bidding strategies for each RTD interval of a cycle day given hourly DAM LBMPs. The assumed bidding strategies are reasonable and realistic because the NYISO publishes DAM schedules by 11am of the day prior to the scheduled dispatch. The bidding strategies do not imply "perfect foresight" as they use DAM LBMPs to estimate future real-time prices, and actual RTD LBMPs to calculate realized profits. For more information on how charge and discharge bids are calculated for each RTD interval, see Section IV.B.2.b of the Consultant's report.

The RTM dispatch uses a hurdle rate to account for uncertainty in future RTM prices, which reflects an opportunity cost of having a limited amount of stored energy and a general risk premium associated with discharging now in advance of unknown future RTM LBMPs. The hurdle rate values were estimated iteratively, by running the model with various potential hurdle rate values (at $5/MWh increments) to find the hurdle rate that maximized RTM net revenues. In this reset, the Consultant developed seasonal hurdle rates applicable for the Winter (January and February), the Summer (June, July, August) and the Shoulder months (all other months) respectively. The seasonal hurdle rates developed by the Consultant remain fixed for the reset period. Seasonal hurdle rates for the BESS peaking plant technology options for the 2025-2029 DCR can be found in Table 12 below.

Table 12: BESS Seasonal Hurdle Rates for the 2025-2029 DCR ($/MWh)

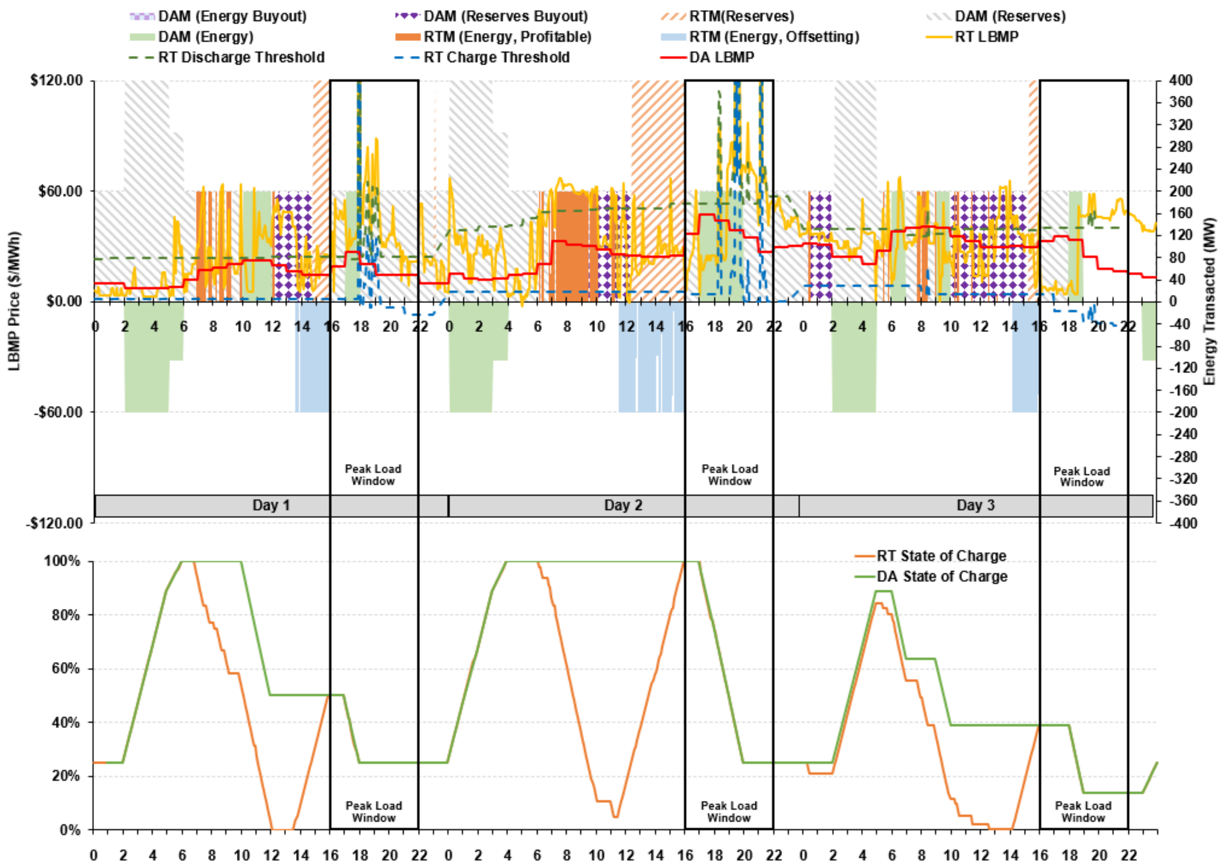
Technology	Season	Central	Capital	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	New York City	Long Island
2-Hour BESS	Summer	75	80	140	140	115	140
	Winter	60	190	190	190	195	85
	Shoulder	15	35	235	235	220	45
4-Hour BESS	Summer	40	65	140	140	130	110
	Winter	20	95	105	105	125	30
	Shoulder	15	20	235	235	210	30
6-Hour BESS	Summer	55	50	90	90	70	105
	Winter	15	35	30	30	110	20
	Shoulder	10	15	235	235	210	25
8-Hour BESS	Summer	20	250	30	30	35	110
	Winter	55	35	35	30	105	20
	Shoulder	10	20	235	235	210	25

In addition to developing seasonal hurdle rates, the Consultant developed other improvements for the RTD interval pricing model. The updated model buys out of DAM reserve positions whenever the BESS technology has a state of charge in real-time less than the reciprocal of its rated battery duration. This enhancement was made to account for the requirement that batteries must have at least one hour of stored energy to earn reserve revenues. The model also includes sub-5-minute intervals to reflect the activation of RTD Correction Action Modes (CAMs).

Using the RTM logic described above, Figure 2 below provides an example demonstrating the operation of the RTM logic of the RTD interval pricing model. For every RTD interval, the model evaluates whether the actual RTD LBMP for that interval is high enough to trigger real-time discharging or low enough to trigger real-time charging based on the assumed hurdle rate. These real-time charging and discharging activities affect the battery’s state of charge (SOC) which can impact the battery's ability to fulfill its pre-established DAM energy and reserve positions. The model adjusts by buying out of DAM energy and reserve positions that have become physically infeasible due to real-time deviations from the DAM schedule.

In response to concerns raised by certain stakeholders regarding the potential impacts of real-time deviations on the going forward derating factor for the BESS options, the Consultant has revised the model to restrict the BESS from taking real-time actions that would prevent the BESS from fulfilling its day-ahead schedule during the peak Load Window (PLW) due to insufficient state of charge; therefore, avoiding the potential for adverse impacts to the derating factor in future Capability Years. For purposes of the model, the PLW will be fixed for the reset period based on the PLW effective for the 2024-2025 Capability Year (i.e., hour beginning (HB) 1:00 p.m. through HB 8:00 p.m. for Summer Capability Period months and HB 4:00 p.m. through HB 9:00 p.m. for Winter Capability Period months). NYISO staff concurs with this additional refinement of the model.

Figure 2: AGI Battery Model Step 2 Example: Load Zone C, November 30 -December 2, 2022, 4 Hour BESS



For additional information on how the energy storage resource net EAS revenues model evaluates economics for each interval and assigns dispatch, please see Section IV.B.2.b of the Consultant's report.

The estimated annual revenue for each BESS option determined by the model is increased by an adder to account for revenues related to providing voltage support service (VSS). For the 2025-2029 DCR, the Consultant has recommended that the VSS adder be defined as a methodology/formula based on the compensation structure described in Rate Schedule 2 of the Services Tariff. This compensation structure provides an annual payment value equal to the applicable VSS compensation rate, multiplied by the sum of a VSS supplier's lagging MVAr capability and the absolute value of such supplier's leading MVAr capability. For the BESS options, the Consultant determined that the lagging MVAr capability is 124 MVArs and the leading MVAr capability is –124 MVArs. For the 2025-2026 Capability Year, the VSS adder was determined to be $4.10/kW-year based on the VSS compensation rate of $3,307.31 for 2024 (i.e., ((124 MVArs + |–124 MVArs|) * $3,307.31/MVAr)/(200 MW * 1,000 kW per MW). As part of the annual updates for this reset period, the applicable adder value will be updated to reflect the VSS compensation rate in effect at the time of each annual update. NYISO staff agrees with the Consultant's recommended methodology for determining the appropriate VSS adder value for the BESS options for this reset period.

NYISO staff concurs with the commitment and dispatch logic of the RTD interval battery net EAS revenues model developed by the Consultant (including the additional refinements to address considerations related to DAM schedules during the PLW), as well as the Consultant's recommendation to use RTD interval prices to estimate the net EAS revenues for the BESS options evaluated for this DCR. The Consultant developed the model in "R," an open-source software programming language that is available to all stakeholders. The model is posted publicly on the NYISO's website.

Thermal Net EAS Model Logic

To evaluate the SCGT technologies for this DCR, the Consultant utilized the same thermal net EAS model that was developed as part of the prior DCR. This simulated dispatch model uses a rolling 3-year historical set of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and non-fuel variable costs and operational characteristics of the peaking plant technology.

The logic used in the model follows what one would expect a competitive supplier with perfect foresight to offer (i.e., optimal dispatch, with offers set at the opportunity cost of producing energy or reserves). The model accounts for the option of supplying in either the DAM or RTM, as well as the option to supply either energy or reserves on an hourly basis. Unit parameters (capability and heat rate) are considered separately for the Summer Capability Period and Winter Capability Period. Annual revenues are adjusted downward based on the plant's equivalent demand forced outage rate (EFORd).

The estimated annual revenue value determined by the model for each SCGT option is then increased by an adder ($/kW-year) to account for an estimate of annual VSS revenues. For the 2025-2029 DCR, the Consultant has recommended that the VSS adder be defined as a methodology/formula based on the compensation structure described in Rate Schedule 2 of the Services Tariff. This compensation structure provides an annual payment value equal to the applicable VSS compensation rate, multiplied by the sum of a VSS supplier's lagging MVAr capability and the absolute value of such supplier's leading MVAr capability. For the 7HA.03 units, the Consultant determined (based on a nominal capacity rating of 400 MW) that the lagging MVAr capability is 300 MVArs and the leading MVAr capability is –180 MVArs. For the 2025-2026 Capability Year, the VSS adder for the 7HA.03 option was determined to be $3.97/kW-year based on the VSS compensation rate of $3,307.31 for 2024 (i.e., ((300 MVArs + |–180 MVArs|) * 3,307.31/MVAr)/(400 MW * 1,000 kW per MW). For 7HA.02 units, the Consultant determined (based on a nominal capacity rating of 330 MW) that the lagging MVAr capability is 225 MVArs and the leading MVAr capability is –125 MVArs. For the 2025-2026 Capability Year, the VSS adder for the 7HA.02 option was determined to be

$3.51/kW-year based on the VSS compensation rate of $3,307.31 for 2024 (i.e., ((225 MVArs + |−125 MVArs|) * 3,307.31/MVAr)/(330 MW * 1,000 kW per MW). As part of the annual updates for this reset period, the applicable adder value will be updated to reflect the VSS compensation rate in effect at the time of each annual update. NYISO staff agrees with the Consultant's recommended methodology for determining the appropriate VSS adder value for the SCGT options for this reset period.

NYISO staff concurs with the commitment and dispatch logic of the SCGT net EAS revenues model developed by the Consultant and addresses certain, specific aspects of the model in the following sections. NYISO staff also agrees with the Consultant's recommendation to use hourly real-time prices to evaluate the net EAS revenues of the SCGT options considered for this DCR.

The Consultant developed the SCGT net EAS revenues model in "R," an open-source software programming language that is available to all stakeholders. The model is posted publicly on the NYISO's website.

Gas Hub Selection

The net EAS revenues that are estimated for the SCGT peaking plant options use selected gas hubs for each location evaluated for purposes of estimating natural gas costs incurred to operate. The gas hub recommendations were derived based on the consideration of several factors. NYISO staff agrees with the Consultant's recommended gas hub selection for each of the locations evaluated in the study. The recommended gas hubs are shown below.

Table 13: NYISO Staff Recommended Gas Hubs by Location

Location	Gas Hub
Central	Dawn Ontario (December - March) & Tennessee Zone 4 200L (April - November)
Capital	Iroquois Zone 2
Hudson Valley (Dutchess)	Iroquois Zone 2
Hudson Valley (Rockland)	Tennessee Zone 6
NYC	Transco Zone 6 NY (February - November) & Iroquios Zone 2 (December - January)
Long Island	Iroquois Zone 2

The following selection criteria was used in developing the above recommendations:

- Market Dynamics: The gas hub selected should reflect consistency with LBMPs within the respective Load Zone, maintaining that consistency over a longer period.

- Liquidity: The gas hub selected should have enough historical data readily available to assess historical trade volumes.

- Geography: The gas hub selected should be geographically located in an area that is accessible to the potential SCGT peaking plant for a particular location.

- Precedent/Continuity: The gas hubs utilized in other studies and analysis should be taken into consideration to the extent relevant and informative to the objectives of the DCR. The following were considered by the Consultant in developing the gas hub recommendations for this DCR: the gas hubs used for the 2021-2025 DCR, the MMU's 2022 State of the Market report (2022 SOM), and the 2021-2040 System & Resource Outlook published by NYISO (2021-2040 Outlook).

The Consultant collected and analyzed historical data regarding market dynamics and liquidity and included charts and tables in the Consultant's report to compare the data for the different potential gas hubs in each Load Zone.[19]

Considering market dynamics, trading liquidity, and geography, the Consultant recommends using TGP Zone 4 (200L) as the natural gas index for Load Zone C during the April to November period. For the winter months of December to March, the Consultant recommends using Dawn Ontario as the gas hub for Load Zone C.

For Load Zone G (Rockland County) Tennessee Zone 6 is the recommended gas hub. Other gas hubs, like the Millenium pipeline, with geographic proximity did not provide sufficient correlation with market dynamics or exhibited other concerns such as liquidity. By contrast, Tennessee Zone 6 is a liquid trading hub which reasonably reflects the fuel cost of the SCGT peaking plant technology options evaluated in this reset. While the Tennessee Zone 6 gas hub delivery point is outside Rockland County, the Tennessee Gas Pipeline (TGP) system delivers to points along the southern side of Rockland County west of the Hudson River.

Considering market dynamics and geography, the Consultant recommended using Iroquois Zone 2 as the natural gas index for Load Zone F, Load Zone G (Dutchess County), and Load Zone K. Specifically for Load Zone K, Iroquois Zone 2 serves as the most accurate proxy for gas prices during constrained conditions.

In Load Zone J, the Consultant recommends using Transco Zone 6 NY during February – November

[19] *See* Consultant Final Report (Updated Version) at 96-104.

and Iroquois Zone 2 during December – January. During February – November, Transco Zone 6 NY offers pricing that aligns with the expected long-term equilibrium between gas and electricity markets for pipelines with immediate proximity to Load Zone J. In December – January, pricing available for interruptible natural gas is better represented by the pricing offered by Iroquois Zone 2 due to retail local distribution company (LDC) gas demand taking priority of Transco Zone 6 NY capacity.

Based on the foregoing, NYISO staff agrees with the Consultant's recommended gas hubs for all locations.

