Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years

Draft Report – Results Subject to Change

Results and recommendations contained herein are preliminary and subject to change. The results herein use data for the period September 1, 2020 through August 31, 2023. The results will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.

Analysis Group, Inc.
1898 & Co.

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This Draft Report provides values for the 2025/2026 Capability Year Installed Capacity (ICAP) Demand Curves as well as methodologies and inputs to be used in determining the ICAP Demand Curves for the 2026/2027, 2027/2028, and 2028/2029 Capability Years. *All numerical results presented in this Draft Report include data as required for the estimation of net Energy and Ancillary Services (EAS) revenues and escalation of capital costs. Net EAS revenues are estimated using data for the three-year period September 2020 through August 2023. The values will be updated in September 2024 to reflect data for the period September 2021 through August 2024.*

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Acronyms and Glossary

Capitalized terms that are not specifically defined in this Report shall have the meaning set forth in the NYISO Market Administration and Control Area Services Tariff and Open Access Transmission Tariff.

Acronym or Abbreviation	Description
AC	Alternating Current
AF	Attachment Facilities
AFUDC	Allowance For Funds Used During Construction
AIS	Air Insulated Switchgear
AP	Amortization Period
ARV	Annual Reference Value
ASC	Startup Cost
ATWACC	After Tax Weighted Average Cost of Capital
BACT	Best Available Control Technology
BESS	Battery Energy Storage System
BPCG	Bid Production Cost Guarantee
Btu	British Thermal Units
CAFs	Capacity Accreditation Factors
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CEQR	New York City Environmental Quality Review
CFR	Code of Federal Regulations
CLCPA	Climate Leadership and Community Protection Act
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Cost of Debt
COE	Cost of Equity
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CRIS	Capacity Resource Interconnection Service

Acronym or Abbreviation	Description
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbines
CTO	Connecting Transmission Owner
DAF	Developer Attachment Facilities
DAM	Day-Ahead Market
DAMAP	Day-Ahead Margin Assurance Payment
DCF	Discounted Cash Flow
DCR	Quadrennial ICAP Demand Curve Reset Process
D/E Ratio	Ratio of Debt to Equity
DMNC	Dependable Maximum Net Capability
EAS	Energy and Ancillary Services
EC	Emissions Costs
EFORd	Equivalent Demand Forced Outage Rate
EIA	U.S. Energy Information Administration
EOL	End-Of-Life
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, Construction
ERC	Emission Reduction Credits
ERP	Equity Risk Premia
FERC	Federal Energy Regulatory Commission
FEMA	Federal Emergency Management Agency
FICA	Federal Insurance Contributions Act
FTE	Full Time Equivalent
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GE	General Electric International, Inc.
GE-MAPS	GE's Multi-Area Production System
GHG	Greenhouse Gases

Acronym or Abbreviation	Description
GIS	Gas Insulated Switchgear
GSU	Generator Step Up Transformer
HHV	Higher Heating Values
HR	Heat Rate
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
ICR	NYCA Minimum Installed Capacity Requirement (MW)
IDC	Interest During Construction
IPP	Independent Power Producer
IRM	NYCA Installed Reserve Margin (%)
IRS	Internal Revenue Service
ISO	International Organization for Standardization
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
kW-month	Kilowatt-month
kW-year	Kilowatt-year
LAER	Lowest Achievable Emission Rate
LBMP	Locational Based Marginal Pricing
LCR	Locational Minimum Installed Capacity Requirement
LDC	Local Distribution Company
LFP	Lithium Iron Phosphate
LI	Long Island (Load Zone K)
LOE	Level of excess
LOE-AF	Level of excess adjustment factor
LOLE	Loss of Load Expectation
MECL	Minimum Emissions Compliant Load
MHPS	Mitsubishi Hitachi Power Systems

Acronym or Abbreviation	Description
MIS	Minimum Interconnection Standard
MMBtu	Million Btu
MMU	Market Monitoring Unit (Potomac Economics)
MPs	Market Participants
MPT	Main Power Transformer
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NCA	Lithium Nickel Cobalt Aluminum Oxide
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NMC	Lithium Nickel Manganese Cobalt Oxide
NNSR	Nonattainment New Source Reviews
NOx	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review
NYC	New York City (Load Zone J)
NYCA	New York Control Area
NYCRR	New York Codes, Rules and Regulations
NYISO	New York Independent System Operator, Inc.
NYSDEC	New York State Department of Environmental Conservation
NYSRC	New York State Reliability Council, L.L.C.
O_2	Oxygen
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
OFO	Operational Flow Order
OTR	Ozone Transport Region

Acronym or Abbreviation	Description
PBE	Purpose-Built Enclosure
PCS	Power Conversion System
P(fuel)	Price of Fuel
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, L.L.C.
POI	Point of Interconnection
ppmvd	Parts per million by volume on a dry basis
PSC	New York State Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch gauge
PTE	Potential to Emit
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
ROE	Return on Equity
ROS	Rest of State (Load Zones A-F)
RP	Reference point price
RS1	NYISO Rate Schedule 1 Charge
RTD	Real-Time Dispatch
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCGT	Simple Cycle Gas Turbine
SCR	Selective Catalytic Reduction
SDU	System Deliverability Upgrades
SER	Significant Emission Rates
Siemens	Siemens Energy Inc.
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SRP	Summer Reference Point Price

Acronym or Abbreviation	Description
SUF	System Upgrade Facilities
SWR	Summer-to-winter ratio
tpy	Tons per year
UARG	Utility Air Regulatory Group
UCAP	Unforced Capacity
ULSD	Ultra-low Sulfur Diesel
UOL	Upper Operating Unit
U.S.	United States
VOC	Volatile Organic Compounds
VOM	Variable Operations and Maintenance Costs
VSS	Voltage Support Service
WACC	Weighted Average Cost of Capital
WRP	Winter Reference Point Price
WSR	Winter-to-summer ratio
ZCP	Zero Crossing Point
ZCPR	Zero Crossing Point Ratio

Figures and Tables

I. Introduction and Summary

A. Introduction

Section 5.14.1.2 of the New York Independent System Operator, Inc. (NYISO) Market Administration and Control Area Services Tariff (Services Tariff) requires that locational Installed Capacity (ICAP) Demand Curves be established periodically through a review by an independent consultant, and be reviewed with stakeholders and the NYISO through a process that culminates in the filing with the Federal Energy Regulatory Commission (FERC) of ICAP Demand Curves approved by the NYISO Board of Directors.

On July 20, 2023, the NYISO contracted with Analysis Group Inc. (AG) to conduct the independent review of ICAP Demand Curves, to be used starting in Capability Year 2025/2026. AG teamed with 1898 & Co. to complete the development of ICAP Demand Curve parameters, described in this Draft Report (Report).[1]

The results and recommendations provided in this Report are preliminary and subject to change. The values provided herein for estimating net EAS revenues are based on data for the three-year period September 2020 through August 2023. The values will be updated in September 2024 to reflect data for the period September 2021 through August 2024.

B. Study Purpose and Scope

The purpose of this Report is to summarize the results of our study of the ICAP Demand Curve parameters. As required by the Services Tariff, the Report evaluates the net cost of a peaking plant, defined 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," with the scale (i.e., number and size of units) identified in the consultant's review.[2] The Services Tariff identifies multiple requirements for the development of ICAP Demand Curve parameters. Our review and analysis conforms to these various requirements. For example, the Services Tariff requires that the periodic review of ICAP Demand Curves:

> "…assess (i) 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 …; and (ii) the likely projected annual Energy and Ancillary Services revenues of the peaking plant for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services … including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review"[3]

The costs and revenues are to be determined under conditions that reflect specified excess supply conditions in NYCA and in each Locality. Specifically, the Services Tariff requires that:

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[1] 1898 & Co. is a business, technology, and security consultancy which is a part of Burns & McDonnell.
[2] NYISO, Market Services Tariff (hereafter "Services Tariff"), Section 5.14.1.2.2.
[3] Services Tariff, Section 5.14.1.2.2.

> "…[t]he 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…"[4]

Several additional elements to be included in the quadrennial review are specified in the Services Tariff, including the following:

- The appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves declines to zero (the zero crossing point (ZCP));
- The translation of the annual net revenue requirement of the peaking plant into monthly values that reflect differences in seasonal capability; and
- The escalation factor and inflation component of the escalation factor applied to the ICAP Demand Curves.[5]

The Services Tariff also specifies the process for selecting the independent consultant, and development of a schedule for the consultant's analysis and review of the consultant's findings and report by stakeholders, NYISO, the Market Monitoring Unit (MMU), and the NYISO Board of Directors. The entire process – herein referred to as the ICAP Demand Curve reset (DCR) process – is to be completed and filed with FERC no later than November 30 of the year prior to the first Capability Year in which the ICAP Demand Curves shall apply (in this case, the Capability Year beginning May 1, 2025).

C. Study Process

AG and 1898 & Co. have conducted the ICAP Demand Curve review in an open and transparent process that involved the full vetting of issues raised by stakeholders. AG and 1898 & Co. have worked with the NYISO throughout the process to conduct an orderly and transparent presentation of key issues for discussion with stakeholders, and to ensure that the ICAP Demand Curve review was consistent with the requirements under the Services Tariff and the structure and experience of New York's wholesale electricity markets. Table 1 contains a list of stakeholder meetings in which AG or 1898 & Co. participated, and the issues discussed with stakeholders at each meeting.

AG/1898 & Co.'s review of ICAP Demand Curve matters with stakeholders helped identify important scoping issues, evaluate concepts and metrics relevant to the DCR process, and provide guidance for AG/1898 & Co.'s consideration of and recommendations on key DCR issues and outcomes. While the content of and findings in this Report rest solely with AG and 1898 & Co., it reflects the results of a productive and deliberative process involving full and substantive input throughout a comprehensive stakeholder process that unfolded over the course of approximately one year.

[4] Services Tariff, Section 5.14.1.2.2.
[5] Services Tariff, Section 5.14.1.2.2.

Table 1: Summary of AG and 1898 & Co. Stakeholder Engagement

Date	Topic
August 24, 2023	Introduction to team and DCR process/timeline
September 26, 2023	High-level considerations for technology screening process Initial discussion of potential peaking plant technologies for evaluation
November 8, 2023	Discussion of technology screening criteria and peaking plant technologies for evaluation Review of net Energy and Ancillary Services (EAS) revenue model for thermal/fuel-fired and battery technologies Process for selecting gas hubs for pricing in the thermal/fuel-fired net EAS revenue model
December 15, 2023	Technology screening overview Preliminary scope assumptions for SCGT and battery storage technologies
January 25, 2024	Discussion of level of excess adjustment factors (LOE-AFs) Preliminary recommendations for net EAS revenue models (i.e., thermal/fuel-fired, and storage) Review of financial parameters
February 29, 2024	Proposed approach for LOE-AFs Preliminary recommendations of gas hubs for pricing in the thermal/fuel-fired net EAS revenue model Update on battery net EAS model enhancements
March 13, 2024	Methodological changes to net EAS storage model to allow for 5-minute interval pricing in the real-time energy market Preliminary assessment of potential magnitude of impacts associated with using 5-minute real-time pricing for net EAS storage model
March 25, 2024	Preliminary net EAS revenue results Initial results of 5-minute real-time battery modeling Technology selection considerations Preliminary unit performance, capital costs, and O&M estimates
April 17, 2024	Updated recommendations of gas hubs for pricing in the thermal/fuel-fired net EAS revenue model Discussion of financial parameter considerations for capital structure, cost of debt, cost of equity, amortization period, and property taxes Continued discussion of 5-minute real-time battery modeling enhancements
May 20, 2024	Continued discussion of 5-minute real-time battery modeling enhancements Evaluation of selective catalytic reduction (SCR) emission controls and dual fuel for thermal/fuel-fired technology options Preliminary reference point prices

	Updated preliminary BESS unit performance, capital cost, and O&M estimates
May 30, 2024	Preliminary financial parameter recommendations for capital structure, cost of debt, cost of equity, amortization period, and property taxes Updated preliminary BESS unit performance, capital cost, and O&M estimates

Note: [1] All materials are posted and available on the NYISO website, available here: https://www.nyiso.com/icapwg

D. Study Analytic Approach and Outline

The creation of ICAP Demand Curves for NYCA and each Locality includes four specific tasks, organized and described in this Report as follows:

- ***Assessment of the peaking plant technology (Section II).*** In this step, we evaluate and develop information on technologies with the goal of fulfilling the Services Tariff's requirement that the peaking plant be the technology with the lowest fixed and highest variable costs and be economically viable.[6] Specifically, we evaluate available technologies consistent with the Services Tariff's definition in NYCA and each Locality with respect to capital costs, operating costs, operating life and other operating parameters, degree of successful commercialization and operational history, and applicable siting and environmental permitting requirements. Based on these factors, we also consider whether and how the peaking plant could be practically constructed within each Locality and ROS, and how a potential developer would evaluate various design capabilities and environmental control technologies when making investment decisions in consideration of project development and operational risk, and opportunities for revenues over the economic life of the project.[7] The technology choice assessment, including the recommended technology, its installed capital cost, and operational costs and parameters, is presented in Section II.
- ***Estimation of the gross cost of new entry (gross CONE) (Section III).*** In this step, we estimate the fixed annual costs of the peaking plant options, including the recovery of and return on upfront capital costs, taxes, insurance and fixed operations and maintenance (O&M). A levelized fixed charge is calculated to ensure recovery of capital costs and taxes given financial parameters that reflect the specific risks associated with merchant plant development in the NYISO markets.
- ***Estimation of net EAS revenues for the peaking plant technology (Section IV).*** In this step, expected EAS revenues for the peaking plants in NYCA and each Locality, net of operating costs, are estimated using models constructed by AG for this purpose. The models include a mechanism to adjust the location based marginal prices (LBMPs) and reserve prices used in the applicable net EAS revenues model to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[8]
- ***Determination of the reference point price and ICAP Demand Curve in NYCA and each Locality (Section V).*** In this step, gross CONE estimates (from Section III) and expected net EAS revenues (from Section IV) are combined to calculate the reference point price (RP) values for the ICAP Demand Curves for NYCA and each Locality. Other parameters that govern the shape and slope of the ICAP Demand Curves, including the ZCP, seasonal reliability risks, and seasonal differences in the quantity of available capacity, are also considered.

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[6] Services Tariff, Section 5.14.1.2.2.

[7] FERC has found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058, Docket No. ER11-2224-000, at P 37 (January 28, 2011)). FERC has also held that "[a]n economically viable technology must be physically able to supply capacity to the market, but other than this requirement … economic viability determinations are a 'matter of judgment.'" (*See New York Independent System Operator, Inc.*, 146 FERC ¶ 61,043 at P 60 (January 28, 2014)). FERC has further clarified that the "peaking plant represents the hypothetical marginal plant, and, therefore, must be able to be replicated." (*See New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 at P 65 (January 17, 2017)). These considerations are discussed in greater detail in Section II.

[8] The Services Tariff requires that net EAS revenues be estimated for the peaking plant technology under system conditions that reflect the applicable minimum Installed Capacity Requirement (ICR) plus the capacity of the peaking plant, which AG defines as the "level of excess" or LOE. The derivation of the LOE-AFs and how historical market prices are adjusted to reflect LOE conditions are described in detail in Section III. *See* Services Tariff, Section 5.14.1.2.2.

- ***Annual updating of NYISO ICAP Demand Curve reference point prices (Section VI).*** In this step, RPs and ICAP Demand Curves are updated annually based on escalation of installed capital costs, recalculation of net EAS revenues using updated electricity prices, fuel prices, emission cost data, and determination of the amount of capacity available seasonally.[9]

In this study, we analyze the currently prescribed Localities for the ICAP Market, which includes the G-J Locality, New York City or NYC (Load Zone J) and Long Island or LI (Load Zone K), as well as the state as a whole, or the NYCA.

Each of the steps described above involves a complex mix of historical data, forecasts, and modeling techniques geared towards developing an appropriate representation of New York electricity market structures and dynamics. It involves extensive review of relevant data and analytic methods, and requires a selection of methods, models and data from among a range of reasonable alternatives based on the application of decision criteria and professional judgment. It also involves a comprehensive review with stakeholders of the purpose, effectiveness, and appropriateness of selected assumptions, methods and data.

AG and 1898 & Co. developed their recommendations for this DCR through the continuous interaction with stakeholders over a nearly year-long period. AG and 1898 & Co. received feedback on proposals and analyses from NYISO and stakeholders in written and verbal form across numerous meetings of the ICAP Working Group (ICAPWG).

The DCR requires not only analysis of a wide array of quantitative market, financial, and economic data and analytics, but also the application of reasoned judgment when the empirical evaluation is limited by sparse, uncertain, and variable historical data and forecast assumptions. Consequently, AG established a set of objectives and criteria against which it reviewed and considered DCR-related matters and methodological issues on both quantitative and qualitative bases. The objectives and criteria were developed to help guide the analysis and provide a framework for the evaluation of process and analytic alternatives. Specifically, AG established that potential DCR issues should be evaluated against the following objectives and criteria:

- *Economic Principles* – Proposed changes to ICAP Demand Curve parameters and methods should be grounded in economic theory and reflect the structure of, and incentives in, the NYISO administered markets.
- *Accuracy* – ICAP Demand Curve parameters should reflect the actual cost of new entry in New York with as much certainty as is feasible.
- *Transparency* – The DCR calculations and periodic updates to net CONE should be clear and transparent to Market Participants (MPs), and annual update methods and calculations should be understandable and allow MPs to develop market expectations.
- *Feasibility* – The DCR design and implementation should be practical and feasible from regulatory and administrative perspectives.

[9] The NYISO operates its capacity market in two separate, six-month Capability Periods. This construct recognizes the differences in the amount of capacity available over the course of each year and the impact of these differences on revenues throughout the year. The seasonal availability of capacity is used to account for the differences in capacity available. These factors are discussed in greater detail in Section IV.

- *Historical Precedent and Performance* – DCR designs should be informed by quantitative analysis based on historical data (to the extent feasible), and should draw from lessons learned in the markets with experience in administration of capacity markets (NYISO, ISO New England Inc. (ISO-NE), and the PJM Interconnection, L.L.C. (PJM)). Consistency between DCRs (to the extent feasible and warranted) also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

E. Summary of Recommendations and Overview of RP Results

AG has applied the methods, models and equations described in this Draft Report to identify RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2025-2026. These values are presented in Table 2, below.

To arrive at these results, AG and 1898 & Co. considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the RP values provided herein. **Note that all numerical results presented below will be updated in September 2024 to use the finalized data as required for the estimation of net EAS revenues and escalation of capital costs.** Specifically, AG and 1898 & Co. conclude the following:

- The two-hour battery energy storage system (BESS) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a BESS would use lithium-ion technology and a modular, purpose-built enclosure (PBE) form factor.
- For the two-hour BESS, we assume a fifteen-year amortization period, and incorporate additional costs for capacity augmentation to ensure consistent performance and nominal capacity value over the assumed life of the resource. Capacity augmentation costs are included in the two-hour BESS' variable operations and maintenance (VOM) costs, reflecting the fact that capacity augmentation costs are related to the total throughput of the battery.
- The appropriate method to evaluate the peaking plant technology is to identify the technology that minimizes the cost of Unforced Capacity (UCAP). An economic evaluation focused solely on the cost of ICAP would fail to account for variation in Capacity Accreditation Factors (CAFs) and derating factors across technology options.[10]
- The state of New York has begun a process to decarbonize the power sector over the next couple of decades, including passage of the Climate Leadership and Community Protection Act (CLCPA) in 2019. The CLCPA does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology during the 2025-2029 DCR period. It does, however, affect the development and operation of such facilities, which could in turn affect present-day financial analysis parameters (e.g., the appropriate amortization period). For this DCR, our review included two categories of units that at least initially were powered using fossil fuels. First, we reviewed installation and operation of a fossil unit in each location designed to exclusively run on fossil fuels (and thus assumed to not operate in 2040 or beyond). Second, we reviewed installation and operation of a unit initially operating on fossil fuels, but retrofitted to operate on

[10] On June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. AG will continue to monitor the status of this proposal for purposes of its assessment for this study.

hydrogen fuel beginning in 2040. For the fossil-only unit, we applied a 13-year amortization period to reflect CLCPA's requirement for 100% of load to be served by zero-emissions resources by 2040, and consistent with the decisions by FERC accepting this amortization period method in the 2021-2025 DCR.[11] For the fossil-hydrogen unit, we studied the potential costs associated with retrofitting a turbine to run on hydrogen fuel, and the costs of storing associated hydrogen fuel onsite.

- For the fossil-fuel fired unit analysis, the GE 7HA.03 frame turbine represents the highest variable cost, lowest fixed cost simple cycle gas turbine (SCGT) peaking plant option that is economically viable. To be economically viable and practically constructible, a 7HA.03 SCGT would be built with selective catalytic reduction (SCR) emission control technology in all locations, whether constructed as gas-only or dual-fuel.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures related to capacity accreditation, consideration of applicable reliability and local distribution company (LDC) retail gas tariff requirements, and developer expectations, we expect that developers would include dual fuel capability in all locations.
- The weighted average cost of capital (WACC) used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 14.0% cost of equity, for a WACC of 9.99%. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 9.02% for all locations other than Load Zone J and 8.76% for Load Zone J.
- For the purposes of modeling net EAS revenues for BESS technologies in the real-time market (RTM), it is appropriate to use Real-Time Dispatch prices transacting on a nominal 5-minute basis. Consistent with the 2017-2021 and 2021-2025 DCRs, we continue to model net EAS revenues for fossil peaking plant options in the RTM using average hourly prices.
- The ICAP Demand Curves should maintain the current zero crossing point (ZCP) values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

Table 2 provides parameters for the 2025/2026 Capability Year ICAP Demand Curves for each location, consistent with the conclusions and technology findings described above. Table 3 through Table 5 provide additional information for the other technologies evaluated. For all locations, the appropriate peaking plant technology and design, as well as the net EAS model structure (including the granularity of real-time prices used by such models) selected as the basis for the 2025/2026 Capability Year ICAP Demand Curves remain fixed for the four-year duration of the reset period.

[11] New York Independent System Operator, Inc., 183 FERC ¶ 61,130 (May 19, 2023); and New York Independent System Operator, Inc., 185 FERC ¶ 61,010 (October 4, 2023).

Table 2: Preliminary ICAP Demand Curve Parameters ($2024 ICAP)

2-Hour BESS (RTD interval pricing net EAS model)

Parameter	Source	Current Year (2025-2026) C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Gross Cost of New Entry ($/kW-Year)	[1]	$125.81	$126.49	$128.85	$125.85	$182.78	$127.04
Net EAS Revenues ($/kW-Year)	[2]	$61.58	$78.78	$69.33	$70.39	$74.00	$98.87
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$64.23	$47.71	$59.53	$55.47	$108.78	$28.17
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$12,846	$9,543	$11,905	$11,093	$21,756	$5,633
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Summer to Winter DMNCs	[7]	1.033	1.033	1.058	1.058	1.067	1.072
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$6.96	$5.17	$6.45	$6.01	$11.78	$3.05
Winter ($/kW-Month)	[11]	$3.75	$2.78	$3.47	$3.24	$6.35	$1.64
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,392	$1,034	$1,290	$1,202	$2,357	$610
Monthly Revenue (Winter)	[13]=[11]*[9]	$749	$557	$694	$647	$1,269	$329
Seasonal Revenue (Summer)	[14]=6*[12]	$8,350	$6,203	$7,738	$7,211	$14,141	$3,662
Seasonal Revenue (Winter)	[15]=6*[13]	$4,496	$3,340	$4,167	$3,883	$7,615	$1,972
Total Annual Reference Value	[16]=[14]+[15]	$12,846	$9,543	$11,905	$11,093	$21,756	$5,634
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$7.27	$5.40	$7.23	$6.74	$13.45	$3.86
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$5.50	$4.08	$6.87	$6.40	$12.59	$4.20
Summer ICAP Maximum Clearing Price ($/kW-Month)		$21.37	$21.49	$23.48	$22.93	$33.90	$26.11
Winter ICAP Maximum Clearing Price ($/kW-Month)		$16.15	$16.24	$22.32	$21.80	$31.73	$28.45
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS. [2] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023 and the seasonal capacity availability values are based on data for the same period. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** [3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [4] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.**

Table 3: Comparison of UCAP Preliminary Reference Point Prices by Technology

($2024 UCAP/kW-Month)

Technology	Fuel Type/ Emission Control	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
		Current Year (2025-2026)					
Summer Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$22.89	$19.67	$29.48	$27.54	$36.33	$29.47
	Gas Only, with SCR	$21.49	$18.38	$29.01	$26.99	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$26.17	$25.05	-	$29.45	-	-
	Gas Only, no SCR	$24.50	$23.35	-	$28.90	-	-
2-hour BESS	Battery Storage	$13.39	$9.95	$13.14	$12.24	$24.54	$7.46
4-hour BESS	Battery Storage	$22.76	$19.33	$22.96	$21.87	$36.85	$14.87
6-hour BESS	Battery Storage	$25.61	$23.09	$27.65	$26.44	$41.99	$24.15
8-hour BESS	Battery Storage	$32.51	$30.42	$35.39	$33.98	$51.35	$33.36
Winter Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$16.71	$14.40	$30.48	$28.47	$38.02	$59.74
	Gas Only, with SCR	$15.69	$13.46	$30.00	$27.91	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$18.67	$17.87	-	$29.98	-	-
	Gas Only, no SCR	$17.48	$16.66	-	$29.42	-	-
2-hour BESS	Battery Storage	$10.12	$7.52	$12.49	$11.64	$22.97	$8.13
4-hour BESS	Battery Storage	$17.20	$14.61	$21.83	$20.79	$34.49	$16.21
6-hour BESS	Battery Storage	$19.35	$17.45	$26.29	$25.14	$39.31	$26.32
8-hour BESS	Battery Storage	$24.56	$22.99	$33.64	$32.30	$48.07	$36.35

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm and the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 15 ppm. [3] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023 and the seasonal capacity availability values are based on data for the same period. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** [4] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [5] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.** [6] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 4: Comparison of Preliminary Gross CONE by Technology ($2024/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$260.72	$257.63	$274.05	$258.67	$321.70	$285.06
	Gas Only, with SCR	$249.23	$246.47	$262.80	$247.43	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$274.58	$271.21	-	$270.83	-	-
	Gas Only, no SCR	$260.66	$257.70	-	$257.21	-	-
2-hour BESS	Battery Storage	$125.81	$126.49	$128.85	$125.85	$182.78	$127.04
4-hour BESS	Battery Storage	$198.67	$199.65	$203.01	$198.75	$282.74	$202.50
6-hour BESS	Battery Storage	$279.12	$280.51	$285.27	$279.24	$385.42	$286.70
8-hour BESS	Battery Storage	$358.73	$360.53	$366.73	$358.86	$492.46	$370.12

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm and the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 15 ppm.

Table 5: Comparison of Preliminary Net EAS by Technology ($2024/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$72.82	$96.37	$67.86	$66.07	$80.40	$134.16
	Gas Only, with SCR	$72.82	$95.76	$59.89	$58.64	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$56.16	$62.41	-	$54.78	-	-
	Gas Only, no SCR	$56.16	$63.04	-	$45.23	-	-
2-hour BESS	Battery Storage	$61.58	$78.78	$69.33	$70.39	$74.00	$98.87
4-hour BESS	Battery Storage	$71.68	$91.81	$77.13	$78.83	$81.68	$118.50
6-hour BESS	Battery Storage	$75.74	$97.15	$80.20	$83.15	$84.52	$128.55
8-hour BESS	Battery Storage	$77.41	$97.24	$81.24	$84.71	$85.41	$132.17

Note: [1] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** [2] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [3] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [4] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.** [5] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

II. Technology Options and Costs

A. Overview

The Services Tariff specifies that the ICAP Demand Curve review shall assess and consider the following:

> "… 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"[12]

The peaking unit is defined 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," and the peaking plant is defined as "the number of units (whether one or more) that constitute the scale identified in the periodic review."[13] The FERC precedent regarding peaking plant technology indicates that, "only reasonably large scale, standard generating facilities that could be practically constructed in a particular location should be considered."[14] In this section, we consider the following:

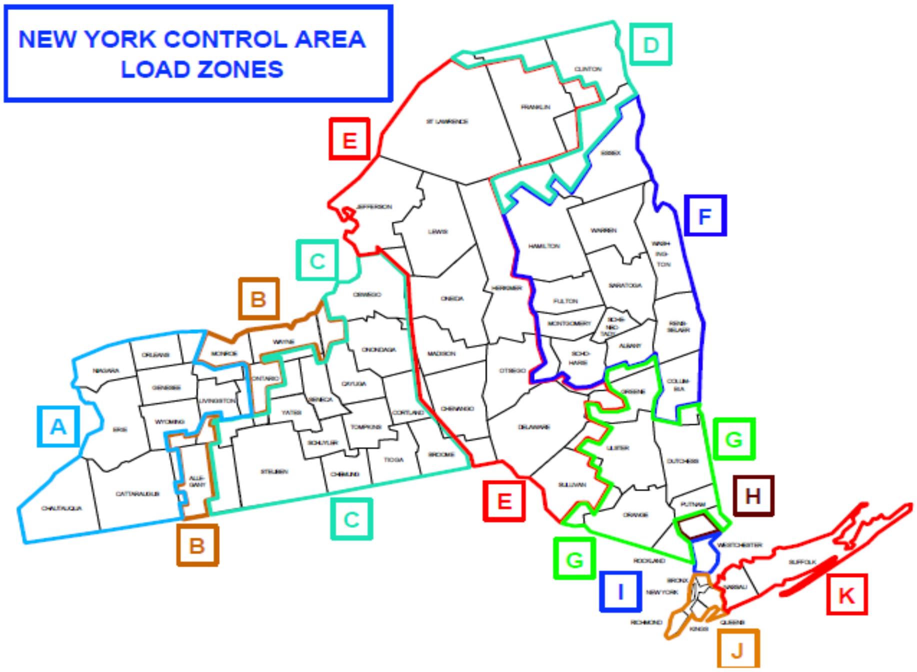
1. Simple Cycle Plant – Simple cycle plants consist of one or more fuel-fired combustion turbines. This study analyzes multiple types and generations of simple cycle technologies, as well as various fuel options including natural gas, liquid fossil fuels, and/or hydrogen.

2. Energy Storage Plant - A battery storage plant is also included in the analysis. Battery storage options with duration capabilities of 2-hours, 4-hours, 6-hours, and 8-hours have been evaluated.

In Section II.B, we apply screening criteria to identify alternative technology options that will be evaluated in the DCR study. Section II.C summarizes applicable environmental and siting requirements, which have implications for installed capital costs, and fixed and variable operations costs. Dual fuel capability for fossil-fired SCGT options, capital costs, fixed O&M costs, and variable O&M costs are evaluated in Sections II.D, II.E, and II.F, respectively. Section II.G describes technical and performance characteristics needed to evaluate net EAS revenues.

[12] Services Tariff, Section 5.14.1.2.2.
[13] Services Tariff, Section 5.14.1.2.2.
[14] See, e.g., *New York Independent System Operator, Inc.,* 134 FERC ¶ 61,058, Docket No. ER11-2224-000, at P 37.

Figure 1: Load Zones and Localities



B. Technology Screening Criteria

1898 & Co. was engaged to select simple cycle gas turbine and energy storage technology option(s) to evaluate as the potential peaking plant for each ICAP Demand Curve. 1898 & Co. evaluated peaking plant technology options for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K (see Figure 1). Additionally, a simple cycle turbine option that could potentially comply with the 2040 zero-emissions energy supply requirement of the CLCPA by retrofitting to operate on hydrogen fuel (selected as a proxy for a potential zero-emissions fuel option) beginning in 2040 was evaluated for informational purposes only.

To comply with the Service Tariff requirements, 1898 & Co. utilized the following screening criteria for peaking technology selection:

- Standard generating facility technology – available to most market participants;
- Proven technology – operating experience at a utility power plant;
- Unit characteristics that can be economically dispatched;
- Ability to cycle and provide peaking service;
- Can be practically constructed in a particular location; and
- Can meet environmental requirements and regulations.

The analysis of potential options identified both simple cycle turbine technologies and energy storage technology as technical candidates for peaking operation. Simple cycle turbine technologies are the current peaking plant technology underlying each of the ICAP Demand Curves. Energy storage technology is capable of peaking operation within discharge duration and state of charge limitations, which are constraints that do not apply to simple cycle turbine technologies with reliable fuel supply. Energy storage technologies were included alongside simple cycle turbine technologies for economic evaluation. Selected representative battery technologies are described in Section II.B.6.

1. Simple Cycle Turbine Technologies

Described below are the peaking plant technology options that satisfy the screening criteria and reflect the following key features for each technology option:

1. *Aeroderivative Combustion Turbines*

   - Number of starts does not impact maintenance schedule
   - Fast start up time (less than 10 minutes) and ramp rates
   - Reasonably sized units (approximately 20 to 100 MW) available where multi-unit plants are advantageous
   - Typically require higher fuel gas pressures than frame units
   - Decades of utility scale operating experience

2. *Frame Combustion Turbines*

   - Commercially available frame units range in size from approximately 50 to 430 MW.
   - Larger frame units typically provide lower cost per kW of output (benefit of economies of scale)
   - F-class turbines exhibit nominal output in the 200-250 MW range.
   - Advanced class turbines, which may also be labeled G, H, or J-class, exhibit nominal output in the 275 – 430 MW range.
   - Frame units typically include dry low emissions combustion systems for NO_x control on natural gas operation. Water injection is required for NO_x controls with liquid fuel operation. A selective catalytic reduction (SCR) emissions controls system will be required for units with NOx emissions greater than 15 ppm.
   - F class units can provide significant capacity in 10 minutes and full output in 11 to 14 minutes; Maintenance impacts may apply to fast starts.
   - Advanced class units have similar startup capabilities, though fast start packages are available for full load in 10 minutes, assuming purge credit and start permissives are met. Maintenance impacts may apply with fast start capability.
   - Major maintenance cost may be based on operating hours or start quantity, depending on operation. In general, each gas turbine model will have a number of operating hours and number of starts prior to reaching a maintenance interval. Whichever is reached first, hours or starts, will dictate the when major maintenance should occur.
   - Depending on the application, frame turbine models may be available with different NO_x emissions rates. Performance is impacted by the NO_x emissions rate controls.
   - Decades of utility scale operating experience

3. *Reciprocating Internal Combustion Engines (RICE)*

- Utility scale applications most commonly rely on heavy duty, medium speed engines in the 9-11MW and 18-20 MW classes.
- Compression ignition models have gas and liquid fuel capability. Spark ignition models are only capable of gas operation.
- Fast start up time as low as five minutes for natural gas engine and seven minutes for dual fuel engine. Engine jacket temperature must be kept warm to accommodate start times under 10 minutes.
- Shutdown as quickly as one minute
- High efficiency, good partial load performance
- Altitude and ambient temperature have minimal impact on the electrical output of reciprocating engines.
- Gas pressure requirements are lower than combustion turbines.
- Installed costs are often similar to those of aeroderivative combustion turbine facilities of similar size.
- Maintenance intervals are based on operating hours and are independent of number of starts.
- Reciprocating engines are typically installed with SCR emissions controls to control NO_x emissions to approximately 5ppm on natural gas fuel.