Fuel Transportation Adder

The SCGT net EAS revenues model also incorporates an adder for each Load Zone to estimate the cost of transporting natural gas and/or oil to the hypothetical SCGT peaking plant in each location. In keeping with the concept that the costs of the hypothetical peaking plant are generalized to apply to the entire Load Zone, as opposed to a precise location within a Load Zone, the transportation adders are meant to estimate the generalized cost of procuring natural gas or oil within a Load Zone. The transportation adder is not meant to directly calculate the cost of getting gas from a specific point on the pipeline to a specific location within a given Load Zone.

The transportation adders used in the SCGT net EAS revenues model range from $0.20 to $0.27 per MMBtu for natural gas and $1.50 to $2.00 per MMBtu for oil, depending on location.[20] Natural gas and oil procured to meet both DAM and RTM (if the unit did not receive a DAM commitment) schedules will include this adder when calculating the cost to produce electricity for each interval; fuel procured or sold in real-time also incurs an additional intraday premium or discount, as discussed below.

Fuel Premium/Discount

In addition to transportation costs and taxes for each fuel, a real-time intraday price premium relative to day-ahead for purchases, and discount for sales, is applied to natural gas in the SCGT net EAS revenues model. A generator purchasing natural gas in real-time is likely to receive a more expensive price relative to the day-ahead price for natural gas. Conversely, a generator selling back natural gas in real-time will likely receive a discounted natural gas price, as compared to the cost initially incurred to purchase such gas day-ahead. These premiums and discounts account for opportunity costs that result from purchasing or selling fuel in real-time. These opportunity costs are observed in the natural gas markets and include factors such as balancing charges, illiquidity in the market, and imperfect information. The premiums and

[20] *See* Table 47 of the Consultant Final Report (Updated Version).

discounts used in the model vary by Load Zone, ranging from 10%-30%.[21]

Additionally, opportunity costs are reflected in the model for the SCGT options to take a reserve position in the markets. These costs can vary by resource type, given that units with dual fuel capability have flexibility to operate on alternative fuel types which can mitigate this risk as compared to gas only units. The opportunity cost for dual fuel units, which represent the recommended SCGT design in all locations for this reset, is assumed to be $2.00/MWh. The opportunity cost for these units is based on the MMU's analysis of historical bid data from dual fuel units in Load Zones J and K developed for the last reset.[22]

The natural gas price premiums and discounts values used in the model were developed by the MMU and used in the net revenue analysis for gas-fired and dual-fuel units included in its 2023 State of the Market Report.[23] In practice, the natural gas premium or discount is considered in the SCGT net EAS revenues model when determining whether it is more economic for a unit to meet its DAM schedule or receive a different schedule in RTM.[24]

Table 14: Fuel Adders

Region	Gas Transportation ($/MMBtu)	Intraday Gas Premium/Discount	Tax (Gas/ULSD)	Oil Transportation ($/MMBtu)
NYCA	$0.27	10%	-	$2.00
G-J	$0.27	10%	-	$1.50
NYC	$0.20	20%	6.9% (Gas); 4.5% (ULSD)	$1.50
LI	$0.25	30%	1.0% (Gas)	$1.50

Consideration of Dual-fuel Capability in the Net EAS Model

For units with dual-fuel capability, the SCGT net EAS revenues model considers the economics associated with operating with either natural gas or ULSD. The model compares the fuel prices associated

[21] *See* Table 47 of the Consultant Final Report (Updated Version).

[22] Patton, David and Pallas LeeVanSchaick to Analysis Group and Burns & McDonnell, "MMU Comments on Independent Consultant Initial Draft ICAP Demand Curve Reset Report and the forthcoming draft of NYISO Staff DCR Recommendations," July 31, 2020, pp. 7-9.

[23] *See* Potomac Economics, *2023 State of the Market Report for the New York ISO Markets* (May 2024) at A-29, available at: https://www.nyiso.com/documents/20142/2223763/2023-State-of-the-Market-Report.pdf.

[24] *See* Consultant Final Report (Updated Version) at 105.

with natural gas or ULSD and selects the more economic fuel type for that peaking plant for a given run.[25] It is assumed that the peaking plant operates on this fuel type for a full runtime block, as units are not allowed to switch fuel types within a given run. Additional information on the treatment of dual-fuel capable units in the net EAS revenues model is included in Section IV.B.2.a of the Consultant's report.

Level of Excess Adjustment Factors

Services Tariff Section 5.14.1.2.2 requires that "the cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of (a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues (for purposes of this Section 5.14.1.2.2 hereinafter referred to as the "prescribed level of excess")."

The historical prices used for estimating net EAS revenues reflect "as found" conditions and adjustments are needed to account for the tariff-prescribed level of excess conditions assumed for the DCR. This adjustment is accomplished using "scaling factors" that are referred to as level of excess adjustment factors (LOE-AFs). LOE-AFs are determined as part of the DCR and remain fixed for the four-year reset period.

Consistent with the last reset, GE Energy Consulting (GE) was contracted to perform a series of Multi-Area Production System (MAPS) runs to simulate wholesale energy prices under various levels of excess to assist in developing the LOE-AFs. For the purposes of the DCR, GE performed two sets of MAPS runs: one run was modeled on the "as-found" system and one run modeled the system at the prescribed level of excess. Both cases were modeled using the base case from the 2021-2040 System and Resource Outlook for model years 2021-2022 and the 2023-2042 System and Resource Outlook for model years 2023-2027.

As described in Section IV.B.2.d of the Consultant's report, LOE-AFs were calculated by averaging Day-Ahead LBMPs for each month by Load Zone and period. In this reset, the DAM LBMPs were also weighted by the relative frequency that each month and year combination is utilized as an input in net EAS revenue estimates over the entire reset period.[26] NYISO staff concurs with the Consultant's opinion that weighing DAM LBMPs under this methodology better aligns LOE-AFs and the historical prices they are applied to. Table 15 and Table 16 provide the resulting LOE-AFs for both the SCGT and BESS peaking plant options

[25] For dual fuel units, the otherwise applicable opportunity cost for providing reserves day-ahead is eliminated for hours in which ULSD prices (plus applicable transportation charges) are lower than natural gas prices (plus applicable charges).

[26] *See* Table 48 of the Consultant Final Report (Updated Version).

used in the model.

Table 15: BESS Peaking Plant Level of Excess Adjustment Factors

Load Zone	Peak Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Central (Zone C)	High On-Peak	0.933	0.947	-	-	-	0.972	0.939	0.954	-	-	-	0.905
	Off-Peak	0.976	0.976	0.982	0.996	1.000	0.995	0.993	1.000	0.983	0.983	0.972	0.972
	On-Peak	0.965	0.963	0.972	0.996	1.001	0.984	0.976	0.990	0.966	0.976	0.952	0.942
Capital (Zone F)	High On-Peak	1.040	1.029	-	-	-	1.006	0.952	0.978	-	-	-	0.998
	Off-Peak	1.031	1.020	1.019	1.011	1.027	1.010	1.008	1.014	1.005	1.003	1.019	1.035
	On-Peak	1.043	1.038	1.023	1.016	1.041	1.007	1.004	1.013	1.002	1.014	1.005	1.022
Hudson Valley (Zone G)	High On-Peak	1.147	1.099	-	-	-	1.082	1.278	1.126	-	-	-	1.150
	Off-Peak	1.042	1.026	1.022	1.023	1.034	1.019	1.038	1.032	1.020	1.016	1.026	1.056
	On-Peak	1.092	1.066	1.045	1.036	1.064	1.033	1.076	1.063	1.037	1.033	1.055	1.095
NYC (Zone J)	High On-Peak	1.061	1.049	-	-	-	1.046	1.180	1.050	-	-	-	1.058
	Off-Peak	1.030	1.025	1.020	1.022	1.031	1.020	1.030	1.028	1.015	1.012	1.019	1.042
	On-Peak	1.055	1.051	1.025	1.032	1.051	1.038	1.045	1.039	1.030	1.031	1.022	1.058
Long Island (Zone K)	High On-Peak	1.021	1.055	-	-	-	1.025	1.175	1.032	-	-	-	1.025
	Off-Peak	1.018	1.044	1.026	1.007	1.017	1.017	1.018	1.013	1.014	1.015	1.015	1.027
	On-Peak	1.015	1.056	1.022	1.006	1.031	1.030	1.032	1.019	1.022	1.025	1.015	1.041

Table 16: SCGT Peaking Plant Level of Excess Adjustment Factors

Load Zone	Peak Period	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Central (Zone C)	High On-Peak	0.991	0.993	-	-	-	1.016	0.988	1.008	-	-	-	0.971
	Off-Peak	1.004	0.999	1.010	1.005	1.029	1.017	1.014	1.022	0.996	0.997	0.993	1.004
	On-Peak	1.003	0.999	1.007	1.013	1.050	1.022	1.012	1.025	0.993	1.008	0.983	0.991
Capital (Zone F)	High On-Peak	1.043	1.050	-	-	-	1.024	0.994	1.017	-	-	-	1.011
	Off-Peak	1.029	1.021	1.017	1.013	1.030	1.019	1.018	1.025	1.009	1.008	1.016	1.034
	On-Peak	1.045	1.045	1.032	1.019	1.056	1.022	1.022	1.032	1.007	1.026	1.009	1.020
Hudson Valley (Zone G)	High On-Peak	1.130	1.109	-	-	-	1.085	1.220	1.120	-	-	-	1.111
	Off-Peak	1.041	1.026	1.023	1.022	1.039	1.027	1.037	1.037	1.020	1.020	1.028	1.054
	On-Peak	1.080	1.071	1.050	1.034	1.086	1.049	1.075	1.074	1.040	1.046	1.055	1.083
NYC (Zone J)	High On-Peak	1.056	1.049	-	-	-	1.039	1.132	1.048	-	-	-	1.046
	Off-Peak	1.028	1.017	1.019	1.021	1.033	1.021	1.025	1.029	1.013	1.015	1.020	1.043
	On-Peak	1.045	1.036	1.029	1.029	1.055	1.031	1.036	1.038	1.025	1.039	1.023	1.055
Long Island (Zone K)	High On-Peak	0.988	0.988	-	-	-	1.012	1.061	0.998	-	-	-	0.986
	Off-Peak	0.999	0.985	0.975	1.004	1.020	1.012	1.003	1.001	1.021	1.031	0.993	1.000
	On-Peak	0.988	0.984	0.971	1.001	1.033	1.013	1.010	1.001	1.037	1.056	0.982	0.997

Development of ICAP Demand Curves

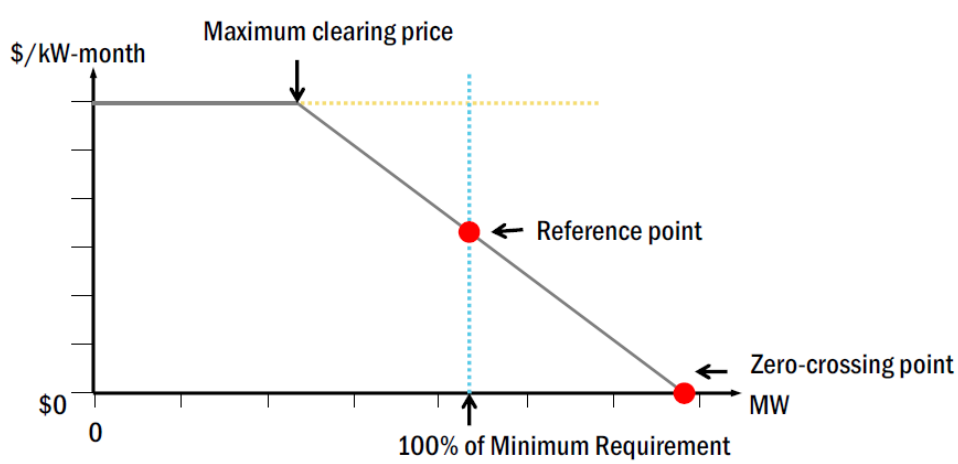
The DCR results in the development of sloped ICAP Demand Curves which are intended to provide price signals for investments in capacity, reduce unnecessary price volatility, and value additional capacity beyond NYCA and Locational Minimum Installed Capacity Requirements. A number of factors are considered in setting the ICAP Demand Curves.

The annual levelized embedded cost of each peaking plant technology option is used in determining the ICAP Demand Curves. An array of inputs is considered in determining this cost, with the inputs made up of initial capital costs, and fixed costs (i.e., costs that do not vary with production from the unit). These include construction and installation costs, fixed O&M costs, and miscellaneous other adjustments, including the cost of back-end emissions control technology and infrastructure related to dual-fuel capability, if applicable to the peaking plant technology option at issue.

Projected annual net EAS revenues of each peaking plant technology option are another key input to the determination of the ICAP Demand Curves. Once the cost of a peaking plant and the estimated net EAS revenue earnings are established, subtracting the net EAS revenues from the cost of the peaking plant yields the annual reference value (ARV), commonly referred to as the "net cost of new entry (net CONE)."

The net CONE value, in $/kW-month, accounting for the tariff-prescribed level of excess conditions, seasonal reliability risks, and seasonal differences in capacity availability, establishes the reference point price for each ICAP Demand Curve. A maximum clearing price of 1.5 times the monthly cost to develop the applicable peaking plant is set as the maximum capacity market clearing price for each ICAP Demand Curve.[27] Finally, a zero-crossing point for each ICAP Demand Curve is set, based on a predetermined amount above the applicable minimum ICAP requirements. The zero-crossing point represents the point at which the value of additional capacity declines to zero.

Figure 3: Illustration of Demand Curve Slope



[27] When establishing the maximum clearing price, per the Services Tariff, the monthly cost to develop the applicable peaking plant is to be determined in a manner consistent with the determination of the reference point for each ICAP Demand Curve.

Inputs for the cost of each peaking plant technology option and the net EAS revenue offset are used to establish ICAP Demand Curves for the NYCA, G-J Locality, New York City (NYC), and Long Island (LI). To capture seasonal reliability risks, starting with the 2025-2026 Capability Year, the NYISO will develop seasonal ICAP Demand Curves by translating the annualized gross CONE values and ARVs to monthly values. Summer reference point prices (SRP) and winter reference point prices (WRP) for each respective curve will be a function of seasonal capacity availability ratios, relative seasonal reliability risks (SLOLE and WLOLE), and seasonal level of excess requirements. For additional information on how the SRP and WRP are calculated, refer to equations (7) and (8) of the Consultant's report.[28] For each Capability Year, there is thus a separate net CONE calculation for each capacity region, and a set of two seasonal ICAP Demand Curves for each capacity region.

The DCR occurs every four years, with an annual update occurring each year in years two through four of the four-year period encompassed by each reset. The annual updates adjust the estimated gross CONE, net EAS revenues, seasonal capacity availability (SWR and WSR), and the relative seasonal reliability risks (SLOLE and WLOLE). These updated parameters are then utilized to establish updated seasonal ICAP Demand Curves for each of the intervening years between resets.

The monthly spot market auctions are the only ICAP auctions that use the ICAP Demand Curves, wherein the demand curves replace bids to purchase capacity. This is because this auction is the last auction before the applicable month when the capacity purchased and sold will be in effect, and thus any remaining Load Service Entity (LSE) capacity obligations that have not already been purchased in prior auctions must be fulfilled in this auction. For the purposes of conducting the ICAP Spot Market Auction, the requirements used in the ICAP Demand Curve are converted to UCAP values. All offers to sell capacity that are at or below the demand curve are awarded in the spot auction, and these MW are allocated to Market Participants based upon deficiencies and LSE capacity requirements, with any excess MW purchased above requirements allocated to LSEs based on load-ratio share.