2. Aeroderivative Combustion Turbine Peaking Options

The aeroderivative combustion turbines that were considered as candidate peaking plant technologies are shown in Table 6. Output and heat rate information is based on manufacturer specifications and heat rates were converted to higher heating value (HHV). Many aeroderivative technologies are offered with model variants for water injection combustion, dry low emissions combustion, wet compression, intercooling, and other options that may impact performance.

Table 6: Aeroderivative Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	LM6000	First introduced in 1997. Mature technology with multiple model variants.	45 - 58 depending on model	9,100 - 9,700 depending on model
General Electric	LMS100	First introduced in 2006. Mature technology with multiple model variants.	100 - 117 depending on model	8,600 - 8,800 depending on model
Siemens	SGT-A35	Core technology based on Rolls Royce RB211. Mature technology.	31-37	9,400
Mitsubishi Hitachi Power Systems	FT4000	First introduced in 2012. Single and twin pack designs available.	72 SWIFTPAC 70 144 SWIFTPAC 140	9,150
Mitsubishi Hitachi Power Systems	FT8	First introduced in the early '90s. Single and twin pack designs available.	31 SWIFTPAC 30 62 SWIFTPAC 60	10,350

Notes:

[1] Data from Original Equipment Manufacturer (OEM) literature. Based on nominal output at ISO conditions (59°F and 60% relative humidity)

[2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

Preliminary screening of the aeroderivative combustion turbine models indicated that the fixed costs per kW for the aeroderivative combustion turbines would be higher than the frame combustion turbines. The larger advanced class frame combustion turbines also offer a competitive heat rate and 10-minute start times for flexibility. Since a frame combustion turbine was selected as the representative technology in the 2021-2025 DCR and there have been no changes that would improve the relative position of the aeroderivative models, no further analysis of the aeroderivative combustion turbine models was performed.

3. *Frame Combustion Turbine Peaking Option*

The candidate frame combustion turbine technologies evaluated for consideration are shown in Table 7.

Table 7: Advanced Frame Technology Combustion Turbines

Manufacturer	Base Model	Experience	Nominal Capacity (MW)[1]	HHV Heat Rate (Btu/kWh)[2]
General Electric	7HA.03	First introduced in 2019, first units went commercial in North America in 2022	430	8,750
General Electric	7HA.02	First introduced in 2017, fleet operating hours of more than 1.4 million hours	384	8,890
Siemens	SGT6-9000HL	First commercial operation in 2022	440	8, 770
Mitsubishi Hitachi Power Systems	501JAC	First unit installed in North America in 2020 and over 1 million fleet operating hours	453	8,610
General Electric	7HA.01	First introduced in 2012	290	9,010
Siemens	SGT6-8000H	Installed fleet has accumulated more than 3 million fired operating hours	310	9,390
Mitsubishi Hitachi Power Systems	MHPS 501GAC	First commercial operation in 2014, mature technology	283	9,470
General Electric	GE 7FA.05	First 7F.05 in operation in 2014 - F-Class is GE fleet leader	239	9,850
Siemens	Siemens SGT6-5000F	Installed fleet has accumulated >15million operating hours	260	9,470

Notes:
[1] Data from OEM literature. Based on nominal output at ISO conditions (59°F and 60% relative humidity) [2] Data from OEM literature. Based on HHV Btu/kWh at ISO conditions.

The results of the screening of the candidate frame combustion turbine models are:

- The GE & Siemens F-class combustion turbines are similar in performance and cost.

- The H/J-class combustion turbines (GE 7HA.03, Siemens 9000HL, and Mitsubishi 501JAC) are similar in performance and cost.
- While the F-class technology has more operational experience than the H/J-class technology, both have proven operational experience in simple cycle peaking configuration with SCR emissions controls.
- The J-class combustion turbines have the lowest fixed costs per Kw compared to the other frame combustion turbines. Since a -G/H-class frame combustion turbine was selected as the representative technology in the 2021-2025 DCR and there have been no changes that would improve the relative position of the smaller F-class and G/H-class models, no further analysis of the smaller frame combustion turbine models was performed.

Two options for the DCR study were chosen from among the frame combustion turbines: The first was a H/J class combustion turbine unit, represented by a 7HA.03, a technology which offers low fixed cost, with high efficiency, and operational experience in North America. The 7HA.03 would require SCR emissions controls. The second was the GE 7HA.02, tuned to NOx emissions of 15ppm, without SCR emissions controls. The 7HA.02 is an advanced class unit with operational experience in North America, and currently serves as the peaking plant technology underlying each of the ICAP Demand Curves.

4. Reciprocating Internal Combustion Turbine Peaking Option

Reciprocating engines are generally competitive with aeroderivative gas turbines, but the initial screening and the results of prior DCRs indicate that RICE technology is not likely to be the lowest cost alternative. Therefore, RICE units were not considered for further study in the DCR.

5. Selected Simple Cycle Turbine Technology for Review

Based on the screening criteria and considerations presented above, costs were developed for the two options indicated below. Two options were selected for advanced class frame combustion turbines; one capable of achieving NOx emissions of 15ppm through dry low emissions technology without SCR emissions controls and one with higher NOx emissions rate from the combustion turbine but including an SCR emissions control system.

- One GE 7HA.03 unit with SCR emissions controls
- One GE 7HA.02 unit without SCR emissions controls (Load Zones C, F, and G (Dutchess County) only)

6. Energy Storage Power Plant

The lithium-ion battery storage market is growing, largely due to declining costs for lithium-ion battery technology and continued penetration of intermittent renewable energy sources. In December 2018, the New York State Public Service Commission (PSC) issued an order establishing a target of 3,000 MW of energy storage by 2030, which was subsequently codified as a requirement in the CLCPA. In 2022, PSC doubled the 2030 storage target to 6,000 MW.

The most likely candidate for new energy storage facilities are battery energy storage systems (BESS) based on lithium-ion technology, which is the most commercially mature battery storage technology in the market at this time. Pumped hydro is the most mature storage technology, with decades of successful operating experience, but this technology is limited in siting potential and requires longer permitting and implementation timelines than battery technologies. Non-lithium technologies were considered in the initial screening process, but preliminary evaluations suggested that the capital costs were higher than similarly sized lithium-ion systems and the market is still maturing for non-lithium alternatives at utility scale. The DCR study includes the following systems for comparison to traditional simple cycle turbine technologies:[15]

- 200 MW, 2-hour (400 MWh stored energy) lithium-ion
- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

The market for lithium-ion batteries is dynamic, and while the stationary storage market is growing, most of the technology innovation and pricing is currently being driven by the electric vehicle market. Lithium-ion represents a broader technology class that includes dozens of battery cathode chemistries, each with its own advantages and disadvantages. Three chemistries have emerged as the leaders in today's market:

- Lithium nickel manganese cobalt oxide (NMC)
- Lithium iron phosphate (LFP)
- Lithium nickel cobalt aluminum oxide (NCA)

Each technology has different energy density, performance, and cost considerations, but all three technologies are generally suitable for the application considered in this DCR study. Since manufacturers and integrators of all three technologies are competing directly today for the same projects, the costs presented in this study are intended to represent a snapshot of the market pricing as it currently stands. These costs are not intended to be directly representative of one chemistry or one OEM.

Technology development in the stationary storage market is trending toward the modular, purpose-built enclosure (PBE) form factor. Battery modules are loaded into modular enclosures in a factory setting and integrated with unit level controls, safety, and thermal management systems. Battery cell and module manufacturers often have their own line of PBE products, but they also commonly sell their battery modules to other integrators who make competing PBE products. The costs in this DCR study assume the use of the modular PBE form factor, but because of the numerous participants and competitive nature of the BESS market, the costs are not intended to represent a specific product provider or battery OEM.

A known limitation of lithium-ion technology is energy capacity degradation. Over time, the energy capacity degrades due to age and cycling behavior. The power (MW) does not degrade, so the BESS can still discharge 200 MW over time, but as the energy capacity (MWh) degrades, the duration of 200 MW discharge becomes shorter. Therefore, for example, a 200 MW, 4-hour discharge duration today will have less than 4-hour discharge duration at rated power in the future.

Should an owner wish to maintain the rated energy capacity of the BESS over time, then the system will likely require augmentation. Augmentation means that new BESS units would be added to the project at intervals over the assumed project life. The original installation would typically be designed to account for future capacity augmentation, and the actual augmentation costs may be part of a long-term agreement that may also account for

[15] The installed battery cell capacity is sized to provide the stated gross MW for the design discharge duration.

routine maintenance. Augmentation costs were considered in the O&M estimates for the DCR study. Because the degradation is impacted by both time and cycling, the study accounts for a “fixed” component of the augmentation cost estimate and a “variable” component of the augmentation cost estimate. Notably, this structure is likely not how the costs are encountered by actual BESS project owners, but it is reasonable to include such a breakdown for this DCR study that considers a range of cycling possibilities driven by the operation of each BESS technology option to earn net EAS revenues in the NYISO-administered markets.

The fixed O&M costs in this study are intended to account for routine BESS equipment maintenance, extended warranties, performance guarantees, the fixed component of the augmentation estimate, balance of plant maintenance, and asset management. Fixed O&M costs are levelized for the assumed project life of each technology. The variable O&M costs in this study are intended to represent the variable component of capacity augmentation, accrued in terms of $/MWh discharged in the net EAS model.

BESS facility roundtrip efficiencies (the fraction of energy charged that can be later discharged) are commonly 80 - 90% when measured on the alternating current (AC) side of the system. The BESS roundtrip efficiency assumed for this study is 85%.

7. Informational Analysis of Hydrogen Fuel Retrofit of SCGT

The State of New York passed the Climate Leadership and Community Protection Act (CLCPA) in 2019 which establishes a goal of 100% zero emissions electricity by 2040. While there is not a precise definition of a “zero emissions” resource, we assume for purposes of this study that it would consist of a generation resource that produces zero direct CO_2 emissions during operation. As such, fossil fuel-fired peaking units are not expected to be able to operate beyond 2040. 1898 & Co. evaluated potential retrofit technologies to comply with the CLCPA for informational purposes.

Post combustion carbon capture has two primary challenges with meeting the CLCPA’s zero emissions energy supply requirement. First, carbon capture technology is currently limited to 90%-95% CO_2 capture rate. This obviously means that some CO_2 emissions would still be produced by the generation resource. Additionally, current carbon capture technology would not be capable of fast startup times and flexible ramp rates that would be expected from the peaking plant technology. Due to these reasons, post combustion carbon capture was not evaluated any further.

Subject to the ultimate regulatory/program requirements to be established for implementing the CLCPA’s zero-emissions energy requirement, there are several potential carbon free fuels that could be viable in 2040, such as hydrogen, ammonia, biodiesel, and renewable natural gas to name a few. All of these are considered emerging technologies and have no commercial operating experience. While each of these fuels pose different benefits and challenges, hydrogen was selected as the proxy fuel to evaluate for informational purposes for this study. All three major gas turbine OEMs are performing research and development on dry low emissions combustor technology capable of firing 100% hydrogen. This combustor technology is expected to be commercially available by 2030. For the purposes of this analysis, 1898 & Co. made the following assumptions:

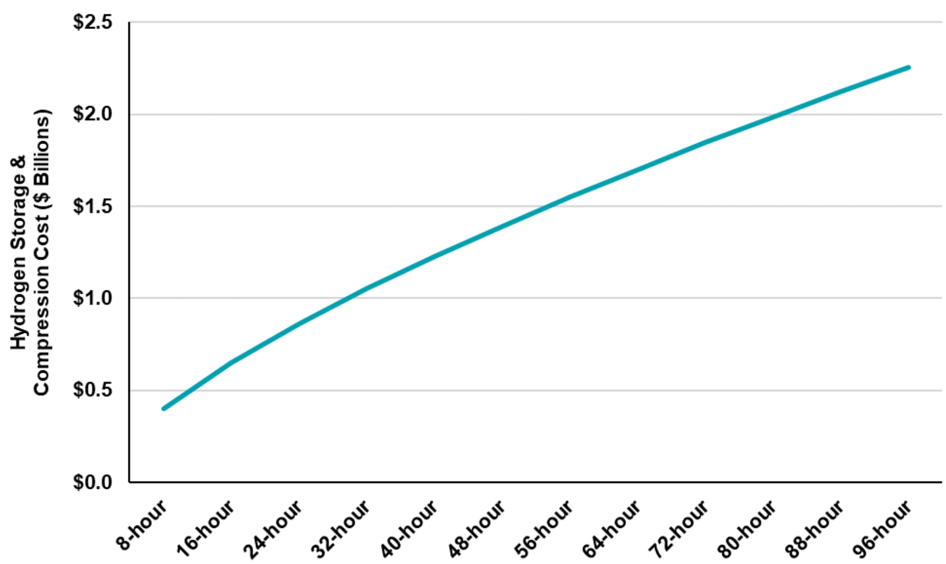
- Hydrogen is assumed to be delivered to the plant site. Pipeline costs have not been considered.
- On-site hydrogen storage is assumed to be needed.
- Hydrogen delivered to site would not require any additional treatment.

The hydrogen combustion retrofit would include the following scope:

- Replace all fuel piping with stainless steel welded piping.
- Replace gas turbine combustor hardware with dry low emissions combustors capable of 100% hydrogen combustion.
- No changes required to the gas turbine compressor, transition pieces, turbine section hardware, or auxiliaries.
- Gas turbine controls would be re-tuned.
- Replace select gas turbine instrumentation (such as flame detection and gas detection).

The hydrogen combustion retrofit scope is estimated to cost approximately $35 million in 2024 dollars. This does not include onsite storage of hydrogen (and associated compression). Figure 2 shows the estimated capital costs for onsite hydrogen storage and compression based on duration. The costs of 96 hours of on-site storage is estimated to exceed $2 billion.

Figure 2: Hydrogen Storage & Compression Cost



Moreover, the capital cost estimates provided above do not include the costs associated with producing and transporting hydrogen to site. This would need to be considered as an incremental operational expense.

As such, the cost of retrofitting a fossil fuel-fired peaking unit to burn 100% hydrogen is currently cost prohibitive. While technologies capable of complying with the CLCPA's zero-emissions energy supply requirement should continue to be monitored, AG and 1898 & Co. did not conduct any further evaluation of hydrogen as a potential peaking plant technology option for this study.

C. Plant Environmental and Siting Requirements

The conceptual designs and cost estimates developed for each fossil plant technology option include the necessary equipment and operating costs in order to meet the federal and New York State environmental requirements and regulations within each of the locations evaluated in this DCR.

1. Air Permitting Requirements and Impacts on Plant Design

Each of the candidate fossil peaking plant technologies would be required to obtain an air permit from the New York State Department of Environmental Conservation (NYSDEC). The air permit will require the plant to meet various Federal and New York State requirements. These requirements, among others, include New Source Performance Standards (NSPS), New Source Review (NSR), National Emission Standards for Hazardous Air Pollutants (NESHAP) and those specified in the New York State Codes, Rules, and Regulations (NYCRR). As discussed below, the fossil peaking plant technologies will also need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment.

a. New Source Performance Standards

The fossil peaking plant technologies will be subject to NSPS, which are included in 40 CFR Part 60. The NSPS that are expected to apply to each of the generating options include:

- Subpart KKKK – Stationary Combustion Turbines (simple cycle and combined cycle plants)
- Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (stationary combustion turbines)

These sections of the NSPS are technology specific and do not vary based on the installation location of the gas turbine. Subpart KKKK requires combustion turbines with heat inputs greater than 850 MMBtu/hour to limit NO_x emissions to less than 15 ppm while firing natural gas and to less than 42 ppm while firing liquid fuels (e.g., ULSD).[16] These standards apply to all the combustion turbine options with heat inputs greater than 850 MMBtu/hr, including the GE 7HA.03 and GE 7HA.02 units. Based on the typical vendor data, the 7HA.03 machine used in this DCR has a NO_x emissions rate of 25 ppm, so it would require SCR emissions controls to satisfy Subpart KKKK.

The base model 7HA.02 emits 25ppm NO_x, which would require SCR emissions controls to comply with Subpart KKKK. However, GE also offers a version of the 7HA.02 unit tuned to emit 15 ppm NO_x, which would not require SCR emissions controls to satisfy Subpart KKKK. There are no hardware changes to the GE 7HA.02 turbine, but the unit is controlled for a lower combustion temperature to reduce NO_x production. Because firing temperature is also proportional to the turbine's output and efficiency, there is also a performance impact (approximately 5% reduction in output).

Subpart TTTTa establishes CO_2 limits for new stationary combustion turbines that commence construction after May 23, 2023 and are capable of selling greater than 25 MW of electricity. Station combustion turbines are split into three categories based on a 3-year rolling average capacity factor; low load, intermediate load, and base load. Low load is defined as having a capacity factor less than 20%. Intermediate load is defined as having a capacity

[16] All emissions rates are listed in parts per million by volume at 15% O2 on a dry basis.

factor between 20% and 40%. Base load is defined as having a capacity factor greater than 40%. The CO_2 emissions limits for low load, intermediate load, and base load stationary combustion turbines is provided in Table 8 below. The 7HA.02 and 7HA.03 units are expected to be able to comply with the intermediate load CO_2 emission limit without any controls. The base load CO2 emissions limit would only be achievable with post combustion carbon capture which is impractical for the units considered in this DCR study. In order to avoid being subject to the base load NSPS standard, which these turbines in simple-cycle mode cannot meet, the peaking plant needs to limit their capacity factors over a 12-operating month or a three-year rolling average basis to less than 40% capacity factor. This limits each of the fossil peaking plant technology options to 3,504 hours of operation based on a 12-month rolling average.[17]

New York State also has performance standards for CO_2 emissions in the NYCRR. Table 8 compares Subpart TTTT requirement to the requirements of NYCRR Part 251 - CO_2 Performance Standards for Major Electric Generating Facilities. Each of the fossil peaking plant technology options must comply with both Subpart TTTT and NYCRR Part 251 requirements.

Table 8: Comparison of 40 CRF Part 60 Subpart TTTTa to NYCRR Part 251 Requirements

Stationary Combustion Turbine	Subpart TTTTa	NYCRR Part 251
Low Load (< 20% Capacity Factor)	120 to 160 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g[2] or 160 lb CO_2/MMBtu
Intermediate Load (20% < Capacity Factor < 40%)	1170 lb CO_2/MWh-g	
Base Load (Capacity Factor > 40%)	100 lb CO_2/MWh-g[1]	

Notes:
[1] Base load limit is 800 lb CO_2/MWh-g prior to 2032.
[2] MWh-g refers to gross generation output.

b. New Source Review

The NSPS requirements discussed above are technology specific, not location specific. In addition to NSPS, new fossil peaking plant technologies will be subject to the EPA's New Source Review (NSR) program, which considers the impacts to the air quality in the vicinity of the emission source. If a project site is located in an area where a criteria pollutant's concentration is below its respective National Ambient Air Quality Standard (NAAQS), then the area is in "attainment" for that pollutant. Areas where a criteria pollutant's ambient concentration is above its NAAQS is classified as a "nonattainment" area, and there are multiple levels of nonattainment (i.e. moderate vs. severe). The NSR program is split into two permitting pathways/regimes: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR). The preconstruction review process for new or modified major sources located in attainment and unclassifiable areas is performed under the PSD requirements. Preconstruction reviews for new or modified major sources located in nonattainment areas is performed under the NNSR program.

In order to improve a nonattainment area's air quality, the NNSR permitting pathway has more stringent permitting thresholds and requires stricter permitting analyses. In an attainment area, a source that would qualify for a PSD

[17] For modeling purposes, we apply the runtime limitations for peaking plant operations by model year, instead of on a rolling average basis.

permit would need to perform a Best Available Control Technology (BACT) analysis, which reviews control technologies that have been installed on similar units for applicability to the new source. BACT analyses allow for the evaluation of cost feasibility when determining the control technology required. On the other hand, in a nonattainment area, a source applying for a permit under NNSR review is required to go through a Lowest Achievable Emission Rate (LAER) analysis, which does not take cost into consideration when determining applicable control technologies and thus typically has much more stringent control requirements. The NNSR only applies to the pollutants that are classified as nonattainment for a project area (meaning that one pollutant could undergo NNSR review if the site location is a nonattainment area for that pollutant, while the other pollutants could be subject to PSD review if the site location for such other pollutants is classified as attainment).

The PSD major source thresholds are listed in Table 9. The major source threshold for new combined cycle facilities is lower (100 tons/year) than the major source threshold for new simple combustion turbines (250 tons/year). The annual emissions are typically based on the potential to emit (PTE) at 8,760 hours/year of operation. If a new source is determined to be a major PSD source, then PSD review would be performed for any pollutant that exceeds the Significant Emission Rates (SER) listed in Table 9.

However, it is possible to “synthetically limit” a unit’s operating profile to maintain emissions for applicable pollutants below the PSD thresholds (both the major source threshold and the SER threshold). By synthetically limiting the PTE, the facility will become a “synthetic minor source”, requiring less strict permitting analyses. For example, a BACT analysis would not be required as a part of a federal synthetic minor permitting application. Synthetic minor sources do have more reporting and recordkeeping requirements to verify that the synthetic limits are maintained during operation of the facility.

On June 23, 2014, the Supreme Court issued a decision in Utility Air Regulatory Group (UARG) v Environmental Protection Agency (EPA), which challenged the EPA “Tailoring Rule”.[18] As a result of this court decision, EPA may not treat greenhouse gases (GHGs) as an air pollutant to determine whether a source is a major source required to obtain a PSD permit. However, EPA can require PSD permits (which are otherwise required) to contain limitations on GHG emissions based on the application of BACT only if another pollutant is also subject to PSD.

For the current DCR, as shown in Table 9, the PSD major source thresholds are 250 tons/year for the fossil peaking plant technologies.

[18] Utility Air Regulatory Group (UARG) v. Environmental Protection Agency, 134 S. Ct. 2427 (2014).

Table 9: PSD Major Facility Thresholds and Significant Emission Rates

Pollutant	CT Major Source Threshold[1] (tons/year)	Significant Emissions Rate (tons/year)
Carbon monoxide (CO)	250	100
Nitrogen oxides (NO_x)	250	40
Sulfur dioxide (SO_2)	250	40
Coarse particulate matter (PM_{10})	250	15
Fine particulate matter ($PM_{2.5}$)	250	10
Volatile organic compounds	250	40
Greenhouse gases (GHG): as CO_2e	Note 2	75,000

Notes:
[1] CT major source thresholds are 250 tons/year since these sources are not one of the source categories listed in section 201-2.1(b)(21)(iii)(a) through (z) of 6 NYCRR.
[2] Per NYSDEC Enforcement Discretion for State GHG Tailoring Rule Provisions Memorandum (October 15, 2014), GHGs alone will not trigger Prevention of Significant Deterioration New Source Review (PSD NSR).

As mentioned above, any pollutant subject to PSD review (i.e. exceeds the PTE thresholds in Table 9) is required to perform a BACT analysis. Absent application of a synthetic operating limit, it is expected that in order for a new fossil-fuel-fired peaking plant technology option in New York State to meet the BACT standard, SCR emissions controls would be required for nitrogen oxide (NO_x) control and an oxidation catalyst would be required for carbon monoxide (CO) and/or volatile organic compounds (VOC) control. In addition to BACT requirements, an air quality impact analysis (air dispersion modeling), and an analysis of other impacts (e.g., soils, vegetation, and visibility) are required for all pollutants subject to PSD review.

NNSR only applies to the pollutants for which a given area is classified as in nonattainment. The current nonattainment areas in New York State are illustrated in Figure 3. These areas are nonattainment for the eight-hour ozone National Ambient Air Quality Standard (NAAQS). NNSR also applies throughout New York State for precursors of ozone (NO_X and VOC), since all of New York State is in the Ozone Transport Region (OTR). Since NO_X and VOC are treated as nonattainment pollutants statewide, proposed facilities may be required to comply with both the PSD requirements for attainment pollutants and NNSR requirements for nonattainment pollutants.

Figure 3: Current Nonattainment Areas in New York

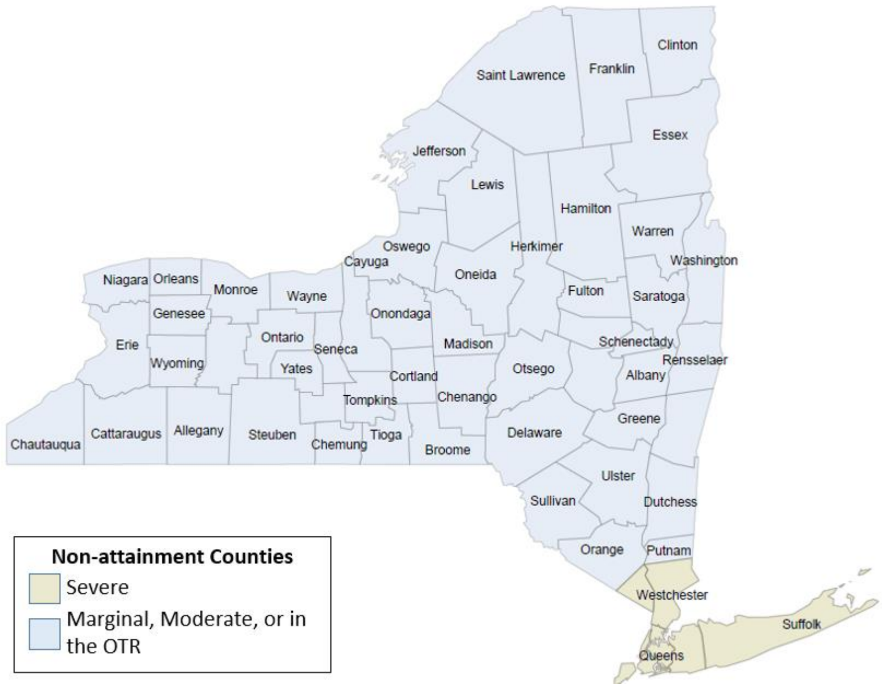


Table 10 presents the nonattainment major facility thresholds and emission offset ratios for each ozone nonattainment classification. Nonattainment areas classified as Severe include the New York City Metropolitan Area and the Lower Orange County Metropolitan Area. The New York City Metropolitan Area includes all of the New York City, as well as Nassau, Suffolk, Westchester, and Rockland Counties. The Lower Orange County Metropolitan Area includes the Towns of Blooming Grove, Chester, Highlands, Monroe, Tuxedo, Warwick, and Woodbury. The remaining areas in the State are classified as either Marginal, Moderate or in the OTR. Table 11 summarizes the ozone nonattainment classification and NNSR major source thresholds for NO_X and VOC for each of the locations evaluated as part of this DCR. There have been no changes to ozone nonattainment since the 2021-2025 DCR.

Table 10: NNSR Major Facility Thresholds and Offset Ratios

Contaminant	Major Facility Threshold (tons/year)	Emission Offset Ratios
Marginal, Moderate, or Ozone Transport Region (OTR):		
Volatile Organic Compounds (VOC)	50	At least 1.15:1
Nitrogen oxides (NO_x)	100	At least 1.15:1
Severe:		
Volatile Organic Compounds (VOC)	25	At least 1.3:1
Nitrogen oxides (NO_x)	25	At least 1.3:1

Table 11: Ozone Nonattainment Classification and Major Source Thresholds by Load Zone

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Ozone nonattainment classification[1]	Moderate	Moderate	Moderate	Severe	Severe	Severe
NNSR NOx Major Source Threshold (tons/year)	100	100	100	25	25	25
NNSR VOC Major Source Threshold (tons/year)	50	50	50	25	25	25

Note: [1] Moderate nonattainment classification due to location in the Ozone Transport Region

NNSR major sources located in nonattainment areas for ozone are required to install LAER technology. LAER is an emission rate that has been achieved or is achievable for a defined source and does not consider cost-effectiveness. SCR emissions control systems for NO_X emissions and an oxidation catalyst for VOC emissions are expected LAER technologies for combustion turbine facilities subject to NNSR.

Similar to the PSD permitting process, a synthetic limit (e.g., application of an annual operating hours cap/limit) could be applied to a new source or facility, which would bring the annual PTE below the thresholds listed above in Table 10 and Table 11. Since the facility would no longer be subject to NNSR, the LAER analysis would no longer be required.

The GE 7HA.03 peaking plant technology option with a 25 ppm NO_x emissions rate would already require the installation of SCR emissions controls per the NSPS Subpart KKKK limits discussed in the prior section. The control technology requirements (required to meet the NSPS or expected to meet LAER requirements as a part of NNSR absent any consideration of a synthetic limitation) are summarized in Table 12 below.

Table 12: Control Technology Requirements for Fossil Technologies Analyzed at Greenfield Sites at Maximum Annual Run Hours

	C - Central		F - Capital		G - Dutchess		G - Rockland		J -NYC		K - Long Island	
	Moderate		Moderate		Moderate		Severe		Severe		Severe	
Technology	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst	SCR	CO Catalyst
1x0 GE 7HA.02, 15 ppm NO_x	No	No	No	No	No	No	Yes	Yes	Yes	Yes	Yes	Yes
1x0 GE 7HA.03, 25 ppm NO_x	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Notes: [1] Values shown are for maximum annual hours of operation (3,504 hours for SCGT technologies).

In addition to the “maximum-hour” compliance analysis performed above, 1898 & Co. also analyzed other methodologies of compliance—specifically limiting the annual hours of operation of each technology in order to reduce emissions below the NNSR threshold to remove the requirement to perform a LAER analysis. The approximate hours per year restriction to eliminate the need to perform LAER for operating solely on natural gas or operating solely on ultra-low sulfur diesel (ULSD) fuel are shown in Table 13 and Table 14 below. The limits displayed in the tables are estimated based on lb/hr emissions rates at ISO conditions. The dispatch analyses take into account seasonal emissions differences due to different seasonal heat rates and capacities, so annual limits in the net EAS model for fossil plants may be different than those shown below.

NO_x emissions are higher for fuel oil operation than natural gas operation. In the case of a unit including dual fuel capability, the synthetic limit may be reached with fewer hours than a gas only unit, based on the quantity of each fuel used over the course of the year. Since the NOx emission rate of the 25 ppm base design of the GE 7HA.02 is above the NSPS KKKK, this unit will require SCR emissions controls to comply with the NSPS standard, which is not influenced by potential application of annual operating hours or project location. Therefore, it is included in the tables below, but not included in the synthetic minor analyses performed.

Table 13: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using Natural Gas Only at a Greenfield Site

Technology	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
	Moderate	Moderate	Moderate	Severe	Severe	Severe
1x0 GE 7HA.02, 15 ppm NOx	997	997	997	N/A[1]	N/A[1]	N/A[1]
1x0 GE 7HA.03, 25 ppm NOx	N/A[2]	N/A[2]	N/A	N/A[1,2]	N/A[1,2]	N/A[1,2]

Notes:
[1] SCR emissions controls are required for these load zones due to being subject to LAER
[2] SCR emissions controls are required for these units per the NSPS KKKK rule.
[3] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59°F and 60% relative humidity).

Table 14: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using ULSD Only at a Greenfield Site

Technology	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
	Moderate	Moderate	Moderate	Severe	Severe	Severe
1x0 GE 7HA.02, 15 ppm NOx	312	312	312	78	78	78
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[1,2]	N/A[1,2]	N/A[1,2]

Notes:
[1] SCR emissions controls are required for these load zones due to being subject to LAER
[2] SCR emissions controls are required for these units per the NSPS KKKK rule.
[3] The evaluation considers 108 hours operating on ultra-low sulfur fuel oil and the remaining hours on gas.
[4] Limits displayed are estimated based on lb/hr emissions rates at ISO conditions (59°F and 60% relative humidity).

Including SCR emissions controls on a simple cycle plant can serve to mitigate certain siting, permitting, and future market risks which are considered by power plant project developers. The fossil peaking plant technologies will need to obtain a Certificate of Environmental Compatibility and Public Need from the New York State Board on Electric Generation Siting and the Environment. In issuing a certificate, the Siting Board is required to determine that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[19]

However, with availability of a synthetic minor approach that may limit run hours, the installation of SCR emissions controls in part reflects economic tradeoffs to the plant developer, with up-front capital costs and additional operating costs balanced against relaxed runtime restrictions. If the unit's expected hours of operation would not be expected to exceed the runtime restriction, then it may not be economic for a new plant to install SCR emissions controls. Considering the balance of costs and risks discussed above, it is AG's and 1898 & Co.'s opinion that the developer of a new plant in all Load Zones would seek to include SCR emissions control technology for a gas only or dual fuel plant at the time of construction due to economic considerations. *First*, SCR emissions controls provides optionality to operate above the synthetic minor operating limit, which could be

[19] New York Public Service Law, Section 168(3)(c) requires that "the adverse environmental effects of the construction and operation of the facility will be minimized or avoided to the maximum extent practicable…"

financially valuable in the future. Future net EAS revenues may be greater than net revenues in the historical years evaluated given the potential increases in demand for operation from the peaking plant from increased levels of renewables and potential retirements of gas turbines downstate due to the NYDEC "peaker rule" (see Section II.C.3 for details on the "peaker rule"). *Second*, the installation of SCR emissions control could mitigate potential permitting and siting risk associated with building a new dual fuel unit in the lower Hudson Valley (see Section II.D for more details on dual fuel) without back-end emissions control technology. *Third*, GE does not offer a version of the SCGT 7HA.03 capable of 15 ppm NOx to comply with NSPS KKKK without SCR emissions controls. As such, configurations without SCR emissions controls are assumed to use a SCGT 7HA.02. The SCGT 7HA.02 can be tuned to meet 15 ppm NOx. The 7HA.02 is a smaller turbine than the 7HA.03. As a result, as depicted in Table 23, on a $/kW basis, the SCGT 7HA.02 without SCR emissions controls is a similar cost as the SCGT 7HA.03 with SCR emissions controls. Moreover, due to higher efficiency and operating limits, net EAS revenues are anticipated to be higher for the SCGT 7HA.03 than SCGT 7HA.02 (as depicted in Table 15). Because the annual net cost is lower for the SCGT 7HA.03 with SCR emissions controls than the SCGT 7HA.02 without SCR emissions controls in all applicable locations, AG and 1898 & Co. recommend SCR emissions controls for the SCGT technology in all locations.

Table 15: Net EAS Revenues (Historical Data Period: 9/1/2020-8/31/2023)

Unit	Zone	SCR	Gas Only	Net EAS Revenues ($/kW-year)
SCGT 7HA.02	C	No	Yes	$56.16
SCGT 7HA.03	C	Yes	Yes	$72.82
SCGT 7HA.02	F	No	Yes	$63.04
SCGT 7HA.03	F	Yes	Yes	$95.76
SCGT 7HA.02	G (Dutchess)	No	Yes	$45.23
SCGT 7HA.03	G (Dutchess)	Yes	Yes	$58.64

Notes:
[1] See Section IV.B for a discussion of the net EAS model for fossil peaking unit technologies.

In addition to installing emissions controls technologies to meet LAER, major sources in nonattainment areas are required to secure emission offsets, or emission reduction credits (ERCs), at the ratios of required ERCs to the facility's PTE presented in Table 10. The ERCs must be the same as for the regulated pollutant requiring the emission offset and obtained from within the nonattainment area in which the new source will locate. Under certain conditions the ERCs may be obtained from other nonattainment areas of equal or higher classification. NO_X and VOC ERCs for major sources locating in an attainment area of New York State may be obtained from any location within the OTR, including other states in the OTR, provided an interstate reciprocal trading agreement is in place.