Capacity Accreditation Factors (CAFs)

In May 2022, FERC approved the market design for CAFs to replace Duration Adjustment Factors (DAFs). Effective May 2024, CAFs are used to calculate the UCAP that an ICAP Supplier is qualified to supply to the NYCA. CAFs were developed to capture the marginal reliability contribution of the ICAP Suppliers within each Capacity Accreditation Resource Class (CARC) toward meeting NYSRC resource adequacy requirements. Specifically, CAFs represent the incremental amount of load that can be supplied

[28] *See* Consultant Final Report (Updated Version) at 118.

by an individual resource (expressed as a percentage of the resource's ICAP) while maintaining the same measure of resource adequacy on the system.[29] CARCs are a defined set of Resources and/or Aggregations with similar technologies, operating characteristics, and marginal reliability contributions. The NYISO annually reviews and establishes the CARCs and applicable CAFs for the upcoming Capability Year. Additionally, the NYISO annually assigns each ICAP Supplier to a CARC, and each ICAP Supplier receives the applicable CAF for its assigned CARC and capacity region. CAFs impact certain of the inputs that go into selection of the appropriate peaking plant technology option for each ICAP Demand Curve. The BESS peaking plant technology options are more vulnerable than the SCGT options to the uncertainty of changing CAFs over time which would affect future revenue streams, and this, in part, informed the Consultant's recommendation to establish financial parameters for the BESS options that differ from the SCGT options. For the SCGT peaking plant technology options, the decision of having dual fuel capability in all locations was partly based on changes in market structures related to capacity accreditation. As described in Section II of the Consultant's report, potential limitations in fuel availability were a part of the qualitative review and resulting recommendation for the SCGT units to be dual fuel.

The Consultant considered the relevant UCAP reference point prices for each technology option to reflect the impact of CAFs and derating factors in selecting the appropriate peaking plant technology option for each ICAP Demand Curve. Selecting the peaking plant technology for each capacity region that would result in curves representing the lowest cost on a UCAP basis appropriately reflects the marginal reliability contribution of these technology options. NYISO staff concurs with this approach to choose the appropriate peaking plant technology for this reset.

Seasonal Capacity Availability Ratios

The NYISO operates a capacity market with two distinct six-month Capability Periods. In calculating the reference point price for each ICAP Demand Curve, the Services Tariff requires that seasonal differences in capacity availability be accounted for. This seasonal adjustment is intended to reflect the fact that differences in capacity availability between the Summer Capability Period and Winter Capability Period contribute to differences in capacity prices throughout the year. To provide for revenue adequacy for the applicable peaking plant when it is needed to assist in maintaining sufficient capacity supply to meet the applicable minimum Installed Capacity requirement, these seasonal differences must be accounted for as part of translating the annual net CONE value for each ICAP Demand Curve to a monthly value for use in the NYISO's ICAP Spot Market Auctions (i.e., the reference point price for each ICAP Demand Curve). The expected seasonal capacity availability ratios (winter-to-summer ratio [WSR] and

[29] The NYSRC's loss of load expectation reliability standard is 0.1 days/year.

summer-to-winter ratio [SWR]) are used to account for these seasonal differences in capacity availability.

Beginning with the ICAP Demand Curves applicable for the 2025-2026 Capability Year: (i) the winter-to-summer ratio shall be used in calculating the reference point for each ICAP Demand Curve applicable for the Winter Capability Period; and (ii) the ratio of the amount of capacity available in the ICAP Spot Market Auctions in the Summer Capability Period to the amount of capacity available in the ICAP Spot Market Auctions in the Winter Capability Period (the "summer-to-winter ratio") shall be used in calculating the reference point for each ICAP Demand Curve applicable for the Summer Capability Period; provided, however, that if a WSR or SWR is a value less than one, the value shall effectively be deemed to be zero for purposes of determining the quantity of additional capacity available in such seasonal when calculating the applicable reference point.

This methodology relies on data published by the NYISO regarding capacity available to be offered in the ICAP Spot Market Auction for each month during the same 36-month historical data period used by the net EAS revenues models. The NYISO will adjust the historical data to account for certain capacity market entry and exit actions by resources, as further described in Section 5.14.1.2.2.3 of the Services Tariff.

The WSR for each capacity region is calculated as the average of the winter-to-summer ratio calculated for each 12-month period (i.e., September through the following August) encompassed by the historical data set. The SWR can be represented as the reciprocal of the WSR. For each 12-month period, the applicable winter-to-summer ratio is calculated as: (i) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six winter months included in the 12-month period (i.e., November through the following April); divided by (ii) the average total capacity available to be offered in the ICAP Spot Market Auctions for the six summer months included in such 12-month period (i.e., September and October and May through August of the following year).

The seasonal capacity availability values (WSR and SWR) used in determining the ICAP Demand Curves for the first year of this DCR (i.e., the 2025-2026 Capability Year) are provided in the table below.

Table 17: Winter-to-Summer Ratio Values for the 2025-2026 Capability Year ICAP Demand Curves

Capacity Region	WSR	SWR
NYCA	1.033	0.968
G-J	1.050	0.952
NYC	1.057	0.946
LI	1.083	0.923

Level of Excess Value for Reference Point Price Calculations

The level of excess (LOE) for each peaking plant technology option is defined as the ratio of the applicable minimum Installed Capacity requirement plus the average degraded net peaking plant capacity to the applicable minimum Installed Capacity requirement. The LOE is expressed in percentage terms and defined by the following equation, where all capacities are expressed in MW.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)}$$

The LOE varies by capacity region, depending on the applicable minimum requirement, and by size of the various peaking plant options evaluated in this study. The applicable minimum ICAP requirement values are based on the peak load forecasts and the IRM/LCR values for the 2024-2025 Capability Year. The tables below provide the applicable forecasted peak load, IRM/LCR values (in percentage terms), and the resulting LOE by capacity region and technology, expressed as a percentage.

Table 18: Battery Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Region	Peak Load (MW)	2024-2025 IRM/LCR	LOE (%) by Technology			
			2-hr BESS	4-hr BESS	6-hr BESS	8-hr BESS
NYCA	31,542	122.00%	100.52%	100.52%	100.52%	100.52%
G-J	15,220	81.00%	101.62%	101.62%	101.62%	101.62%
NYC	11,168	80.40%	102.23%	102.23%	102.23%	102.23%
LI	5,043	105.30%	103.77%	103.77%	103.77%	103.77%

Table 19: Fossil Peaking Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Region	Peak Load (MW)	2024-2025 IRM/LCR	LOE (%) by Technology	
			GE 7HA.03	GE 7HA.02
NYCA	31,542	122.00%	101.04%	100.86%
G-J	15,220	81.00%	103.22%	102.66%
NYC	11,168	80.40%	104.50%	-
LI	5,043	105.30%	107.61%	106.65%

Note: The LOE % calculated for the GE 7HA.02 in LI assumes the unit has SCR emissions controls. The LOE % calculated for the GE 7HA.02 in all other capacity regions does not assume the unit has SCR emissions controls

Relative Seasonal Reliability Risks

In this reset, the newly developed seasonal ICAP Demand Curves incorporate relative seasonal reliability risks (SLOLE and WLOLE) to define summer reference point prices (SRPs) and winter reference point prices (WRPs). The SLOLE, and WLOLE equate to the percentage of the annual loss of load expectation (LOLE) risk expected to occur in the Summer Capability Period and the Winter Capability

Period, respectively. These values are based on the preliminary base case, as approved by the NYSRC, for the NYCA Installed Reserve Margin study covering the Capability Year for which the monthly ICAP reference point price is calculated. For example, the SLOLE and WLOLE values used in determining the 2025-2026 Capability Year ICAP Demand Curves are based on the NYSRC-approved preliminary base case for the 2025-2026 NYCA Installed Reserve Margin study. The WLOLE is equal to 1 minus the SLOLE.[30]

Zero Crossing Point

In the last reset, the zero crossing points for the ICAP Demand Curves were set at 112 percent of IRM for NYCA, 118 percent of LCR for Load Zone K (Long Island), 118 percent of LCR for Load Zone J (New York City), and 115 percent of LCR for the G-J Locality. No additional studies have been conducted to specifically inform the determination of the zero crossing points for the ICAP Demand Curves since the 2014-2017 DCR. As a result, the Consultant recommended that the zero crossing point values for the 2025-2029 DCR remain unchanged. NYISO staff concurs with this recommendation to retain the current zero crossing point values for the duration of this reset period. Any in-depth assessment of potential future revisions to the zero crossing point values would be best conducted as a separate effort outside the context of the DCR.

UCAP Demand Curve Reference Points

The applicable data and information developed was used to calculate the indicative 2025-2026 Capability Year UCAP Demand Curve reference point prices for the various peaking plant options evaluated.

The indicative UCAP reference point prices in Table 20 reflect the use of the final CAFs for the 2024-2025 Winter Capability Period as well as a 2.5% derating factor for the BESS options and 4.1% derating factor for the SCGTs. The Consultant recommended a 4.1% derating factor for SCGTs based on NERC GADS data of performance since 2018 for units that are no more than 10 years old. The Consultant recommended use of a 2% derating factor for the BESS options based on their professional judgment, experience, and information provided by equipment suppliers/manufacturers. The Consultant's recommended value is representative of the longer term expected performance capability of the BESS options. However, this value does not account for current NYISO market rules (as set forth in Section 4.5 of the NYISO Installed Capacity Manual) that require use of "proxy" data for historical months prior to the new unit's commencement of operations. To account for the current market rules, NYISO staff recommends the use of a 2.5% derating factor for the BESS options. The 2.5% derating factor was

[30] *See* Consultant Final Report (Updated Version) at 119.

calculated as a weighted average of the derating factors that the BESS options would be expected to receive across the assumed 20-year amortization period given the currently applicable rules.[31] NYISO staff has utilized a 2.5% derating factor, along with the applicable CAFs, to convert the BESS ICAP reference point prices to indicative UCAP reference point prices.

[31] Under current NYISO rules, until three energy storage resources are participating in the ICAP market and have sufficient historical operating data to establish a "NYISO class average" EFORd for energy storage resources, a new BESS would be assigned an initial derating factor upon ICAP market entry based on the NERC class average EFORd of pumped hydro storage (currently 9.19%). Therefore, to calculate the 2.5% weighted-average derating factor for BESS, NYISO staff assumed the BESS would have a 9.19% derating factor for its first year of operation, a 5.6% derating factor for its second year of operation (average of 9.19% and the 2% expected BESS availability determined by the Consultant), and 2% derating factor for years 3-20 of its assumed economic life.

Table 20: 2025-2026 Capability Year Indicative UCAP Demand Curve Parameters for BESS Peaking Plant Options (for Informational Purposes Only) ($2025)

Technology	Fuel Type & Emission Control	Parameter	Central	Capital	Hudson Valley (Rockland)	Hudson Valley (Dutchess)	New York City	Long Island
BESS (200 MW)	2-hr (400 MWh)	Gross CONE	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
		Net EAS	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
		Annual Reference Value (Net CONE)	$66.52	$45.66	$49.85	$45.75	$130.74	$43.92
		Summer Reference Price	$14.00	$9.61	$11.22	$10.30	$29.99	$11.66
		Winter Reference Price	$10.58	$7.26	$9.65	$8.86	$25.29	$15.07
	4-hr (800 MWh)	Gross CONE	$189.05	$190.40	$196.11	$190.25	$317.01	$202.88
		Net EAS	$63.57	$88.64	$87.34	$87.39	$90.35	$109.40
		Annual Reference Value (Net CONE)	$125.48	$101.76	$108.78	$102.86	$226.66	$93.48
		Summer Reference Price	$21.82	$17.69	$20.29	$19.18	$42.58	$16.59
		Winter Reference Price	$16.49	$13.37	$17.44	$16.50	$35.91	$21.42
	6-hr (1200 MWh)	Gross CONE	$264.35	$266.22	$274.27	$266.07	$424.81	$283.81
		Net EAS	$65.98	$93.58	$93.60	$93.69	$94.49	$120.99
		Annual Reference Value (Net CONE)	$198.38	$172.64	$180.67	$172.37	$330.32	$162.82
		Summer Reference Price	$25.22	$21.95	$24.75	$23.61	$46.88	$24.83
		Winter Reference Price	$19.06	$16.59	$21.28	$20.30	$39.53	$32.07
	8-hr (1600 MWh)	Gross CONE	$338.82	$341.25	$351.53	$340.96	$541.77	$364.11
		Net EAS	$66.48	$93.54	$95.12	$95.24	$94.89	$124.71
		Annual Reference Value (Net CONE)	$272.34	$247.71	$256.40	$245.72	$446.88	$239.40
		Summer Reference Price	$31.85	$28.97	$32.16	$30.82	$57.41	$33.71
		Winter Reference Price	$24.07	$21.89	$27.65	$26.50	$48.41	$43.54

Note: (1) Gross CONE, Net EAS, and Annual Reference Value (Net CONE) shown as $/kw-year. Reference Points shown as $/kw-month. (2) The CAF values used in these results reflect the CAFs applicable to the 2024-2025 Winter Capability Period and will be updated to reflect the CAFs applicable to the 2025-2026 Capability Year for the selected peaking plant technology.

Table 21: 2025-2026 Capability Year Indicative UCAP Demand Curve Parameters for SCGT Peaking Plant Options (for Informational Purposes Only) ($2025)

Technology	Fuel Type & Emission Control	Parameter	Central	Capital	Hudson Valley (Rockland)	Hudson Valley (Dutchess)	New York City	Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	Gross CONE	$270.61	$267.39	$285.53	$268.54	$351.15	$493.88
		Net EAS	$68.32	$97.17	$80.03	$77.34	$87.44	$111.91
		Annual Reference Value (Net CONE)	$202.29	$170.23	$205.50	$191.20	$263.70	$381.97
		Summer Reference Price	$24.50	$20.80	$29.26	$27.22	$39.40	$74.52
		Winter Reference Price	$17.99	$15.14	$26.54	$24.69	$35.86	$253.29
	Gas Only, with SCR	Gross CONE	$258.89	$256.01	$285.71	$257.07	-	-
		Net EAS	$68.32	$96.55	$73.28	$71.82	-	-
		Annual Reference Value (Net CONE)	$190.57	$159.47	$212.43	$185.25	-	-
		Summer Reference Price	$23.08	$19.49	$30.25	$26.38	-	-
		Winter Reference Price	$16.95	$14.18	$27.43	$23.92	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	Gross CONE	$284.49	$281.00	-	$280.72	-	-
		Net EAS	$54.24	$65.49	-	$62.73	-	-
		Annual Reference Value (Net CONE)	$230.26	$215.51	-	$218.00	-	-
		Summer Reference Price	$27.43	$25.80	-	$29.23	-	-
		Winter Reference Price	$19.65	$17.60	-	$25.34	-	-
	Gas Only, no SCR	Gross CONE	$270.18	$267.10	-	$266.71	-	-
		Net EAS	$54.24	$66.89	-	$55.17	-	-
		Annual Reference Value (Net CONE)	$215.94	$200.21	-	$211.54	-	-
		Summer Reference Price	$25.73	$23.97	-	$28.37	-	-
		Winter Reference Price	$18.43	$16.35	-	$24.59	-	-
	Dual Fuel, with SCR	Gross CONE	-	-	-	-	-	$293.98
		Net EAS	-	-	-	-	-	$105.27
		Annual Reference Value (Net CONE)	-	-	-	-	-	$188.71
		Summer Reference Price	-	-	-	-	-	$33.66
		Winter Reference Price	-	-	-	-	-	$78.82

Note: (1) Gross CONE, Net EAS, and Annual Reference Value (Net CONE) shown as $/kw-year. Reference Points shown as $/kw-month. (2) The CAF values used in these results reflect the CAFs applicable to the 2024-2025 Winter Capability Period and will be updated to reflect the CAFs applicable to the 2025-2026 Capability Year for the selected peaking plant technology.

Annual Updates

In accordance with the requirements of Section 5.14.1.2.2 of the Services Tariff, the ICAP Demand Curves will be updated annually for each of the three successive Capability Years encompassed by this reset period (i.e., the 2026-2027 Capability Year, 2027-2028 Capability Year, and 2028-2029 Capability Year) through the updating of (1) Gross CONE values, (2) net EAS revenue estimates using the net EAS revenues model, (3) seasonal capacity availability (SWR and WSR), and (4) the relative seasonal reliability risks (SLOLE and WLOLE). Updates to Gross CONE and net EAS revenues are described in greater detail below. The seasonal capacity availability and relative seasonal reliability risk values will be updated annually by the NYISO in accordance with the requirements of Sections 5.14.1.2.2 and 5.14.1.2.2.3 of the Services Tariff. The table below summarizes certain factors used in the annual updates to ICAP Demand Curve reference point prices, indicating in **bold** those parameters that are updated annually. The remaining parameters are fixed for the reset period.

Table 22: Overview of ICAP Demand Curve Annual Updating

Factor Used in Annual Updates	Type of Value
ICAP Demand Curve Values	
Zero-Crossing Point	Fixed For Reset Period
Reference Point Price Calculation	
Peaking Plant Net Degraded Capacity (ICAP MW)	Fixed For Reset Period
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed For Reset Period
Peaking Plant Winter Capability Period Dependable Maximum Net Capability (DMNC)	Fixed For Reset Period
Installed Capacity Requirements (IRM/LCR)	Fixed For Reset Period
Monthly Available Capacity Values for Use in Calculating WSR	**NYISO Published Values**
Relative Seasonal Reliability Risks (SLOLE and WLOLE)	**Based on the preliminary base case for the IRM study covering the Capability Year for which the monthly ICAP reference point price is calculated**

Updates to Gross CONE

An element of annual updates is the adjustment of Gross CONE values. In each year, the Gross CONE of the peaking plant selected for each ICAP Demand Curve will be updated based on a state-wide, technology-specific escalation factor representing the cost-weighted average of inflation indices for four major plant components: wages, turbines, materials and components, and other costs. The growth rate for all indices is a ratio of (1) the most recently available finalized data as of October 1 in the year prior to the start of the Capability Year for which the updated ICAP Demand Curves will apply and (2) the same data values for time periods associated with the most recent finalized data available for each index as of October 1 of the calendar year in which the NYISO files the results of a DCR with the FERC (i.e., October 1, 2024 in the case of this DCR), minus one.[32]

Thus, in each year, the annual composite escalation rate is calculated as:

$$Annual\ Composite\ Escalation_{\ t} = \sum_{i=1}^{4}(weight_i) * \left(\frac{Index_{i,t}}{Index_{i,DCRYear}} - 1\right) \quad (9)$$

The cost-component weighting factors are calculated for each peaking plant technology reflecting each component's relative share of total peaking plant installed capital costs. The table below provides the (publicly available) index to be used for measuring changes over time for each cost component, and each component's relative weight for each peaking plant technology. The same weighting factors and indices will be used for the duration of the reset period, but the values resulting from the indices will be updated annually based on the indices and component weights described in the table below.

The composite escalation rate (and the rate associated with the general component thereof) will be updated annually as described above. Gross CONE values are adjusted annually by applying the composite escalation rate to the gross CONE values underlying the ICAP Demand Curves for the 2025-2026 Capability Year (i.e., the first Capability Year covered by the four-year duration of this reset period).

NYISO staff concurs with the Consultant's recommended weighting factors and indices, as shown in the tables below. NYISO staff also concurs with the Consultant's recommendation that adjustments to the assumed financial parameters are not necessary to address the potential for the annual updating of gross CONE values to deviate from values that may have been developed as part of the comprehensive assessment undertaken during each DCR. Analysis presented by the Consultant indicates that there is no evidence of a systematic bias for the potential that annual updates will either overestimate or underestimate equivalent gross CONE values that would be derived from the conduct of a full DCR study. As a result, the Consultant concluded that it was not necessary to consider the potential need for an adjustment to the financial parameters specific to the methodology for annually updating gross CONE values during years 2-4 of each reset period.

[32] Services Tariff Section 5.14.1.2.2.1.

Table 23: Gross CONE Composite Escalation Factor Parameters for BESS Peaking Plant Options

Cost Component	Index	Interval	Calculation of Index Value	Annual Growth Rate	Component Weight, by Technology			
					2-Hour BESS	4-Hour BESS	6-Hour BESS	8-Hour BESS
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	3.40%	15.00%	13.00%	13.00%	13.00%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	Average of finalized February, March, April values	1.32%	11.00%	9.00%	8.00%	7.00%
Storage Battery Costs	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Storage Batteries (Excluding Lead Acid), Including Parts for All Storage Batteries (790105)	Monthly	Average of finalized February, March, April values	0.18%	62.00%	65.00%	66.00%	67.00%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	2.64%	12.00%	13.00%	13.00%	13.00%

Table 24: Gross CONE Composite Escalation Factor Parameters for Dual-Fuel SCGT Peaking Plant Options

Cost Component	Index	Interval	Calculation of Index Value	Annual Growth Rate	1x0 GE 7HA.03, 25 ppm	1x0 GE 7HA.02, 25 ppm	1x0 GE 7HA.02, 15 ppm
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	3.40%	21.00%	28.00%	20.00%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	Average of finalized February, March, April values	1.32%	14.00%	15.00%	17.00%
Gas and Steam Turbine Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Turbines and Turbine Generator Sets (97)	Monthly	Average of finalized February, March, April values	4.69%	31.00%	22.00%	25.00%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	2.64%	34.00%	35.00%	38.00%

Updates to the Net EAS Revenue Offset

Net EAS revenues will be recalculated annually using the same net EAS revenues model used to estimate net EAS revenues for the 2025-2026 Capability Year ICAP Demand Curves, but model inputs will include the most recent three-year historical data available for energy and reserve market prices, fuel prices, emission allowance prices, VSS adder, and Rate Schedule 1 charges, if applicable for the peaking plant technology selected for each ICAP Demand Curve. Other peaking plant costs and operational parameters (e.g., heat rate, variable O&M costs, and seasonal hurdle rates for BESS options) needed to run the model, as well as the applicable LOE-AF values, remain fixed for the duration of the reset period. The table below contains a summary of the factors used in the net EAS revenues calculation, with an indication of whether they are updated annually (items in **bold** are updated annually).

Table 25: Overview of Annual Updating of Net EAS Revenues

Factor Used in Annual Updates	Type of Value
Net EAS Revenue Model, including Commitment and Dispatch Logic	Fixed for Quadrennial Reset Period
Hurdle Rates for BESS net EAS Revenue Model	Fixed for Quadrennial Reset Period
Peaking plant Physical Operating Characteristics, including start time requirements, start-up cost minimum down time and runtime requirements, operating hours restrictions and/or limitations (if any), heat rate	Fixed for Quadrennial Reset Period
Energy Prices (day-ahead and real-time)	**NYISO Published Values**
Operating Reserves Prices (day-ahead and real-time)	**NYISO Published Values**
Level of Excess Adjustment Factors	Fixed for Quadrennial Reset Period
Annual Value of VSS*	**Determined via formula with VSS compensation rate updated annually with NYISO published values**
Peaking plant primary and secondary (if any) Fuel Type	N/A for BESS; Fixed for Quadrennial Reset Period
Fuel tax and transportation cost adders	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
Real-time intraday gas acquisition premium/purchase discount	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
Fuel Pricing Points (e.g., natural gas trading hub)	N/A for BESS; Fixed for Quadrennial Reset Period
Fuel Price	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant Variable Operating and Maintenance Cost	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking plant CO2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
CO2 Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant NOx Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
NOx Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant SO2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
SO2 Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
NYISO Rate Schedule 1 Charges	**NYISO Published Values**

Note: Items in **bold** are to be updated during each Annual Update
*The annual value of VSS is determined using the following formula based on the compensation structure described in Rate Schedule 2 of the Services Tariff: VSS compensation rate * (lagging MVAr capability + abs(leading MVAr capability)). The VSS compensation rate will be updated to reflect the NYISO published rate in effect at the time of each annual update.

NYISO will collect LBMP and reserve price data for the three-year period ending August 31st of the year prior to the beginning of the Capability Year to which the updated ICAP Demand Curves will apply. Similarly, applicable data from the specified sources for fuel prices and emission allowance prices will be collected and processed for the same time period. This data would then be used in net EAS revenues model to determine the estimated net EAS revenues of the applicable peaking plant for the upcoming Capability Year.

Updates to Seasonal Capacity Availability Ratios

The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year, and the SWR can be represented as the reciprocal of the WSR. Total ICAP is equal to the sum of total UCAP available (including generation, Special Case Resources, and imports) listed in monthly reports published by the NYISO, converted to ICAP using a locational EFORd. These totals are adjusted for certain resource entry and exit circumstances.[33] Both total winter ICAP and total summer ICAP are calculated as a rolling average from the same three-year historical period that is used when calculating net EAS revenues.

As part of the annual updates, the NYISO will update the WSR and SWR values to reflect historical data for the same three-year period used by the net EAS revenues model.

Updates to Relative Seasonal Reliability Risks

As part of the annual updates, the NYISO will update the SLOLE and WLOLE values, respectively, to reflect the percentage of the annual loss of load expectation expected to occur in the Summer Capability Period and Winter Capability Period. These values will be based on the preliminary base case for the NYCA Installed Reserve Margin study covering the Capability Year for which the monthly ICAP reference point prices are updated.

[33] Services Tariff, Section 5.14.1.2.2.3. Broadly, these adjustments seek to include resource changes in all months of the applicable twelve-month period based on the resource status that is expected to persist at the end of each 12- month period. For new entry of a resource that comes online after September of a given 12-month period and remains in the market for the remaining months of such period, the NYISO will add the resource’s applicable summer or winter MW to any month in which the entering MW are not already included. New entry does not include resources returning from an Inactive Reserves state. If a resource exits the capacity market after September of a given 12-month period and remains in the market for the remaining months of such period, the NYISO will remove the resource’s MW for any months in which it is represented in the applicable 12-month period. Exit includes generator retirements, mothball, or ICAP Ineligible Force Outage State

NYISO Staff Recommendations

Choice of Peaking Unit Technology

NYISO staff concurs with the Consultant's recommendation that a two-hour BESS represents the appropriate peaking plant technology in all locations. Based on its economics in the last reset, BESS was ultimately not selected. However, it was considered an economically viable technology that qualified for consideration as a potential peaking plant option. This same conclusion is reached in this reset recognizing the technical capability of the BESS options and the ability of the underlying resource fleet to support the operation of BESS without requiring a dedicated resource to support its charging requirements. NYISO staff recognizes that the future CAF values can affect the comparative economics of various technology options but believes it is unlikely for the CAFs of the 2-hour BESS to decrease so significantly during this four-year reset period that the 2-hour BESS would no longer qualify as a viable peaking plant technology option or undermine the economics of a 2-hour BESS to such a degree that would warrant selection of a different peaking plant technology option for the 2025-2029 DCR. Notably, the selection of the appropriate peaking plant technology is determined as part of the DCR for each curve and remains fixed for the duration of the four-year period covered by the DCR.

For those capacity regions in which multiple locations were considered, NYISO staff concurs with the Consultant's recommendation to select the location that represents the lowest monthly reference point prices for each applicable ICAP Demand Curve. Accordingly, the NYISO staff recommends that, for purposes of the 2025-2029 DCR, a peaking plant located in Load Zone G (Dutchess County) should be utilized for establishing the G-J Locality ICAP Demand Curve, and a peaking plant located in Load Zone F should be utilized for establishing the NYCA ICAP Demand Curve.

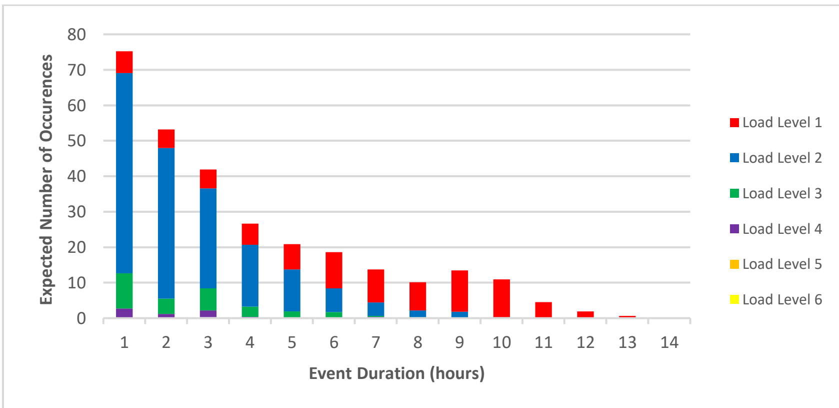
Based on the results, none of the SCGT peaking plant technology options that were evaluated as part of this DCR were selected as the representative peaking plant in any location due to 2-hour BESS being the lower cost, alternative on a UCAP basis in all locations. NYISO staff concurs with this conclusion.

Considerations Regarding 2-hour BESS as the Peaking Plant Technology

Several stakeholders have raised concerns that a 2-hour BESS cannot meet the reliability needs necessary to qualify as a viable peaking plant technology. Specifically, concerns have been expressed regarding whether the 2-hour BESS can assist in avoiding loss of load events and alleviate transmission security concerns. Certain stakeholders have also contended that there may be insufficient energy to charge the 2-hour BESS to support its capability to operate during peak periods. NYISO staff has carefully considered these concerns but concludes that the 2-hour BESS satisfies the requirements to qualify as an economically viable technology option for the reasons provided in this Section.

As shown in Figure 4, NYISO staff analyzed loss of load events reflected in the model utilized for determining the 2024-2025 Capability Year LCRs (2024 LCR Model) and found that a significant percentage of the events are 1-2 hours in duration, and therefore, can be met by a 2-hour BESS. It is also worth noting that a 2-hour BESS is not strictly limited in availability to system operators for only 2 hours. Depending on the size and nature of an event (or other adverse system conditions), a BESS can run for any length of time, just at reduced output. This means that a 200 MW, 2-hour BESS could be operated as equivalent to a 100 MW, 4-hour BESS or even a 50 MW, 8-hour BESS.

Figure 4: Distribution of NYCA Event Duration for Daily LOLE (2024 LCR Model)



Another concern raised by certain stakeholders regarding the potential consideration of a 2-hour BESS as the peaking plant technology is that the resulting market price signals from curves reflecting the use of such technology may not be optimal to meet future reliability needs as the transition to a carbon-free grid continues to unfold in New York. However, the demand curves do not require or otherwise mandate the construction of a particular technology or incremental capacity supply source. Rather, the price signals provided by the demand curves would support any technology or other source of incremental capacity supply that would be economic at or below the net costs of a 2-hour BESS under the conditions of system need defined for establishing the curves. A variety of options to supply incremental capacity supply can be incented through the price signals provided by the ICAP Demand Curves and, more generally, the NYISO-administered markets.