The cost of securing emission offsets was included in the total capital investment estimates for each technology option. The estimated cost of the ERCs were based on the maximum NO_x emissions from natural gas operation. The annual hours were restricted to those needed to comply with NSPS Subpart TTTTa. The annual emissions used in the ERC cost calculations were based on the controlled emission rate assumptions that are shown in Table 16.

Table 16: Emissions Rate Assumptions for Fossil Plants

	NO_X (ppm) [1]	CO (ppm) [1]	VOC (ppm) [1]	CO_2 (lb/MWh) [2]
Natural Gas Firing without SCR/CO Catalyst				
1x0 GE 7HA.02, 15 ppm NO_x	15	9	2	1,120
Natural Gas Firing with SCR				
1x0 GE 7HA.03, 25 ppm NO_x	2	2	1	1,050
Ultra-Low Sulfur Diesel Firing without SCR				
1x0 GE 7HA.02, 15 ppm NO_x	42	12	2.4	1,490
Ultra-Low Sulfur Diesel Firing with SCR				
1x0 GE 7HA.03, 25 ppm NO_x	6	2	2	1,400

Notes:
[1] Parts per million on a dry basis, measured at 15% O_2.
[2] Based on full load, net plant heat rate at ISO conditions, higher heating value (HHV) basis, clean and new condition.

2. *Cap and Trade Program Requirements*

The fossil peaking plant technology options in New York State are also subject to cap-and-trade program requirements including:

- CO_2 Budget Trading Program (6 NYCRR Part 242)
- Cross State Air Pollution Rule (CSAPR) Trading Program
- CSAPR NO_X Ozone Season Group 2 Trading Program (6 NYCRR Part 243)
- CSAPR NO_X Annual Trading Program (6 NYCRR Part 244)
- CSAPR SO_2 Trading Program (6 NYCRR Part 245)
- SO_2 Acid Rain Program (40 CFR Parts 72-78)
- Nonattainment and Ozone Transport Region (OTR) SIP Requirements (40 CFR 51.116 and 40 CFR 51.1316)

The CO_2 Budget Trading Program regulations would apply to all fossil peaking plant technologies assessed. Part 242 establishes the cap-and-trade provisions pursuant to the Regional Greenhouse Gas Initiative (RGGI), a nine-state cooperative effort to reduce greenhouse gas emissions from electrical generating facilities by means of a cap-and-trade program. Under RGGI, each participating state has committed to state regulations that will cap and then reduce the amount of CO_2 that electrical generating facilities are allowed to emit in total across the RGGI region. CO_2 allowances are obtained by generators through a CO_2 allowance auction system and are traded using CO_2 Budget Trading Programs.

In general, Parts 243, 244, and 245 CSAPR regulations apply to any stationary fossil fuel-fired boiler or combustion turbine that serves a generator with a nameplate capacity equal to or greater than 25 MW producing electricity for sale.

The cost of CO_2, NO_X, and SO_2 allowances are included in the economic dispatch and accounted for in the net EAS revenue estimates for each fossil peaking plant technology option. In addition, the cost of ERCs is included in the capital cost estimates for each applicable location as required by NNSR air permitting requirements.

The Clean Air Act sets out specific requirements for a grouping of northeastern states that make up the Ozone Transport Region. It was determined that the NOx, CO, and VOC emissions from these states impacted several other regions/states downwind. States in the OTR region must submit a State Implementation Plan (SIP) and install more stringent controls on equipment in order to control the production of ozone, even if a county or area meets the ozone standards. These requirements are discussed above and have been incorporated into the NYDEC New Source Review for New and Modified Facilities which would apply to the fossil peaking plant technology options assessed for this DCR study.

3. "Peaker Rule"

In 2020, New York State adopted 6 NYCRR Subpart 227-3, "Ozone Season Oxides of Nitrogen (NO_x) Emission Limits for Simple Cycle and Regenerative Combustion Turbines," ("NYDEC Peaker Rule"). This applies to owners and operators of simple cycle and regenerative combustion turbines that are electric generating units with a nameplate capacity of 15 MW or greater that inject power into the transmission or distribution systems, only during the ozone season (May 1 to September 30). By May 1, 2025, the NO_x emission limits will be 25 ppmvd for natural gas and 42 ppmvd for distillate or other liquid fuel oils. As shown in Table 12 above, the new fossil peaking plant technology options assessed for this DCR comply with these thresholds. Therefore, this rule will not directly impact the fossil peaking plant technology options evaluated in this study.

4. Other Permitting Requirements

Public Service Law Article 10 requires any proposed electric generating facilities with a nameplate generating capacity of 25 MW or more to obtain a Certificate of Environmental Compatibility and Public Need. The Article 10 process includes stakeholder intervention processes, including intervener funding provisions by the project developer. In its review, the New York State Board on Electric Generation Siting and the Environment (Siting Board) is required to find that the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable. In doing so, the Siting Board must consider both the state of available technology and the nature and cost of reasonable alternatives.

6 NYCRR Part 487 establishes a regulatory framework for undertaking an analysis of environmental justice issues associated with the siting of an electric generating facility in New York State pursuant to Article 10. Part 487 is intended to enhance public participation and review of environmental impacts of proposed electric generating facilities in environmental justice communities and reduce disproportionate environmental impacts in overburdened communities. Specific analysis requirements are evaluated on a case-by-case basis. The estimates of total capital investment for each technology option include expenditures to conduct environmental justice analysis as part of the project development costs.

D. Dual Fuel Capability

The assessment also requires determining for each location whether the fossil peaking plant technology option should be a natural gas-only resource or have the capability to operate on both natural gas and ULSD (dual fuel). The current peaking plants include dual fuel capability for the NYC, LI, and G-J Locality ICAP Demand Curves. The current peaking plant for the NYCA ICAP Demand Curve is a gas-only design.

In this DCR, we have evaluated whether to recommend including dual fuel capability in each location. As with many of the technology choices considered, we evaluated potential recommendations against a review of relevant data and considerations tied to what developers are likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

The incremental costs for dual fuel capability (which would be deducted for a gas only unit) are assumed to be $26.9 million (2024 $), as shown in the capital cost estimates in Appendix A. The capital costs include gas turbine combustion system modifications provided by the OEM, a fuel oil storage tank with 96 hours of storage capacity, piping (fuel and water), and associated electrical and controls modifications. The owner's costs include the purchase of the fuel inventory and the additional fuel requirements for startup and commissioning.

Based on our evaluation, 1898 & Co. and AG recommend that the peaking plant technology design should include dual fuel capability in all locations. This recommendation is based on the consideration of a number of tradeoffs a developer would consider when deciding whether or not to include dual fuel capability in a development project in New York state and whether, on balance, a developer would more likely than not decide to include dual fuel capability based on such considerations. Specifically, the following observations inform the conclusion:

- The New York State Reliability Council, L.L.C. (NYSRC) imposes strict local reliability standards to NYC and LI to ensure that the loss of a gas facility in those zones do not lead to a loss of electric load, and NYISO maintains a "minimum oil burn program" to implement these standards.[20] NYSRC's local electric reliability rules highly incentivize dual fuel capability for units in NYC and LI. Additionally, nearly all gas fired generation in Load Zones J and K is connected to the LDC gas system, and several LDC gas tariffs require dual fuel capability for generators. Such LDC requirements are in place for National Grid in Load Zones C, F and K; Orange & Rockland and Central Hudson in Load Zone G; and Con Edison in Load Zone J.
- Investment in dual fuel capability balances several economic tradeoffs. On the one hand, there are increases in capital costs associated with the installation of dual fuel capability, and in annual costs tied to maintaining dual fuel systems, testing dual fuel capability, and carrying an on-site inventory of fuel for operations on the alternate stored fuel. On the other hand, these increases in cost could be outweighed by the value associated with potential increases in net EAS revenues from operating on the alternate fuel when the price for the alternate fuel is less than that of natural gas, and allowing production when gas supplies would otherwise be curtailed (such as during certain winter periods when gas supplies may be scarce due to higher demand for all end uses). For example, Table 17 provides estimates of the impact of dual fuel on net EAS revenues for the historical data period 9/1/2020-8/31/2023. Consistent with

[20] New York State Reliability Rules and Compliance Manual, Version 46, June 10, 2022, Section 2.G.2-3, available at https://www.nysrc.org/wp-content/uploads/2023/07/RRC-Manual-V46-final.pdf; NYISO Technical Bulletin 156, April 1, 2019, available at https://www.nyiso.com/documents/20142/2931465/TB_156.pdf/132c16f5-5718-cbd5-2b59-fb564f6ee389.

previous DCRs, the economic argument for dual fuel is weaker in Load Zones C and F than in Load Zone G (Dutchess) or Load Zone G (Rockland).

Table 17: Net EAS Revenues (Historical Data Period: 9/1/2020-8/31/2023)

Unit	Zone	Net EAS Revenues without Dual Fuel ($/kW-year)	Net EAS Revenues with Dual Fuel ($/kW-year)	Percentage Difference	Oil Run Hours (with Dual Fuel)
SCGT 7HA.03	C	$72.82	$72.82	0.00%	0
SCGT 7HA.03	F	$95.76	$96.37	0.64%	126
SCGT 7HA.03	G (Dutchess)	$58.64	$66.07	12.66%	85
SCGT 7HA.03	G (Rockland)	$59.89	$67.86	13.30%	80

Notes:
[1] See Section IV.B for a discussion of the net EAS model for fossil peaking unit technologies.

- However, the value of dual fuel optionality may be greater under LOE market conditions, particularly to the extent that such conditions arise due to shifts in generation resources that increase reliance on gas-fired resources during winter peak periods.
- Due to the potential impact of proposed fuel availability capacity accreditation rules, in addition to other risks associated with gas-only peaking operation and opportunities for additional revenues, developers in Load Zones C and F would more likely than not decide to include dual fuel capability.

E. Capital Investment Costs

Unless otherwise noted, capital cost estimates were prepared for the construction of the following technologies in New York Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K:

- One GE 7HA.03 unit with SCR emissions controls
- One GE 7HA.02 unit without SCR emissions controls (Load Zones C, F, and G (Dutchess County) only)

Capital cost estimates were also prepared for the following energy storage technologies.

- 200 MW, 2-hour (400 MWh stored energy) lithium-ion
- 200 MW, 4-hour (800 MWh stored energy) lithium-ion
- 200 MW, 6-hour (1,200 MWh stored energy) lithium-ion
- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

In addition, for informational purposes, capital cost estimates were prepared for converting the 7HA.03 simple cycle facility to combust carbon free hydrogen in lieu of natural gas beginning in 2040 as a proxy for a potential option to comply with the CLCPA's 2040 zero-emissions energy requirement.

The capital investment costs include the installed cost of the plant, owner's costs, and financing costs during construction. The installed cost estimate is based on a developer entering into an engineer, procure, construct (EPC) contract for project execution. Owner's cost estimates include the electric and gas interconnection facilities, owner development and management activities, fuel inventory (applicable for fossil units with dual fuel capability), builder's risk insurance, and owner's contingency.

Table 18 provides the conceptual design features for the plants in each of the locations evaluated.

Table 18: Recommended Fossil Peaking Plant Design Capabilities and Emission Control Technology

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fuel Capability	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel
Combustion System NO_x Control	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry
	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection
GE 7HA.02 NO_x emissions tuning	15 ppm	15 ppm	15 ppm	15 ppm	15 ppm	15 ppm
Post Combustion Controls for GE 7HA.02 simple cycle	None	None	None	SCR	SCR	SCR
GE 7HA.03 NO_x emissions tuning	25 ppm	25 ppm	25 ppm	25 ppm	25 ppm	25 ppm
Post Combustion Controls for GE 7HA.03 simple cycle	SCR	SCR	SCR	SCR	SCR	SCR

1. Plant Design Basis

The plant design basis is conceptual and consistent with new facility design features that would be constructed in the current market. Key design assumptions include:

1. Site Conditions – In all Load Zones except Load Zone J, the cost estimate is based on a generic, greenfield site. Assumed land requirements for greenfield conditions are summarized below. In New York City, it is assumed that a peaking plant would most likely be built on a brownfield site at low elevation. Therefore, the New York City capital cost estimate includes a nominal allowance for demolition of existing facilities.

2. Storm Hardening – Costs were included to raise the Load Zone J site 4 feet as an allowance to accommodate floodplain zoning requirements and New York City building codes to prevent damage to the facility from flooding analogous to those which occurred due to Hurricane Sandy in 2012. 1898 & Co. considered that the peaking plant in Load Zone J would most likely be located on brownfield sites along the waterfront. The Federal Emergency Management Agency (FEMA) minimum site elevation requirement is 14 feet NAVD88. Site elevations along the waterfront may be as low as 10 feet NAVD88.

3. Fuel – The capital cost estimates were developed based on the fuel assumptions shown above in Table 18 for the fossil peaking plant technology options. The cost delta to add or remove dual fuel capability is also shown in the costs in Appendix A. Dual fuel units include a cost for fuel oil inventory, with storage levels based on the capability to provide 96 hours of operation (equivalent to one week of on-peak operations; 6 days at 16 hours per day). The delivered cost for the initial fuel oil inventory is

assumed to be $3.00 per gallon. Initial commissioning for each fossil peaking plant technology option assumes 50 hours of full load oil use for guarantee and emissions performance testing.

4. Inlet Cooling – Inlet air evaporative coolers were included for the fossil peaking plant technology option. The inlet air evaporative coolers are operated when the ambient temperature exceeds 59°F. The evaporative cooler increases the water content of the air, which reduces its temperature typically 85% to 90% of the difference between the dry bulb and wet bulb temperature. Consequently, the largest temperature reduction occurs when the relative humidity is low. Since the air to fuel ratio in combustion is very high and the density of air increases as the temperature is lowered, the mass flow through the turbine is higher at lower temperature, which increases the MW generated.

5. Gas Pressure – For the fossil peaking plant technology options, the natural gas pressure was assumed to be 250 psig in all locations evaluated. Natural gas compressors were included in the EPC estimates to increase the fuel gas pressure to that required by the combustion turbine options assessed.

6. Emission Control Equipment – In Load Zones C, F, and G-Dutchess, the NO_x limit to trigger PSD is 100 tons per year (tpy). For the fossil peaking plant technology options with NOx emissions rates equal to or less than 15 ppm (such as the 15 ppm NO_x variant of the GE 7HA.02 unit) could potentially receive an air permit without SCR emissions controls by assuming a run-hour limitation to stay below 100 tpy. Analyses by 1898 & Co. and AG suggest that the run hour limitations in Load Zones C, F, and G-Dutchess would significantly limit potential operating hours and EAS revenues such that a 7HA.02 without SCR emissions controls would be less favorable financially. Therefore, for the fossil peaking plant technology options, 1898 & Co. recommends considering the GE 7HA.03 with SCR emissions controls in all locations.

7. Black Start Capability – Black start capability has not been included in the cost estimate for any of the fossil plants or batteries given that the compensation for this service is cost based. Accordingly, the costs of such capability would be recovered in the compensation for such service, and thus have been excluded from both the cost and revenue estimates. This is consistent with the approach for black start capability from the 2021-2025 DCR.

8. Noise Mitigation – Preliminary noise modeling was performed to determine mitigation system assumptions for all technologies. Software modeling was performed with the facility placed in the center of a parcel with the acreage defined in the assumptions for this study. NYSDEC provides guidance for circumstances under which sound creates significant noise impacts within the Program Policy Memorandum titled Assessing and Mitigating Noise Impacts. Projects in New York City are also anticipated to be subject to the New York City Environmental Quality Review (CEQR) requirements and the New York City Noise Control Code. Based on 1898 & Co.'s experience, noise mitigation costs are dependent on the permitting process for a specific site, and such costs may not

necessarily be avoided at a larger site, as exemplified by recent projects in New York.[21] Based on the modeling results and 1898 & Co.'s permitting experience, the design basis assumes that all simple cycle gas turbine options would be installed indoors. For all fossil peaking plant technology options, the buildings also include administrative facilities, control room, and warehouse space. All technologies assessed in this study (i.e. fossil peaking plant technology options and BESS options) include a nominal allowance for sound barrier walls (these are not the same as the walls of the building, but rather a separate, strategically located barrier to mitigate noise impacts for compliance with the threshold described herein). The location and dimensions of the sound walls will vary depending on several site-specific conditions, but the preliminary model results suggest that an allowance for barriers is warranted to meet the threshold of a 6 dBA increase of the assumed ambient sound levels.

9. Water Supply and Wastewater – For all locations except Load Zone J, water supply is assumed to be raw water from an onsite well. Load Zone J assumes a municipal water connection. All locations include a tank for process/fire water. Wastewater and facility drains are collected in onsite tanks and pumped out via trucks for disposal.

10. Energy Storage Sizing – 1898 & Co.'s recent project experience suggests that there is a strong market trend toward modular PBE products for stationary storage projects, and this form factor is assumed for the cost basis. However, because there is a large quantity of OEMs and integrators competing directly in the storage space, and because information supporting the cost estimates is typically proprietary, the costs are not intended to represent a specific product or manufacturer. 1898 & Co. is not selecting a unique design basis, but the sizing process and criteria would be similar among available products. The project is sized to accommodate the power and energy requirements at the point of interconnection (POI), and to account for performance degradation and subsequent augmentation.

Table 19 below shows the assumed losses for the non-battery equipment used in BESS systems.

[21] For example, CPV Valley Energy Center, completed in 2018, is a combined cycle facility that occupies approximately 35 acres of a 122-acre parcel. A majority of the project equipment is located within an acoustical building, the gas turbine is equipped with inlet and exhaust silencers, and the air-cooled condenser utilized low noise fans. In addition, Cricket Valley Energy Center, completed in 2020, is a combined cycle facility that occupies approximately 57 acres of a 193-acre parcel. A majority of the project equipment is located in within acoustical buildings, the gas turbine is equipped with inlet and exhaust silencers, the air-cooled condenser and fin-fan coolers utilized low noise fans, and other items are surrounded by sound barriers. Competitive Power Ventures, "About CPV Valley," https://www.cpv.com/our-projects/cpv-valley/about/. Cricket Valley Energy Center, "Final Environmental Impact Statement," https://www.cricketvalley.com/wp-content/uploads/2017/11/CVE-FEIS-Section-1-Project-Description-final.pdf

Table 19: Key BESS Sizing Assumptions

BESS Sizing Assumptions	
POI Rating (MW)	200
POI Power Factor Capability	0.85
Inverter Loss (%)	1.80%
MV Transformer Loss (%)	0.80%
MV Collection Loss (%)	0.10%
Main Power Transformer Loss (%)	0.40%
Transmission Line to POI Loss (%)	0.10%

Additional sizing considerations are product specific, including the efficiency of the batteries, depth of discharge limitations, the capacity degradation that may occur between shipment and the commercial operations date, and the peak auxiliary load rating (driven by the thermal management system). 1898 & Co. considered information from multiple providers, including those that can be used in Load Zone J, , to determine a generic sizing profile for the 200 MW BESS options.

Because energy capacity degrades due to time and cycling behavior, projects that require consistent energy discharge capability over time must be designed to account for degradation. This is done through overbuild and/or augmentation strategies. Overbuild means additional energy capacity is included in the beginning of life (BOL) installation and incorporated in the initial capital cost. Augmentation means that additional battery enclosures will be added at intervals during the assumed project life to maintain the desired energy discharge capability. There is considerable nuance in overbuild/augmentation strategies, and they will vary based on any number of site specific and owner specific conditions or incentives.

1898 & Co. is accounting for an assumed 15-year project life with full rated energy discharge capability maintained over such assumed life, which impacts the capital cost and O&M cost. The BOL energy discharge capability and capital cost assumes 4 years of energy discharge capacity overbuild. The O&M cost considers the augmentation costs over the 15-year assumed project life. 1898 & Co. considered multiple products and providers when reviewing degradation curves and the related overbuild and augmentation assumptions. Additional information on augmentation is provided in Section F below.

The sizing results are shown in Table 20 below:

Table 20: BESS Sizing Results

BESS Sizing Results				
Rated Power at POI (MW)	200	200	200	200
Discharge Duration at Rated Power (hours)	2	4	6	8
Rated Nominal Energy at POI (MWh)	400	800	1200	1600
Years of Overbuild Assumed (years)	4	4	4	4
BOL Installed Energy Capability Incl. Overbuild (MWh AC at POI)	452	903	1,355	1,806

2. EPC Cost Estimate

EPC cost estimates were prepared for a generic site and do not include preliminary engineering or development activities. The information provided herein was developed solely for the purposes of this study and is not intended for any other purpose such as project specific budgeting, design, or construction activities. The capital cost estimates are based on 1898 & Co. experience as an EPC contractor, engineering design firm, and consultant in the power generation and energy storage industries. 1898 & Co. has recent project execution experience, consulting experience, and/or firm proposal experience on simple cycle turbine and energy storage projects.

Direct costs include the labor, materials, engineered equipment, subcontracts, and construction equipment to construct the facility. This includes site preparation, foundations, structural steel, equipment installation, buildings, associated piping, electrical, and controls tasks. Indirect costs include the construction management, engineering, and startup activities, as well as warranty and general administrative costs. Contingency is included to account for uncertainties in the quantities and pricing, which may increase during detailed design and procurement. In this case, a contingency of 10% was applied to the total direct and indirect project costs, which is typical practice for construction estimates of this type. A 10% EPC contractor fee is also applied to all estimated EPC costs.

- Equipment and Material Costs - Frame turbine costs are based on budgetary estimates from the respective OEMs. As previously noted and further described below, for BESS options, the costs presented in this study are intended to represent a snapshot of the market pricing as it currently stands. These costs are not intended to be directly representative of one chemistry or one OEM. Other equipment and material quantities and costs are based on recent 1898 & Co. project experience with cost estimates, designs, and/or execution for simple cycle turbine and energy storage projects. For all technologies, the EPC electrical scope ends at the high side of the generator step up transformer (GSU), also called the main power transformer (MPT) on storage projects. GSU/MPT costs and installation are included in the EPC cost.
- Labor - Labor costs are based on man-hour durations within each craft multiplied by the respective labor rates. Costs are based on the EPC contractor self-executing the steel, piping, and equipment scopes. All other craft scopes are assumed to be subcontracted. Construction craft base pay and supplemental (fringe) benefits were obtained from the RSMeans Labor Rates for the Construction Industry (RSMeans) for a representative municipality for each Load Zone evaluated. RSMeans is an industry standard construction cost database that includes locational labor rates that are updated annually. Burdened labor rates were developed by adding Federal Insurance Contributions Act (FICA) tax, state and federal unemployment taxes, general liability insurance, and workmen’s compensation insurance. All-in wage rates were developed by adding allowances for small tools, supervision, construction equipment, and subcontractor overhead and profit. Work is assumed to be performed on a 50-hour work week by qualified union craft labor available in the respective area. Direct installation labor man-hours for the base cost estimates are for an ideal location and must be adjusted for locations where productivity is reduced due to a variety of factors, including weather, union rules, construction parking and laydown space limitations, etc. Based on 1898 & Co. experience, man-hours were multiplied by a labor productivity factor for each Load Zone evaluated.
- Energy Storage - Estimates for the BESS options were developed through a similar process, but the estimate results are intended to be indicative of the current state of the BESS market as of Q1 2024, rather than any particular BESS product or provider. To reach these indicative numbers, 1898 & Co. internally performed estimates using two types of modular PBE technology: a “DC” enclosure, where the

battery enclosure and power conversion system (PCS) skid are separate; and an "AC" enclosure where inverters are included in the battery enclosure. 1898 & Co. considered major equipment pricing from multiple providers of DC enclosures and AC enclosures, including those that would be suitable for inclusion in Load Zone J, but because of the confidentiality and competitive nature of the equipment estimates, equipment cost breakouts will not be disclosed in the DCR study. It is also noted that the BESS facility estimates account for the physical space and full substation buildout in the BOL capital cost to accommodate the eventual end-of-life (EOL) energy discharge capability. This shifts some cost from the O&M cost to the capital cost, but would also reduce outage requirements during eventual augmentation estimates. **1898 & Co. will continue to evaluate battery costs through Q2 2024 to ensure battery costs reflect current market conditions when the Report is finalized.**

3. Owner's Costs

Owner's costs include allowances for items such as development activities, project management oversight, Owner's Engineer, legal fees, financing fees, ERCs, fuel inventories, builder's risk insurance, and additional contingency. In Appendix A, 1898 & Co. includes the interconnection costs under the Owner's cost umbrella, but those items are discussed in more detail in the following sections.

Owner's costs can vary greatly depending on the project owner and project opportunity. Key assumptions for Owner's costs are included below:

- The Owner cost line items for lateral items such as gas line, transmission line, and interconnecting switchyard are intended to be standalone estimates, inclusive of the land, development, and execution activities for those items.
- Owner development, oversight, permitting, and management related activities are duration-based, with assumptions for personnel cost for the Owner and/or consultants, plus expenses. Temporary utilities are duration-based costs for power consumed during construction.
- Allowances are included for spare parts, legal fees, and area development concessions that often arise as part of project permitting/siting.
- For the fossil peaking plant technology option, applicable ERC price assumptions for NO_x and VOCs in each location are based on discussions with emissions brokers familiar with the current ERC market in New York. The price assumptions are shown in Table 21. **All results presented in this Draft Report use the same ERC price assumptions as the 2021-2025 DCR. ERC price assumptions will be updated prior to the Final Report.**
- The Startup and Testing Consumables allowance accounts for fuel and consumables during startup. For the BESS options, the allowance is for an assumed net cost of charging and discharging during site testing.
- For the fossil peaking plant technology options, initial fuel inventory accounts for 96 hours of fuel oil storage for the options that include dual fuel capability.
- The sales tax line is intended to be the sales tax for major equipment. The value is shown as zero dollars, as the study assumes that the project owner would receive a tax exemption certificate for capital purchases. Construction supplies and consumables would still be taxable. As applicable, consumable material unit costs in the EPC estimates account for sales tax.
- The Builders risk insurance allowance is based on 0.45% of the EPC capital cost.
- Owner's contingency is based on 5% of the total installed cost including EPC and all Owner's costs.

Table 21: ERC Price Assumptions

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K-Long Island
NO_x ERCs ($/ton)	$1,000	$1,000	$1,000	$6,500	$6,500	$6,500
VOC ERCs ($/ton)	$3,000	$3,000	$3,000	$7,000	$7,000	$7,000

- Construction financing costs, including Allowance for Funds used during Construction (AFUDC) and Interest during Construction (IDC), were estimated during the construction period for each plant type assuming the same 55/45 split of debt and equity and 6.45% cost of debt assumed for the project as a whole. Total construction periods (including pre-construction engineering and approvals) were assumed to differ for each technology, ranging from 30 months for the 2-hour BESS units to 42 months for the 8-hour BESS and fossil peaking plant technology options. As a result, construction financing costs are estimated at 9% of overnight capital costs for simple cycle units, 7.85% for the 2-hour and 4-hour BESS units, 9.24% for 6-hour BESS units, and 11.48% for 8-hour BESS units.

4. Electrical Interconnection Costs

Interconnection costs include Minimum Interconnection Standard (MIS) costs and, if applicable, System Deliverability Upgrade (SDU) costs. The NYISO planning department is conducting a deliverability analysis to determine whether any of the simple cycle plant options or BESS options being evaluated may require SDUs to obtain Capacity Resource Interconnection Service (CRIS). This report preliminarily assumes that all peaking plant technology options in all locations (fossil peaking plant technology options and BESS options) could be developed without a requirement to incur any SDU costs. **The NYISO is continuing to finalize the required deliverability assessment for this study. As a result, this assumption is subject to change if any peaking plant technology option is found to require SDU costs.**

MIS costs are comprised of Developer Attachment Facilities (DAF), System Upgrade Facilities (SUFs) at the POI, SUFs beyond the POI, and Connecting Transmission Owner (CTO) Attachment Facilities (AF). The DAF costs begin at the high side bushing of the GSU. The cost of the GSU/MPT is included in the EPC estimate. 1898 & Co. included separate estimates for the interconnecting switchyard and the transmission line in the Owner's costs.

The transmission line between the facility and the POI is assumed to be one mile long in Load Zone J (New York City) and three miles long in all other locations. The transmission line in Load Zone J is assumed to be installed underground,[22] while the lines in all other locations are assumed to be installed overhead.

The cost of the switchyard was based on the assumptions below:

[22] According to Consolidated Edison Transmission Planning Criteria (TP-7100-18, August 2019) and its fundamental design principles, underground transmission is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, nearly all existing transmission in New York City is already underground. As a result, 1898 & Co. assumed an underground interconnection for the plants evaluated in this study.

- Air insulated switchgear (AIS) for all locations except Load Zone J, which would include gas insulated switchgear (GIS) technology.[23]
- 345 kV high side voltage for all locations except Load Zone K, which is assumed at 138 kV.
- 3-position ring bus for 1x GE 7HA.03, 1x GE 7HA.02, and BESS options.

The costs for the switchyard, transmission line to POI and SUFs at POI were estimated by 1898 & Co. Budget pricing was obtained for the major electrical components. Bulk materials costs, installation labor costs, construction indirect and other indirect costs such as design, engineering and procurement were factored into the estimates developed for this study. A right-of-way allowance of $1 million per mile is included in all transmission line estimates.

5. Gas Interconnection Cost

For the fossil peaking plant technology options, gas interconnection cost estimates are based on 1898 & Co.'s experience with gas laterals and available information on pipeline projects recently planned or completed in New York. Recent projects in New York and Connecticut suggest that 5 miles is a reasonable assumption for gas lateral length in all Load Zones except Load Zone J. 1898 & Co. developed costs reflecting an average gas lateral length of one mile in Load Zone J and five miles in all other locations, with a 16-inch diameter pipeline for the GE 7HA.02 and GE 7HA.03 options. The average cost for a metering and regulation station was estimated at $3.5 million in all locations.

These costs represent a generalized estimate to interconnect with either an interstate natural gas pipeline or a gas LDC distribution system. As described above, units with dual fuel capability are expected to have greater geographic siting flexibility, including the ability to interconnect with an LDC. Project-specific interconnection costs for an actual plant may be higher or lower, depending on a multitude of factors including distance, terrain, and existing right-of-way.

6. Water Supply Costs

Water supply is only required for the fossil peaking plant technology options. The BESS technology options do not use water. For the fossil peaking plant technology options, Load Zone J assumes a municipal water connection and the line item accounts for a 1-mile, 8" diameter water line. The estimated cost for the water line connection in Load Zone J is based on 1898 & Co.'s experience and review of publicly available information for water main installation and/or restoration in Load Zone J. For all other locations, the water supply for the fossil peaking plant technology options is based on an onsite well that is included in the EPC capital cost, so there are no costs shown in this Owner's Cost line item.

7. Summary of Capital Investment Costs

Capital investment costs for each location and technology option are summarized in the tables below. For the GE 7HA.03 simple cycle units, dual fuel capability and SCR emissions controls are included for all locations. For the

[23] According to Consolidated Edison Transmission Planning Criteria (TP-7100-18, August 2019) and its fundamental design principles, GIS switchyard is not mandated for new generation facilities interconnecting to the Con Edison transmission system in Load Zone J; however, it is 1898 & Co.'s experience that power generation facilities and switchyards in dense urban areas such as those in Load Zone J require GIS facilities due to space constraints and aesthetic considerations.

GE 7HA.02 simple cycle units, SCR emissions controls are not included (this option was only considered for Load Zones C, F, and G (Dutchess County)). The fossil peaking plant technology options are assumed to be subject to an annual operating hours limitation for compliance with NSPS for GHG. Cost buildups are included in Appendix A. Capital costs in $/kW units are based on the total capital cost divided by the ICAP performance of each plant option evaluated.

Table 22: Preliminary Capital Cost Estimates ($2024 million)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with Dual Fuel and SCR)	$652	$663	$659	$697	$787	$737
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	$565	$575	$569	-	-	-
Energy Storage						
BESS 2-hour	$247	$249	$247	$254	$333	$249
BESS 4-hour	$386	$388	$386	$396	$510	$394
BESS 6-hour	$541	$544	$542	$555	$692	$558
BESS 8-hour	$697	$701	$697	$715	$887	$722

Note:
[1] All estimates include construction financing costs

Table 23: Preliminary Capital Cost Estimates ($2024/kW)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with Dual Fuel and SCR)	$1,677	$1,656	$1,659	$1,754	$1,948	$1,823
1x0 GE 7HA.02 (with Dual Fuel, without SCR)	$1,760	$1,738	$1,734	-	-	-
Energy Storage						
BESS 2-hour	$1,236	$1,244	$1,237	$1,271	$1,665	$1,247
BESS 4-hour	$1,931	$1,942	$1,932	$1,980	$2,549	$1,971
BESS 6-hour	$2,707	$2,722	$2,708	$2,776	$3,461	$2,788
BESS 8-hour	$3,485	$3,505	$3,486	$3,575	$4,433	$3,609

Note:
[1] All estimates include construction financing costs.

F. Fixed & Variable Operating and Maintenance Costs

In addition to the initial capital investment, there are ongoing costs associated with the simple cycle and energy storage options. These include fixed operating and maintenance (O&M) costs, variable O&M costs, and fuel costs. The following sections describe the components that are included in the fixed O&M and the variable O&M. Appendix A contains tables that provide a breakdown of the fixed and variable O&M cost estimates for each technology in each location evaluated.

1. Fixed O&M Costs

The fixed O&M includes two components, fixed plant expenses and fixed non-operating expenses. Fixed plant expenses are O&M expenses that are not affected by plant operation (i.e. not related to fuel consumption or annual electric generation).

a. Fixed Plant Expenses

Fixed O&M costs for all technology options were developed using 1898 & Co. proprietary tools that generate cost estimates for plant staff labor, routine maintenance, training, laboratory expenses, safety equipment, building and grounds maintenance, and administrative and general costs.

The plant staff labor costs are based on the staffing levels in Table 24. The full-time equivalent (FTE) employees are comprised of O&M staff, management and administrative staff. Energy storage facilities are assumed to be remotely monitored by existing Owner staff, and therefore the fixed O&M results do not include labor personnel costs.

Table 24: Staffing Levels and Salaries Used for O&M Estimates

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
SCGT Options	7	7	7	7	7	7
BESS Options	0	0	0	0	0	0
Annual Salary (Wage plus Benefits)						
Full-Time Equivalent Personnel	$158,500	$174,200	$205,700	$257,100	$275,700	$275,700

1898 & Co. updated labor rates for this study using the cumulative change in the average wage rates for the respective Load Zone areas in the RSMeans Labor Rates for the Construction Industry. Note that the labor rates from the RSMeans source were not used for O&M personnel wage rates, but the average labor escalation is anticipated to be reflective of general labor trends.

b. Site Leasing Costs

The site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. The costs associated with temporary areas for laydown and parking during construction are included in the EPC pricing. 1898 & Co. used a combination of publicly available listing values and additional information provided by stakeholders (including a stakeholder provided assessment by JLL) to assess industrial zoned property in New

York. Particularly in Load Zone J, this resulted in a wide range of observed values. For all technologies, 1898 & Co. estimated annual lease rates by initially escalating the assumed values from the 2021-2025 DCR study to $2024 using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator (Q1 2019-Q1 2024). The resulting escalated values were then compared to the observed range of leasing costs identified by 1898 & Co's review. Based on this assessment, 1898 & Co. determined that, for purposes of this study, the escalated values represent reasonable values for all locations, except Load Zone J. Load Zone J has experienced increased demand for industrial zoned property resulting in property values that have outpaced the GDP based escalation. 1898 & Co. used the JLL report data to determine the average sale price over the last 5 years of M-3 zoned property, over 4 acres, without existing buildings, within a 3-mile radius of an existing substation within Load Zone J. This average was used as the assumed land lease cost in Load Zone J in lieu of escalating the 2021-2025 DCR study assumed values.

Table 25: Site Leasing Cost Assumptions ($2024)

	Load Zone J	Load Zone K	Load Zones C, F, and G
Land Requirement - Simple Cycle Options (acres)	12	15	15
Land Requirement - BESS 2-hour (acres)	6	9	10
Land Requirement - BESS 4-hour (acres)	9	12	14
Land Requirement - BESS 6-hour (acres)	12	16	18
Land Requirement - BESS 8-hour (acres)	15	20	22
Lease Rate ($/acre-year)	$644,000	$30,000	$26,000

c. Total Fixed Operations and Maintenance

The total fixed O&M expenses for all technology options including the fixed plant expenses, site leasing costs, and property insurance are shown in Table 26. As described below, property taxes and insurance are estimated separately as a percentage of total installed costs. Property taxes are not included in Table 26.

The BESS fixed O&M costs are intended to account for routine O&M for the BESS equipment and BOP equipment, extended warranties for BESS equipment, capacity and performance guarantees for the BESS equipment, and allowances for asset management, standby auxiliary power cost, and inverter replacement/repair. Fixed O&M costs are levelized for the assumed project life of each respective technology.

Fixed costs for BESS also include the "fixed" component of the augmentation cost estimate. In the industry, it is likely that augmentation events would be milestone costs at certain intervals, but for the purposes of accommodating differing cycling scenarios, the total augmentation cost was broken into fixed and variable components. 1898 & Co. built up augmentation estimates for two scenarios: 180 cycles per year for the assumed life of the project and 365 cycles per year for the assumed life of the project. These total lifetime costs were then annualized and algebraically split into the fixed amount that would be common for all cycling scenarios, and the variable amount that follows the cycling/dispatch behavior.

Table 26: Fixed O&M Estimates ($2024/kW- year)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies[1]						
1x0 GE 7HA.03 (Dual Fuel, with SCR)	$14.9	$14.9	$15.6	$17.0	$36.1	$17.9
1x0 GE 7HA.02 (Dual Fuel, without SCR)	$18.0	$17.9	$18.1	-	-	-
Energy Storage[2]						
BESS 2-hour	$22.68	$22.73	$22.69	$22.87	$41.85	$23.03
BESS 4-hour	$37.62	$37.68	$37.62	$37.88	$66.95	$38.08
BESS 6-hour	$53.34	$53.42	$53.35	$53.70	$92.50	$54.11
BESS 8-hour	$68.04	$68.14	$68.04	$68.50	$117.27	$69.11

Notes:
[1] Based on degraded performance at ICAP conditions
[2] Based on 200,000 kW net output at point of interconnection.
[3] Fixed O&M reflects capacity augmentation costs assuming a 15-year operating lifetime for BESS technologies.

d. Taxes

Property taxes are equal to the product of (1) the unadjusted property tax rate for the given jurisdiction, (2) an assessment ratio, and (3) the market value of the applicable peaking plant technology option, reflecting the installed capital cost exclusive of any SDU costs.

Outside of Load Zone J, the effective property tax rate is assumed to be 0.6% for all fossil peaking plant technology options based on the assumption that the plant will enter into a Payment in Lieu of Taxes (PILOT) agreement, which will be effective for the full amortization period. PILOTs are typically developed based on project specific and regional economic conditions and are expected to vary based on the unique circumstances of each county and project at the time of negotiations. A 0.75% rate was used in the prior two resets. However, a review of PILOT data available from the New York State Comptroller's Office indicated that 0.6% is a reasonable assumption for this study that is consistent with current PILOTs agreements for natural gas plants in New York.[24]

[24] The Office of the New York State Comptroller provides financial data for local governments, including Industrial Development Agencies (IDA). *See* Office of the New York State Comptroller, "Financial Data for Local Governments," http://www.osc.state.ny.us/localgov/datanstat/findata/index_choice.htm. AG identified PILOT agreements for 10 natural gas plants, with effective PILOT tax rates ranging from 0.15% to 5.63%, and the median value of these rates was 0.67%, calculated as the ratio of current PILOT payments to initial project dollar amount. Available data indicates that PILOT payments may not be fixed over time, with some increasing, some decreasing and some remaining constant over the duration of the PILOT agreement. These projects in the sample include a wide range of developments, including both greenfield and brownfield developments, repowering of units, and large combined cycle units. AG also reviewed PILOT agreements for 4 battery projects, with effective PILOT tax rates ranging from 0.03% to 1.92% with a median of 0.21%.

In New York City, the property tax rate equals 4.77%, which is equal to the product of (1) the Class 4 Property rate (10.592%) and (2) the 45% assessment ratio.[25]

However, the New York Real Property Tax Law Section 489-BBBBBB(3)(b-1) provides a 15-year tax abatement in New York City for the peaking plant underlying the NYC ICAP Demand Curve.[26] Accordingly, it is assumed that each fossil peaking plant technology option would receive this exemption and incurs taxes only for years 16 and beyond.[27] Notably, however, this Load Zone J specific tax abatement is currently scheduled to expire for construction activities occurring after April 1, 2025. AG and 1898 & Co. are continuing to monitor the status of this abatement and any potential for the enactment of an extension to the current expiration. Although the abatement has initially been considered as applicable for the fossil peaking plant technology options in Load Zone J, if the abatement is not extended, the application of this abatement will be revised with the 4.77% tax rate described above applied to all years of the assumed life of the fossil peaking plant technology options in Load Zone J.

Energy storage plants are provided a 15-year tax abatement statewide pursuant to New York Real Property Tax Law Section 487.[28] A 15-year property tax exemption is assumed for all battery storage plants in all locations for this study.[29] The property tax rate applicable to BESS options for any remaining portion of the assumed life of the plants would be the 0.6% rate identified above for locations other than Load Zone J and the 4.77% rate identified above in Load Zone J.[30]

Property tax rates assumed in this report are summarized in the table below:

Table 27: Property Tax Rates by Technology

	Load Zone J (NYC)	All Other Locations
Technology	**Years 1-15**	**Years 1-15**
BESS	0.00%	0.00%

	Load Zone J with Extended Abatement	Load Zone J without Extended Abatement	All Other Locations
Technology	**Years 1-13**	**Years 1-13**	**Years 1-13**
Fossil Peaking Plant Technology Options	0.00%	4.77%	0.60%

[25] *See* New York City Department of Finance, “Property Tax Rates,” https://www.nyc.gov/site/finance/property/property-tax-rates.page and New York City Department of Finance, “Determining Your Assessed Value,” https://www.nyc.gov/site/finance/property/calculating-your-property-taxes.page
[26] *See* New York Real Property Tax Law Section 489-BBBBBB(3)(b-1)
[27] Any underlying level of real property tax on the land leased for the fossil peaking plant technology options in Load Zone J that is not covered by the abatement is assumed to be accounted for within the land lease rate.
[28] *See* New York State Department of Taxation and Finance, Exemption Administration Manual, Section 4.01, RPTL Section 487.
[29] Any underlying level of real property tax on the land leased for the battery storage peaking plant options that is not covered by the abatement are assumed to be accounted for within the land lease rate.
[30] Based on the assumption of a 15-year amortization period for the BESS options, the tax abatement would apply for all years of such assumed life.

e. Insurance

Insurance costs are estimated as 0.6% of the EPC capital cost. This same assumption was used for the last two DCRs. This cost assumption is also consistent with values identified from prior 1898 & Co. consulting experience in New York and elsewhere.

2. Variable O&M Costs

For fossil peaking plant technology options, variable O&M costs are directly related to plant electrical generation. Where applicable, variable O&M costs include routine equipment maintenance, makeup water, water treatment, water disposal, ammonia (if SCR emissions controls are included in the design), SCR catalyst replacements (if applicable), CO catalyst replacements (if applicable), and other consumables not including fuel. In the tables in Appendix A, variable O&M for water and SCR emissions controls related items are shown separately.

The fossil peaking plant technology options do not include demineralized water treatment systems in the EPC capital cost, so the O&M assumptions include temporary demineralized water trailers for treatment, as applicable. Demineralized water is assumed for water injection for NO_x control for fuel oil operation on all fossil peaking plant technology options. This is reflected in the higher cost for water-related O&M for those cases. The GE 7HA.03 and GE 7HA.02 units have dry combustion on gas operation. Water consumed for inlet evaporative cooling is not demineralized. Raw water source is assumed to be well water for all locations except Load Zone J. In Load Zone J, use of municipal water is assumed at $6 per 1,000 gallons.

Wastewater and plant drains are collected in permanent onsite tanks for periodic removal using pump trucks. The variable O&M for fossil peaking plant technology options accounts for the pump truck, hauling, and disposal fees.

Major maintenance, shown in Table 28, for combustion turbines is broken out separately from routine variable O&M for all fossil peaking plant technology options. Combustion turbine major maintenance typically consists of combustion inspections, hot gas path inspections, and major inspections. Cost estimates account for a complete cycle through the first major inspection, based on manufacturer budgetary estimate information and 1898 & Co.'s experience.

Major maintenance costs for the frame engine options (GE 7HA.03 and GE 7HA.02) are dependent on the operating profile, so they may be based on dollar per gas turbine start ($/GT-start) basis or dollar per gas turbine hour of operation. In general, if there are more than 36 operating hours per start, the major maintenance cost will be hours based. If there are less than 36 hours per start, the major maintenance cost will be start-based. Note that the $/GT-hr and $/start costs are not meant to be additive. The operational profile determines whether the annual maintenance costs will be based on hours or starts for all fossil peaking plant technology options.

A summary of the non-major-maintenance variable O&M cost for each fossil technology option in each location is provided in

Table 29 and Appendix A. For the BESS options, the variable O&M costs in this study are intended to represent the variable component of capacity augmentation, accrued in terms of $/MWh discharged in the net EAS model. Variable O&M costs for BESS units are provided in Table 30.

Table 28: Major Maintenance ($2024 USD)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fossil Peaking Plant Technology Options							
1x0 GE 7HA.03 (25 ppm, with SCR)	$/GT-hour	$650	$650	$650	$650	$650	$650
	$/start	$23,100	$23,100	$23,100	$23,100	$23,100	$23,100
1x0 GE 7HA.02 (15 ppm, without SCR)	$/GT-hour	$620	$620	$620	-	-	-
	$/start	$23,000	$23,000	$23,000	-	-	-

Table 29: Natural Gas Variable O&M Costs ($2024/MWh)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Fossil Peaking Plant Technology Options							
1x0 GE 7HA.03 (25 ppm, with SCR)	With SCR	$1.45	$1.45	$1.45	$1.45	$1.54	$1.50
1x0 GE 7HA.02 (15 ppm, without SCR)	No SCR	$0.90	$0.90	$0.90	-	-	-

Notes:
[1] Excludes fuel consumed and revenues from electricity produced during start.
[2] Based on natural gas operation at 59°F/ 60% RH.

Table 30: BESS Variable O&M Costs ($2024/MWh)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K – Long Island
BESS Technology Options						
2-Hour Duration	$6.68	$6.68	$6.68	$6.68	$6.68	$6.68
4-Hour Duration	$6.80	$6.80	$6.80	$6.80	$6.80	$6.80
6-Hour Duration	$6.56	$6.56	$6.56	$6.56	$6.56	$6.56
8-Hour Duration	$6.73	$6.73	$6.73	$6.73	$6.73	$6.73

Notes:
[1] Variable O&M costs reflect the variable component of capacity augmentation costs levelized over the 15-year assumed lifetime of the BESS unit.

G. Operating Characteristics

The plant operating characteristics used to evaluate the fossil peaking plant technology options in each location are:

- Summer and winter degraded capacity ratings, summer dependable maximum net capability (DMNC), winter DMNC and ICAP plant capacity (net output) and net heat rate (fuel efficiency);

- Average degradation of net capacity and net heat rate as plant ages;
- Equivalent forced outage rate on demand (EFORd); and
- Plant startup time and fuel required for startup.

The net output and net heat rate for all the combustion turbine options are impacted by ambient conditions (temperature and relative humidity) and site elevations. The site elevations in each location are identified in Table 31.

Table 31 also provides the ambient temperatures and relative humidity for the summer, winter, summer DMNC, winter DMNC and ICAP for all fossil peaking plant technology options. The summer and winter ambient conditions in each location are determined at the average winter and summer conditions. The summer and winter DMNC ambient conditions in each location are determined at the average of the ambient conditions recorded at the time of the applicable Transmission District's seasonal peak during the previous four like Capability Periods, as recorded at the nearest representative weather station. The ICAP ambient condition is defined as 90°F and 70% relative humidity. The ICAP DMNC value is used to express capital costs and fixed O&M on an equivalent $/kW and $/kW-year basis. Net EAS revenues utilize performance values (e.g., heat rate) associated with average summer and winter conditions, respectively, since net EAS revenues are calculated throughout the full year. **All results presented in this Draft Report use the same summer and winter DMNC conditions as the 2021-2025 DCR. Summer and winter DMNC conditions will be updated prior to the Final Report to reflect the updated DMNC methodology that will be in place starting in 2025.**

The detailed plant performance data for each technology option in each location is provided in Appendix A.

Gross performance ratings for GE 7HA.03 and GE 7HA.02 options are based on data requested from GE's online gas turbine performance estimator program at specific ambient conditions from Table 31. All performance ratings shown for the fossil peaking plant technology options are based on natural gas operation. Minimum load is defined as the minimum emissions compliant load (MECL), as reflected in the OEM ratings. Appendix A includes full load and minimum load performance estimates at the conditions identified in Table 31.

1898 & Co. adjusted these performance results for auxiliary loads, system losses, and performance degradation. Heat rates are calculated for higher heating value (HHV). The power plant performance begins to degrade once the facility begins to operate. Some of the degradation is not recoverable, however, most of the performance loss is recovered after major equipment overhauls. The plant performance degradation percentages used to calculate degraded output and heat rate from new and clean percentages for the fossil peaking plant technology options are shown in Table 32. These degradation adjustments are indicative of average degradation between overhauls, based on 1898 & Co. experience on past projects. The same adjustment values were also assumed for the 2017-2021 and 2021-2025 DCRs.

The net plant capacity and net plant heat rates at the ICAP ambient conditions (90°F and 70% relative humidity) for each location for the fossil peaking plant technology options are shown in Table 33 and Table 34, respectively. Performance for all ambient conditions is provided in Appendix A. Average degraded net plant capacities are used throughout the economic analysis as described in Sections III and IV. The use of the average degraded net plant capacity is used to reflect expected operations over the life of the plant.

Table 31: Ambient Conditions for 2025-2029 DCR

Load Zone	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity (%)
C: Central	1099	Summer	85.5	49.7
		Winter	-3.1	14.4
		ISO	59.0	60.0
		Summer DMNC	88.9	57.7
		Winter DMNC	10.8	55.7
		ICAP	90.0	70.0
F: Capital	279	Summer	86.2	48.1
		Winter	4.3	7.2
		ISO	59.0	60.0
		Summer DMNC	89.4	54.7
		Winter DMNC	13.2	59.1
		ICAP	90.0	70.0
G: Dutchess County	492	Summer	87.6	46.4
		Winter	7.9	7.13
		ISO	59.0	60.0
		Summer DMNC	87.6	51.5
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
G: Rockland County	492	Summer	87.6	46.4
		Winter	7.9	7.13
		ISO	59.0	60.0
		Summer DMNC	87.6	46.4
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
J: New York City	10	Summer	89.78	43.9
		Winter	18.0	5.9
		ISO	59.0	60.0
		Summer DMNC	93.3	58.8
		Winter DMNC	21.1	46.4
		ICAP	90.0	70.0
K: Long Island	85	Summer	85.8	73.0
		Winter	15.6	6.56
		ISO	59.0	60.0
		Summer DMNC	88.8	59.0
		Winter DMNC	16.5	50.2
		ICAP	90.0	70.0

Table 32: Average Plant Performance Degradation over Economic Life

Plant	Average Degradation of Net Output	Average Degradation of Net Heat Rate
1x0 GE 7HA.03	3%	1.8%
1x0 GE 7HA.02	3%	1.8%

Table 33: Average Net Plant Capacity ICAP (kW)

Natural Gas (kW)	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with SCR)	389,000	400,300	397,400	397,400	404,100	404,000
1x0 GE 7HA.02 (without SCR)	321,026	330,682	328,126	-	-	-

Note:
[1] Based on degraded ICAP performance. Degradation not included.

Table 34: Average Net Plant Heat Rate ICAP (Btu/kWh)

Natural Gas (Btu/kWh)	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
1x0 GE 7HA.03 (with SCR)	9,070	9,060	9,070	9,070	9,060	9,060
1x0 GE 7HA.02 (without SCR)	9,183	9,173	9,173	-	-	-

Note:
[1] Based on degraded ICAP performance. Degradation not included.

Table 35: BESS Net Power at POI (MW)

Net Power (MW)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Energy Storage						
BESS 2-hour	200	200	200	200	200	200
BESS 4-hour	200	200	200	200	200	200
BESS 6-hour	200	200	200	200	200	200
BESS 8-hour	200	200	200	200	200	200

Notes:
[1] BESS is sized for 200 MW net at the POI. Energy discharge capability is maintained through capacity augmentation throughout the assumed project life.
[2] Heat rate is not applicable to BESS units because fuel is not directly consumed.

For the fossil peaking plant technology options, EFORd is defined as "a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is demand on the unit to generate."[31] The North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS) continuously collects availability/reliability data from more than 5,000 power plants in North America. The data is organized by plant type, size ranges and plant age ranges. 1898 & Co. included EFORd data extracted from NERC GADS based on the performance since 2018 for units that are no more than 10 years old. Based on NERC GADS data, 1898 & Co. recommends a derating factor of 4.1% for the fossil peaking plant technology options. This value is somewhat higher than the 2.9% EFORd assumed in the 2021-2025 DCR.

Based on capacity market rules for energy storage resources, the capacity derating factors for battery units will be calculated based on an Upper Operating Limit (UOL) metric, which depends on both forced outages and average state of charge.[32] Based on OEM data on the expected forced outage rates for new battery installations, a 2% outage rate is assumed for all of the BESS options. This outage rate is somewhat lower than the 3% outage rate assumed in the 2021-2025 DCR.

The original equipment manufacturers provided start-up times and start up curves that were used to calculate the start-up fuel consumption for the fossil peaking plant technology options. The start-up data is included in Appendix A. For the fossil peaking plant technology options, both conventional start- up and fast start- up information is provided. The GE 7HA.03 and GE 7HA.02 units can achieve full output in 10 minutes.

III. Gross Cost of New Entry

Gross CONE encompasses all costs associated with plant construction and operations aside from those arising from providing energy and ancillary services, which are addressed in Section IV. Gross CONE includes the recovery of capital costs, including a return on investment. The annualized cost associated with a capital investment reflects the financial parameters described in Section III.A that capture the investor's cost of capital and the period over which the return of and return on upfront capital investment is assumed to be recovered. Section III.B describes the translation of these up-front capital costs, along with time-varying tax costs, into a levelized fixed charge (i.e., an annual carrying charge) that allows full recovery of the plant's capital costs over the course of the plant's assumed economic life. Finally, Section III.C provides estimates of the gross CONE, including the levelized fixed charge, fixed O&M expenses, and insurance.

A. Financial Parameters

The development of a new supply resource requires the upfront investment of new capital to construct the facility. The financial parameters translate these upfront technology and development costs into an annualized value that is an element of gross CONE for each location evaluated. Subtracting the estimated annual net EAS revenues from this annualized gross CONE value produces the annual reference value (ARV), which is often referred to as the net CONE value. That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant

[31] *See* IEEE-SA Standards Board, "IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity," IEEE Standard 762-2006, published March 15, 2007.
[32] NYISO, "Capacity Market Rules for Energy Storage Resources," presentation to the Installed Capacity Working Group, August 23, 2018.

technologies. This translation from up-front to annualized value is reflected in the so-called "levelization" factor. The parameters that affect the levelization factor (the "financial parameters") include:

- The weighted average cost of capital required by the developer, based on the developer's required cost of equity (COE), its cost of debt (COD), and the project's capital structure, as reflected in the ratio of debt to equity (D/E ratio);
- The term, in years, over which the project is assumed to recover its upfront investment, referred to as the amortization period (AP); and
- Applicable tax rates, which affect the costs of different types of capital.

These elements are not determined in isolation. Appropriate values for these parameters need to reflect the interrelationships among them, and as a whole appropriately reflect the financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market and policy context. While we discuss each item separately below, ultimately our selection of the parameters making up the assumed WACC and the AP is based on an evaluation of how these parameters, in combination, reflect the financial risks of project development.

The selection of these financial assumptions should capture industry expectations about capital costs, and reflect project-specific risks, including development risks and risks to future cash flows for a merchant developer, based on investor expectations over the life of the project. Many factors can affect investor risks – such as uncertainty in input (fuel prices) and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; the development of energy and environmental policies with implications for industry demand, costs, revenues and the operability of the facility; and the pace and nature of technological change. Further, data that may be available on individual components of the WACC and the AP can vary with factors specific to circumstances, including location, corporate structure, prevailing economic/financial conditions, fuel and electricity market expectations, financial hedges (such as power purchase agreements), and the nature and impact of current and potential future market and regulatory factors.

Ultimately, the recommended WACC and the AP reflect our view of the risks associated with the merchant development of a peaking plant in the NYISO market context, and the return required by investors to compensate for those risks. AG's recommendations are based on our professional judgment, reflecting the particular circumstances of merchant development of a peaking plant in the NYISO market context; the sources of information identified and described below; past professional experience, including conversations with independent power producers and the finance community; and AG's view of industry conditions, market factors, and relevant state policy at the time of this study, including past experience with merchant development in the NYISO markets.

AG also presents its thoughts on some of the key perspectives with respect to development approaches and key existing and emerging development, market, and regulatory risks that are needed to interpret available data and information. Finally, AG presents its recommended assumptions for WACC and AP based on our careful review of all of these factors from the perspective of potential resource developers in the New York electricity market.

1. Amortization Period

The AP is the term over which the project developer expects to recover upfront capital costs, including the return of and on investment. In the context of the DCR, it is the period of time (in years) over which the discounted cash flow from net EAS revenue streams (net of annual fixed costs) are netted out against the upfront capital investment cost of the peaking plant. The AP, often referred to as the “economic life” of the asset, can differ from the plant’s expected physical or operational life. While the physical life of the plant reflects the expected length of time the plant will remain in operation (usually before major overhauls would be required), the economic life can differ due to financial considerations, particularly risks associated with assuming future revenue streams in light of market and technological uncertainties.

The AP must balance risks over the full physical life of the plant. On the one hand, plant owners will earn net revenues over the full physical life of the plant (while incurring costs for component replacement and maintenance overhauls over time). Based on extensive operating experience, an expected physical life of at least thirty years is reasonable for a fossil peaking plant technology options.[33] On the other hand, many factors create risks to future cash flows. These include changes in markets, technologies, regulations, policies, and underlying demand from consumers. To the extent that any of these changes lead to a long-term outlook for revenues that is less than assumed in the current analysis or captured in annual updates, investors would tend to under recover total costs. To account for these risks, investors may seek a shorter AP.

Consistent with the 2021-2025 DCR, for fossil peaking technology options, we recommend an assumed AP that reflects the requirement of the CLCPA that all load in New York be supplied by zero-emissions resources as of 2040.[34] In principle, the owner of a fossil generating facility constructed now could implement plant modifications prior to 2040 that would allow the plant to continue to operate, for example, by using a zero-carbon fuel (e.g., hydrogen) in place of the current fossil fuels. While we recognize this may be possible, the technology and/or markets to accomplish this and continue to operate in compliance with the CLCPA beyond 2039 cannot be assumed to exist at this time. Thus, the developer of a fossil peaking plant would face substantial uncertainty about the financial returns of a fossil peaking plant under the CLCPA starting in 2040, given the uncertain availability and cost of zero-emission technologies, markets, and alternative fuels.

To evaluate amortization periods for the fossil peaking plant technology options in light of the CLCPA’s 2040 zero-emissions energy requirement, we estimate the number of years over which lenders and investors would seek to recover their investment given the fossil peaking plant technology options considered for this DCR. We do not assume upgrades, modifications or other future design changes to the fossil peaking plant technology options that could potentially facilitate continued operation as a zero-emission resource beginning in 2040. This time period will vary depending on when a fossil peaking plant commences operations. For example, the developer of a fossil-fueled peaking plant that begins operation at the start of the first Capability Year encompassed by this DCR (i.e., commencing operation on May 1, 2025) should not expect an operating life exceeding approximately 14.7 years

[33] Units may require significant capital expenditures to retrofit or upgrade units to maintain in operation. The current analysis does not consider these incremental investments in the discounted cash flow analysis.

[34] New York State, Chapter 106 of the Law of 2019. Requirements established by the CLCPA include: (1) a goal to reduce GHG emissions 85% over 1990 levels by 2050, with an incremental target of at least a 40% reduction by 2030; (2) producing 70% of electricity from renewable resources by 2030 and 100% from zero-emissions resources by 2040; (3) increasing energy efficiency by 23% over 2012 levels; (4) building 6 GW of distributed solar by 2025, 3 GW of energy storage by 2035, and 9 GW of offshore wind by 2035; (5) electrification of the transportation sector, as well as water and space heating in buildings.

(i.e., the time between May 1, 2025 and December 31, 2039) without plant retrofits to remain compliant with the CLCPA's zero-emission requirement beginning in 2040. Similarly, a new fossil-fueled plant commencing operations at a later point in time would expect to operate for a shorter economic life. Table 36 shows the economic life the fossil peaking plant technology options could reasonably assume depending on the Capability Year encompassed by this DCR in which the fossil-fueled peaking plant commences operations.

Given these factors, AG recommends an AP of 13 years for all fossil peaking plant technology options in all locations. This is an appropriate assumption given the balance of risks and uncertainty faced by fossil-fueled peaking plant project developers in New York markets. As shown in Table 36, 13 years represents the average economic operating life of the fossil peaking plant technology options over the four-year period covered by this DCR.

An amortization period of 13 years for all fossil peaking plant technology options strikes a reasonable balance between many considerations, including the general regulatory and technological risk faced by investors in fossil fuel resources within New York, the specific operational limits posed by the CLCPA regarding fossil fuel use for electricity generation beginning in 2040, and the uncertainty that exists at this time regarding the availability and cost of conversion technologies and/or fuels that may or may not be available to extend a plant's economic life beyond 2039. Moreover, a 13-year amortization period is consistent with the method recommended by AG in the 2021-2025 DCR, which was accepted by FERC in an order issued on May 19, 2023 in Docket No. ER21-502.[35]

Table 36: Potential Economic Operating Life of Fossil Plants

Capability Year	Potential Operating Life of Fossil Peaking Plant Technology Options	Average Operating Life of Fossil Peaking Plant Technology Options 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: [1] The potential commercial operating life was calculated by counting the number of years between May 1 of each applicable Capability Year and January 1, 2040.

The amortization period for the BESS options face a different set of considerations than the fossil peaking plant technology options. Unlike fossil plants, battery storage plants do not face the same regulatory constraints from the CLCPA that would limit future operations beginning in 2039. On the other hand, the BESS options face unique financial risks. *First*, battery storage faces physical performance risks, as there is no current commercial operating experience with battery storage operating for more than 10 years. Thus, battery storage operation – generally and within New York – faces uncertainties 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. *Second*, battery storage faces market performance risks. One such risk arises because battery storage is still a relatively early-stage technology likely to experience further improvements in operational performance, particularly cycling energy

[35] New York Independent System Operator, Inc., 183 FERC ¶ 61,130 (May 19, 2023).

losses. Thus, the first wave of battery storage plants to operate in New York may be less competitive than battery units that enter the market at a later date with more advanced and/or efficient technologies. This reduced competitiveness may translate into lower net revenues over time, particularly toward the end of the assumed life of the asset. These technology effects are more significant for battery technologies, given their early state of technological development, compared to the fossil peaking plant technology options. Another market risk relates to Capacity Accreditation Factors (CAFs) that are used in determining the quantity of UCAP a resource can supply. Going forward, CAFs will vary each year depending on the mix of resources in the system, load profiles and other factors. Changes in CAFs create uncertainty for future revenue streams as a lower CAF would reduce revenues and a larger CAF would increase revenues. However, future CAF values are uncertain given uncertainty in the expansion of, for example, battery storage technology and intermittent renewables in New York, which could tend to have countervailing impacts on battery storage CAFs depending on the timing, magnitude, and types of future resource additions.

As discussed in Section II, we partly address some of the uncertainties associated with future battery operations by analyzing battery storage plants in which the augmentation costs to counter battery cell degradation over an extended timeframe are captured, in part, by O&M costs (with components of such augmentation costs allocated to both fixed and variable O&M), and an assumption of initial overbuild captured in up-front capital costs. However, we recognize that given the relative newness of battery storage technologies in power system operations, and the uncertainty associated with both storage facility longevity and market revenues, lenders and investors would likely seek to recover costs on an expedited timeframe relative to existing power system technologies with long-standing operational experience. Considering these factors, and consistent with our recommendations from the 2021-2025 DCR, we assume an AP for battery storage technologies of 15 years.

2. Weighted Average Cost of Capital

The cost of capital for a new peaking plant will reflect the proportion of each source of capital in the project's capital structure – that is, the ratio of debt and equity capital to their sum – and their “costs” – that is, the cost of debt and the required return on equity. Notably, an entity will choose the appropriate capital structure for a given project based on the expected costs of debt and equity, which, in turn, will vary depending on the chosen project’s capital structure, because this structure affects the likelihood that debt will be paid and equity will receive return of and on investment. Thus, the return on equity, cost of debt and capital structure are inter-related.

The appropriate WACC for use in the DCR needs to reflect the project-specific risks associated with the development of a new peaking plant by a merchant developer within the NYCA in the timeframe of interest in this DCR (i.e., 2025-2029) under conditions of a need for new capacity as required by the tariff-prescribed level of excess conditions assumed for purposes of the DCR. However, data are not available to directly observe the WACC for such a project and conditions. As a result, AG developed its recommended WACC based on data from a number of different sources.

Our primary source of information is financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets – that is, independent power producers (IPPs). Merger and acquisition activity involving IPP firms has affected the availability of information on these firms. In particular, the purchase of publicly traded firms by private firms limits data availability, even if those firms subsequently are listed publicly at a later date.[36] AG's assessment considers this data, with an understanding that project-level and company-level WACC values will differ when specific projects are more or less risky than the company as a whole.[37]

AG also considers a variety of other sources of information, including estimated WACCs for publicly traded companies developed by financial analysts (e.g., in the context of so-called "fairness opinions") and independent assessments of capital costs and the costs of merchant plant development. These independent assessments include information on the WACC under different corporate structures, including "project finance," in which the project is financed as a stand-alone entity without recourse to a company's balance sheet.

AG's recommendations are based on its professional judgment, reflecting the information and data identified below; past professional experience, including conversations with IPPs and the finance community; and an appropriate balancing of these various sources of information and experiences considering the market risks faced by a new merchant peaking plant being developed within the NYISO markets.

In evaluating this data, AG views the appropriate WACC for a new peaking plant as being informed by both the WACCs for IPP firms and the appropriate adjustments needed to capture stand-alone project factors. As noted above, the appropriate cost of capital for a specific project should reflect the particular risks faced by that project, not the risks associated with the company or investors that are considering the development of that project.[38] The WACC for a new merchant project may exceed that of publicly-traded IPP companies because, for example, these companies have portfolios of assets that balance and mitigate risks, and thus lower the overall WACC at the company level. These portfolios include various financial assets, including financial hedges and long-term contracts, as well as portfolios of physical assets spanning varied geographies (including regions with different load profiles), technologies, fuels and vintages. By contrast, publicly available information on financing arrangements for individual projects, whether through stand-alone project finance or via a corporate balance sheet, is limited. Regardless, information on capital costs from corporate IPPs can inform choices about the appropriate WACC for a peaking plant, recognizing the need to account for project-specific risks.

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[36] For example, Talen Energy was formed in June 2015, taken private in in December 2016 and subsequently publicly relisted in May 2023. *See* Munawar, Adnan, "Riverstone completes $5.2B acquisition of Talen Energy," S&P Global Market Intelligence, December 6, 2016, https://www.spglobal.com/marketintelligence/en/news-insights/trending/5183c2giwe8eid5el82qva2 and "Talen Energy Corporation Announces Listing to OTC Pink Market," available at: https://talenenergy.investorroom.com/2023-06-23-Talen-Energy-Corporation-Announces-Listing-to-OTC-Pink-Market Energy Capital Partners purchased Calpine in March 2018. *See* Energy Capital Partners, "Consortium Led by Energy Capital Partners Completes Acquisition of Calpine Corporation; Announces Management Roles and Board of Directors," March 8, 2018, https://www.ecpartners.com/news/consortium-led-by-energy-capital-partners-completes-acquisition-of-calpine-corporation-announces-management-roles-and-board-of-directors. Vistra Energy acquired Dynegy in April 2018. *See* Vistra Energy, "Vistra Energy Completes Merger with Dynegy," April 9, 2018, https://investor.vistraenergy.com/investor-relations/news/press-release-details/2018/Vistra-Energy-Completes-Merger-with-Dynegy/default.aspx.]] In 2022, Constellation Energy was spun off from Exelon Corporation. https://www.constellationenergy.com/our-company/our-story/about-constellation.html.

[37] "The company cost of capital is *not* the correct discount rate if the new project is more or less risky than the firm's existing business. Each project should in principle be evaluated at its *own* opportunity cost of capital." Brealey, Richard, Steward Myers, and Franklin Allen, *Principles of Corporate Finance*, Ninth Edition, New York: McGraw-Hill/Irwin, 2008, p. 239.

[38] As noted in one text, "It is clearly silly to suggest that [a company] should demand the same rate of return from a very safe project as from a very risky one." Brealey, Richard, Steward Myers, and Franklin Allen, *Principles of Corporate Finance*, Ninth Edition, New York: McGraw-Hill/Irwin, 2008, p. 240.

Below, AG evaluates the individual financial parameters that bear on the recommended WACC, recognizing the interrelationships among these parameters in determining the WACC and the need for adjustments for project-specific risks.