The NYISO's markets work holistically to provide incentives for resources to provide energy and other reliability services as needed. The ICAP Demand Curves reflect the revenue streams that the selected peaking plant technology would need to receive from the ICAP market to obtain sufficient total revenues to support market entry under the system conditions specified for use in establishing the ICAP Demand Curves and ensure sufficient capacity supply to meet resource adequacy needs. Historically, however, new entry of resources and additional capacity supply have occurred under system conditions with greater excess capacity than the conditions assumed in establishing the ICAP Demand Curves indicating sufficient market revenue earning capability for such capacity supply additions at lower costs than the applicable peaking plant.

Additionally, certain stakeholders have expressed concerns that if a 2-hour BESS is used to establish the ICAP Demand Curves, the capacity market would be unable to produce adequate prices to retain existing generation needed for reliability. Based on the results for the 2025-2026 Capability Year, all else equal, demand curves resulting from the selection of a 2-hour BESS as the peaking plant technology would be expected to produce equal or greater capacity market revenues compared to the curves in effect over the past five years. Thus, it is not expected that demand curves based on a 2-hour BESS would be the driving force behind any retirement decisions. There is risk, however, that units may retire over the coming years, but environmental and regulatory requirements/policies or other factors (e.g., an immediate and non-discretionary need for major capital expenditure) would be most likely to cause of such a decision, not the demand curves resulting from this reset.

CAF Considerations

Several stakeholders and the MMU have raised concerns that if the reliability value, as measured by the CAFs, of a 2-hour BESS were to materially decline during its assumed amortization period, it may no longer represent the appropriate peaking plant technology and undermine the ability of an investor to recover the costs of such asset over the assumed amortization period. The risk of potential revenue insufficiency due to the possibility of future declines in CAF values for a 2-hour BESS over time does not materialize for the four-year period covered by this reset because the required translation of the ICAP Demand Curves to a UCAP basis for purposes of administering the spot market auctions expressly incorporates the CAF of the applicable peaking plant. Thus, any changes to such CAF values during this reset period will be reflected in the resulting UCAP based curves and continue to ensure revenue adequacy for the applicable peaking plant under the prescribed level of excess conditions used in establishing the curves. However, these parties contend that the potential risk for future declines in CAF values for a 2-hour BESS could result in another technology being selected to serve as the applicable peaking plant in future resets. These parties argue that such an outcome could result in the 2-hour BESS not being capable of recovering its costs over the duration of the assumed amortization period. Accordingly, such parties contend that this potential risk must be accounted for in determining the net CONE of a 2-hour BESS.

The identified potential risk of future changes to the peaking plant technology is inherent in the nature of the periodic comprehensive review of the ICAP Demand Curves required by the Services Tariff. The reset process is designed to reassess the appropriate technology options and costs associated therewith every four years, requiring the selection of the technology that represents the lowest fixed, and highest variable cost option among economically available alternatives at the time of each reset. The Services Tariff does not guarantee that a technology selected in one reset will persist as the appropriate technology for the next reset. In fact, changes in peaking plant technology have occurred multiple times in past resets as newer and/or more efficient technology options have become available and are more economic than a technology selected to serve as the peaking plant in the prior reset.

While there is a potential for the CAF values for a 2-hour BESS to decline in the future (as noted below), it is unclear what CAFs and costs for other technology options will look like in the future and if this risk would result in a technology change in future DCRs. Thus, we agree with the Consultant's recommendation to account for this risk in establishing the appropriate financial parameters for BESS technologies.

NYISO staff has also reviewed multiple sensitivity analyses of CAFs to understand their potential future trajectory. These sensitivity analyses were run using General Electric's Multi-Area Reliability Simulation (GE-MARS) software, which is the same software utilized when setting the IRM, LCRs, and CAFs for each Capability Year. Table 26 shows the 2-hour and 4-hour BESS CAFs for four cases:

- "2024 LCR Model" – This model represents the expected system for the current 2024-2025 Capability Year and is the model used to calculate the currently effective CAFs. The Consultant used these CAF values to calculate indicative UCAP reference point prices. The indicative UCAP demand curves are considered in evaluating the appropriate technology selection for this reset due to the need to account for the impacts of technology options with varying CAFs.

- "2024 IRM Sensitivity" – This case represents the current system, utilizing the 2024–2025 IRM final base case as a starting point, but with the addition of the Champlain Hudson Power Express transmission line (which is expected to enter service in 2026) and certain assumed additions of incremental renewables and storage (+1 GW land-based wind, +2.5 GW utility-scale solar, +1.7 GW offshore wind, and 200 MW of utility-scale storage). The incremental renewables and storage assumptions align with the quantities initially identified for inclusion in the 2024 Reliability Needs Assessment (RNA) base case. This case is meant to inform the potential trajectory of CAFs over the four-year period of this DCR and is expected to be more representative of potential CAFs toward the end of the four-year period, if the assumed levels of incremental renewables and storage come to fruition.

- "2024 RNA Base Case Year 2030" – This case utilizes year 2030 of the first pass draft base case for the 2024 RNA as a starting point. The case was then brought to at-criteria conditions using the NYISO's

LCR optimizer. The case has modest incremental renewables and storage compared to today's system (+905 MW of utility-scale solar, +1,700 MW of offshore wind, and +40 MW of utility-scale storage). Additionally, compared to the 2024 IRM Sensitivity, this case reflects the baseline load assumptions for 2030 from the NYISO's 2024 Load & Capacity Data report (Gold Book) as well as all other assumptions from the first pass draft base case for the 2024 RNA for year 2030.

- "2022 RNA Policy Case Model Year 2030" – This case reflects a system with assumed resource fleet changes that could meet the 70% renewable energy by 2030 requirement established by the CLCPA. This case assumes a number of changes forecast at the time of the 2022 RNA, which may not materialize given the issues/complications that have arisen in the broader economy since the time the assumptions for this case were developed. This case is meant to represent an extreme scenario for the potential change in 2-hour and 4-hour CAFs by 2030.

Table 26: 2-Hour and 4-Hour BESS CAFs (Rest of State and NYC)

Case	Rest of State (ROS) CAFs 2-Hour BESS	Rest of State (ROS) CAFs 4-Hour BESS	Load Zone J CAFs 2-Hour BESS	Load Zone J CAFs 4-Hour BESS
2024 LCR Model[1]	55% (Summer) 55% (Winter)	64% (Summer) 67% (Winter)	56% (Summer) 55% (Winter)	69% (Summer) 67% (Winter)
2024 IRM Sensitivity	43%	82%	40%	79%
2024 RNA Base Case Year 2030	68%	90%	67%	89%
2022 RNA Policy Case Model Year 2030	36%	38%	25%	27%

[1] These CAFs are currently effective for the 2024-2025 Capability Year. The NYISO submitted a waiver request on July 2, 2024 to update the 2024-2025 Capability Year CAFs beginning November 1, 2024. FERC issued an order accepting the waiver on August 15, 2024. See Docket No. ER24-2463, New York Independent System Operator, Inc., Petition for Prospective Tariff Waiver, for a Shortened Comment Period and Expedited Action (July 2, 2024); and New York Independent System Operator, Inc., 188 FERC ¶ 61,128 (2024).

Considering the results of the CAF sensitivity analyses, NYISO staff concurs that the 2-hour BESS is expected to remain more economic than the 4-hour BESS and SCGT peaking plant technology options over all or nearly all of the 2025-2029 period covered by this reset. Any potential change in relative economics driven by CAFs for the tail-end of this reset period would be appropriately addressed during the next reset when the selection of the appropriate technology to anchor the demand curves is fully reassessed and the actual changes in the resource fleet and resulting impact on CAFs are known.

Table 27: NYISO Staff Recommended 2025-2026 Capability Year ICAP Demand Curve Parameters ($2025)

Technology		NYCA	G-J	J	K
2-hour BESS	Gross Cone	$122.81	$122.67	$212.99	$131.34
	Net EAS	$77.15	$76.92	$82.25	$87.42
	Annual Reference Value (Net CONE)	$45.66	$45.75	$130.74	$43.92
	Summer Reference Point	$5.17	$5.56	$16.16	$6.02
	Winter Reference Point	$3.91	$4.78	$13.63	$7.77
	Summer Max Clearing Price	$20.86	$22.35	$39.50	$26.99
	Winter Max Clearing Price	$15.76	$19.22	$33.30	$34.86

Table 28: NYISO Staff Recommended 2025-2026 Capability Year ICAP Demand Curve Parameters ($2025)

		Current Year (2025-2026)					
Parameter	Source	C - Central	F - Capital	Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Gross Cost of New Entry ($/kW-Year)	[1]	$121.90	$122.81	$126.75	$122.67	$212.99	$131.34
Net EAS Revenues ($/kW-Year)	[2]	$55.38	$77.15	$76.90	$76.92	$82.25	$87.42
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$66.52	$45.66	$49.85	$45.75	$130.74	$43.92
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Winter to Summer DMNCs	[7]	103.30%	103.30%	105.00%	105.00%	105.70%	108.30%
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.21	$4.95	$5.40	$4.96	$14.16	$4.76
Winter ($/kW-Month)	[11]	$3.88	$2.66	$2.91	$2.67	$7.63	$2.56
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,441	$989	$1,080	$991	$2,833	$952
Monthly Revenue (Winter)	[13]=[11]*[9]	$776	$533	$582	$534	$1,525	$512
Seasonal Revenue (Summer)	[14]=6*[12]	$8,647	$5,936	$6,480	$5,948	$16,996	$5,710
Seasonal Revenue (Winter)	[15]=6*[13]	$4,656	$3,196	$3,489	$3,203	$9,152	$3,075
Total Annual Reference Value	[16]=[14]+[15]	$13,303	$9,132	$9,970	$9,150	$26,148	$8,784
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$7.53	$5.17	$6.06	$5.56	$16.16	$6.02
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$5.69	$3.91	$5.21	$4.78	$13.63	$7.77
Summer ICAP Maximum Clearing Price ($/kW-Month)		$20.71	$20.86	$23.09	$22.35	$39.50	$26.99
Winter ICAP Maximum Clearing Price ($/kW-Month)		$15.65	$15.76	$19.86	$19.22	$33.30	$34.86
Demand Curve Length		12%	12%	15%	15%	18%	18%

BESS Derating Factor

To reflect the impact of the current NYISO market rules in determining an initial derating factor that a new BESS would receive upon entering the ICAP market and the expected operating performance of BESS over its assumed economic life (i.e., the assumed 20-year amortization period), NYISO staff recommends the use of a 2.5% derating factor (as further discussed in the "UCAP Demand Curve Reference Points" subsection of the "Development of ICAP Demand Curves" section above) in conjunction with the applicable CAFs for the applicable Capability Year when translating the ICAP reference point prices to UCAP terms.

MMU Review of Recommended ICAP Demand Curve Parameters

Please see Appendix A.

Timeline

Stakeholders will have the opportunity to provide written comments to the Board by October 9, 2024, with oral presentations to the Board scheduled to occur on October 14, 2024. On or before November 30, 2024, the NYISO will file with FERC the Board's final recommended ICAP Demand Curve parameters for the 2025-2026 Capability Year (i.e., commencing May 1, 2025), as well as the methodologies and assumptions for conducting annual updates of the ICAP Demand Curves for the subsequent three Capability Years (i.e., the 2026-2027, 2027-2028, and 2028-2029 Capability Years).

Appendix A

POTOMAC ECONOMICS

Memorandum

TO: NYISO

FROM: David B. Patton, Pallas LeeVanSchaick, and Joe Coscia

DATE: August 23, 2024

RE: Technology Choice for the 2025-2029 Demand Curve Reset ("DCR")

NYISO's capacity demand curve is intended to facilitate efficient investment and retirement decisions that will satisfy NYISO's planning needs. This is accomplished by setting the demand curve level based on the net cost of new entry ("Net CONE") for the lowest-cost peaking resource, although other types of resources may actually enter. Identifying a suitable technology given New York's zero-emission mandate by 2040 is a unique challenge in this DCR process. This memo provides our comments on the recommended selection of the 2-hour battery as the demand curve technology by the Analysis Group ("AG"), as well as our recommendation that NYISO select a combustion turbine ("CT") amortized over 20 years.

A. Executive Summary

1. The 2-Hour Battery Recommendation

In its July 30 Interim Final Report, AG recommended the 2-hour battery amortized over 20 years for the demand curve unit technology. We do not find this advisable for the following reasons:

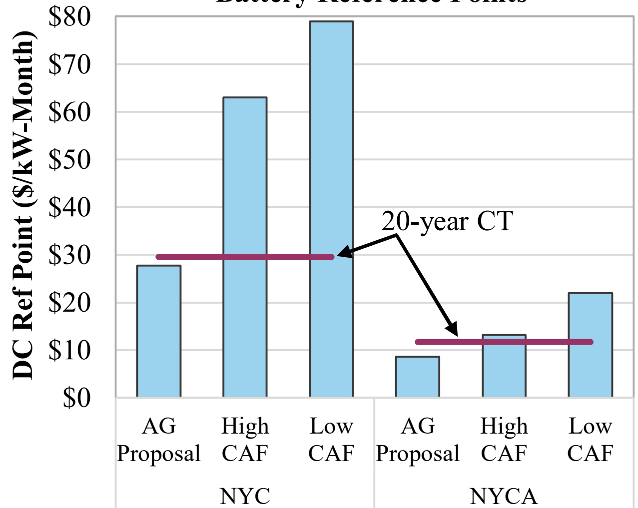
- AG underestimates the Net CONE of the battery because it does not properly consider the impact of falling Capacity Accreditation Factors ("CAF") over the 20-year amortization period. A more reasonable analysis, shown in Figure 1, would indicate that the demand curves under the 2-hour battery would exceed those of a combustion turbine.
- Even accepting AG's recommendations, the CAFs for the 2-hour battery will likely fall during the demand curve reset period, raising the demand curve levels through the annual adjustment process higher than for a CT amortized over 20 years.
- 2-hour batteries are limited in their ability to meet the future reliability needs of the system. Studies show that long-duration dispatchable resources are needed to satisfy NYISO's needs as the State transitions to a zero-emission fleet by 2040. For example:
  - NYSERDA's Integration Analysis to support the Climate Action Council Scoping Plan similarly found that large quantities of dispatchable resources (e.g., hydrogen-burning units or 100-hour batteries) will be needed for reliability in prolonged periods of low renewable output when short-duration batteries will be inadequate.[1]

[1] See "Integration Analysis Technical Supplement", Appendix G to NYS Climate Action Council Scoping Plan (Dec 2022), prepared by Energy and Environmental Economics (E3) and Abt Associates, pages 47-51.

- NYISO's recent 2023-2042 System & Resource Outlook study finds that at least 20 GW of dispatchable emissions-free resources capable of multi-day operation (such as hydrogen-fired CTs) are needed to replace existing fossil capacity by 2040.[2]

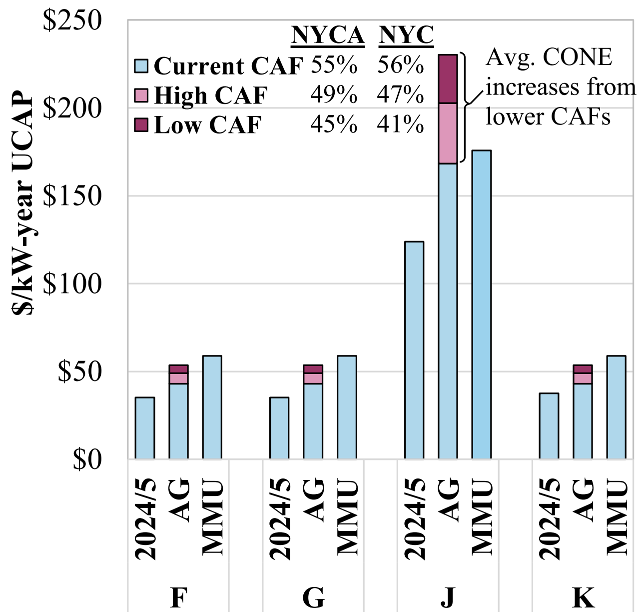
Regarding the first concern, a falling CAF over the life of a 2-hour battery will likely cause it to lose revenue in future years, thereby *raising its initial Net CONE*. Based on forecasted trajectories for the CAFs, it is unlikely to remain the demand curve reset unit after this cycle. If one assumes the demand curve is set based on a CT in the next cycle, the *current* Net CONE for the 2-hour battery and the corresponding demand curve reference points would rise sharply as shown in Figure 1. Even if one adopts an optimistic assumption that that CAF will fall less (i.e., the "high CAF" scenario), the reference point and resulting capacity prices would be higher than for a 20-year CT in all areas.

Figure 1: CAF Effects on 2-Hour Battery Reference Points



However, even if one accepts the Net CONE estimated by AG for the 2-hour battery, it will still likely produce higher prices in New York City over the 4-year demand curve reset period than a 20-year CT (the second concern listed above). Figure 2 compares forecasted clearing prices over the next four years under the current (2024-25) demand curves and the AG and MMU-recommended demand curves given the current capacity surplus. For the AG-recommended demand curves, the figure shows: (i) prices in the first year based on the current CAF level; (ii) the average increase in prices in the last 3 years with CAFs at the high end of our estimates in these years; and (iii) the additional increase in prices in the last 3 years assuming CAFs at the low end of our estimates of realistic CAFs in these years.

Figure 2: Forecasted Prices in Reset Period



This analysis shows that the AG proposal is likely to produce much higher prices in New York City after year 1 of the demand curve period than the MMU-recommended curves. Prices after year 1 in the rest of the state area may be comparable under the AG and MMU-recommended curves in the "Low" CAF case, with the MMU-recommended curves producing only slightly higher prices in the optimistic "high" CAF case.[3]

[2] See NYISO 2023-2042 System & Resource Outlook (July 2024), pages 8-9.

[3] Due to the current levels of surplus capacity in the G-J Locality and Long Island, the clearing prices in those areas are set on the NYCA demand curve. Additional detail is provided in Section B.

Hence, we find that a 2-hour battery is not advisable for NYISO to select as the Demand Curve Technology, both because: a) it cannot effectively satisfy the reliability needs of the system in the future; and b) it is not the lowest cost technology if future changes in CAFs are properly considered in the calculation of Net CONE.

2. Combustion Turbine Amortized over 20 Years

We recommend selecting a CT amortized over 20 years as the demand curve unit technology. The primary argument against selecting a CT is that it is challenging to permit it in New York State. However, the Department of Environmental Conservation ("DEC") has acknowledged that it could permit a fossil fuel generator identified to be needed for reliability by NYISO.[4] In addition, we find a number of compelling factors that demonstrate that a CT amortized over 20 years is the most reasonable choice for the demand curve technology:

- The clean energy transition will likely require the retrofit of much of the existing gas-fired capacity to burn clean fuel and a new CT will be among the most cost-effective units to retrofit. It is also reasonable to expect that Net CONE will rise to reflect new emission-free dispatchable resources. Hence, a new CT is well-positioned to operate profitably for more than 20 years.
- Properly accounting for the revenue effects of falling CAFs over the next 20 years for the 2-hour battery reveals that its true Net CONE currently is much higher than the Net CONE for a CT amortized over 20 years (See Section B of this memo).
- Even if one accepts AG's estimate of a battery's current CONE, a CT amortized over 20 years would avoid price increases from falling CAFs in the next four years.

The remaining sections in this memo address the following areas:

- Section B identifies flaws in AG's evaluation of the 2-hour battery and estimates the Net CONE that would result from addressing the flaws.
- Section C shows that the AG-recommended curves create substantial price risk over the 4-year demand curve reset period associated with near-term reductions in CAFs.
- Section D explains why it would be reasonable for NYISO to select a CT amortized over 20 years as the demand curve unit technology.
- Section E provides our conclusions and recommendations.

B. Evaluation of the 2-Hour Battery Storage System Net CONE

In its July 30 Interim Final Report, AG recommended the 2-hour battery amortized over 20 years for the demand curve unit technology. Table 1 shows its results for four key locations. The Net CONE of the 2-hour battery is initially calculated per kW-year of installed capacity ("ICAP"). The 2-hour battery's Net CONE in ICAP (shown in the first row) is divided by CAF (in the

[4] See the DEC's *Notice of Denial of Title V Air Permit*, *DEC ID: 3-3346-00011/00017, Danskammer Energy Center*, dated October 27, 2021, at page 13: "Danskammer has not offered a sufficient basis for the [DEC] to justify the Project…based upon publicly available studies and reports by the [NYISO],…at least through 2030, there is no demonstrated reliability need or justification for the Project."

second row) to determine the Net CONE per kW-year of UCAP (in the third row). This is converted to a monthly value (kW-month of UCAP) to set the demand curves (in the fourth row).

Table 1: Analysis Group Interim Final Report Recommendations

Parameter		F – Capital	G – Dutchess	J - NYC	K – Long Is.
Net CONE per kW-year (ICAP)	(1)	\$47.20	\$49.50	\$126.96	\$27.73
Capacity Accreditation Factor	(2)	55.42%	56.16%	55.93%	52.76%
Net CONE per kW-year (UCAP)	= (1)/(2)	\$85.17	\$88.14	\$227.00	\$52.56
Summer Reference Point in \$ per kW-month (UCAP)	(3)	\$9.84	\$10.93	\$28.64	\$7.35

This section identifies flaws in AG's evaluation of the 2-hour battery and estimates the Net CONE that would result from addressing the flaws, which would lead to selecting a CT as the demand curve technology. This section is divided into the following parts:

- Part 1 summarizes the available studies of future CAF values for the 2-hour battery and shows future high and low CAF scenarios that we use in this memo.
- Part 2 considers how future CAF values after the initial four-year demand curve period would affect the decision to invest in a 2-hour battery.
- Part 3 addresses AG's argument that the CAF degradation risk to a 2-hour battery investor is comparable to risks faced by other technologies.
- Part 4 demonstrates why the costs of a 2-hour battery exceed those of a CT even if the CT is fully amortized before 2040.
- Part 5 explains that the net energy and ancillary services revenues of the 2-hour battery would also decrease significantly over the 20-year amortization period and how this would further support the selection of a CT as the demand curve technology.
- Part 6 provides a summary of our conclusions.

1. Recent capacity accreditation studies and development of future CAF scenarios

AG makes the flawed assumption that the falling CAF will not prevent the battery from being amortized evenly over a 20-year period. The 2-hour battery CAF is widely expected to drop over the coming years as the penetration of batteries increases and the Northeast US region shifts from a summer peaking system to a system with primarily winter reliability risk. The following five studies estimated the marginal capacity value of 2-hour storage in various scenarios:

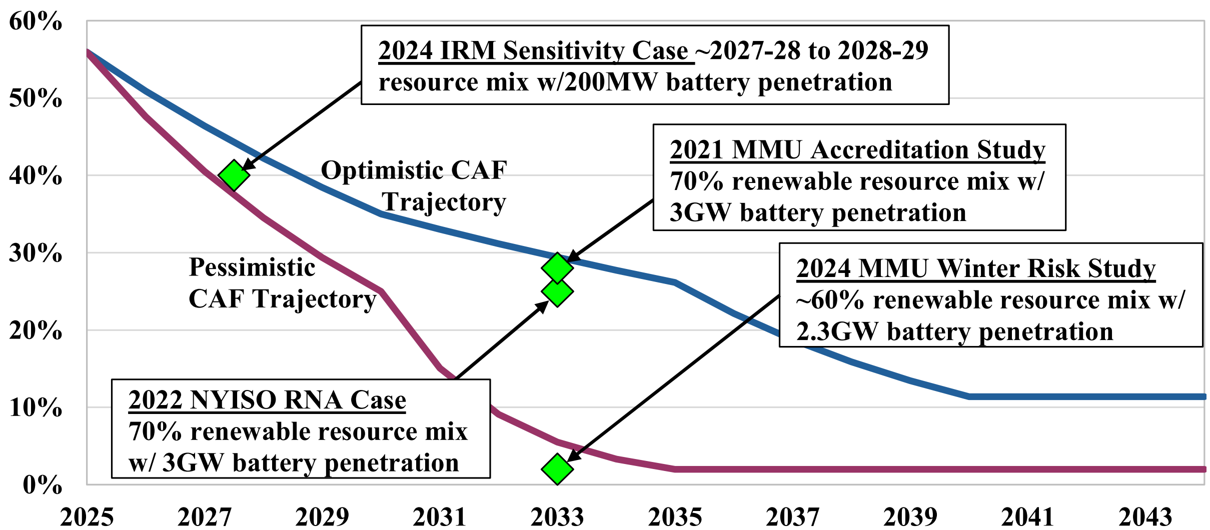
- NYISO (2022): **25 percent** (assumes 3 GW of 4-hour storage in NYC from the Capacity Accreditation consumer impact study of 70 percent renewables by 2030).[5]

[5] See NYISO Staff Draft DCR Report, pages 59-60, "2022 RNA Policy Case Model Year 2030" Case.

- NYISO (2024): **40 percent** (assumes 200 MW of 4-hour storage in NYC from this demand curve reset study with CHPE and 5.2 GW of additional renewables viewed as potentially likely in the 2027-2028 and 2028-2029 Capability Years).[6]
- Potomac Economics (2021): **28 percent** (assumes 3 GW of 4-hour storage and 70 percent renewables by 2030 from our 2021 study of marginal capacity accreditation).[7]
- Potomac Economics (2024): **2 percent** in 2033 assuming delayed completion of State targets for renewables, storage, and electrification and detailed modeling of winter reliability risk drivers (e.g., firm versus non-firm fuel resources and oil inventory limits), which result in the lower estimate.[8]
- NYSERDA's Energy Storage Roadmap (2022) found that the marginal value of shorter-duration storage resources is likely to decline rapidly over time and proposed a contract mechanism to protect developers from future CAF reductions.[9]

All of these studies indicate that we should expect the 2-hour battery's CAF to decline rapidly in the near future, although there is a wide range in the specific projections. Importantly, *none of these studies assume the State achieves its 2030 goal of 6 GW of battery storage installations.* Higher penetration of battery storage will tend to reduce their future CAF levels. Figure 3 shows the results of these studies for NYC (displaying the two studies of 70 percent renewables in 2033 given current progress) and includes realistic optimistic (i.e., high CAF) and pessimistic (i.e., low CAF) future CAF trajectories that we use to analyze 2-hour battery investments.

Figure 3: Future Expected CAF Changes in NYC for the 2-Hour Battery



This figure shows that even in the optimistic case, CAF levels for a 2-hour battery in New York City will drop from the current 56 percent to slightly over 11 percent by 2040. The optimistic

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6 See NYISO Staff Draft DCR Report, pages 59-60, "2024 IRM Sensitivity" Case.

7 See MMU 11/2/2021 ICAPWG presentation, slide 43.

8 See our 2023 State of the NYISO Markets report, page 100.

9 See December 28, 2022 Energy Storage Roadmap (NYPSC Case 18-E-0130), pages 31 and 37.

estimates were generated from our resource adequacy model ("PE-RAM") assuming partial completion of the 2030 goals in 2030 and full completion of 2035 and 2040 goals. These CAFs are relatively high because they do not consider distinctions between firm and non-firm fuel resources. The pessimistic CAF trajectory shows the CAF for a 2-hour battery dropping from 56 percent in 2025 to 2.0 percent by 2035. In 2030, this CAF is based on the 2022 NYISO RNA Case. In 2035 and 2040, these CAFs are low because they consider firm versus non-firm fuel resource distinctions, which become significant as winter reliability risks increase. The figure shows that recently published estimates by NYISO fall between these two CAF trajectories.[10]

2. AG does not reasonably consider the effects of falling CAFs

These anticipated CAF reductions will be considered by battery storage developers. The battery storage advocacy group, NY BEST, recently stated: "the decline in [CAFs] is presently one of the most significant considerations of developers and financers, into their analysis."[11] Since the demand curves are intended to reflect that CONE for new peaking resources as perceived by resource developers, the CONE must reasonably reflect the effects of expected CAF reductions.

AG has dismissed this concern arguing that if the CAF falls during the 20-year amortization period, the Net CONE per kW-year of UCAP will increase to offset the CAF degradation. In other words, if the CAF drops by 50 percent, the Net CONE will double. However, this is only true if 2-hour batteries remain the demand curve technology over the 20-year period, which is not a credible expectation given the magnitude of the net CONE increase that would be implied.

To illustrate how the CAF affects the incentives to invest in a 2-hour battery resource, Figure 4 shows the Net CONE of a battery in New York City over 20 years as the CAF falls in an optimistic case. It compares this to the Net CONE of the resource if the CAF were to remain fixed at the current level and to a CT amortized over 20 years.

Figure 4: Battery Net CONE in NYC with Optimistic CAF

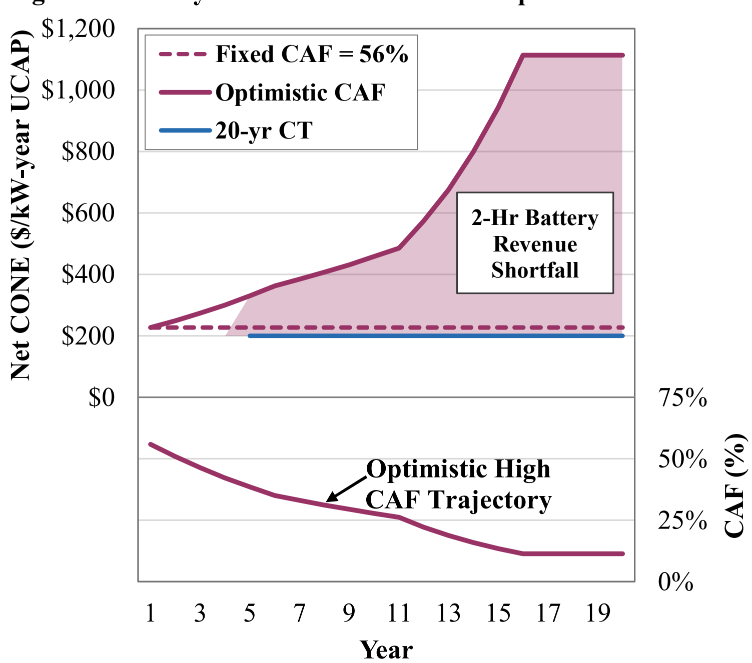

Figure 4 shows that if the CAF falls from 56 percent in Year 1 to 11 percent by year 20, the Net CONE of a 2-hour battery would rise by almost 400 percent to $1113 per kW-year (UCAP). As the CAF falls, its costs will quickly become much higher than the Net CONE of a CT. This should cause the CT to become the demand curve technology, causing a predictable

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10 Each trajectory was set by interpolation using a constant multiplier between 2025, 2030, 2035, and 2040.