Cost of Debt ("COD")

The cost of debt reflects a project developer's ability to raise funds on debt markets. Table 37 below reports the cost of debt measured as the average yield to maturity of long-term bonds observed between December 16, 2023 and March 15, 2024 for four power companies with meaningful ownership of merchant units: AES, Constellation, NRG, and Vistra. Those companies are publicly traded and, therefore, have the advantage of providing sufficient information to compute the COD (and, as explained below, the cost of equity capital). We refer to these companies as the "Proxy Group" for this study. Between December 16, 2023 and March 15, 2024, the average yield to maturity of these bonds has ranged from 5.31% to 6.31%.[39] Further details on these debt issuances are provided in Appendix B.

Two out of the four companies listed above have below-investment grade long-term debt credit ratings as of March 15, 2024 (NRG and Vistra are both rated BB). AES and Constellation have credit ratings above investment grade (equal to BBB- and BBB+, respectively) as of March 15, 2024.

AG also considered data on the generic cost of corporate debt.

Figure 4 below provides the generic corporate COD for companies with BBB, BB, and B credit ratings. The figure shows that the COD decreased following actions by the Federal Reserve to lower interest rates following the COVID-19 outbreak, with rates falling below 4% for BB-rated debt. In 2022, rates for BB-rated debt started to increase gradually following the increases in interest rates by the Federal Reserve. Towards the end of 2022, rates for BB-rated debt stabilized between 6 and 8%.

Based on these factors, AG recommends a COD of 6.70%. This recommendation reflects a number of factors, including: BB-rated debt; recent debt costs the need to capture current market conditions; differences between COD to IPPs relative to generic debt indices; and differences between corporate and project-specific risks (controlling for comparable BB-rated riskiness). **This preliminary recommendation is subject to change, as AG will continue to review updated data on bond yields through Q2 2024 to ensure final recommended COD values reflect current market conditions.**

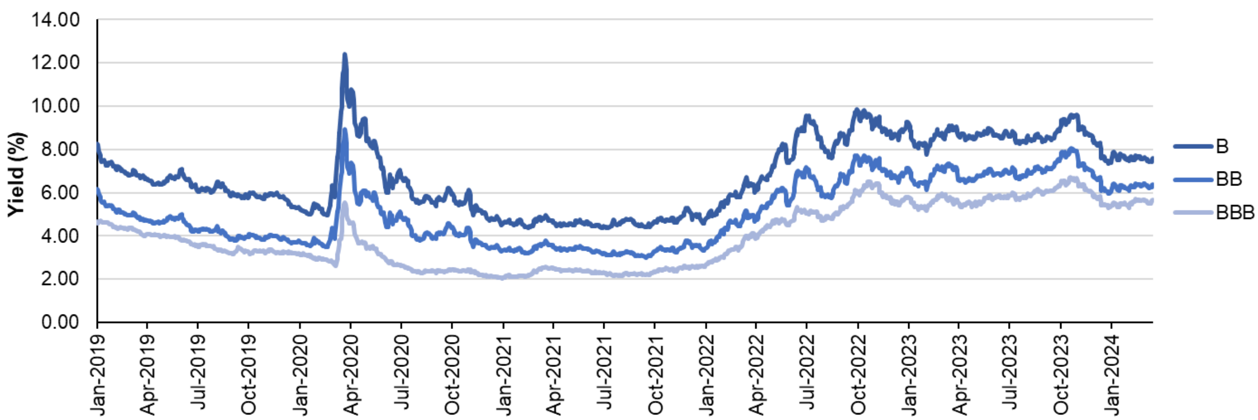
[39] Yields to Maturity are computed as the arithmetic average of all outstanding corporate bonds, weighted by the bond's face value amount, issued by each IPP with maturity between 10 and 20 years.

Table 37. Bond Yields of Representative IPP Companies, Dec. 16, 2023 – Mar. 15, 2024[40]

Company	Credit Rating	Average Yield to Maturity
AES	BBB-	5.48
Constellation	BBB+	5.31
NRG	BB	6.31
Vistra	BB	5.67
Average	**n/a**	**5.69**
Median	**n/a**	**5.57**
Min	**BB**	**5.31**
Max	**BBB+**	**6.31**

Notes: S&P Capital IQ; Bloomberg Data License. Average Yield to Maturity reflects the arithmetic average of all outstanding corporate bonds, weighted by the bond's face value amount, issued by each IPP with maturity between 10 and 20 years.

Figure 4: Bond Yields for B, BB, and BBB Bonds, Jan 1, 2019 to Mar. 15, 2024



Source: Federal Reserve Bank of St. Louis, FRED, ICE BofA US High Yield Index Effective Yield (series BAMLH0A2HYBEY, BAMLH0A1HYBBEY, and BAMLC0A4CBBBEY).

Cost of Equity ("COE")

The COE is the cost incurred to remunerate equity investors for their required return on equity (ROE) on their investment. Our recommended COE is developed primarily relying on estimated cost of equity capital for the Proxy Group described above. For reference, in the 2021-2025 DCR, AG evaluated the cost of equity for two companies within the current Proxy Group, NRG Energy and Vistra Energy. The Proxy Group used in this study includes up to four IPPs, in part, thanks to increased data availability.

[40] First observed YTM rate date: December 18, 2023 (December 16, 2023 is a Saturday).

We estimate the COE using the Capital Asset Pricing Model (CAPM).[41] Table 38 reports the estimated COE values under several scenarios. Each scenario is based on different assumptions used to estimate key parameters of the COE, such as beta, different subsamples of IPPs, and different Equity Risk Premia (ERP). Appendix B provides further details on each scenario and on the computation of COE under the CAPM. As these companies' business activities extend outside of merchant power generation and their generation asset holdings reflect a portfolio of assets with various vintages (and contract structures), their cost of equity is not necessarily comparable to the required cost of equity for a new peaking plant project in New York.

Table 38: Cost of Equity for Publicly Traded IPPs

Scenario	Beta Computation	Sample IPPs	Range of COE values using ERP of 5.50%	Range of COE values using ERP of 7.14%
1	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG, AES	10.51%-11.49%	12.33%-13.60%
2	Computed using ValueLine (5 years, weekly observations)	Vistra, NRG, AES	10.84%-11.81%	12.76%-14.03%
3	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG	11.45%-11.49%	13.55%-13.60%
4	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES, Constellation	10.51%-14.08%	12.33%-16.97%
5	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES	9.32%-10.29%	10.78%-12.05%

Notes: COE estimates are obtained using the CAPM based on a risk-free rate of 4.40%, computed as the 90-day Average of the Twenty-Year Treasury Constant Maturity Rate. "Scenario" describes the scenario considered in the computation of COE, as detailed in Appendix B. "Beta Computation" describes the way levered betas are obtained. "Sample IPPs" describes the set of IPP used in the computation of COE. "Range of COE values using ERP of 5.50%" and "Range of COE values using ERP of 7.14%" report the COE value ranges obtained under each scenario using an Equity Risk Premium ("ERP") of 5.50% and 7.14%, respectively.

In developing our estimates, we note independent estimates of the COE for new power plants developed in other, but related, contexts. Net CONE studies in neighboring markets provide a benchmark for comparison. PJM and ISO-NE have used COEs ranging from 12.8% to 13.8% in recent net CONE studies.[42] These values reflect different methodologies and data sources. Our recommendations also reflect certain publicly available sources of information on project financing, as well as non-public information reviewed in our professional activities.

In general, new investment in a peaking plant in New York faces a mix of market and regulatory risks that could increase or decrease future returns. Future policy and regulatory changes may affect market conditions, including: changes in loads, particularly in light of new loads (e.g., data centers) and policy efforts to increase electrification of heating and transportation; the mix of resources in the NYCA system given legislative changes, such as the CLCPA and policies to achieve its ends (e.g., potential procurements by state agencies, such as the New York State Energy Research and Development Authority); and technology-specific changes in CAFs given these changes in loads and system resources. Market outcomes may also change due to modifications to NYISO

[41] Other approaches not used include the Discounted Cash Flow (DCF) and historical risk premium. Similarly, AG notes that utility regulators may consider a variety of information and models (including CAPM, DCF, or historical risk premiums) when setting the COE for regulated utilities. Therefore, AG did not consider a comparison of CAPM estimates of COE for regulated utilities when estimating the relevant COE for a merchant power plant developer. This choice is consistent with the assumption that the rate of return for a "safer" project is not the same as the return for a riskier project that does not benefit from guaranteed cost recovery.
[42] Appendix B reports a list of these recent studies.

market rules over time, such as initiatives targeting potential ancillary service enhancements. Our assessment accounts for these various considerations, along with the general risks facing new merchant investment.

Based on this information, AG recommends a COE of 14.0%, reflecting a balance between the IPP values (which range from 9.32% to 16.97%) and project-specific considerations.

Debt to Equity Ratio

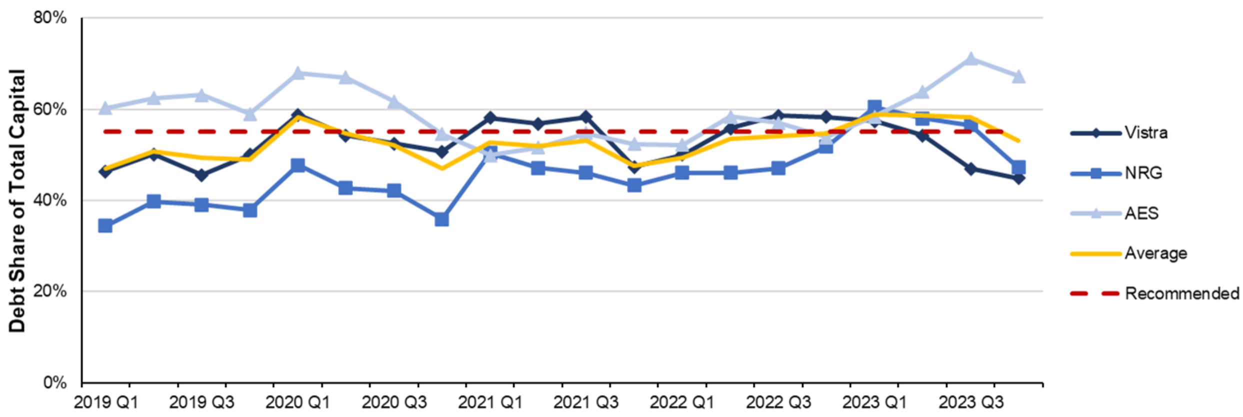
The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of the capital supporting the investment. Thus, a merchant peaking plant project could reasonably be developed through a range of capital structures.

AG recommends a D/E ratio of 55% debt to 45% equity given a balance of tradeoffs involved with greater or lesser leverage. Our assumption reflects the inter-relation of the capital structure with the cost of debt and return on equity, and different approaches to project development (e.g., balance sheet and project finance), and accounts for various indirect costs of financing (such as financial hedges) implicitly and not explicitly. Figure 5 shows the debt share of capital for AES, NRG, and Vistra, along with their average, over the past 5 years.[43] In early 2023, corporate capital structure was similar across the proxy group companies and in line with our recommendation. Since, capital structures have diverged somewhat, while their average across companies maintains a value consistent with our recommendation. While a corporate level capital structure is not necessarily informative to the capital structure for a given project, it does inform the capital structure for assets in the industry which is relevant to new project capital structure. Our recommendation is consistent with the capital structure adopted in recent similar studies for ISO-NE and PJM, which assume values similar to 55% in each study.[44]

[43] The market value of equity is calculated as enterprise value minus cash and cash equivalents; data for the calculations is from S&P Capital IQ.

[44] *See, e.g.,* ISO New England Inc. and New England Power Pool, Docket No. ER24- -000; Targeted Adjustment to Certain Forward Capacity Market Parameters to Reflect the Minimum Offer Price Rule Elimination, *dated* November 15, 2023; The Brattle Group, PJM Cost of New Entry: Estimates for Combustion Turbines and Combined Cycle Plants in PJM with June 1, 2018 Online Date, report prepared for PJM Interconnection, L.L.C., May 15, 2014; ISO New England, Inc., Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate on Behalf of ISO New England Inc. Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, FERC Docket No. ER14-1639-000, April 1, 2014; Concentric Energy Advisors, ISO-NE CONE and ORTP Analysis, report prepared for ISO New England, Inc., January 13, 2017.

Figure 5: Debt Share of Total Capital for Representative IPP Companies, Q1 2019 to Q4 2023



Note: Debt share of Total Capital is equal to net debt divided by the sum of net debt and the market value of equity. Source: S&P Capital IQ (obtained by AG)

Calculation of the WACC

AG's assessment of factors related to the calculation of the WACC has considered the data on the following: COE, COD, and D/E ratios presented above; facts and circumstances unique to the NYISO markets, including the extent of past experience with merchant development; the rapidly-changing nature of federal and state energy and environmental policies, including passage of the CLCPA; and likely project/ownership structures for new peaking plant development in New York. The calculation of the before-tax WACC is shown in equation 1.

$$WACC = \ Debt\ Ratio * COD + (1 - Debt\ Ratio) * ROE \qquad (1)$$

The ATWACC is calculated as shown below in equation 2:

$$ATWACC = \ Debt\ Ratio * COD * (1 - composite\ tax\ rate) + (1 - Debt\ Ratio) * ROE \qquad (2)$$

This calculation reflects the common tax treatment of interest as a deductible expense for corporate income tax purposes. Income taxes reflect Federal tax rates (assumed to be 21%), corporate New York State tax rates (6.5%),[45] and, for Load Zone J, the New York City business corporation tax rate (8.85%).[46] These tax rates result in composite income tax rates of 33.13% (NYC) and 26.14% (all other locations).[47]

Using these equations and the considerations presented above, AG recommends a WACC of 9.99%, based on a debt ratio of 55%, a COD of 6.70%, and a COE of 14.00%. This results in a nominal ATWACC of 9.02% in NYCA, LI, and the G-J Locality and 8.76% in NYC.

[45] *See* New York State Department of Taxation and Finance, Form CT-3/4-I.
[46] *See* New York City Department of Finance, "Business Corporation Tax," http://www1.nyc.gov/site/finance/taxes/business-corporation-tax.page.
[47] The composite rate reflects the fact that state and local taxes are deductible from federal corporate taxes.

The recommended ATWACC is consistent with previous and currently approved cost of capital values in NYISO and other neighboring market (e.g., ISO-NE and PJM) for net CONE evaluations utilized for capacity market purposes, which range between 7.5% and 8.89%.[48]

The ATWACC proposed for this DCR reflects a combination of factors. Relative to the other ISOs/RTOs, developers within New York may face greater project-specific risk that arises from the lack of long-term contracts, greater uncertainty over the mix of supply and demand resources that will result from changes in regional markets and energy policies over time, potentially more challenging siting and development opportunities within New York, and potential operational and price impacts of the state's move towards power sector decarbonization over the next two decades. Relative to the 2021-2025 DCR, the slightly higher ATWACC reflects the slightly lower cost of debt, the higher risk-free rate, the changes in tax law, and potential changes in project specific risks that reflect uncertainty with respect to future environmental regulations or other market developments.

B. Levelization Factor

To estimate the ARV, it is necessary to translate one-time installed capital costs into an annualized cost over the assumed economic life of the plant. This annualized cost is fixed over the plant's economic life, such that an owner receiving revenues equal to this cost would have enough funds to offset exactly the original upfront investment, including a return on capital. AG refers to this amount as the levelized fixed charge (e.g., an "annual carrying charge"). This charge reflects both the recovery of and return on upfront capital costs and the tax payments associated with this investment that vary over time due to depreciation schedules and variation in certain tax levels over time (i.e., availability of a 15-year property tax abatement for battery storage options in all locations and the potential availability of a 15-year tax abatement for fossil peaking plant technology options in Load Zone J).

The levelization factor is the ratio of the levelized fixed charge to total installed capital costs. This factor is developed in three steps. First, annual costs are calculated as the sum of principal debt payments, interest on debt, income tax requirements, property taxes, and the target cash flow to equity.[49] Second, the net present value of the total carrying costs is levelized over the assumed economic life of the plant using the real ATWACC. Third, the levelization factor is calculated as the ratio of the levelized fixed charge to the total installed capital cost.

Annualized costs, including the required COE, are expressed in constant real 2024 dollars. Capital costs were estimated by 1898 & Co. as of Q1 2024, so will be escalated to reflect costs as of Q2 2025, when the 2025-2026 Capability Year (which runs from May 1, 2025 - April 30, 2026) begins. The difference between Q2 2025 and Q1 2024 is 5 quarters, or 15 months, so the cost escalation factor applied to the Q1 2024 capital costs will reflect cost escalation as of the last 15 months of available data. AG anticipates applying the same price indices as the 2021-2025 DCR.

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[48] Appendix B reports details on previous and currently approved cost of capital values.

[49] Similarly, using the required cash flow to equity, income taxes can be calculated as:

$$Income\ Tax = \frac{t}{(1-t)} * (Cash\ Flow\ to\ Equity + Principal\ Debt\ Payments - Depreciation)$$

The analysis assumes forward-looking inflation of 2.12% annually in both capital costs and net EAS revenues. This inflation rate reflects the combined effect of many factors likely to affect future operational costs and net EAS revenues. The recommended value is consistent with the current long-term inflation forecasts from the Survey of Professional Forecasters as reported by the Philadelphia Federal Reserve Bank in Q1 2024,[50] as well as long-term inflation in electricity prices as reported by the EIA Annual Energy Outlook. [51]

Table 39 provides a summary of all financial parameters used in each location, including financing costs, tax rates, depreciation schedules, and the assumed amortization period. Property tax rates were discussed in Section II. Annual depreciation schedules are provided in

Table 40. Depreciation schedules are based on the Federal Internal Revenue Service (IRS) Publication 946 and follow the half-year convention. Fossil peaking plant options are depreciated with a 15-year schedule, and BESS options are depreciated with a 5-year schedule.[52]

[50] The Survey of Professional Forecasters forecast headline CPI of 2.24% between 2020-2029 and headline PCE of 2.00% between 2024-2033. *See* Federal Reserve Bank of Philadelphia, "First Quarter 2024 Survey of Professional Forecasters," February 9, 2024, https://www.philadelphiafed.org/-/media/frbp/assets/surveys-and-data/survey-of-professional-forecasters/2024/spfq124.pdf

[51] *See* EIA Annual Energy Outlook (AEO) 2023, March 16, 2023, Table 3: Energy Prices by Sector and Source. The EIA forecasts real price growth for residential electricity of -0.2% for the period 2022 to 2050 and nominal price growth of 2.2% for the Nation as a whole. For the mid-Atlantic, which includes portions of the PJM footprint in addition to New York, the EIA AEO forecasts real growth of 0.4% and nominal growth of 2.7%.

[52] Under the Inflation Reduction Act, battery units qualify for a 5-year MACRS depreciation schedule. For additional information, see: https://www.irs.gov/credits-deductions/cost-recovery-for-qualified-clean-energy-facilities-property-and-technology#qualified

Table 39: Summary of Financial Parameters by Location

Finance Category	NYCA	G-J	NYC	LI
Inflation Factor (%)	2.12%	2.12%	2.12%	2.12%
Debt Fraction (%)	55.00%	55.00%	55.00%	55.00%
Debt Rate (%)				
Nominal	6.70%	6.70%	6.70%	6.70%
Real	4.48%	4.48%	4.48%	4.48%
Equity Rate (%)				
Nominal	14.00%	14.00%	14.00%	14.00%
Real	11.63%	11.63%	11.63%	11.63%
Composite Tax Rate (%)	26.14%	26.14%	33.13%	26.14%
Federal Tax Rate	21.00%	21.00%	21.00%	21.00%
State Tax Rate	6.50%	6.50%	6.50%	6.50%
City Tax Rate	0.00%	0.00%	8.85%	0.00%
WACC Nominal (%)	9.99%	9.99%	9.99%	9.99%
ATWACC Nominal (%)	9.02%	9.02%	8.76%	9.02%
ATWACC Real (%)	6.76%	6.76%	6.51%	6.76%
Investment Tax Credit for BESS Capital Costs	30.00%	30.00%	30.00%	30.00%
Amoritization Period (Years)	13-Year for SCGT; 15-Year for Battery	13-Year for SCGT; 15-Year for Battery	13-Year for SCGT; 15-Year for Battery	13-Year for SCGT; 15-Year for Battery
Tax Depreciation Schedule	5-Year MACRS (Battery); 15-Year MACRS (SCGT)	5-Year MACRS (Battery); 15-Year MACRS (SCGT)	5-Year MACRS (Battery); 15-Year MACRS (SCGT)	5-Year MACRS (Battery); 15-Year MACRS (SCGT)
Fixed Property Tax Rate (%)	0.6% with 15-Year Abatement for Battery	0.6% with 15-Year Abatement for Battery	4.77% with 15-Year Abatement for Battery and SCGT	0.6% with 15-Year Abatement for Battery
Insurance Rate (%)	0.60%	0.60%	0.60%	0.60%
Levelized Fixed Charge (%)	11.92% BESS 14.65% SCGT	11.92% BESS 14.65% SCGT	12.09% BESS 14.66% SCGT	11.92% BESS 14.65% SCGT

Notes: [1] The levelized fixed charge (%) for NYC differs from NYCA, the G-J Locality, and LI based on the treatment of property taxes and capital costs. Levelized fixed charge also vary for the simple cycle fossil peaking plants, and battery plants due to differences among these various options as it relates to the construction timeline, amortization period, and depreciation period. [2] NYC reflects the 15-year property tax abatement for both fossil and battery storage peaking plant options. NYCA, the G-J Locality, and LI reflect a 15-year property tax abatement for the battery storage peaking plants, and a 0.5% property tax rate for fossil peaking plants.

Table 40: Modified Accelerated Cost Recovery Tax Depreciation Schedules

Year	Tax Depreciation	
	5 Year (Battery)	15 Year (Simple Cycle)
1	20.00%	5.00%
2	32.00%	9.50%
3	19.20%	8.55%
4	11.52%	7.70%
5	11.52%	6.93%
6	5.76%	6.23%
7	0.00%	5.90%
8	0.00%	5.90%
9	0.00%	5.91%
10	0.00%	5.90%
11	0.00%	5.91%
12	0.00%	5.90%
13	0.00%	5.91%
14	0.00%	5.90%
15	0.00%	5.91%
16	0.00%	2.95%

Source: [1] Table B-1 of IRS Publication 946.

C. Annualized Gross Costs

Using the levelization factor developed above and the capital and fixed O&M costs presented in Section II, Table 41 provides annualized gross CONE values for each peaking plant within each location.

Table 41: Preliminary Gross CONE by Peaking Plant Technology and Load Zone ($2024/kW- Year)

		Current Year (2025-2026)					
Peaking Plant Technology	**Source**	**C - Central**	**F - Capital**	**G - Hudson Valley (Rockland)**	**G - Hudson Valley (Dutchess)**	**J - New York City**	**K - Long Island**
1x0 GE 7HA.03, Dual Fuel with SCR	Fixed O&M	$7.98	$8.03	$9.54	$8.64	$27.88	$9.88
	Insurance	$6.93	$6.88	$7.47	$6.97	$8.18	$7.98
	Levelized Fixed Charge	$245.81	$242.73	$257.04	$243.06	$285.64	$267.20
	Gross CONE	$260.72	$257.63	$274.05	$258.67	$321.70	$285.06
1x0 GE 7HA.03, Gas-only with SCR	Fixed O&M	$7.98	$8.03	$9.54	$8.64	-	-
	Insurance	$6.52	$6.47	$7.06	$6.56	-	-
	Levelized Fixed Charge	$234.74	$231.97	$246.20	$232.23	-	-
	Gross CONE	$249.23	$246.47	$262.80	$247.43	-	-
1x0 GE 7HA.02, Dual Fuel, no SCR	Fixed O&M	$9.60	$9.63	-	$9.70	-	-
	Insurance	$6.99	$6.93	-	$7.01	-	-
	Levelized Fixed Charge	$257.99	$254.65	-	$254.12	-	-
	Gross CONE	$274.58	$271.21	-	$270.83	-	-
1x0 GE 7HA.02, Gas-only, no SCR	Fixed O&M	$9.60	$9.63	-	$9.70	-	-
	Insurance	$6.48	$6.44	-	$6.52	-	-
	Levelized Fixed Charge	$244.58	$241.63	-	$240.99	-	-
	Gross CONE	$260.66	$257.70	-	$257.21	-	-
2-Hour BESS	Fixed O&M	$17.65	$17.65	$17.65	$17.65	$35.67	$17.70
	Insurance	$5.03	$5.08	$5.22	$5.04	$6.18	$5.33
	Levelized Fixed Charge	$103.13	$103.77	$105.99	$103.16	$140.93	$104.00
	Gross CONE	$125.81	$126.49	$128.85	$125.85	$182.78	$127.04
4-Hour BESS	Fixed O&M	$28.95	$28.95	$28.95	$28.95	$56.13	$28.95
	Insurance	$8.67	$8.73	$8.93	$8.67	$10.82	$9.13
	Levelized Fixed Charge	$161.05	$161.97	$165.13	$161.12	$215.80	$164.42
	Gross CONE	$198.67	$199.65	$203.01	$198.75	$282.74	$202.50
6-Hour BESS	Fixed O&M	$40.80	$40.80	$40.80	$40.80	$77.14	$40.90
	Insurance	$12.54	$12.62	$12.90	$12.55	$15.36	$13.21
	Levelized Fixed Charge	$225.78	$227.09	$231.57	$225.89	$292.93	$232.59
	Gross CONE	$279.12	$280.51	$285.27	$279.24	$385.42	$286.70
8-Hour BESS	Fixed O&M	$51.85	$51.85	$51.85	$51.85	$97.35	$52.05
	Insurance	$16.19	$16.29	$16.65	$16.19	$19.92	$17.06
	Levelized Fixed Charge	$290.69	$292.39	$298.24	$290.82	$375.19	$301.01
	Gross CONE	$358.73	$360.53	$366.73	$358.86	$492.46	$370.12

Note: [1] Property taxes are included in the levelized fixed charge.

IV. Energy and Ancillary Services Revenues

A. Overview

The Services Tariff requires that the periodic review of ICAP Demand Curves be established considering, in part,

- "…the likely projected annual Energy and Ancillary Services revenues of the peaking plant for the first Capability Year covered by the periodic review, net of the costs of producing such Energy and Ancillary Services… including the methodology and inputs for determining such projections for the four Capability Years covered by the periodic review."[53]

The costs and revenues are to be determined under conditions that reflect specified capacity supply conditions. Specifically, the Services Tariff requires that:

- "…[t]he 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…"[54]

AG refers to these tariff-specified conditions as the "LOE" conditions.

In this Section, we present the method used to estimate the net EAS revenues of the peaking plant technology options for NYCA and each Locality evaluated for this DCR. Consistent with the LOE requirement, net EAS revenues are calculated under conditions in which system resources equal either (1) NYCA Minimum Installed Capacity Requirement (ICR) plus the capacity of the peaking plant in NYCA, or (2) Locational Minimum Installed Capacity Requirement (LCR) plus the capacity of the peaking plant in individual Localities.[55]

First, AG summarizes its approach for estimating net EAS, including a description of the net EAS models (including net EAS models for both the fossil peaking plant and BESS technologies), the data inputs, and the approach to adjusting prices to be consistent with LOE market conditions.[56] Second, AG summarizes the process for annually updating estimated net EAS revenues over the reset period. Finally, AG presents results of applying the net EAS revenues model for the 2025/2026 Capability Year.

[53] Services Tariff, Section 5.14.1.2.2.
[54] Services Tariff, Section 5.14.1.2.2.
[55] Note that ICR is defined in terms of MW, equal to total capacity needs (i.e., peak demand plus reserve requirements, in MW). The ICR is based on the Installed Reserve Margin (IRM), which is the level of reserve capacity in excess of peak load required in the NYCA, denominated in percentage terms. Throughout this report, AG uses both terms, when appropriate. For example, when describing system capacity need in MW, AG uses ICR. When referencing the required level of reserves in percentage terms, AG uses IRM.
[56] For BESS options, AG developed a net EAS model that evaluates potential real-time revenue earnings using a net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch prices (i.e., nominal 5-minute interval prices), as well as a net EAS model that evaluates potential real-time earnings using hourly real-time prices. For the 2025-2029, AG recommends use of the net EAS model using RTD interval pricing for the BESS options.

B. Approach to Estimating Net EAS Revenues

1. Overview

For each Capability Year, RPs in NYCA and each Locality are based on estimated gross CONE (described in Section III, above) less the expected net revenues the peaking plant would earn in NYISO's energy and ancillary services markets at the tariff-prescribed LOE conditions. The net revenues earned from participating in these markets reflect the prices paid for supply of Energy and Ancillary Services net of the fuel and variable costs of production. Because RPs are established to ensure sufficient revenues for new entry, estimates of net EAS revenues should reflect the forward-looking expectation of net revenues under LOE conditions consistent with the requirements of the Services Tariff.

Net EAS revenues are estimated based on the simulated dispatch of the peaking plant using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), coincident fuel and emission allowance prices, and data on the non-fuel variable costs and operational characteristics of the peaking plant technology. AG's approach assumes that annual average net revenues earned over the prior three years provide a reasonable estimate of forward-looking expectations, particularly in light of the annual updating mechanism, which ensures that RPs evolve (albeit with a lag) to reflect actual EAS market outcomes over time (as adjusted for LOE conditions).

AG's models estimate the net EAS revenues of the peaking plant technology options for the historical 3-year period assuming that the resource earns the maximum possible revenues by supplying energy or reserves in either the Day-Ahead Market (DAM) or Real-Time Market (RTM). Each year, as part of an annual updating of the ICAP Demand Curves, net EAS revenues will be recalculated using the applicable model for the relevant peaking plant technology selected for each ICAP Demand Curve, but with updated data on LBMPs, reserve prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges.

2. Net EAS Model Construct

a. Fossil Peaking Plant Model Logic

For all fossil peaking plant technology options, the AG simulated dispatch model uses a dispatch logic functionally consistent with NYISO energy and ancillary services markets.[57] Specifically, the AG model estimates the net EAS revenues earned by the peaking plant on an hourly basis assuming dispatch of the plant and market offers set at the opportunity cost of producing energy or providing reserves.[58] In the model, the fossil peaking plant technology options can earn revenues through supplying in one of four markets: (1) DAM commitment for energy, (2) DAM commitment for reserves, (3) RTM dispatch for energy, or (4) RTM supply of reserves. In addition, a plant maintains the ability to buy out of either DAM energy or reserves commitments, based on changes in RTM prices. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual-fuel

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[57] In practice, an individual plant's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical peaking plant considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to plant-specific cost, operational, and fuel portfolio management factors that vary from those of the hypothetical peaking plant.
[58] AG assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant.

capability (if applicable) is accounted for through the option to generate on natural gas or ultra-low sulfur diesel (ULSD) based on a comparison of fuel prices.

Figure 6 and Figure 7 contain schematics of the commitment/dispatch logic for the DAM and RTM, respectively, for the fossil peaking plant technology options. The model first determines whether to commit the plant to supply energy or reserves in the DAM based on the net revenues of each position. Similar to DAM commitment, RTM dispatch determines the operating state (supplying energy, supplying reserves, not supplying) contingent on the fossil peaking plant's DAM commitment. Consistent with the 2017-2021 and 2021-2025 DCRs, the model utilizes historical hourly real-time prices for the RTM. For the 2025-2029 DCR, AG did not evaluate the fossil peaking plant technology options for potential use of Real-Time Dispatch interval prices in real-time.

The fossil peaking plant can change operating status from its DAM commitment if such a switch in operating status is sufficiently profitable in real-time. Real-time fuel costs reflect a premium for purchases and discount for sales relative to day-ahead gas prices. The value of this premium varies by location. These intraday premiums/discounts reflect potential operating or other opportunity costs to securing (or not using) fuel in real-time, which may be incurred due to balancing charges with an LDC, illiquidity in the market during periods of tight gas supply, or imperfect information on the part of either the buyer or seller.[59] This additional cost is incorporated into RTM buy out decisions for all fossil peaking plant technology options. As illustrated in Figure 7, fossil peaking plants can exist in one of nine operating states in each hour, based on the DAM and RTM choices. These "operating" states include:

- DAM energy commitment, with RTM energy dispatch
- DAM energy commitment, with a buy out and a RTM reserves dispatch
- DAM energy commitment, with a buy out and no dispatch in the RTM
- DAM reserves commitment, with a RTM reserves dispatch
- DAM reserves commitment, with a buy out and a RTM energy dispatch
- DAM reserves commitment, with a buy out and no dispatch in the RTM
- No DAM commitment, with no dispatch in the RTM
- No DAM commitment, with an energy dispatch in the RTM
- No DAM commitment, with a reserves dispatch in the RTM

When evaluating an energy commitment in either the DAM or RTM, the model ensures that all costs, including start-up costs, can be recovered.[60] In the DAM, start-up costs for the fossil peaking plant technology options can be recovered over the full runtime block, which is determined dynamically based on profitable hours; within the RTM, fossil peaking plant technology options must recover their startup costs over two hours.

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[59] These costs are based on estimates previously reported by the NYISO Market Monitoring Unit (MMU) based on their review of available data. The real time premium/discount is applied to all operating hours throughout the year. In practice, these annual average values may over-estimate net EAS revenues during some hours (e.g. winter months) if the DAM-RTM price difference is driven by changes in gas market conditions and under-estimate net EAS revenues during other hours (e.g., during periods of gas liquidity). During periods of gas liquidity, this could either overstate the true cost of selling out of a gas position in real-time or overstate the true cost of purchasing gas in real-time, thereby foregoing a potential RTM dispatch. On net, these effects would tend to both decrease and increase real time net EAS revenues in various hours throughout the year.

[60] The model does not allow a plant to be committed uneconomically. In actual operation of the markets, to the extent that a plant would be committed uneconomically, it would be eligible to receive either Day-Ahead Margin Assurance Payment (DAMAP) or a Bid Production Cost guarantee (BPCG) payment. These payments would compensate a plant for its costs, offsetting losses on a daily basis.

The fossil peaking plant technology options are also constrained by applicable runtime limitations as described in Section II.C. For fossil peaking plants modeled with SCR emissions control technology, the NSPS limitation for CO_2 is a limiting constraint on hours of operation. 1898 & Co. estimated the maximum annual runtimes for all combustion turbines with SCR emissions control technology to be 3,504 hours. For combustion turbines without SCR emissions control technology, the limiting constraint is the NSPS requirement for NO_x emissions. Plants without SCR emission controls in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions. Operating limits are modeled in the Net EAS Revenue model as constraints on the total amount of combined NO_x emissions allowed each year from either natural gas or ULSD operations. Due to differences in heat rate and capacity by season, the exact emissions per run hour also differs by season. The mass of NO_x emissions is calculated for each profitable run hour, and the total amount of emissions per year is limited to the NSPS maximum.[61]

Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-synchronized reserve markets at their opportunity cost to taking a day-ahead reserve position. This cost can reflect many factors, including performance (forced outage) risks and costs and risks associated with securing fuel supplies to fulfill a reserve obligation. Depending on the resource type, these fuel-related costs can reflect the cost of holding fuel supplies or the expected cost of obtaining adequate fuel supplies in the intraday markets, and risk premiums associated with taking an uncovered reserve position. These costs differ between gas-only units and dual fuel units, given a dual fuel unit's flexibility to operate on natural gas or their alternate fuel, which can mitigate the risk of a day-ahead reserve position. Based on a review of historical bid data from dual fuel units in Load Zones J and K provided by the MMU, the opportunity cost to taking a day-ahead reserve position is assumed by the model at $2.00/MWh for dual fuel units in Load Zones G (Dutchess County), G (Rockland County), J, and K.[62] For gas-only units in Load Zones C and F, the opportunity cost is set to the intraday premium of buying natural gas during the operating day.

If a fossil peaking plant receives a day-ahead reserve position, the cost to actually supply energy into the RTM reflects the market fuel price plus a real time intraday premium associated with buying natural gas in real time. Dual fuel plants do not face an opportunity cost to provide reserves when ULSD prices (plus applicable transportation charges) are lower than natural gas prices (plus applicable charges).[63]

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[61] The model evaluates environmental runtime limits on a model-year basis, where model years cover a 12-month period from September 1 to August 31 (e.g. September 1, 2021 to August 31, 2022). If a plant is committed above its applicable environmental emissions limit during that period, the model removes the least profitable energy (either DAM or RTM) runtime blocks until the plant is in compliance. Plants are allowed to earn DAM reserve revenues at the prevailing DAM reserve price during runtime blocks removed in this fashion.

[62] 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.

[63] This assumption may under- and overstate opportunity costs under some circumstances, but provides a reasonable estimate of opportunity costs on balance across hours and Load Zones.

Figure 6: Net EAS Revenues Model Day-Ahead Commitment Logic for Fossil Peaking Plant Technology Options

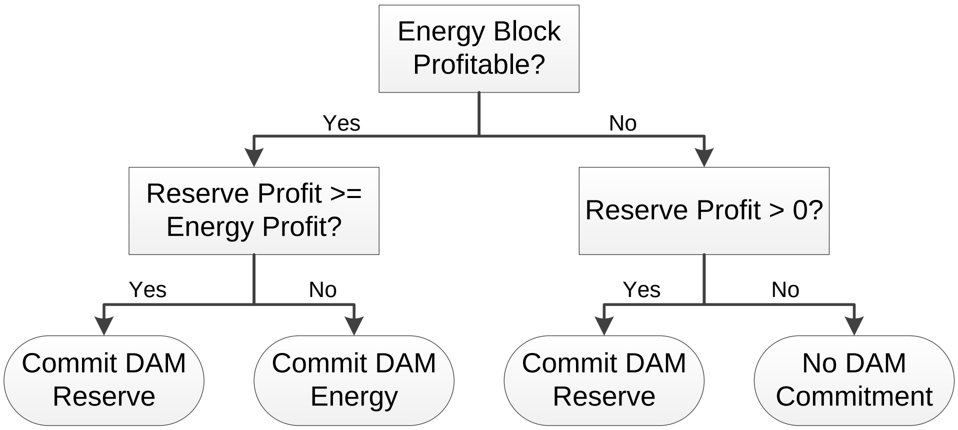
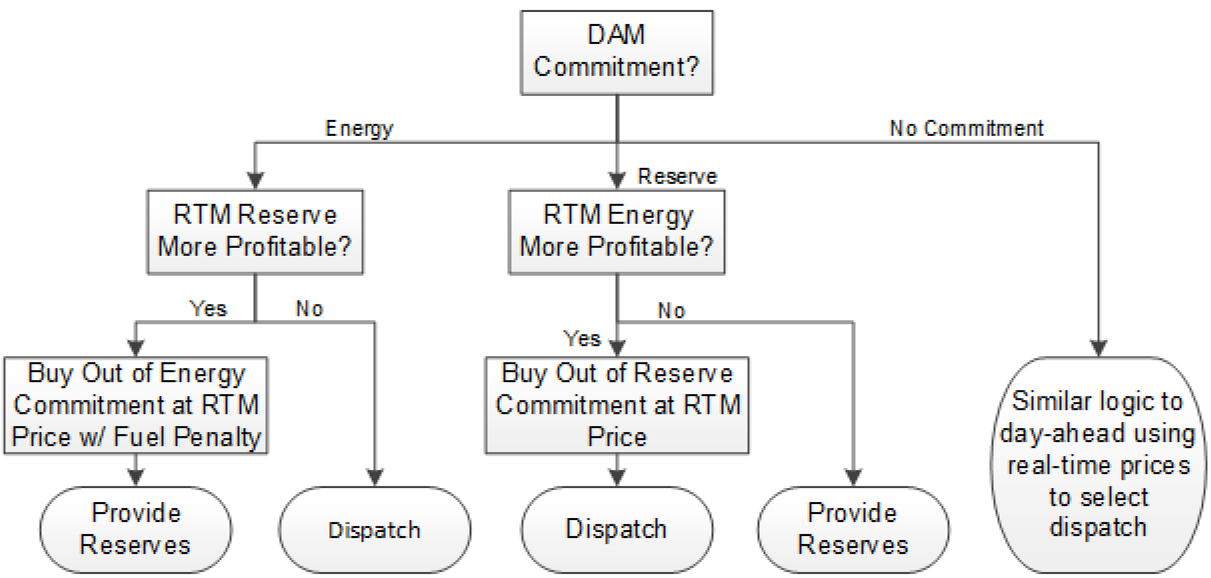


Figure 7: Net EAS Revenues Model Real-Time Supply Logic for Fossil Peaking Plant Technology Options



The net EAS revenues model estimates hourly revenue streams for the fossil peaking plant technology options based on hourly prices for both DAM and RTM over the three-year historical period. Within this hourly model, the fossil peaking plant technology options are assumed to be fully committed for the duration of the hour. That is, the net EAS revenues model for peaking plants does not allow for partial dispatch or minimum load operations.

Equation 3 provides a simplified representation of the net EAS revenues (NEAR) calculation used when considering energy dispatch in each hour, where profits are determined using parameters specific to each location and, when applicable, each fossil peaking plant technology option:[64]

$$NEAR = LOE - AF * LBMP - HR * P(fuel) - VOM - ASC - EC - RS1 \qquad (3)$$

Where:

$LOE - AF$ = LOE adjustment factors for each Load Zone and time period

$LBMP$ = Hourly LBMPs (either DAM or RTM) for each Load Zone

HR = Heat rate for the applicable peaking plant and Load Zone

$P(fuel)$ = Price of fuel (natural gas or, if applicable, oil), which varies by day and Load Zone, including relevant transportation costs and real time intraday premium/discount

VOM = Variable operations and maintenance costs

ASC = Startup cost

$RS1$ = NYISO Rate Schedule 1 charge (varies annually, but is constant across Load Zone and technology)

EC = Emission costs, where costs are a function of both emission rates and allowance prices for CO_2, NO_X (annual and seasonal) and SO_2 (CSPAR and Acid Rain) that is:

$$EC = (CO2Rate * CO2\_Price) + (NOxRate * NOx\_Price) + (SO2Rate * SO2\_Price)$$

When estimating total annual net EAS revenues for the fossil peaking technology options, the model separately considers relevant unit parameters for Summer and Winter Capability Period months, including each fossil peaking plant's seasonal capacity and heat rate. Total annual revenues are the sum of revenues earned during each hour of the year (reflecting seasonal capacity ratings), with energy and reserves revenues derated by the fossil peaking plant's EFORd.

[64] That is, equation 3 does not fully represent the tradeoffs between DAM and RTM energy and reserve profits, or the ability of the plant to buy out of its DAM commitments.

As a final step, the model calculates the annual average net EAS revenues as the simple average of all revenues over the three-year period, plus an adder for providing voltage support service (VSS).[65]

An important component of the net EAS revenues model is the ability of the model to assess the fossil peaking plants with either dual fuel capability (if applicable) or gas only operation. When evaluating fuel commitment decisions, the model compares the applicable fuel costs in each hour. For a dual fuel unit, the fossil peaking plant is assumed to operate on the most economic fuel for a full runtime block. The model does not permit fossil peaking plants to fuel switch within an individual block.

Notably, the model does not consider potential limitations in gas only operations; all fossil peaking plants are assumed to be able to procure fuel as needed, at historical prices.[66] As described in Section II, AG considered potential limitations in fuel availability as part of its qualitative review, given NYISO's proposal to incorporate fuel availability considerations in the assignment of capacity accreditation factors. As noted in Section II, AG expects the combination of forthcoming CAF determinations and other factors would lead a developer to install dual-fuel technology in all locations. Consequently, it is not necessary to attempt to model the potential for natural gas fuel limitations in the net EAS modeling process.

b. Battery Model Logic

Like the fossil model, the AG simulated dispatch model for battery storage uses a dispatch logic that is functionally consistent with NYISO energy and ancillary services markets.[67] For BESS options, AG uses a DAM model consistent with the method employed in the 2021-2025 DCR. AG also developed a net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch (RTD) prices (i.e., nominal 5-minute interval prices), as well as a net EAS model that evaluates potential real-time revenue earnings using hourly real-time prices.[68] For the 2025-2029 DCR, AG recommends use of the net EAS model that utilizes RTD interval prices for the BESS options.

As further detailed below, the dispatch logic of the models developed for the BESS options maximizes net EAS revenues while accounting for the battery technology's unique technical properties, including limited energy storage capacity, the need for a balancing of energy charges and discharges, energy losses during charging, and operational practices that can reduce battery degradation. We first describe how the model accounts for these technical characteristics, and then describe the model's framework for determining participation in the NYISO

[65] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Specifically, net EAS revenues are converted to current year dollars using the Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the three-year historical data period. The net EAS escalation rate is the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the nominal period covered by the historical data, measured as the change from the oldest year to the most recent year of such nominal period. For example, for the historical data period from 9/1/2020-8/31/2023, the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) would be measured over the nominal period from 2021 to 2023.
[66] Similarly, the model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AG does not expect OFOs to meaningfully affect the net EAS revenues of dual fuel plants, particularly in Load Zone J and K, where OFOs are more common. To the extent that OFO days are correlated with periods of high natural gas prices, these plants would already be expected to run on oil.
[67] In practice, an individual plant's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical battery plants considered here. Actual revenues could be higher or lower than modeled revenues for various reasons related to plant-specific cost, and operational factors that vary from those of the hypothetical battery plants evaluated in this study.
[68] Additional information regarding the net EAS model using hourly real-time prices is provided in Appendix E.

markets, which follows three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch.

Battery Model: DAM Modeling Logic

Due to the physical energy limitations of a battery, the models developed for BESS options determine charge and discharge of the battery simultaneously in hour-pairs in the DAM energy and reserve markets. Each hour-pair includes an hour in which the battery purchases energy (to charge the battery) and an hour in which it supplies energy (through discharge of the battery). This logic ensures there is always a balance between energy inflows and outflows. The model also limits the range of stored energy to between zero and the battery's maximum storage capacity.

For each hour-pair, the models account for energy losses when charging and assumes the full charge or discharge of the battery's capacity. However, because of charging losses, more time is required for a full charge of the battery than is required for a full discharge; thus, to maintain the energy balance of inflows and outflows of power, additional charging time is required for any given level of stored energy.

Along with consuming and supplying energy, the battery can supply reserves. The battery is assumed to be eligible to provide 10-minute spinning reserves when it has no DAM or RTM energy discharge position but has at least one hour capability of stored energy and/or was scheduled to be charging for the hour. The battery can supply reserves at either its full capacity or the amount of energy that remains stored, whichever is smaller. When the battery is charging, the models assume it can supply reserves at either its full capacity or the amount of energy that remains stored plus the amount of power scheduled to be withdrawn from the grid for charging purposes.

When the battery is not charging or discharging, a target storage level of 50% of the battery's capacity is assumed. For example, a 4-hour battery would maintain a target level of 2 hours of charge between charge and discharge.

The dispatch logic for battery storage is split into three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch. Figure 8, Figure 9, and Figure 10 illustrate how the model is solved for two illustrative days in the three steps. The left axis (and lines) show the LBMPs and reserve prices determined by the NYISO markets in each hour. The right axis (and bars) shows the battery energy transactions determined by the model; positive values represent MW discharged onto the grid while negative values represent MW withdrawn from the grid for charging. Withdrawal MW should not be mistaken for actual inflows into the battery, as in these cases the battery only received 85% of the energy withdrawn because of charging inefficiencies.

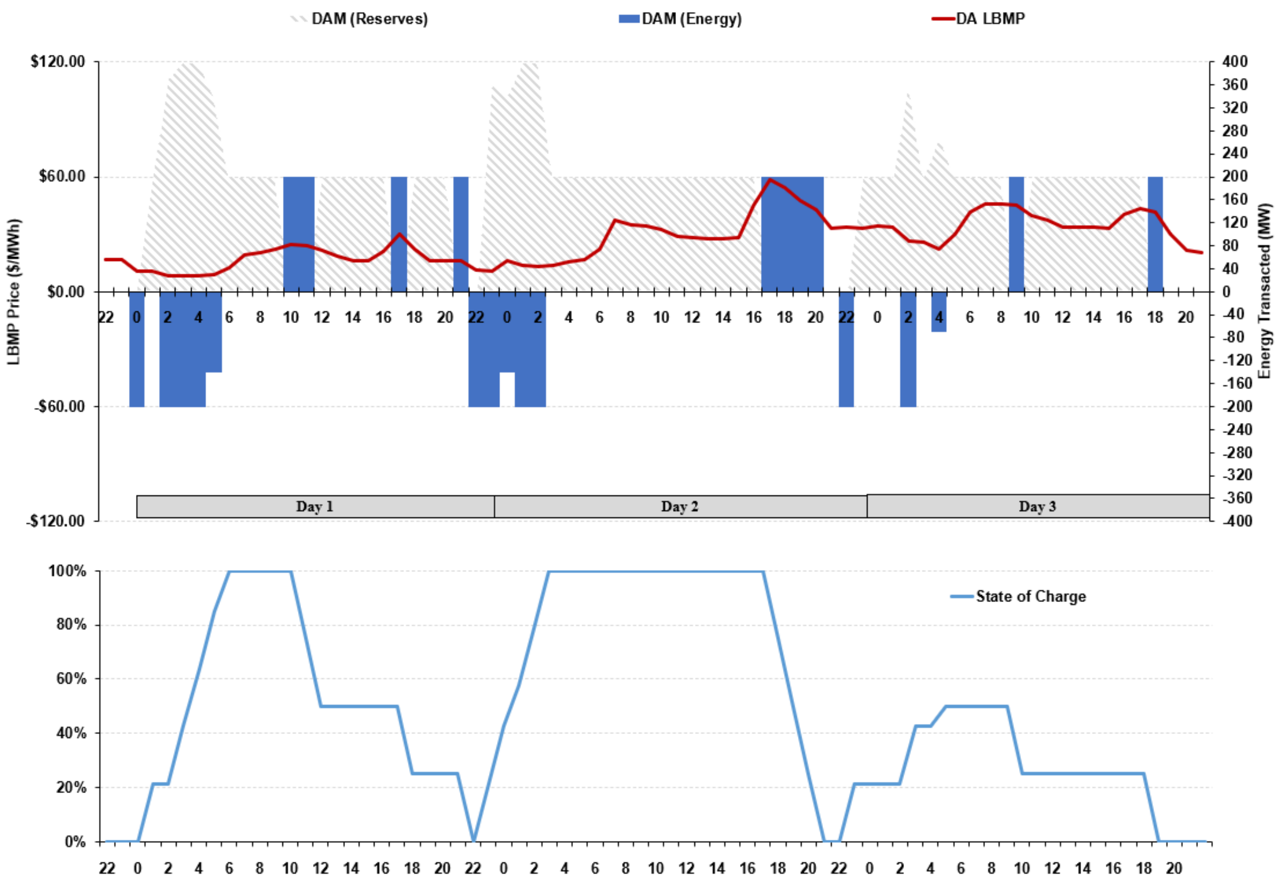
The **first step** determines the daily DAM positions. The model determines whether to commit a set of hour-pairs to charge and discharge energy in the DAM based on maximizing net revenues in the energy and reserve markets for a cycle-day.[69] For each cycle-day, the models generate every feasible day-ahead position hour-pair given the current position of the battery storage resource. The logic then ranks the profitability of adding each set of hour-pair positions to the current position. If adding the hour-pair to the battery's position increases profitability relative to doing nothing, the model will do so and repeat this process. The model will also add hour-pairs to its position in

[69] A cycle-day is defined as a 24-hour period between 10:00 pm and 9:59 pm the following day.

order to hit the target level of energy for the battery (i.e., 50% of the battery's capacity), even when it does not increase revenues.

This step outputs a full cycle-day of DAM positions, an example of which can be seen for two days in Figure 8. Hour-pairs are committed on the first and second DAM days, as depicted by the blue energy discharge bars above the y-axis and corresponding charging hours below the y-axis. The battery resource provides reserves whenever it has energy stored or is charging. In each case, the model cannot feasibly position another hour-pair that would drive greater profits than the determined set of positions.

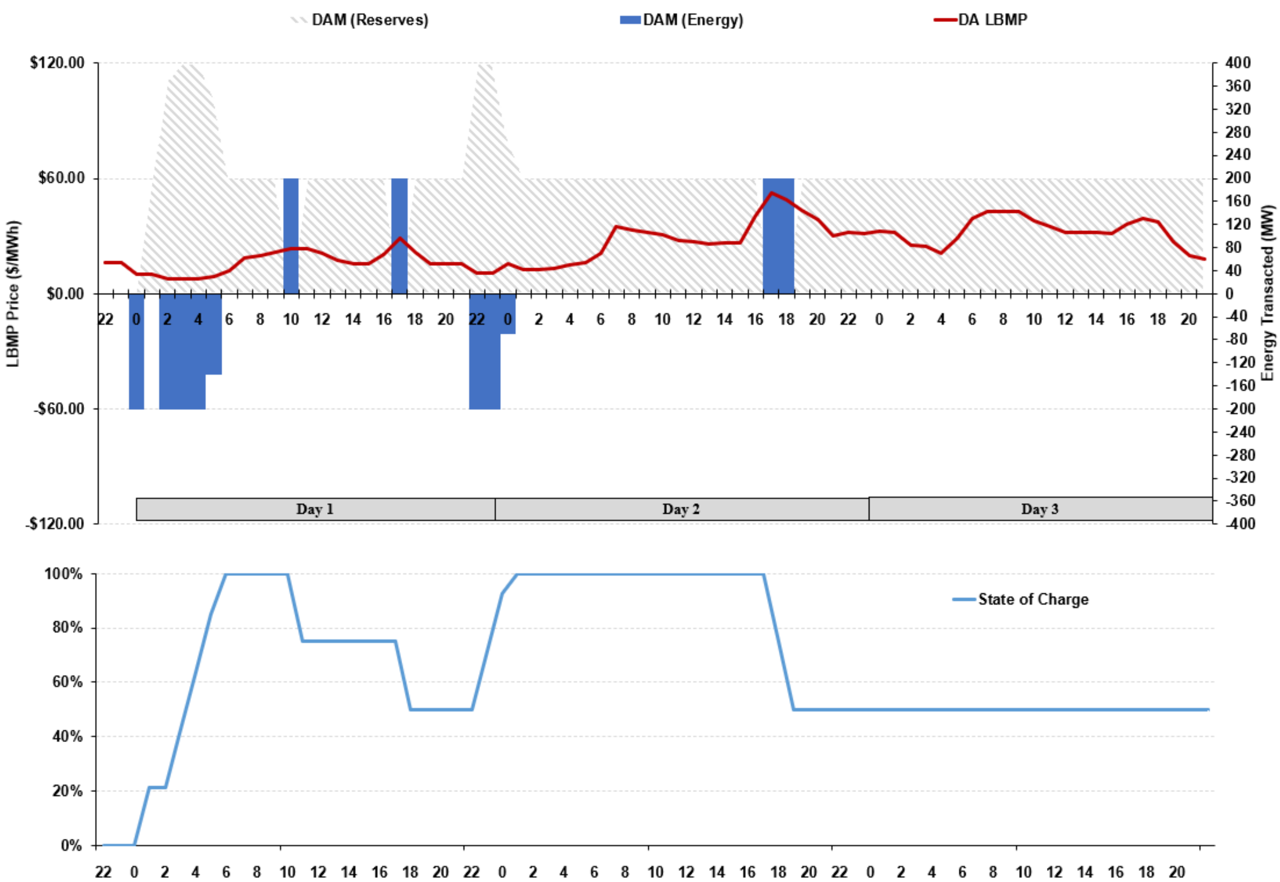
Figure 8: AG Battery Model DAM Example:
Zone C, November 29 - December 2, 2022, 4 Hour Battery



The **second step** considers whether net revenues are maximized by emptying the battery each day or maintaining stored energy between cycle-days. The model determines the multi-day behavior of the battery by comparing net EAS revenues of these two different options.[70]

The outcomes of this second step can be seen in Figure 9. Here, the model determined it was more profitable to enter the day of 11/30 with a higher SOC, and thus it eliminated two discharge hours on 11/29.

Figure 9: AG Battery Model Multi-Day Example: Zone C, November 29 - December 2, 2022, 4 Hour Battery



The **third step** determines any incremental RTM positions. In the RTM, the battery plant supplies (and consumes) energy given arbitrage opportunities presented by RTM LBMPs. The plant's RTM operational decisions are contingent on the DAM positions established in steps 1 and 2. While we assume the battery does not buy out of a

[70] The models calculate net EAS revenues of maintain energy levels across days by adjoining adjacent cycle-days. For each pair of days, the models create a new set of DAM commitments by eliminating the appropriate number of discharge hours on cycle-day 1 and charge hours on cycle-day 2 in order to maintain the target energy level (i.e., 50% of the battery's capacity) between both days. Net EAS revenues are recalculated based off the new energy levels across both cycle-days. If net EAS revenues are higher with the new set of DAM commitments, then the revised commitments are implemented by the models. Otherwise, the initial DAM commitments are left unchanged. The models pair adjacent cycle-days moving forward day-by-day considering any commitment changes made by the previous pair of cycle-days. This process concludes the DAM commitments made by the models.

DAM energy position unless there would be a violation of the battery's physical operating limits, the battery can buy out of DAM reserve position and take on a RTM energy position instead.

For the 2025-2029 DCR, AG developed a net EAS model that evaluates potential real-time revenue earnings using RTD prices (i.e., nominal 5-minute interval prices), unlike the 2021-2025 DCR, which employed a net EAS model for BESS technologies that employed hourly real-time prices. AG provides a description of the previous hourly real-time price methodology and associated results in Appendix E. For the 2025-2029 DCR, AG recommends use of the net EAS model that evaluates potential real-time revenue earnings using Real-Time Dispatch prices for all BESS options.

Battery Model: RTM Logic for RTD Interval Pricing Model

To evaluate real-time arbitrage opportunities, the RTD interval pricing model employs a conceptually distinct approach from the DAM model. Unlike DAM LBMPs, RTM LBMPs transact on a nominal 5-minute basis. Batteries are capable of providing quick charging and discharging on a 5-minute basis. Moreover, 5-minute intervals may have higher volatility and greater opportunities for energy arbitrage revenues for batteries than LBMPs averaged over e.g. a 60-minute interval basis. As such, AG has developed a new method to model net EAS revenues in NYISO's RTM using RTD prices.

Conceptually, AG's approach begins with developing a bidding strategy to identify profitable RTM charging or discharging opportunities. Intuitively, a reasonable bidding strategy has to identify profitable opportunities for charging in the real-time market (when the RTD LBMP is sufficiently low), or discharging in the real-time market (when the RTD LBMP is sufficiently high). Given a day-ahead schedule of hourly DAM LBMPs, we define real-time discharge bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Charge\ Cost_i + Hurdle\ Rate_s + Discharging\ Costs$$

where:

- Expected Subsequent Charge Cost$_i$ equals 115% * (DAM LBMP + NYISO Rate Schedule 1 costs + transmission cost [for charging energy]), where DAM LBMP is set based on the lowest cost DAM hourly LBMP following interval *i*, NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations, and transmission cost reflects charges associated with use of the transmission system for charging energy.
- *Hurdle Rate$_s$* is calculated *ex ante* using historic data for three separate seasons *s* and established as fixed values for the entire reset period
- *Discharging Costs* reflect the net costs associated with real-time discharge including NYISO Rate Schedule 1 costs, VO&M, and any DAM reserve buyout costs.

Similarly, we define real-time *charging* bids for each RTD interval *i* of the subsequent day as:

$$Expected\ Subsequent\ Discharge\ Revenue_i - Hurdle\ Rate_s - Charging\ Costs$$

where:

- *Expected Subsequent Charge Cost$_h$* equals 85% * (DAM LBMP – NYISO Rate Schedule 1 costs – VO&M), where DAM LBMP is set based on the highest revenue DAM hourly LBMP following interval *i*, NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations, and VO&M reflects charges associated with variable operations and maintenance (e.g. capacity augmentation costs).
- *Hurdle Rate$_s$* is calculated *ex ante* using historic data for each separate season *s* and established as fixed values for the entire reset period
- *Charging Costs* reflect the net costs associated with charging, including NYISO Rate Schedule 1 costs, and transmission costs. Because charging allows batteries to earn incremental reserve revenues, charging costs are reduced by the applicable RTD reserve price for 10-minute spinning reserves during charging periods in real-time.

Because NYISO posts the Day-Ahead schedule by 11 a.m. on the day prior to the Dispatch Day, this bidding strategy is feasible for real-world battery operators. These bids/offers represent the RTD LBMPs required to deviate from the day-ahead schedule and could be submitted to NYISO well in advance of the real-time market deadline of 75 minutes before the start of the operating hour. This bidding strategy reflects the fact that, in real-time, a resource operator would not know with certainty future RTD LBMPs and could use the DAM LBMP as an approximation for future real-time prices. However, once these RTM positions are entered into, the RTD interval pricing model will use actual RTD LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position. As such, there is no “perfect foresight” embedded in the battery’s RTM bidding strategy within the RTD interval pricing model, and it is possible for the hypothetical battery operator to make a mistake in the sense of failing to maximize net EAS revenues on an *ex post* basis.

Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for future real-time price uncertainty. The hurdle rate captures the opportunity cost of limited available energy i.e. the fact that, if the battery used its limited energy to earn revenues in low priced hours, it may not have sufficient stored energy be earn higher revenues in the future. We calculate the revenue-maximizing hurdle rate directly by using the RTD interval pricing model to estimate net EAS revenues under alternative hurdle rates from $0 to $250 over the September 1, 2020 to August 31, 2023 period, and selecting the hurdle rate that yields the highest net EAS revenues.

To capture other relevant features of NYISO’s RTM, AG implemented additional enhancements within the RTD interval pricing model beyond the inclusion of 5-minute pricing intervals:

1. As in the DAM model, batteries require at least one hour of stored energy to earn reserve revenue (e.g. 25% state of charge [“SOC”] for a 4-hour battery). To operationalize this constraint, the RTD interval pricing model will buy out of DAM reserve positions whenever SOC < $\frac{1}{(Rated\ Battery\ Duration)}$
2. Addition of sub-5-minute intervals due to activation of RTD Corrective Action Modes (RTD-CAMs).
3. Seasonal hurdle rates which are separately optimized in three distinct seasons: Winter (December, January, and February), Summer (June, July, and August), and Shoulder (all other months).

Figure 10 provides an example of the RTM logic of the RTD interval pricing model. In every five-minute interval, the model calculates whether the actual RTD LBMP for such interval is sufficiently high to induce real-time discharging, or sufficiently low to induce real-time charging. Charging and discharging in real-time then impact the battery’s SOC, which subsequently may impact the ability of the battery to meet its previously determined DAM energy and reserve positions. The model buys out of DAM energy and reserve positions which are no longer physically feasible due to charging or discharging deviations in real-time relative to the DAM schedule.

Figure 11 presents marginal net EAS revenues evaluated for different assumed seasonal hurdle rates, compared to if no hurdle rate was used (i.e., a hurdle rate equal to $0/MWh). For each location evaluated in this study, a revenue maximizing opportunity cost value is chosen (i.e., the maximum point on the figure). Table 42 reports the optimal hurdle rate by location and battery duration. These hurdle rates are used in the RTD interval pricing model and will remain fixed for the four year reset period of this DCR.

Figure 10: AG Battery Model RTM Example: Zone C, November 29 - December 2, 2022, 4 Hour Battery

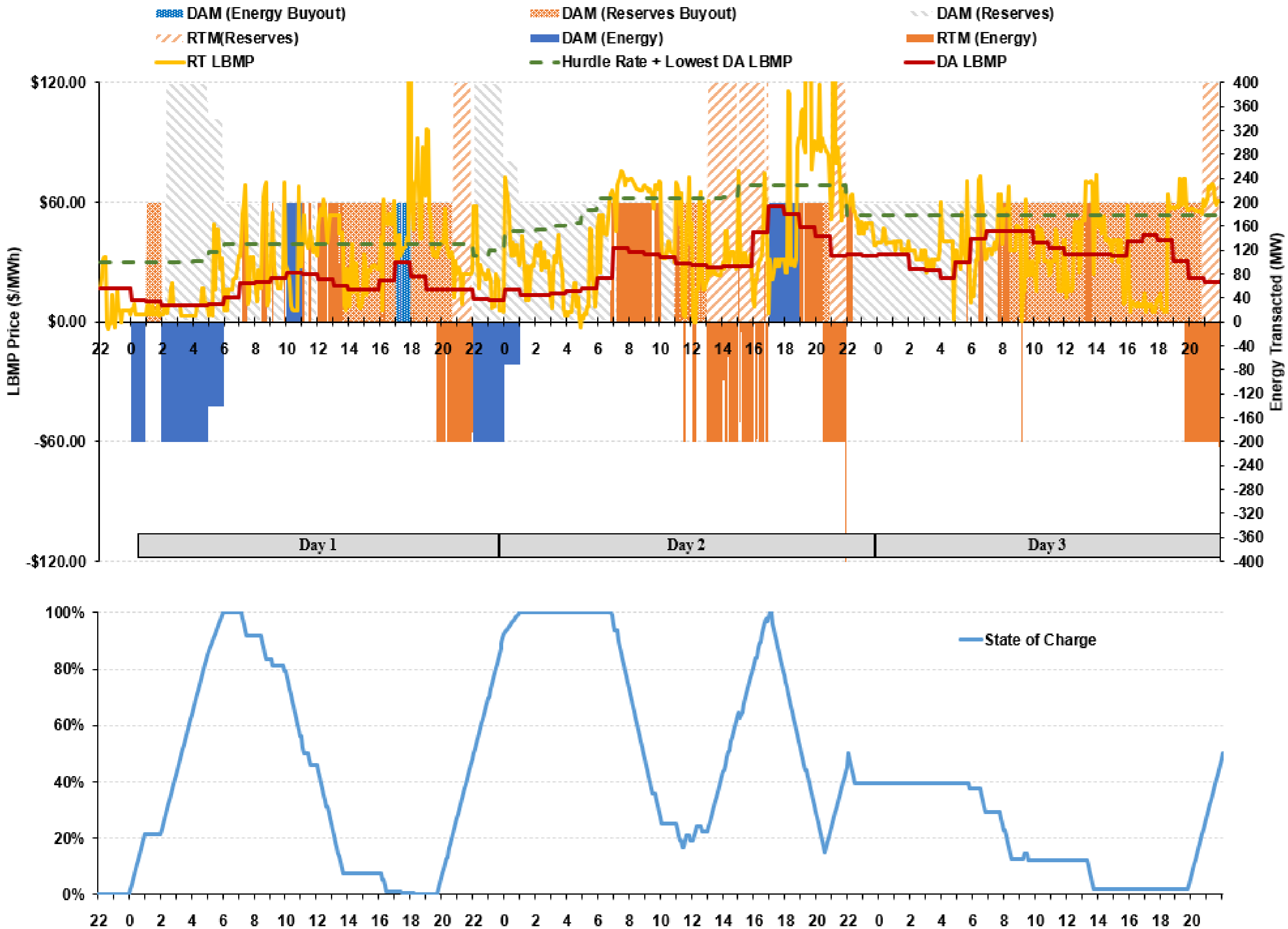
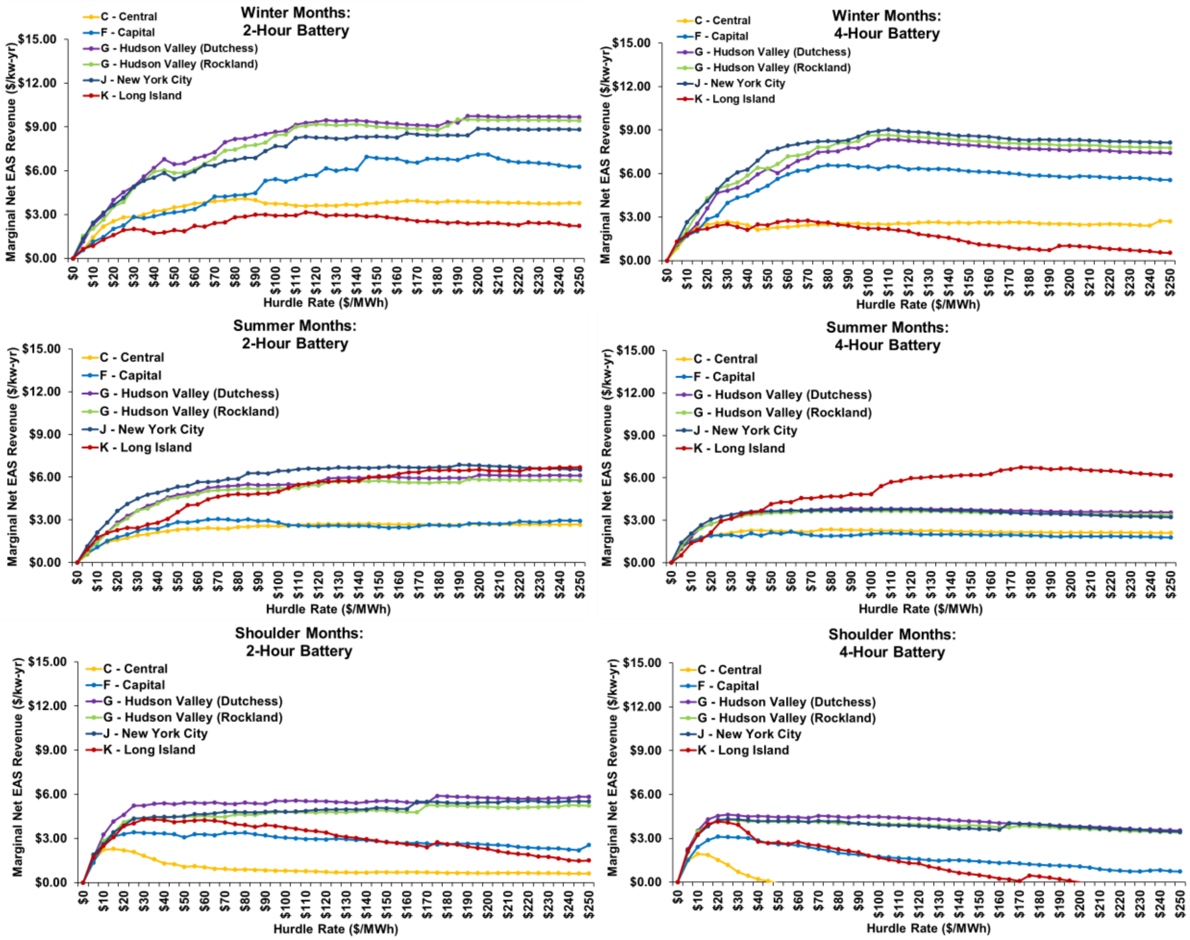
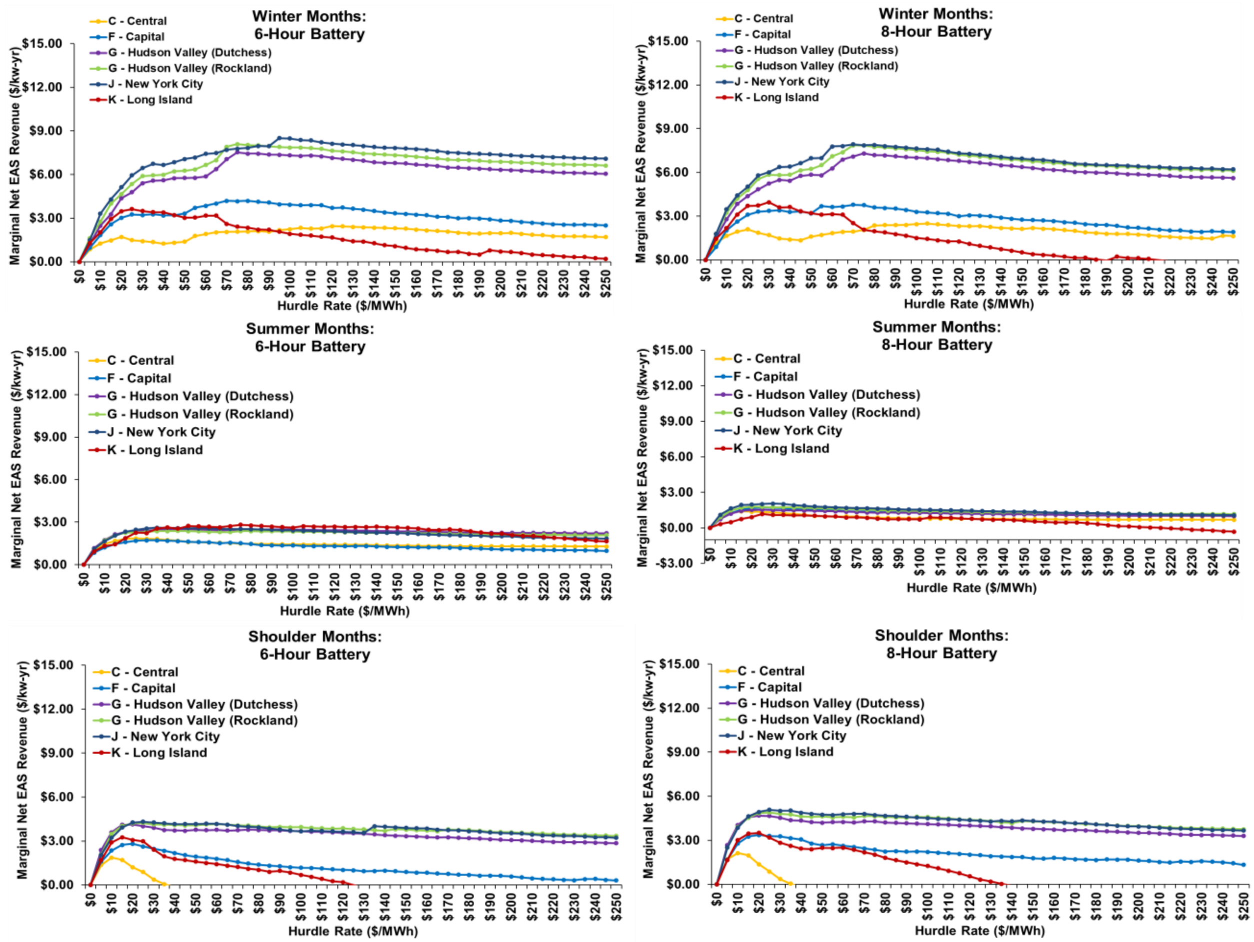