11 New York Battery and Energy Storage Technology Consortium ("NY BEST") DCR comments, June 28, 2024, at page 2.

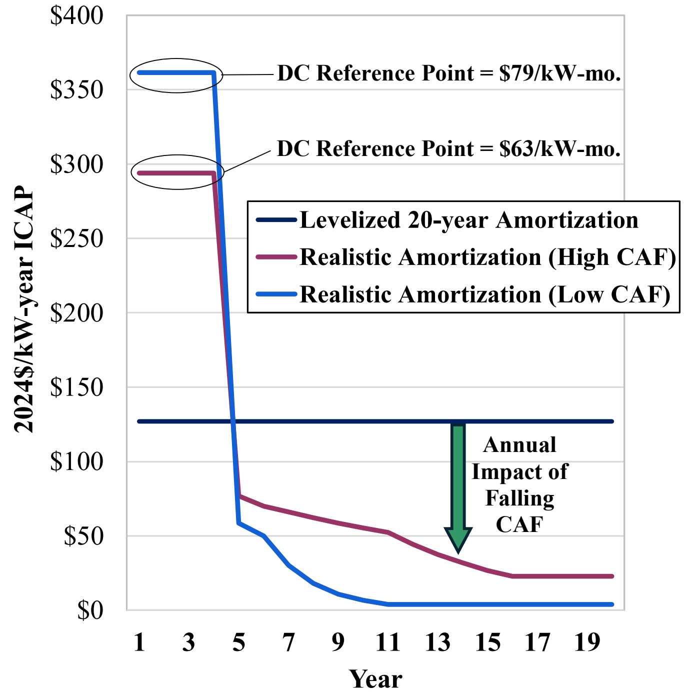
revenue shortfall for the battery shown in the figure. This should cause developers to require more revenue in the near term.

Figure 5 illustrates how a New York City battery investor's annual capacity revenue needs (in ICAP terms) would vary over the 20-year period based on the "Realistic High" and "Realistic Low" CAF trajectories. The revenues fall after year 4 because:

- Other lower-cost technologies will set the demand curves; and
- Falling CAFs will reduce the capacity revenues for 2-hour batteries because it is paid in UCAP terms.

The falling capacity revenues after year 4 must be offset by higher revenues in the first four years when the battery would set the demand curve. These higher initial revenues would offset the falling revenues in future years to provide the same revenues as the 20-year levelized revenues shown in the figure. This indicates that it is unreasonable to assume the 2-hour battery can be amortized evenly over 20 years. AG's assessment of the 2-hour battery storage is incomplete because it does not reasonably consider capacity accreditation risks. A reasonable evaluation of these risks would reveal that the 2-hour battery is more expensive than a CT amortized over 20 years. The analyses shown in Figures 4 and 5 are shown for other zones in New York in the Appendix to this memo.

Figure 5: Capacity Revenue to 2-Hour Battery in NYC



3. Reply to AG's contention that CAF degradation is like any technological change

In the Interim Final Draft Report, AG asserts that the risk of CAF degradation is no different from the risk to a CT developer that its technology may be superseded by a newer superior technology that reduces capacity prices and revenues. This ignores the profound difference in the magnitude of risk of falling returns to a 2-hour battery developer versus a CT developer:

- The risk is almost entirely one-sided for the 2-hour battery – Figure 4 and 5 shows that that the revenue even under the most optimistic CAF trajectory may fall more than 80 percent resulting in a shortfall amounting to the vast majority of the revenue needed by the 2-hour battery resource developer to break even on its investment.
- In contrast, CT developers may see increases or decreases in revenues. Future technological improvements lead to downside risk for a developer, while the developer would benefit from possible increases in future entry costs. Over the last 20 years, the inflation-adjusted Net CONE varied between a minimum of 76 percent and a maximum of 128 percent of the Net CONE from the 2004 demand curve study period.

- CT developers also face potential upside given that virtually all CTs built more than 20 years ago remained in operation well beyond 20 years, which delivers revenues exceeding those assumed under the 20-year amortization.

4. Proper Amortization Raises Net CONE of 2-Hr Battery above that of 13-year CT

Although we do not consider it reasonable to fully amortize the CT before 2040, even a CT fully amortized before 2040 would be more economic than a properly amortized 2-hour battery. AG assumes that if a CT is selected, the amortization period would fall in each of the upcoming demand curve resets, from 13 years in the current reset to 5 years in the 2032 reset. Ironically, this would *reduce* the Net CONE of a resource entering by 2027:

- Such a resource would expect the rising Net CONEs in each of the upcoming demand curve resets;
- This would *lower* the Net CONE of the CT in the current period from $127 per kW-year in ICAP terms to roughly $100 per kW-year – substantially lower than the Net CONE of the 2-hour battery.

This analysis is presented in the Appendix to this memo.

5. Degradation of Net Revenue from Operating Reserves

The 2-hour battery is assumed to earn high revenues from the sale of 10-minute spinning reserves in the day-ahead market. This accounts for 72 percent of energy and ancillary services net revenue based on the assumption that the battery storage unit would sell reserves in the DAM in 89 percent of hours. Stakeholders have pointed out that:

- Battery storage ICAP will reach ~5 GW by ~2033; but
- The requirement for 10-minute spin is only 655 MW and the total contingency reserve requirement is only 2620 MW.

Thus, it is inevitable that the revenues from 10-minute spinning reserves will fall as the penetration of batteries increases. While we do not estimate the impact in this memo, it would have an effect similar to the falling CAF evaluated above and further reduces the reasonableness of the 2-hour battery as the demand curve technology.

6. Conclusion Regarding 2-Hour Battery Net CONE

Our analysis demonstrates that the anticipated reduction in CAFs for 2-hour batteries will likely lead to another technology becoming more economic, thereby reducing revenues after the initial few years of investment. AG has largely ignored this risk and it has led AG to substantially under-estimate of Net CONE for the 2-hour battery. This conclusion is not sensitive to the specific characteristics of the competing technology because it is driven by the unique limitations of the 2-hour battery. We also find that the net revenues assumed from operating reserves has been over-estimated and will decrease as the penetration of battery resources increases.

Hence, a rational investor would require much larger returns in the initial years after the investment to make up for the anticipated CAF degradation. We find that if this risk was properly evaluated, the net CONE of the 2-hour battery rise significantly, making it too costly to be selected as the demand curve technology.

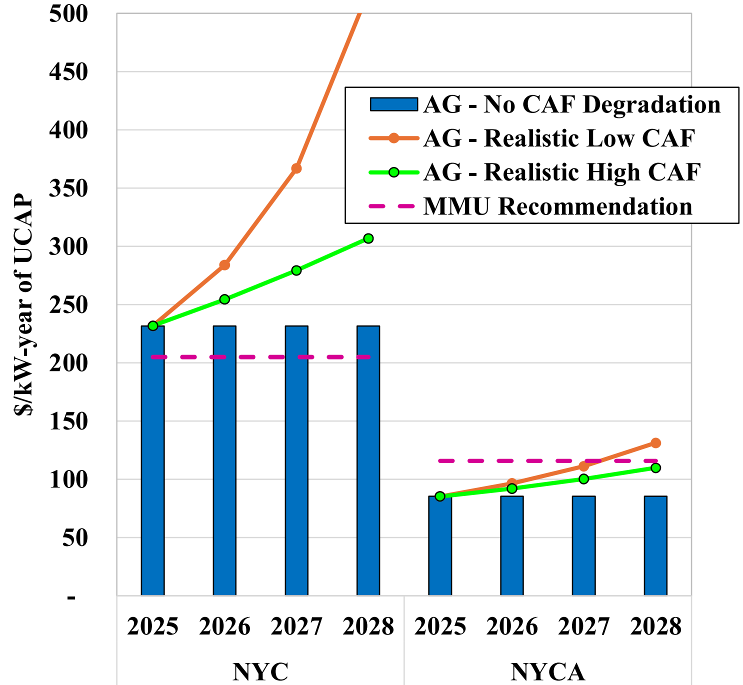
C. Risk to Consumers from a Falling CAF

Based on the CAF levels in the 2024-25 Capability Year, AG finds the 2-hour battery to be the most economic unit. However, the cost of the battery will increase substantially over next four years in UCAP terms if the CAF falls. To illustrate the sensitivity of the demand curves to the 2-hour battery CAF updates, Figure 6 compares the Net CONE values for the 2-hour battery the 20-year CT for New York City and NYCA. Since the values for the 2-hour battery are sensitive to its CAF, the figure shows a fixed CAF, high CAF and low CAF scenarios.

Because the 2-hour battery is smaller than the MMU-recommended CT, the Annual Reference Values (that determine the demand curves) are lower for the 2-hour battery all else equal. However, we find that the Annual Reference Value for the 2-hour battery will exceed the value for the 20-year CT if the CAF falls below:

- 53 percent in NYC; and
- 41 percent in NYCA.

Figure 6: Net CONE Values in DC Reset Period



The NYISO's IRM Sensitivity Case, which roughly corresponds to years 3 and 4 of the demand curve reset period, estimated CAFs for the 2-hour battery of 40 and 43 percent for New York City and NYCA, respectively. This indicates that the 2-hour battery is likely to be much more costly in NYC than a CT and comparable to a CT in NYCA.

This case also included only 200 MW of utility scale battery storage. Given the new NYSERDA program to subsidize energy storage resources and the sensitivity of the demand curves to small changes in the CAFs, it seems likely that the CAFs will fall more rapidly over the next four years, causing the AG recommendation to produce higher demand curves than a 20-year CT.

D. Assessment of a Combustion Turbine

Given the shortcomings of the 2-hour battery, we recommend selecting a CT amortized over 20 years. Part 1 of this section discusses our rationale for the recommended 20-year amortization period. Part 2 discusses several objections that have been made to selecting a CT.

1. Recommendation to Amortize the Combustion Turbine over 20 Years

While AG's evaluation of the CT was generally reasonable, we recommend amortizing the investment over 20 years rather than over 13 years as recommended by AG. The 13-year recommendation is based on the simple assumption that a CT built today would have to retire by 2040 because of the mandates of the CLCPA. We do not believe this is a reasonable assumption given recent studies, which indicate that reliability will require a substantial quantity of dispatchable resources, which will likely be comprised of:

- Existing gas-fired resources retrofitted to burn clean fuel; and
- New dispatchable emission-free resources ("DEFRs")

A new CT entering now will likely be among the most cost-effective units to retrofit. In future years, the Net CONE of the new DEFR technology will likely set the demand curves at levels much higher than the levelized Net CONE of the new CT. Additionally, the characteristics of a new CT will likely make it among the most flexible and efficient existing units, increasing its energy and ancillary services ("E&AS") net revenues after 2040.

Therefore, a new CT is well-positioned to operate profitably for more than 20 years, so it is much more reasonable to assume the CT will be retrofitted than to assume it will be retired. As a result, it is reasonable to assume that a CT built in the next few years would be amortized evenly over 20 years.

Based on these changes, we estimate a levelized Net CONE of $200/kW-year (UCAP) for the CT amortized over 20 years. Given our assessment in Section B, we estimate this would be more economic than the 2-hour battery with its CAF risks reasonably evaluated.

2. Potential Objections to the Combustion Turbine Amortized over 20 Years

In discussions related to the demand curve technology, various objections to the combustion turbine have been raised. The following discussion addresses each objection.

A CT may not be capable of complying with the CLCPA 2040 mandate.

Some cite the lack of CTs currently burning 100 percent clean fuel as evidence that it is not technically or financially feasible. However, it is technically feasible for a CT to become compliant with retrofits and a source of clean fuel. While these are not in operation today because they would not be financially viable, it is reasonable to assume they will become viable in the future if the State is committed to achieving its 2040 goals and less expensive technologies are prohibited by State regulations.

A CT will be difficult to permit and site…unless amortized over 13 years.

This concern is partly driven by the denial of a permit to the proposed Danskammer Energy Center by the NY DEC in 2021. In this denial, however, the DEC clearly stated that the project could have been sited if there was any evidence of a reliability need for the project.[12] Hence, it is likely that a generator could obtain a permit under the conditions modeled in the DCR when a capacity region has a minimal capacity surplus.

Importantly, any difficulty in permitting a new fossil fuel peaking unit would not be addressed by fully amortizing the unit before 2040. The DEC explicitly indicated that a willingness to retire in 2040 did not provide a basis for granting it a permit. Hence, the challenges of siting a new CT do not support the use of a shorter amortization period than 20 years.

Previous decisions of the 4th Circuit Court of Appeals may require a 13-year amortization.

The US Circuit of Appeals for the DC Circuit ("the Court") remanded FERC's initial decision to reject NYISO's proposal to use a 17-year amortization period in the previous DCR. FERC subsequently approved the 17-year proposal, which was later upheld by the Court. Some assert that this implies that NYISO must limit a CT to having a 13-year amortization period in this DCR.[13] However, this is a misinterpretation of the Court's decisions—nothing in the Court's decisions would prevent NYISO from proposing a 20-year amortization period if it is properly explained.

The Court's first decision stated that FERC did not provide adequate reasoning for its rejection of NYISO's FPA Section 205 proposal to use a 17-year amortization period and its requirement for NYISO to use a 20-year amortization period.[14] The Court rejected the justifications provided by FERC for its rejection of the 17-year amortization period:

- FERC reasoned that the New York Public Service Commission ("PSC") might exercise its discretion to allow fossil-fueled generators to remain in service after 2039. The Court noted that such speculation about future regulations was "inconsistent with [FERC's] precedents" and that such changes must be adequately reasoned.
- FERC agreed with commenters stating that "NYISO's proposed 17-year amortization period fails to consider that the [Climate Act] does not require that power generators retire in order to satisfy the 2040 zero-emission requirement." The Court stated that "FERC failed to explain why it found [these] comments compelling, or why it believed that fossil-fueled plants might continue to operate after 2040."
- Importantly, the Court clarified that: "We express no view on whether the more detailed explanations FERC offered in its briefing could support the same result if adopted by the agency and supported by the record."

[12] See the DEC's *Notice of Denial of Title V Air Permit*, *DEC ID: 3-3346-00011/00017, Danskammer Energy Center*, dated October 27, 2021, at page 13: "Danskammer has not offered a sufficient basis for the [DEC] to justify the Project notwithstanding its inconsistency with the Statewide GHG emission limits…based upon publicly available studies and reports by the [NYISO],…at least through 2030, there is no demonstrated reliability need or justification for the Project."

[13] See *Indep. Power Producers of N.Y., Inc. v. FERC*, No. 21-1166, 2022 WL 3210362, (D.C. Cir. Aug. 9, 2022) (per curiam). See *New York Public Service Commission v. FERC*, No. 23-1192, [], (D.C. Cir. Jun. 14, 2024).

[14] At pages 3-4.

Hence, FERC had the option of seeking to expand the record and improving the reasoning underlying the decision in favor of the 20-year amortization period for the CT. However, rather than defend its original decision, FERC responded to the first Court decision by approving NYISO's proposal to amortize the CT over 17 years. The PSC filed a petition for review to challenge this FERC decision.