Figure 11: Change in RTM Net EAS Revenues for Alternative Hurdle Rates, by Location and Season 2-Hour BESS and 4-Hour BESS



Note: [1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh hurdle rate. [2] "Winter months" are December – February, "Summer months" are June – August, and "Shoulder months" are all other months in the year. [3] This assessment was conducted using data for the three-year period September 1, 2020 to August 31, 2023. **The assessment will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024**

Figure 12: Change in RTM Net EAS Revenues for Alternative Hurdle Rates, by Location and Season
6-Hour BESS and 8-Hour BESS



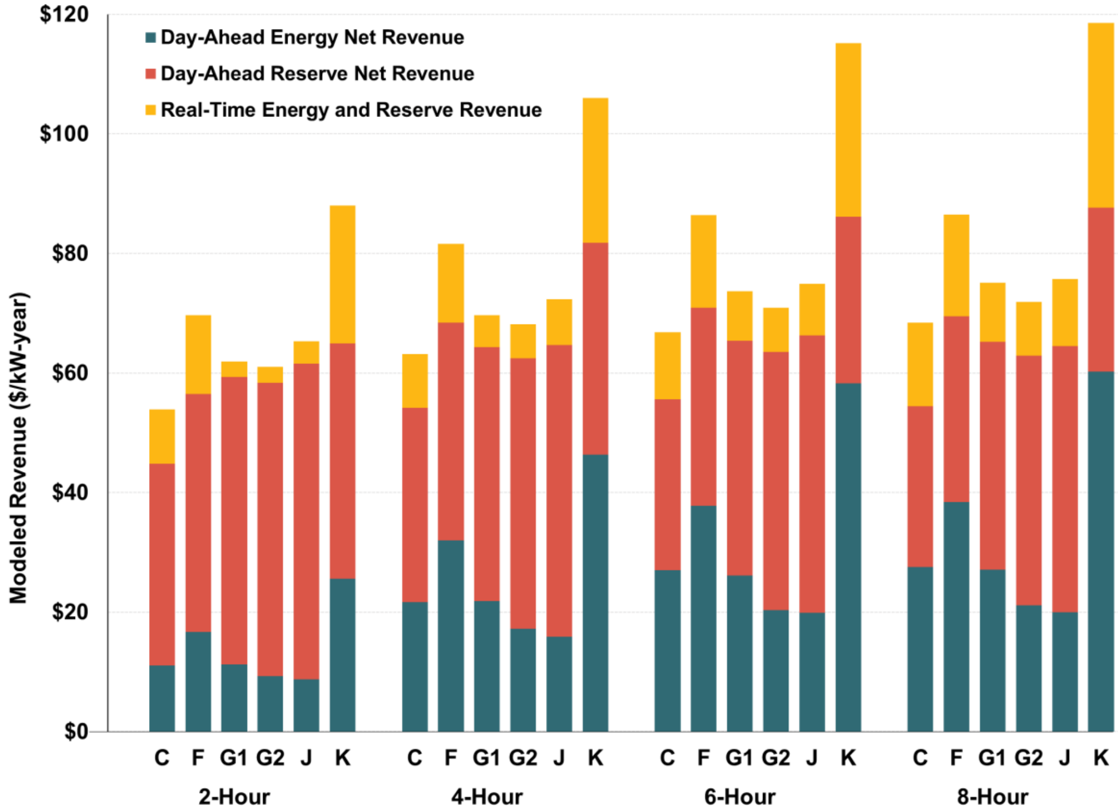
Note: [1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh hurdle rate. [2] "Winter months" are December – February, "Summer months" are June – August, and "Shoulder months" are all other months in the year. [3] This assessment was conducted using data for the three-year period September 1, 2020 to August 31, 2023. **The assessment will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.**

Table 42. Seasonal Hurdle Rates for the 2025-2029 DCR by Location and Duration

2-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$85	$70	$200	$195	$200	$115
Winter	$145	$200	$200	$195	$210	$250
Shoulder	$15	$25	$175	$170	$190	$30
4-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$80	$60	$85	$85	$105	$70
Winter	$245	$80	$110	$110	$110	$175
Shoulder	$10	$20	$25	$25	$25	$20
6-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$25	$30	$50	$45	$35	$25
Winter	$120	$80	$75	$75	$95	$75
Shoulder	$10	$20	$20	$25	$25	$15
8-Hour Battery Seasonal Hurdle Rates ($/MWh)						
	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Summer	$15	$25	$25	$25	$30	$25
Winter	$105	$70	$75	$70	$70	$30
Shoulder	$10	$20	$20	$20	$25	$20

Note: [1] "Winter" is December – February, "Summer" is June – August, and "Shoulder" is all other months in the year. [2] The seasonal hurdle rate values were determined using data for the three-year period September 1, 2020 to August 31, 2023. **These values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.**

Figure 13. BESS Net EAS Revenues by Market and Product
September 2020 - August 2023 Price Data



Note: [1] "G1" refers to Load Zone G (Dutchess County) and "G2" refers to Load Zone G (Rockland County). [2] Appendix E presents detailed information on net EAS revenues by BESS technology option over the three-year review period including revenues and hours by day-ahead commitment and real-time dispatch behavior. Appendix E also includes results for both the recommended battery model employing Real-Time Dispatch prices, and the hourly pricing battery model employed in the 2021-2025 DCR.

As depicted in Figure 13, a significant portion of battery net EAS revenues come from day-ahead reserve revenue. Energy revenues (whether in the DAM or RTM) are generally higher in locations with higher price volatility in the historical three-year period, like Load Zone K.

To summarize, batteries can exist in one of ten operating states in each hour, based on the combination of DAM and RTM positions. These "operating" states include:

- DAM energy position, with RTM energy dispatch
- DAM energy and reserve position, with RTM energy and reserve dispatch
- DAM reserves position, with a RTM reserves dispatch
- DAM reserves position, with a RTM energy dispatch
- DAM reserves position, with a RTM energy and reserve dispatch
- DAM reserves position, with no dispatch in the RTM
- No DAM position, with a RTM reserve dispatch
- No DAM position, with a RTM energy dispatch
- No DAM position, with a RTM energy and reserve dispatch
- No DAM position, with no dispatch in the RTM

The models for BESS options estimate revenues streams for the battery plants based on prices over the applicable three-year historical period. Total annual revenues are the sum of revenues earned during each year with energy and reserves revenues derated by the plant's assumed UOL availability factor.[71] As a final step, the model calculates the annual average net EAS revenues as the simple average of all revenues over the three-year period, plus an adder for providing VSS.[72] Unlike the fossil peaking plant model, the batteries have no seasonal differences in unit performance parameters or ratings.

c. Model Data

The data used in the net EAS revenues models include, as applicable by peaking plant technology option, locational energy and reserve prices, daily fuel prices and daily emission allowance prices (for CO_2, SO_2, and NO_x) for the three-year period (September through August) ending in the year prior to the beginning of the Capability Year to which the relevant ICAP Demand Curves will apply.[73] Other peaking plant costs and operational parameters (e.g., heat rate, VOM costs) needed to run the model are established at the time of the DCR, and described in Section II and Appendix A.

i. LBMPs and Reserve Prices

DAM and RTM LBMPs and reserve prices use zonal integrated hourly average values that are available through the NYISO market and operation data. For real-time prices, hourly or RTD interval prices are used depending on the peaking plant technology option. For BESS options, AG uses RTD interval prices.[74] Hourly real-time prices are used for all fossil peaking plant technology options.

Reserve prices are based on prices for 10-minute non-spinning reserves for the fossil peaking plant technology options, as 1898 & Co., in discussion with NYISO, has determined that these unit types are capable of supplying 10-minute non-spinning reserves. For BESS options, prices for spinning reserves are used. For the fossil peaking plant technology options, hourly reserve prices are utilized for both DAM and real-time. For BESS options, the RTD interval pricing net EAS model uses hourly spinning reserve prices for the DAM. The RTD interval pricing net EAS model uses RTD interval reserve prices in real-time.

In addition to energy and reserve revenues, all peaking plant technology options can supply VSS. VSS revenues are determined outside the applicable net EAS model. VSS payments are added to the final estimate of annual net EAS revenues determined using the applicable net EAS model and are based on actual settlement data analyzed by the NYISO. The annual average VSS revenue was preliminarily found to be $2.48/kW-year for fossil peaking plant technology options and BESS options using the same methodology for the 2021-2025 DCR.[75] **AG is continuing to assess the methodology for determining VSS revenues for**

[71] As described in Section II.G, total annual battery revenues are derated by 2% to account for forced outages.
[72] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Specifically, net EAS revenues in historic years are converted to current year dollars using the Bureau of Economic Analysis' Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the three-year historical data period. The net EAS escalation rate is the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) over the nominal period covered by the historical data, measured as the change from the oldest year to the most recent year of such nominal period. For example, for the historical data period from 9/1/2020-8/31/2023, the change in the Gross Domestic Product Implicit Price Deflator Index (Seasonally Adjusted) would be measured over the nominal period from 2021 to 2023.
[73] For the results presented in this Draft Report for the 2025/2026 Capability Year ICAP Demand Curves, we use data for the three-year period September 1, 2020 through August 31, 2023. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.**
[74] Further information regarding the alternative BESS model using hourly real-time prices is provided in Appendix E. AG recommends use of the RTD interval pricing model for BESS options for the 2025-2029 DCR.
[75] Using the methodology from the 2021-2025 DCR, VSS adder values were calculated as average VSS revenues of resources, based on NYISO settlement data over the time period of January 2020 through December 2023.

the 2025-2029. Any updates to such methodology and the resulting revenue value will be reflected in AG's final report. These VSS revenues are included as an adder for all peaking plant technology options in all locations evaluated in this study.

ii. Oil and Natural Gas Prices

For the fossil peaking plant technology options, natural gas prices are based on price indices for natural gas market hubs selected by AG for each location evaluated as reported by S&P Global Market Intelligence (SPGMI). SPGMI gas indices are developed using price and volume data submitted from market participants at various points along identified sections of pipelines, and represent volume-weighted average prices, excluding outliers that are greater than two standard deviations from the mean.[76] AG's net EAS revenues model for the fossil peaking plant technology options aligns gas day delivery and DAM LBMPs, and applies a fixed intraday premium or discount for real time gas purchases, as discussed below.

Despite the existence of numerous gas price index hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a fossil peaking plant in a given location. AG considered several gas index options for each location evaluated in this study, based on the following selection considerations:

- *Market Dynamics.* The gas index should reflect gas prices consistent with LBMPs, recognizing that other factors such as transmission congestion also influence the frequency and level of spikes in LBMPs. Ideally, the gas index used in fossil peaking plant net EAS revenues calculations should seek to reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions that may not be representative of the level of excess conditions prescribed for use in establishing the ICAP Demand Curves.
- *Liquidity*. The natural gas index should have a reasonable depth of historical data available, representing trades occurring at sufficient volumes over a reasonable period of time.
- *Geography.* The natural gas index (which typically reflects average trading prices over a broad geographic area) should represent trades across pipelines that have an appropriate geographic relationship to the applicable fossil peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points. While recognizing the relevance of geographic proximity, AG also considered whether gas indices fully captured variation in pricing within a given location, particularly to the extent that such pricing variation is relevant to delivery to the relevant fossil peaking plant. **Figure 14** depicts the geographic location of natural gas hubs in and around New York.
- *Precedent/Continuity.* The natural gas pricing selected for each location evaluated in this study should reflect and be supported by information collected from multiple sources and should take into account what is used for other NYISO planning and market evaluation purposes.[77] While the appropriate choice of representative gas pricing can vary in accordance with the purpose and objectives of a particular study/analysis, consistency and continuity should be considered when other factors do not clearly indicate an alternative.

[76] *See,* S&P Global Methodology and specifications guide US and Canada natural gas, May 2020.
[77] In particular, we reviewed gas hubs used in the 2021-2025 DCR study, 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 recommended natural gas pricing for each location was selected based on balancing the considerations listed above, recognizing that the natural gas indices do not necessarily capture all factors affecting the market-based pricing for natural gas to a hypothetical fossil peaking plant.

In considering geography, a fossil peaking plant in certain of the locations evaluated for this study could be directly served by lines represented by particular natural gas indices. In these cases, we have aimed to select among natural gas indices for pipelines that deliver to the location of interest, given consideration of market dynamics, liquidity and precedent/continuity. However, for some locations, available indices that meet all relevant considerations may not represent delivery points within the location of interest. In these cases, selection among available natural gas indices aim to identify the index or indices that reasonably represents the natural gas prices that would be faced by a fossil peaking plant within that location.

Because the price for natural gas to a fossil peaking plant would reflect market-based pricing, an index outside the region may provide a reasonable estimate of prices, particularly given the addition of incremental gas transportation charges within the net EAS model for fossil peaking plant technology options. When selecting an index (and appropriate transportation charges) from among multiple candidates for a given location, many specific factors may be considered, including: the type of service likely to be used for gas delivery, including interruptible service at tariff rates and/or purchase of firm rights released on a shorter term basis by holders of those firm rights (but likely not the purchase of longer-term firm rights to transportation); reasonable estimates of transportation charges from a point of delivery (potentially outside a particular location of interest) to the hypothetical fossil peaking plant given factors such as tariff charges for delivery between points and market prices for other types of service; levels and locations of congestion that would cause differences in market-based prices for natural gas under tight natural gas market conditions; assumptions that seek to avoid either over- or under-estimating expected natural gas prices, given variation in prices across different market conditions, particularly relative to other indices; dual fuel capability, which would cause the fossil peaking plant technology options to switch to lower-cost fuel oil when natural gas prices are high; and the extent to which prices represented by certain natural gas indices (including geographically proximate indices) reasonably represent long-run equilibrium prices that a developer of a hypothetical fossil peaking plant technology option would expect as a new entrant (including consideration of the potential for increases in gas demand from such new entry and other factors to potentially increase congestion on these gas delivery lines and tend to bring differences in multiple potentially representative gas hubs into a long-run equilibrium not represented by short-run historical prices).

Figure 14. Geographic Locations of New York Natural Gas Hubs

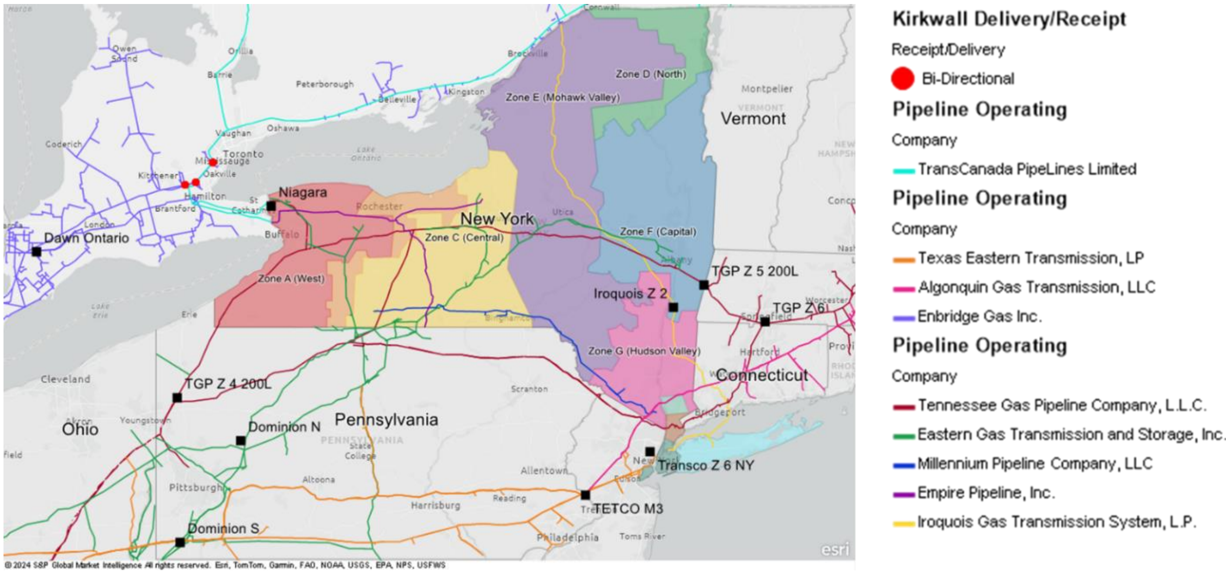
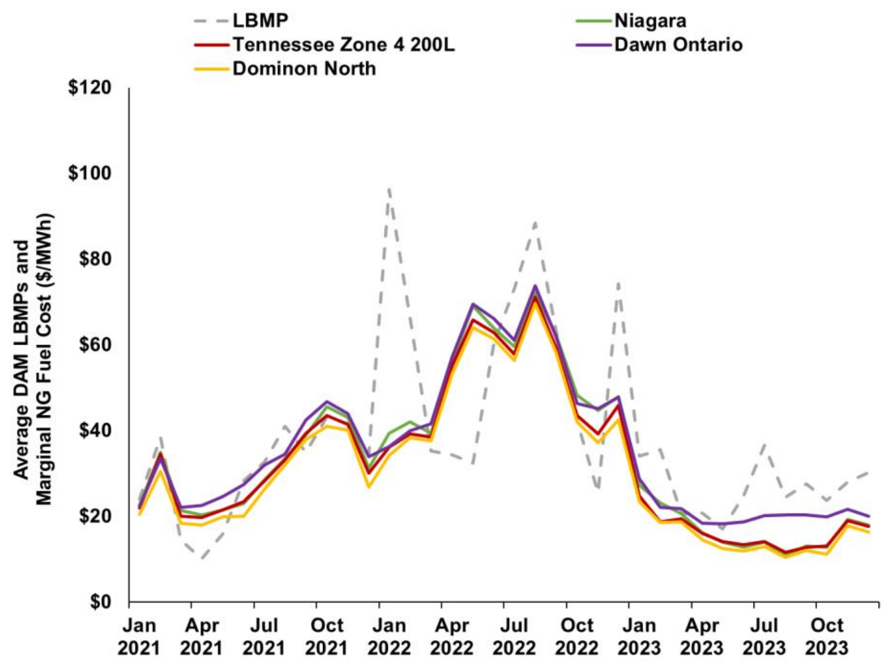


Figure 15 through Figure 19 provide comparisons of gas prices for various hubs and LBMPs for Load Zone C, Load Zone F, Load Zone G, Load Zones J, and Load Zone K, respectively. These figures compare the monthly average fuel costs for a hypothetical fossil generator (with a heat rate of 8,890 Btu/ kWh) to monthly average DAM LBMPs for 2021 to 2023.[78]

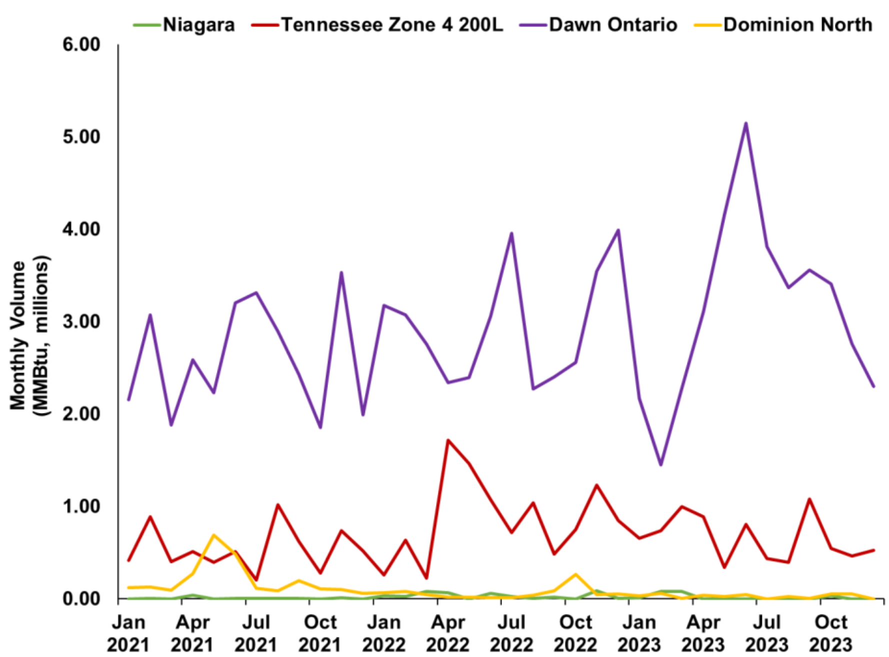
[78] The assumed heat rate of 8,890 Btu/kWh falls within the range of heat rates for both the GE 7HA.03 and GE 7HA.02 units.

Figure 15: Market Dynamics and Liquidity Analysis: Load Zone C

a. Natural Gas Price Indices and DAM LBMPs



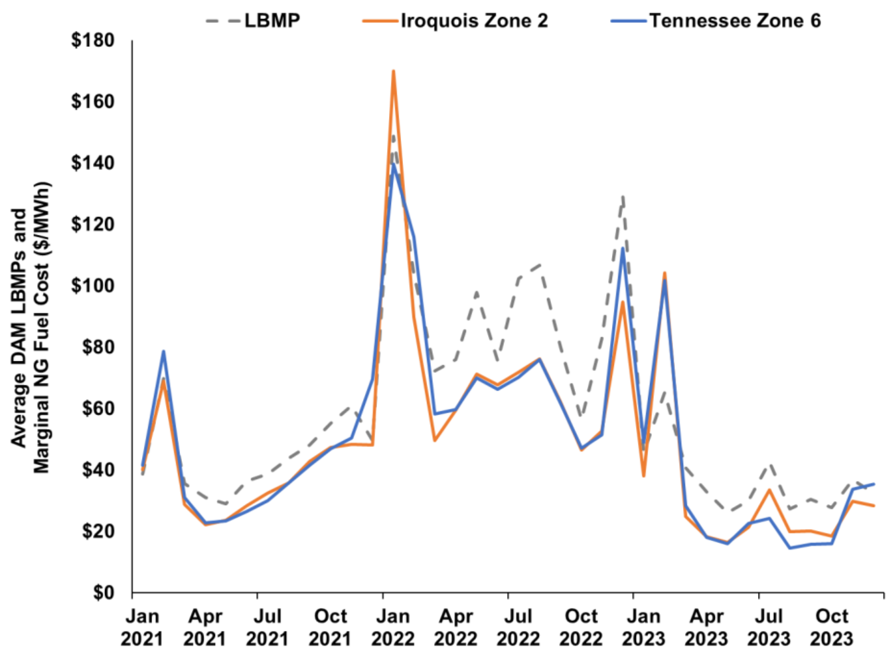
b. Liquidity Analysis



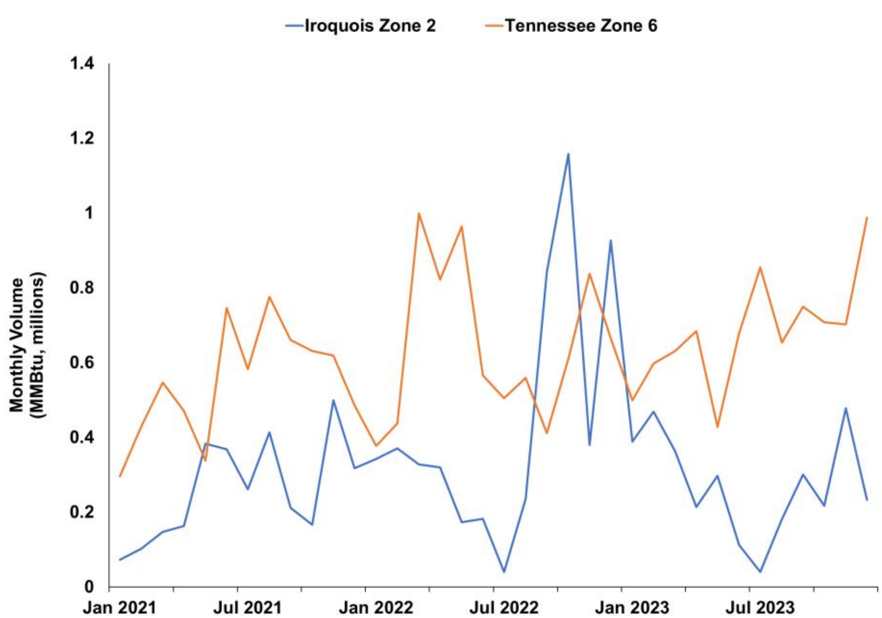
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. Sources: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 16: Market Dynamics and Liquidity Analysis: Load Zone F

a. Natural Gas Price Indices and DAM LBMPs



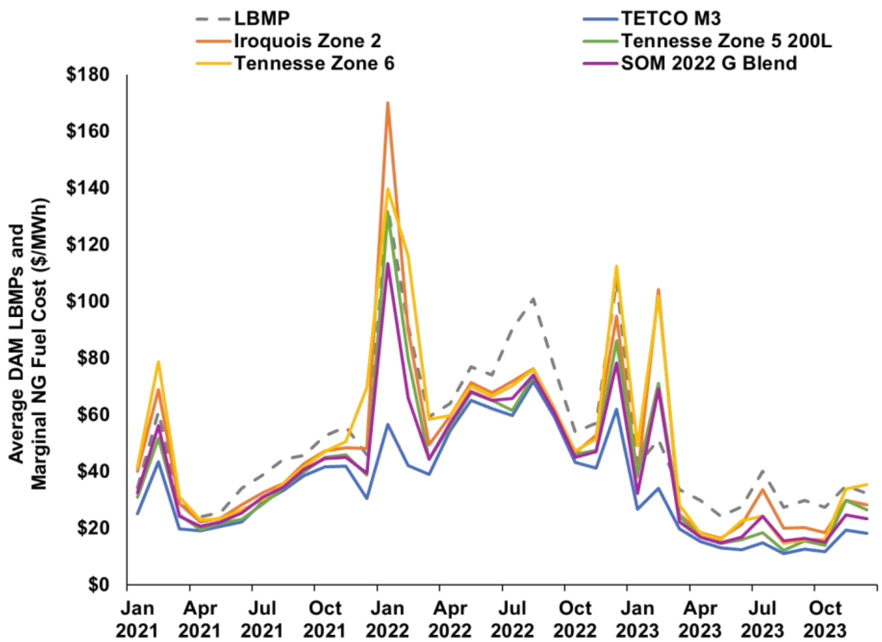
b. Liquidity Analysis



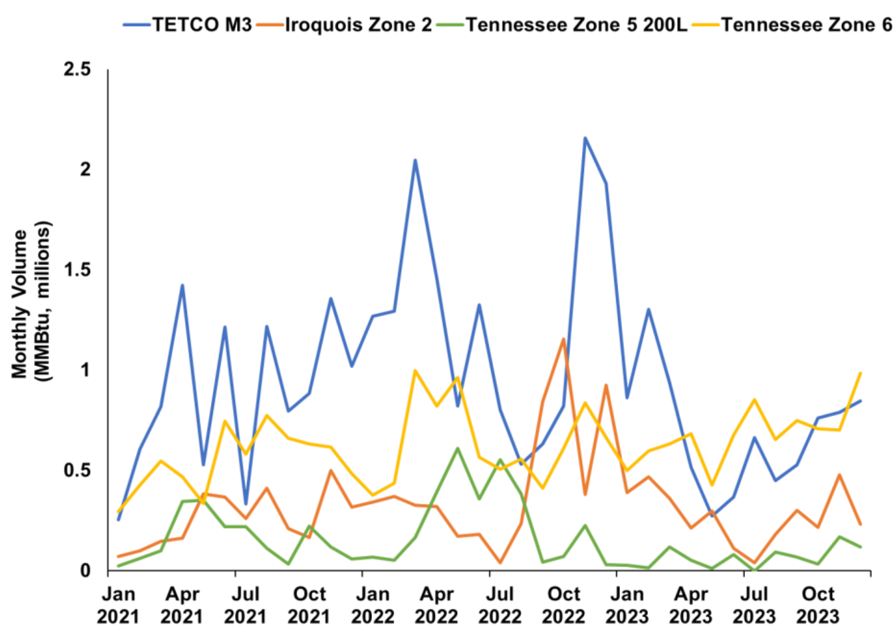
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 17: Market Dynamics and Liquidity Analysis: Load Zone G

a. Natural Gas Price Indices and DAM LBMPs



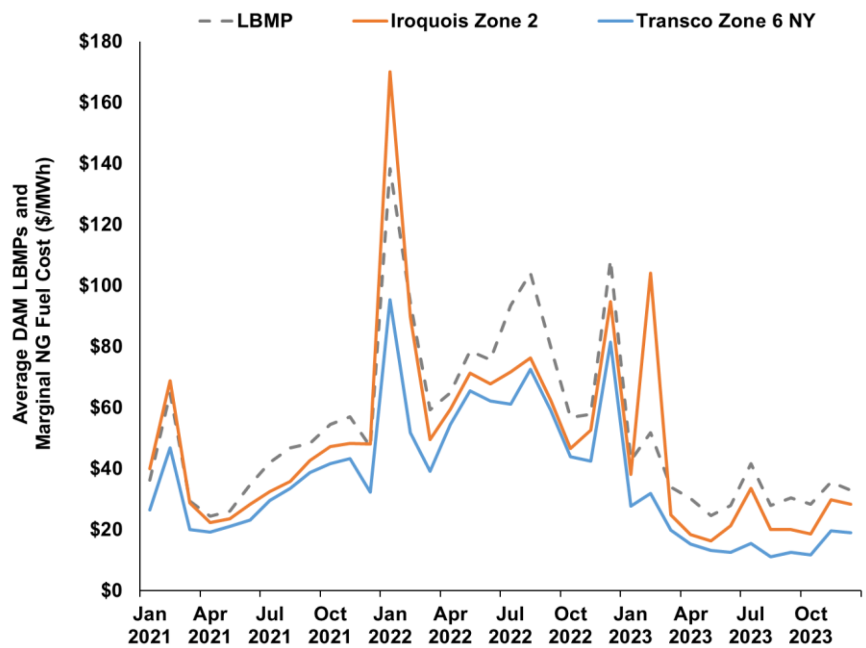
b. Liquidity Analysis



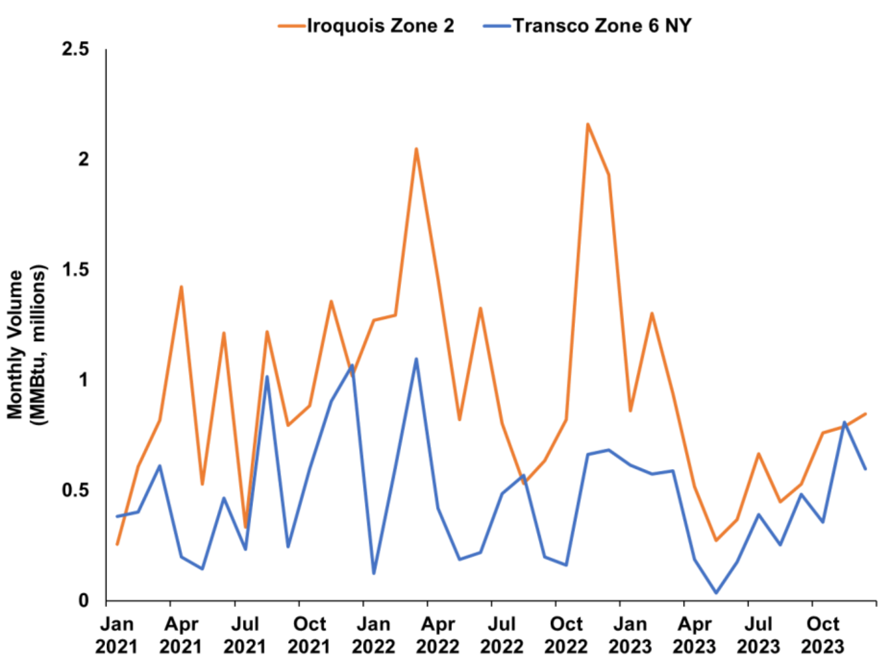
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 18: Market Dynamics and Liquidity Analysis: Load Zone J

a. Natural Gas Price Indices and DAM LBMPs



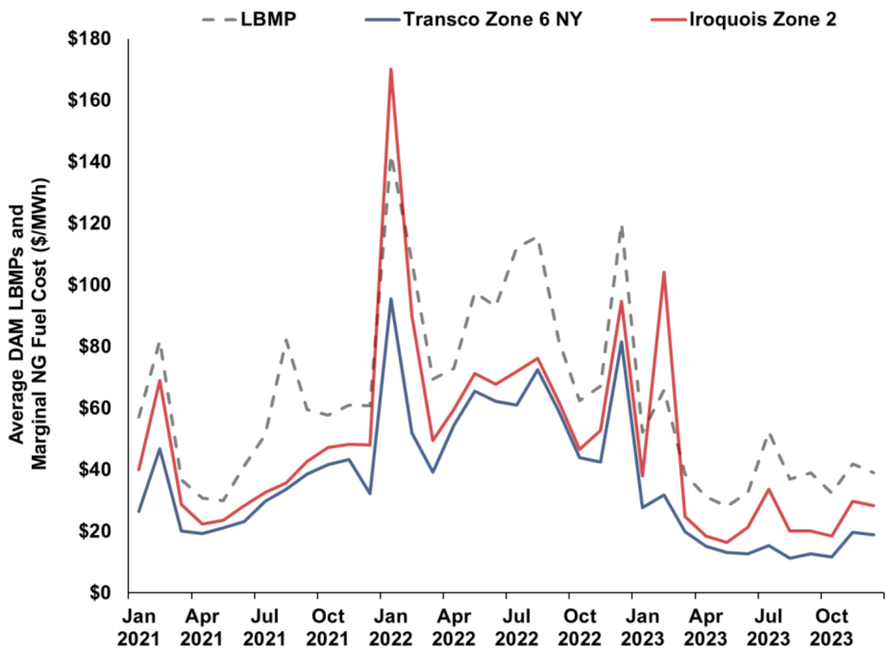
b. Liquidity Analysis



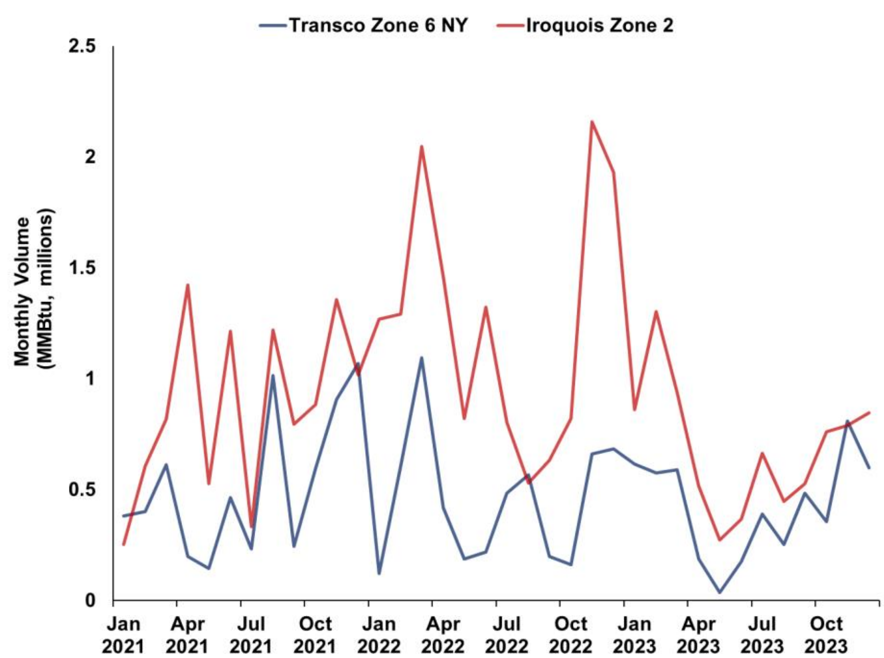
Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Figure 19: Market Dynamics and Liquidity Analysis: Load Zone K

a. Natural Gas Price Indices and DAM LBMPs



b. Liquidity Analysis



Note: [1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8,890 Btu/kWh. **Sources**: [1] S&P Global Market Intelligence (obtained by AG). [2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports for LBMP data.