The Court's second decision denied the PSC's petition for review of FERC's order on remand following the Court's first decision. The Court found the 17-year amortization to be within the zone of reasonableness, but *did not find 20 years to be unreasonable*, stating:

> To the extent that any approach to setting rates here would have required some degree of guesswork, Section 205 of the Federal Power Act (and our prior judgment) required FERC to resolve the matter in favor of [NYISO]'s reasonable prediction.[15]

This demonstrates that there is no Court precedent that would favor a 13-year amortization period over a 20-year amortization period. Further, NYISO has the option of building a record that would support FERC's approval of a 20-year combustion turbine, which would include the valid arguments in the prior subsection of this memo.

NYC property tax abatement for a new CT will expire in 2025.

There is some risk that the 15-year property tax abatement will not be renewed past April 2025 because this would increase the Net CONE of a new CT. This concern is not sufficient to disqualify the CT because:

- There is a long history of tax abatement renewals and if the CT is the demand curve technology, the State would have greater incentives to renew the abatement; and
- Even if the abatement is not renewed, the increase in net CONE for the 20-year CT will not be sufficient to make it more expensive than a properly evaluated 2-hour battery.

No CTs are currently in the interconnection queue.

This should not deter NYISO from selecting a CT as the demand curve technology for several reasons. First, the State currently has programs to subsidize renewable generation, hydro imports from Quebec, and battery storage, which is currently shifting investment incentives away from CT projects. However, since direct State subsidies to battery storage resources cannot be reflected in the Net CONE of the demand curve technology, the CT is still the technology with the lowest Net CONE even if none are currently in the interconnection queue.

Second, New York City is the only area of the State where the capacity surplus is relatively close to the "level of excess" at which the capacity demand curve is designed to motivate entry of new supply. However, materials related to NYISO's 2024 Reliability Needs Assessment indicate that it expects the 1,250 MW CHPE HVDC project and the 816 MW Empire Wind 1 offshore wind project to come online by the end of 2026, which is expected to generate a substantial capacity

[15] At page 12.

surplus in New York City through 2030.[16] These expectations are likely limiting current CT development, but it may emerge in the future as capacity surpluses fall in specific areas due to load growth and/or retirements of existing generation.

E. Conclusions and Recommendations

Based on our analysis of alternative demand curve technologies, the MMU does not support the selection of the 2-hour battery for two primary reasons:

- AG's analysis supporting the 2-hour battery recommendation does not reasonably consider the impact of potential CAF reductions over the proposed 20-year amortization period. If the CAF risks to a battery developer were fully considered, we believe the evaluation would show that the 2-hour battery has a higher Net CONE than a CT amortized over 20 years.
- AG's recommendation is at odds with studies of the resource mix needed to achieve a reliable zero-emission power grid, which suggest 2-hour batteries will not play a significant role.

We recommend selecting a CT amortized over 20 years. The recommended 20-year amortization of the CT is supported by the following arguments in this memo:

- The transition to a zero-emission power system will likely require much of the existing fossil fuel capacity to be retrofitted to burn clean fuel and a new CT would be among the most cost-effective units to retrofit.
- The need for new dispatchable emission-free resources in the future will also likely raise the demand curves in the future as 2040 approaches.
- Hence, a new CT is well-positioned to operate profitably in a zero-emissions power system well beyond 2040.

Finally, our recommendation to select a 20-year CT would eliminate the substantial risks to consumers of cost increases associated with CAF volatility over the next four years. We find that selecting a 20-year CT would likely result in much lower clearing prices in New York City and only slightly higher prices in other areas over the four-year demand curve period of May 2025 to April 2029.

Hence, we recommend the NYISO consider modifying its DCR technology recommendation to be a CT amortized over 20 years.

16 See *2024 RNA Preliminary Results*, presented to the ESPWG/TPAS, July 25, 2024. Slide 17 indicates resource adequacy margins are not anticipated become tight until 2033, while slide 32 indicates that transmission security margins are anticipated to be substantial until the summer of 2031.

APPENDIX

1. Analysis of a CT with Decreasing Amortization

Figure 7 illustrates how a CT investment might be amortized over the 13 years before 2040 if it expected CTs entering in 2031 and 2035 would need to be fully amortized before 2040. The figure shows that this would actually reduce the CT net cost of entry in 2027 and 3031 compared to a 20-year levelized amortization schedule.

Figure 7: Capacity Revenues to 2-Hour Battery if CTs Fully Amortized by 2040

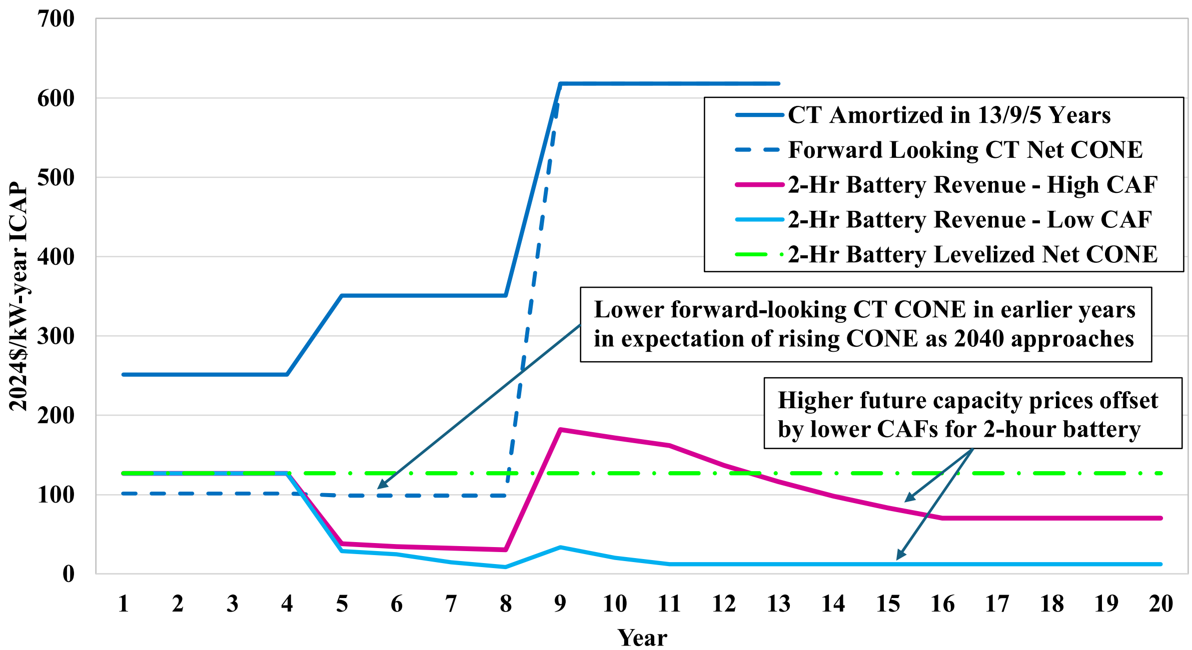


Figure 7 shows the annual capacity revenue that would be recovered by a 2-hour battery in each year of the investment assuming it receives: (a) the 20-year levelized amortized revenue requirement in Years 1 to 4, (b) capacity revenue based on the Net CONE of a CT entering in 2031 and fully amortized before 2040, and (c) capacity revenue based on the Net CONE of a CT entering in 2035 with a 5-year levelized amortization and continuing at this level through the remainder of the 20 years of the 2-hour battery investment. These are shown for our realistic high and low CAF scenarios.

In the high CAF scenario, the 2-hour battery developer earns 17 percent less capacity revenue (on a net present value basis) than needed to make the investment profitable. In the low CAF scenario, the 2-hour battery developer earns 54 percent less capacity revenue than needed to make the investment profitable. The figure shows that if capacity prices rose in the last five years before 2040 and continued through 2046, it would tend to increase revenues to a 2-hour battery investment, but not enough to make the investment profitable because of the significant CAF degradation. Hence, even if a CT had to be fully amortized before 2040, it would not support the selection of a 2-hour battery as the demand curve unit technology.

2. *Analysis of CAF Effects on Net CONE in Other New York Areas*

The following figures present the results of Figures 4 and 5 in this memo, calculated for localities other than New York City.

Figure 8A: 2-Hour Battery Net CONE in NYCA w/ Optimistic CAF

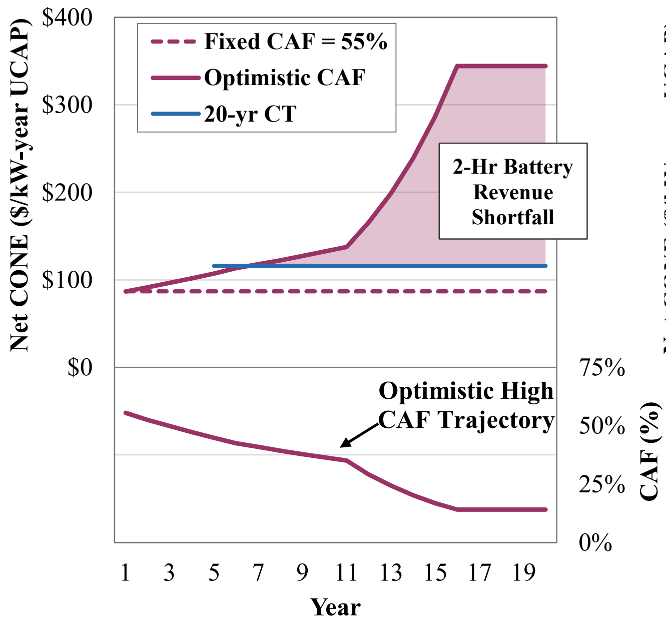


Figure 8B: 2-Hour Battery Net CONE in G-J w/ Optimistic CAF

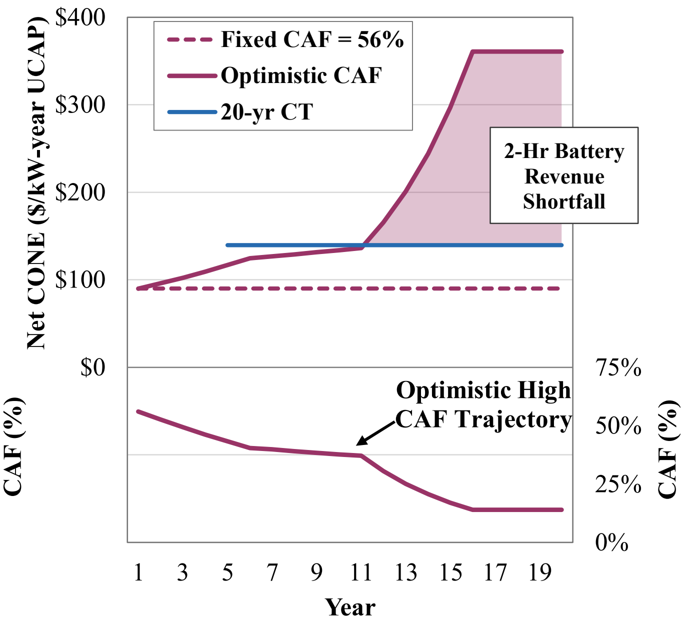


Figure 8C: 2-Hour Battery Net CONE in Long Island with Optimistic CAF

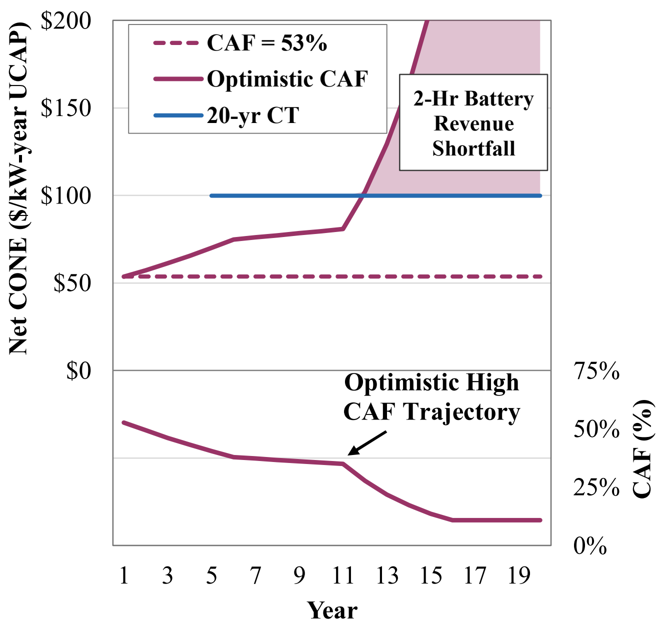


Figure 9A: Annual Capacity Revenue to 2-Hour Battery in Long Island

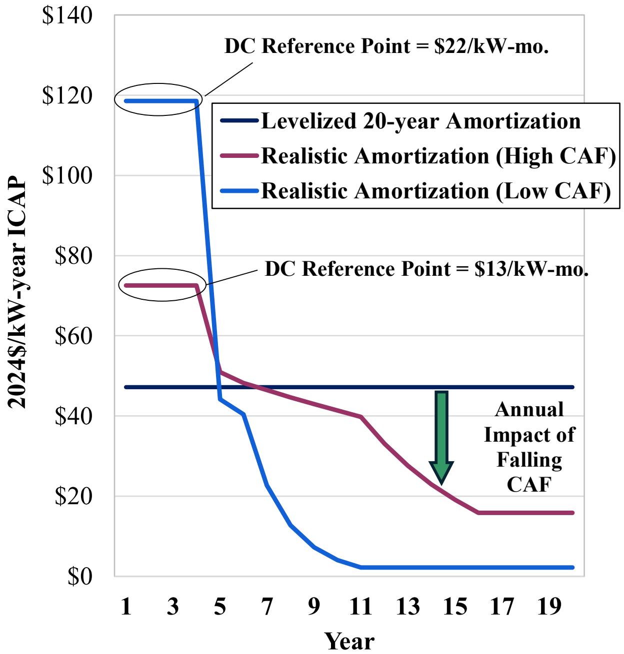


Figure 9B: Annual Capacity Revenue to 2-Hour Battery in Long Island

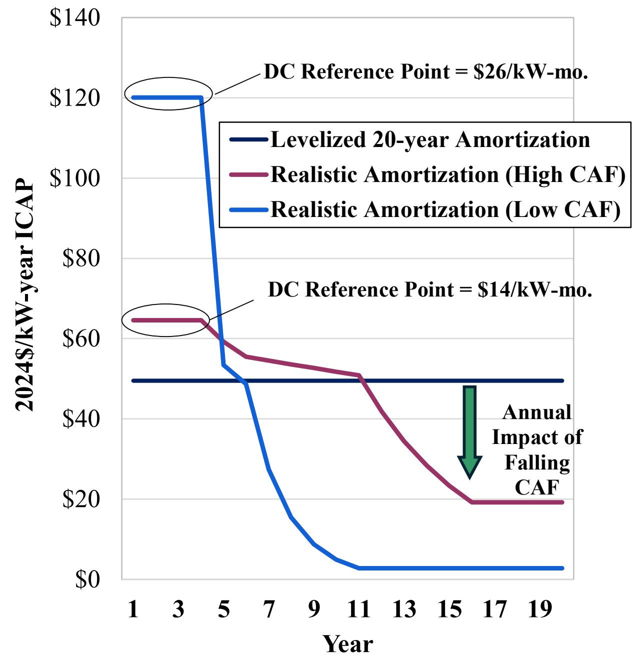


Figure 9C: Annual Capacity Revenue to 2-Hour Battery in Long Island