Table 43 identifies the gas hubs selected by AG based on the considerations listed above, along with consideration of input and discussions with stakeholders and the Market Monitoring Unit. Table 44 summarizes AG's assessment of potentially applicable natural gas indices for each location based on the criteria identified above.

Table 43: Recommended Gas Index by Location

Load Zone	Natural Gas Index
Load Zone C	Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November)
Load Zone F	Iroquois Zone 2
Load Zone G (Dutchess County)	Iroquois Zone 2
Load Zone G (Rockland County)	Tennessee Zone 6
Load Zone J	Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)
Load Zone K	Iroquois Zone 2

Table 44: Natural Gas Hub Selection Criteria, By Location

Load Zone C[79]				
Decision Criteria	**Dawn Ontario &Tennessee Zone 4 200L Blend**	**2022 SOM Load Zones B,C,E Blend**	**Dominion North**	**2021-2040 Outlook Load Zones A-E Blend**
Market Dynamics	Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation
Liquidity	Medium/High	Low/Medium	Medium	Medium
Geography	Yes	Yes	Yes	No
2021-2025 DCR	No	Yes	No	No
2022 SOM	No	Yes	No	No
2021-2040 Outlook	No	No	No	Yes
Recommendation	✓			

[79] The "Dawn Ontario – Tennessee Zone 4 200L Blend" is comprised of Dawn Ontario spot prices from December to March and Tennessee Zone 4 200L spot prices from April – November; the 2022 SOM utilizes a blend comprised of Niagara spot prices from December to March and Tennessee Zone 4 200L spot prices from April to November for Load Zones B, C and E; the 2021-2040 Outlook uses a blend comprised of the weighted average of spot prices from Dominion South (91%), Tetco M3 (7%), and Columbia (2%) for Load Zones A-E.

Load Zone F[80]		
Decision Criteria	**Iroquois Zone 2**	**Tennessee Zone 6**
Market Dynamics	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	Medium
Geography	Yes	No
2021-2025 DCR	Yes	No
2022 SOM	Part of Load Zone F Blend	Part of Load Zone F Blend
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend
Recommendation	✓	

Load Zone G (Dutchess County)				
Decision Criteria	**Iroquois Zone 2**	**Tetco M3**	**Tennessee Zone 5 200L**	**SOM 2022 Load Zone G Blend[81]**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	High	Medium	Medium
Geography	Yes	No	Yes	Yes/No
2021-2025 DCR	Yes	No	No	No
2022 SOM	Part of Load Zone G Blend	Part of Load Zone G Blend	No	Yes
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Recommendation	✓			

[80] The 2022 SOM utilizes the lesser of the spot prices from a Tennessee Zone 6 and Iroquois Zone 2 for Load Zone F. The "Load Zones F-I Blend" from the 2021-2040 Outlook is comprised of the weighted average of the spot prices from Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%) and Tetco M3 (3%).
[81] The SOM 2022 "Zone G Blend" is comprised of the average of spot prices from Iroquois Zone 2 and Tetco M3.

Load Zone G (Rockland County)					
Decision Criteria	**Iroquois Zone 2**	**Tetco M3**	**Tennessee Zone 6**	**Tennessee Zone 5 200L**	**SOM 2022 Load Zone G Blend**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity	Medium	High	Medium	Medium	Medium
Geography	No	No	Yes/No	Yes	Yes/No
2021-2025 DCR	No	Yes	No	No	No
2022 SOM	Part of Load Zone G Blend	Part of Zone G Blend	No	No	Yes
2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Recommendation			✓		

Load Zone J			
Decision Criteria	**Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)**	**Transco Zone 6 NY**	**Iroquois Zone 2**
Market Dynamics	High LBMP Correlation	High LBMP Correlation	High LBMP Correlation
Liquidity	Medium	Medium	Medium
Geography	Yes	Yes	Yes/No (depending on season)
2021-2025 DCR	Yes	Yes	No
2022 SOM	Yes	Yes	No
2021-2040 Outlook	Yes	Yes	No
Recommendation	✓		

Load Zone K		
Decision Criteria	**Transco Zone 6 NY**	**Iroquois Zone 2**
Market Dynamics	High LBMP Correlation	High LBMP Correlation
Liquidity	Medium	Medium
Geography	Yes	Yes
2021-2025 DCR	No	Yes
2022 SOM	No	Yes
2021-2040 Outlook[82]	Part of Load Zone K Blend	Part of Load Zone K Blend
Recommendation		✓

For Load Zone J, Transco Zn 6 NY is the natural gas index for a highly liquid trading hub that reflects pipelines with immediate proximity to Load Zone J and pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets. However, during winter months, prices available for interruptible/non-firm natural gas are more representative of pricing for Iroquois Zone 2, likely due to prioritization of firm gas use for retail LDC gas demand using Transco Zone 6 NY capacity. To improve the correlation between zonal LBMPs and natural gas hubs, AG recommends Transco Zone 6 NY for February – November and Iroquois Zone 2 for December – January (See Table 45) for Load Zone J.

Table 45. Load Zone J Gas Hub-Zonal DAM LBMP Correlation: December - January and February

Month	Gas Hub	Zonal LBMP Correlation	Recommendation
December-January	Transco Zone 6 NY	0.819	
	Iroquois Zone 2	0.895	✓
February	Transco Zone 6 NY	0.736	✓
	Iroquois Zone 2	0.520	

Sources: [A] S&P CapIQ (Fuel Prices; obtained by AG). [B] NYISO (DAM LBMPs). **s**: Zonal LBMP correlations calculated from daily averages of hourly DAM zonal LBMPs.

For Load Zone F, Load Zone G (Dutchess County), and Load Zone K, AG recommends the use of Iroquois Zone 2 as the natural gas index. These recommendations reflect a balance of considerations, particularly market dynamics and geography. For Load Zone K in particular, Iroquois Zone 2 reflected the best proxy for gas prices during constrained conditions.

For Load Zone G (Rockland County), AG recommends the use of Tennessee Zone 6 as the natural gas index. Certain indices with geographic proximity did not provide a reasonable expectation of the long-run equilibrium between gas and electricity markets or exhibited other concerns such as liquidity. In particular, the Millennium

[82] The “Load Zone K Blend” from the 2021-2040 Outlook is comprised of the weighted average of the spot prices from Iroquois Zone 2 (51%) and Transco Zone 6 NY (49%).

pipeline crosses through Rockland County, but it may not have the required flexibility of supply for a fossil peaking plant during all seasons. The Millennium pipeline also has limited reported trading volume in years before 2019, which raise liquidity concerns for use as a proxy gas pricing hub. By contrast, Tennessee Zone 6 is a liquid trading hub which reasonably reflects the fuel cost of a generator such as the fossil peaking plant technology options evaluated in this study, that is expected to operate intermittently throughout the year. 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.

In Load Zone C, a number of pipelines, including those owned by TGP, Dominion, and Millennium, cross the zone. Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, AG recommends the use of TGP Zone 4 (200L) as the natural gas index for Load Zone C for the April – November period. For the winter months of December-March, AG recommends the use of Dawn Ontario as the gas hub for Load Zone C. As depicted in Figure 10(b), Dawn Ontario is far more liquid than other natural gas hubs in the region, such as Niagara. Additionally, Dawn Ontario's prices closely track other natural gas hubs in the region.

For fossil peaking plant technology options that include dual fuel capability, oil prices are based on the New York Harbor Ultra –Low Sulfur Number 2 Diesel spot price as reported by the Energy Information Administration (EIA).[83]

Table 46 identifies assumptions for various additional costs associated with the use of natural gas or ULSD (for plants assumed to include dual fuel capability) for the fossil peaking plant technology options. Both natural gas and oil incur transportation and tax costs. Natural gas transport costs range from $0.20 to $0.27 per MMBtu, while oil transport costs range from $1.50 to $2.00 per MMBtu.[84] Within the net EAS model for fossil peaking plant technology options, if the fossil peaking plant was not committed Day-Ahead, real-time net EAS revenues reflect natural gas fuel costs that include an additional intraday gas premium, which ranges from 10% to 30% depending on location. The use of these premiums (discounts) is described above.

Table 46: Fuel Cost Adders by Capacity Region

Capacity 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

Note: [1] NYC ULSD tax is based on current sales tax rates. Sources: [1] Potomac Economics, 2023 State of the Market Report for the New York ISO Markets, May 2024, Table A-29. [2] New York State Department of Taxation and Finance, Publication 718-A: Enactment and Effective Dates of Sales and Use Tax Rates, effective November 2023.

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[83] Data is available from the EIA. *See* EIA, "New York Harbor Ultra-Low Sulfur No 2 Diesel Spot Price," https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=eer_epd2dxl0_pf4_y35ny_dpg&f=d.

[84] As discussed in Section II, fossil peaking plant technology options that include dual fuel capability are assumed to maintain a 96 hour fuel oil inventory. Fuel burn above 96 hours is assumed to be replaced at the daily spot price plus the applicable oil transportation cost. The model does not include limitations to, or assumptions for, the time necessary to refuel. This assumption is supported by estimated oil burn rates projected by the net EAS revenues model. Using data for the period September 1, 2020 through August 31, 2023, AG found that for dual fuel fossil peaking plant technology options in all locations – assuming the GE 7HA.03 with dual fuel and SCR emissions controls – no units burns more than 96 hours of fuel oil during a single model year.

iii. Emission Allowance Prices:

For the fossil peaking plant technology options, allowance prices for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) are obtained from S&P Global Market Intelligence, and represent national annual prices for both pollutants, and seasonal prices for NO_x.[85] CO_2 allowance prices for the fossil peaking plant technology options are obtained from the Regional Greenhouse Gas Initiative's (RGGI) auction results, representing RGGI-region clearing prices established on a quarterly basis. [86]

iv. Other Fossil Peaking Plant Model Data

As noted earlier, the LBMPs, reserve prices, fuel prices, and emission allowance prices are all updated annually to recalculate the net EAS inputs to annual updates of the ICAP Demand Curves. The net EAS revenues model for fossil peaking plant technology options requires additional input data to carry out the calculations, which are not updated as part of the annual update process. This data falls into three main categories:

1. **Fossil peaking plant operating characteristics**: this data includes heat rates, emissions rates, summer/winter capacity ratings, operating capabilities (e.g., start time), and locations (to identify the appropriate LBMPs and gas hubs) for each fossil peaking plant technology option.
2. **Fossil peaking plant operating costs:** this data includes variable O&M costs, unit start-up costs, natural gas transportation cost adders and taxes, and RTM fuel premiums for each fossil peaking plant technology option.
3. **Fossil peaking plant revenue and pricing data**: this data include a voltage support services adder for each fossil peaking plant technology option. This category also includes level of excess adjustment factors (LOE-AFs), discussed below in Section IV.B.2.d and in Appendix C.

Operating characteristics and costs are summarized further in Table 46 and Appendix A.

v. Battery Specific Data

The net EAS revenues models for BESS options use the same data as the fossil model for a wide variety of parameters, including LBMPs, LOE-AFs, and Rate Schedule 1 charges. The BESS net EAS models require additional input data. This data falls into three main categories:

1. **BESS operating characteristics:** this data includes charging efficiency, storage duration, and the assumed target charge level (i.e., 50% of the battery's capacity), all provided by 1898 & Co. for each BESS option
2. **BESS operating costs:** these data include variable O&M costs provided by 1898 & Co. for each BESS option
3. **BESS revenue and pricing data:** these data include RTD prices (i.e. nominal 5-minute interval prices), transmission service charge rates as applicable to charging withdrawals, and prices for spinning reserves, which are the basis for reserve prices in the battery model. These are both available on the NYISO website. For VSS revenues, the same $2.48/kW-year adder as applicable to the fossil peaking plant technology options is applied to the BESS options.

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[85] Annual and seasonal allowance prices are reported on each weekday. Daily values are applied to all hours in the day. Allowance prices are carried forward from a Friday through the subsequent weekend when data is not reported.
[86] RGGI's quarterly auctions take place at the start of January, April, July, and October; daily costs are assigned based upon the most recent auction price. Results are available at RGGI, "Auction Results," https://www.rggi.org/auctions/auction-results.

d. Level of Excess Adjustment Factors

All results presented in this Draft Report use LOE-AFs from the 2021-2025 DCR. Average LOE-AFs for the 2021-2025 DCR were relatively modest, ranging from 1.02 in Load Zones F and J to 1.06 in Load Zone C across all months and periods. This section will be updated with LOE-AFs employing the new methodology described below.

The net EAS revenues model incorporates adjustment factors to zonal LBMPs and reserve prices to account for the Services Tariff requirement that costs and revenue estimates used in determining the ICAP Demand Curves reflect system conditions with capacity equal to the applicable minimum Installed Capacity Requirement plus the capacity of the peaking plant in NYCA and each Locality (the LOE condition).[87] Consistent with previous DCRs, this Services Tariff requirement is addressed through the development of a set of LOE adjustment factors (LOE-AFs) that modify the historical LBMPs and reserve prices used in the net EAS revenue calculations to approximate prices under LOE conditions.

For example, if actual LBMPs are based on system conditions with resource margins well above the tariff-prescribed LOE conditions, net EAS revenues would likely be lower than the peaking plant would experience under LOE conditions. In this case, the adjustment factors should tend to increase net EAS revenue estimates (i.e., reflect a multiplier greater than one). Conversely, if actual LBMPs are at system conditions reflecting a shortage of resources relative to the tariff-prescribed LOE conditions, estimated net EAS revenues would likely exceed those that the peaking plant would experience at LOE conditions, leading to adjustment factors of less than one.[88]

AG will develop a set of LOE-AFs based on production cost model simulations conducted by GE Energy Consulting (GE), using GE's Multi-Area Production System (MAPS, or GE-MAPS). GE-MAPS generates hourly, locational marginal prices based on a detailed production cost simulation system of NYISO and connected power regions, with system operations and dispatch based on forecasted load, generating asset operational and cost characteristics, and a representation of constraints on the transmission system. For the purposes of this Report, GE relied on supply and load assumptions from the 2021-2040 System and Resource Outlook base case for model years 2021-2022, and the 2023-2042 System and Resource Outlook base case for model years 2023-2027. LOE-AFs are developed through the comparison of two modeling cases. A base case represents current system conditions ("as found" conditions), while an "LOE" case represents system conditions at the tariff-prescribed LOE.

To better align LOE-AFs and the historical prices they are applied to, AG will calculate LOE-AFs by averaging Day-Ahead LBMPs for each month, relevant Load Zone, and period (i.e., "on-peak," "high on-peak," and "off-peak;" consistent with the groupings used in the 2021-2025 DCR). Periods will be defined in the following manner:

- *On-peak* hours are all hours between 7 am and 10:59pm, Monday through Friday except for NERC defined holidays and Peak Load Window hours (below).
- *Peak Load Window* hours are as follows: [89]

[87] Services Tariff, Section 5.14.1.2.2
[88] If actual system conditions on which historical prices are based are exactly the same as the LOE conditions, then the adjustment factor (for that given time period and Load Zone) would be 1.0.
[89] These definitions correspond to the peak load windows proposed by NYISO for wind and solar resources to determine relative capacity value weightings as part of the Market Design Concept Proposal. *See*, e.g., NYISO, "Tailored Availability Metric," presentation to the ICAP Working Group and the Market Issues Working Group, November 21, 2019. AG reviewed average annual LBMPs by Load Zone and month and confirmed that peak periods are consistent with this definition.

  - Summer (June-August): hours beginning 1 pm until 6:59 pm
  - Winter (December-February): hours beginning 4 pm until 9:59 pm
- *Off-peak* are all hours not defined as included within on-peak or peak load window hours.

As depicted in Table 47, DAM LBMPs will be weighted by how many times the given month and year combination are utilized as an input in the net EAS revenue estimates over the reset period. Over the reset period, the theoretical maximum number of times that LBMPs for a given month could be utilized is 12 (i.e., the rolling three-year historical periods used in the net EAS revenue estimates, multiplied by the four Capability Years covered by the DCR). The LBMP weightings reflect how many times LBMPs from each month and year combination are utilized as an LBMP input over the reset period divided by 12. For example, LBMPs from September 2021 will only be used in the net EAS revenue estimates for the 2025-2026 Capability Year ICAP Demand Curves. Thus, the LBMP weighting for September 2021 is 1/12 = 8%.

To model system conditions appropriate under the LOE case, system loads were adjusted in each Load Zone so that the resulting ratio of peak load to available resources equaled the applicable reserve margin consistent with LOE market conditions – i.e., ICR/LRC plus the capacity of the proposed peaking plant (the 2-hour BESS unit) for each capacity region.

Table 47. LBMP Weightings by Month and Modeled Year to Calculate LOE-AFs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	0%	0%	0%	0%	0%	0%	0%	0%	8%	8%	8%	8%
2022	8%	8%	8%	8%	8%	8%	8%	8%	17%	17%	17%	17%
2023	17%	17%	17%	17%	17%	17%	17%	17%	25%	25%	25%	25%
2024	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
2025	25%	25%	25%	25%	25%	25%	25%	25%	17%	17%	17%	17%
2026	17%	17%	17%	17%	17%	17%	17%	17%	8%	8%	8%	8%
2027	8%	8%	8%	8%	8%	8%	8%	8%	0%	0%	0%	0%

LBMPs and reserve prices will then be multiplied by the LOE-AFs to approximate prices that would be faced by a peaking plant at LOE market conditions, consistent with the requirements of the Services Tariff. For example, if the three-year average LBMP during a given peak hour in a Load Zone in July is $50/MWh, and the LOE-AF for peak hours in July is 1.02 for such location, then the LBMP for that hour used in net EAS calculations would be $50 * 1.02 = $51/MWh.

C. Results

The values in this Draft Report are for the 2025/2026 Capability Year. For subsequent Capability Years encompassed by this reset period, the net EAS revenues will be calculated using the same model applicable to the relevant peaking plant technology option selected as the basis for each ICAP Demand Curve, but with updated data as part of the annual update process described in Section VI below.

Net EAS results for the Capability Year 2025/2026, by location, are summarized in Table 48 through Table 50. Included are the average annual net EAS revenues (in nominal $/kW-year) over the three-year historic period, summarized by peaking plant type and location, as well as average annual values for run hours, unit starts, and hours of operation per start. Appendix D includes detailed data for each peaking plant, with net EAS revenues reported by DAM position and RTM dispatch, fuel use, and year.

The net EAS revenues values provided herein are based on data for the three-year period September 2020 through August 2023. The values will be updated in September 2024 to reflect data for the period September 2021 through August 2024.

Table 48: Preliminary Net EAS Model Results for Fossil Peaking Plants by Location, Dual Fuel Capability

		Annual Average Net EAS Revenues ($/kW-year)		Annual Average Run Hours		Annual Average Reserve Hours	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	$72.82	$56.16	1,829.67	600.33	51	63
F	Capital	$96.37	$62.41	2,498.67	554.00	138	137
G	Hudson Valley (Dutchess)	$66.07	$54.78	1,349.00	563.67	256	269
G	Hudson Valley (Rockland)	$67.86	-	1,507.33	-	217	-
J	New York City	$80.40	-	2,853.00	-	127	-
K	Long Island	$134.16	-	3,502.00	-	93	-

		Annual Average Unit Starts		Annual Average Hours per Start	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	122	33	15.0	18.4
F	Capital	176	39	14.2	14.2
G	Hudson Valley (Dutchess)	130	67	10.4	8.5
G	Hudson Valley (Rockland)	133	-	11.3	-
J	New York City	175	-	16.3	-
K	Long Island	196	-	17.9	-

Notes: [1] Results reflect data for the period September 1, 2020 through August 31, 2023 and the LOE-AFs from the 2021-2025 DCR. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024, as well as the LOE-AFs applicable for the 2025-2029 DCR**. [2] Assumes a preliminary $2.48/kW-year VSS revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.** [3] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 49: Preliminary Net EAS Model Results for Fossil Peaking Plants by Location, Natural Gas-Only

		Annual Average Net EAS Revenues ($/kW-year)		Annual Average Run Hours		Annual Average Reserve Hours	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	$72.82	$56.16	1,829.67	600.33	51	63
F	Capital	$95.76	$63.04	2,483.33	585.33	135	134
G	Hudson Valley (Dutchess)	$58.64	$45.23	1,440.67	586.67	221	233
G	Hudson Valley (Rockland)	$59.89	-	1,557.67	-	182	-

		Annual Average Unit Starts		Annual Average Hours per Start	
		Combustion Turbine With SCR	Combustion Turbine Without SCR	Combustion Turbine With SCR	Combustion Turbine Without SCR
Load Zone		1x0 GE 7HA.03	1x0 GE 7HA.02	1x0 GE 7HA.03	1x0 GE 7HA.02
C	Central	122.00	32.67	15.0	18.4
F	Capital	177.67	33.33	14.0	17.6
G	Hudson Valley (Dutchess)	135.67	69.67	10.6	8.4
G	Hudson Valley (Rockland)	137.33	-	11.3	-

Notes: [1] Results reflect data for the period September 1, 2020 through August 31, 2023 and the LOE-AFs from the 2021-2025 DCR.. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024, as well as the LOE-AFs applicable for the 2025-2029 DCR**. [2] Assumes $2.48/kW-year VSS revenues for combustion turbine plants, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change**. [3] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 50: Preliminary Net EAS Model Results for BESS by Location

Peaking Plant Technology	Current Year (2025-2026)					
	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Net EAS Revenues						
2-Hour BESS	$61.58	$78.78	$69.33	$70.39	$74.00	$98.87
4-Hour BESS	$71.68	$91.81	$77.13	$78.83	$81.68	$118.50
6-Hour BESS	$75.74	$97.15	$80.20	$83.15	$84.52	$128.55
8-Hour BESS	$77.41	$97.24	$81.24	$84.71	$85.41	$132.17
Percentage of Total Discharged Energy Relative to Maximum-Rated Throughput						
2-Hour BESS	70.0%	61.5%	34.3%	44.0%	29.8%	75.5%
4-Hour BESS	60.8%	55.0%	29.0%	40.3%	26.2%	67.1%
6-Hour BESS	52.0%	47.9%	24.0%	34.9%	22.1%	65.8%
8-Hour BESS	44.7%	42.1%	21.7%	29.9%	19.5%	53.6%
Average Daily Hours of Discharge						
2-Hour BESS	1.40	1.23	0.69	0.88	0.60	1.51
4-Hour BESS	2.43	2.20	1.16	1.61	1.05	2.69
6-Hour BESS	3.12	2.88	1.44	2.10	1.33	3.95
8-Hour BESS	3.58	3.37	1.74	2.39	1.56	4.29

Notes:

[1] Results reflect data for the period September 1, 2020 through August 31, 2023 and the LOE-AFs from the 2021-2025 DCR. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024, as well as the LOE-AFs applicable for the 2025-2029 DCR.**

[2] Assumes $2.48/kW-year VSS revenues`, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.**

[3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E.

[4] Maximum-rated throughput is equal to (nominal output) * (nominal discharge duration) * (number of operating days) for each BESS option.

V. ICAP Demand Curve Model and Reference Point Prices

A. Introduction

The ICAP Demand Curves are designed to ensure that the ICAP market provides sufficient revenues to support the development of the hypothetical peaking plant selected to serve as the basis for each ICAP Demand Curve, as necessary to maintain resource adequacy. In Sections III and IV, AG established the values for gross CONE and net EAS revenues for the peaking plant technology options in all locations evaluated in this study. The difference in annualized gross CONE and net EAS revenues is defined as the ARV. That is, the ARV is equal to the net annual revenue requirement for each of the peaking plant technology options. This section describes how the resulting ARVs are translated into RPs that form an anchor for the slope of the ICAP Demand Curve in each capacity region, thereby accounting for the tariff-prescribed LOE conditions and seasonal nature of the ICAP markets. With these conclusions in hand, AG presents the resulting ICAP Demand Curve parameters for each capacity region for 2025-2026 Capability Year. Section VI summarizes the procedures for annual update of ICAP Demand Curve parameters through the formulaic approach established at the time of this DCR.

Beginning with the 2025-2026 Capability Year, the NYISO will implement enhancements to the current methodologies for translating the annualized gross CONE values and ARVs to monthly values used in establishing the ICAP Demand Curves. The enhancements provide for express accounting of relative seasonal reliability risks. The proposed enhancements will also result in the production of seasonal ICAP Demand Curves (i.e., separate curves applicable to the summer and winter periods encompassed by each Capability Year). Consistent with current requirements, the seasonal curves applicable for each Capability Year will continue to be designed to ensure that the hypothetical peaking plant used to establish each ICAP Demand Curve earns sufficient revenues annually to cover its cost of market entry under the capacity market supply conditions assumed in determining the ICAP Demand Curves (i.e., the tariff-prescribed LOE conditions).[90]

B. Selection of the Peaking Plant Technology

AG will calculate seasonal monthly ICAP/UCAP reference point prices consistent with the above-described new methodology approved by FERC for implementation beginning with the 2025-2026 Capability Year. As specified in the Installed Capacity Manual, the metric transacted in the ICAP market is UCAP:

> *"[E]ach price on each ICAP Demand Curve shall be converted into a price on the corresponding UCAP Demand Curve by dividing it by the product of: (a) the Capacity Accreditation Factor of the peaking plant used to establish the applicable ICAP Demand Curve, and (b) one minus the applicable derating factor of such peaking plant."*[91]

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[90] FERC Docket No. ER24-701-000, *New York Independent System Operator, Inc.*, Proposed Installed Capacity Demand Curve Enhancements (December 19, 2023); and FERC Docket No. ER24-701-000, , *New York Independent System Operator, Inc.*, Letter Order (February 15, 2024).
[91] Installed Capacity Manual, April 2024, available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf

As such, to reflect the impact of Capacity Accreditation Factors (CAFs) and derating factors on the choice of peaking plant technology option for each ICAP Demand Curve, AG considers the relevant UCAP reference point prices for each technology option in selecting the appropriate peaking plant technology for each demand curve. An economic evaluation of the peaking plant technology options without consideration of CAFs or derating factors would fail to appropriately reflect the marginal reliability contribution of each peaking plant technology option towards meeting NYSRC resource adequacy requirements for the upcoming Capability Year. The selected peaking plant technology for each capacity region should result in curves representing the lowest cost on a UCAP basis.

For the purposes of this Draft Report, AG used NYISO's Final CAFs for the 2024-2025 Capability Year, as reported in February 2024.[92] [93]

C. ICAP Demand Curve Shape and Slope

The ICAP Demand Curves are designed with three basic elements: a cap on the maximum allowable prices, a floor on prices (at zero), and a sloped demand curve that determines prices for varying levels of capacity supply between this cap and floor. In principle, the ICAP Demand Curve slope reflects the declining marginal value of additional capacity in terms of incremental improvements in reliability – that is, as the quantity of capacity increases. Incremental capacity provides diminishing value in terms of reductions in loss of load expectation (LOLE). The sloped portion of the demand curve, in principle, is intended to capture this declining value. However, at some point, this value becomes so small that incremental capacity provides no meaningful improvement in reliability. To capture this limit, the ICAP Demand Curves include a ZCP, which reflects the point at which incremental capacity is deemed to provide no incremental value and the price declines to zero. Along with capturing the declining marginal value of capacity, a sloped demand curve also reduces the volatility of capacity market prices, which can reduce developer financial risk thereby providing a market environment more conducive to capital investment to support resource adequacy. Such sloped design also reduces incentives for the exercise of market power.

The ICAP Demand Curves are constructed such that the applicable peaking plant would recover its ARV when the system is at the LOE – that is, the applicable IRM/LCR plus the capacity of the relevant peaking plant - while also accounting for expected difference in the seasonal availability of capacity supply. Given differences in costs to construct new capacity supply resources between locations throughout New York as well as transmission constraints that limit flows between Load Zones, separate ICAP Demand Curves are established for NYCA and each Locality. Each ICAP Demand Curve is comprised of three portions (each of which is a straight line) reflecting the three components discussed above:[94]

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[92] Final CAFs for the 2024/2025 Capability Year posted on February 26, 2024, available at: https://www.nyiso.com/documents/20142/43275262/24_02_29_ICAPWG_FinalCAFs.pdf/b1cf7d7f-06eb-ac49-f471-958fa317d90c

[93] AG understands that, on June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. The NYISO presented the updated CAFs on May 8, 2024, available at: https://www.nyiso.com/documents/20142/44546131/NYC-TSL-Potential-Market-Problem-05-08-2024-ICAPWG.pdf. AG will continue to monitor the status of this proposal for purposes of its assessment for this study.

[94] As described in Section V.A, beginning with the 2025-2026 Capability Year, separate ICAP Demand Curves applicable for each Capability Period encompassed by a Capability Year will be established.

1) Maximum allowable price: A horizontal line with the price equal to 1.5 times the applicable monthly gross CONE value for each capacity region;
2) Sloped segment: A sloped straight-line segment that intersects with number (1) and passes through two points: (a) the point at which the capacity is equal to the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, and the price is equal to the NYCA/Locality RP, and (b) the zero crossing point at which the price is equal to zero; and
3) Price floor: A horizontal line with the price equal to zero and the quantity includes all quantities greater than the ZCP quantity.[95]

Ultimately, the slope of the sloped portion of the line is determined by the RP and ZCP. As described below, the RP is a function of the ARV, the ZCP ratios (ZCPR), the impact of additional capacity from the tariff prescribed LOE conditions, and seasonal factors (including the relative reliability risk by season and the expected seasonal differences in capacity availability). The following sections provide additional detail on the ZCPR, seasonal capacity availability and LOE factors. Following this discussion, the RP formula and ICAP Demand Curve geometry is presented in greater detail.

1. Zero crossing point

In the 2014-2017 DCR, the ZCPs for the ICAP Demand Curves were set at 112% of IRM for NYCA, 118% of LCR for Long Island, 118% of LCR for New York City, and 115% of LCR for the G-J Locality. This decision retained the then-current ZCPs for NYCA, NYC, and LI, and set the ZCP for the G-J Locality midway between the values for NYC and NYCA. Prior to this decision, two separate analyses of the ZCP were performed to inform ZCP decisions. The first analysis was a study completed by FTI that evaluated the economics of setting the ZCPs based on GE-MARS analysis of loss of load expectations associated with varying levels of capacity in the market.[96] While FTI had recommended revising the ZCPs based on the results of its analysis, the independent consultant for the 2014-2017 ultimately recommended adjusting ZCPs to a point midway between then-current values and the values recommended by FTI. After the completion of the independent consultant's study report for the 2014-2017 DCR, an analysis was performed by the MMU that was also based on GE-MARS modeling completed by NYISO staff.[97]

Both the FTI and MMU recommendations for potential changes to ZCPs were based on assessments of the point at which additional capacity beyond the applicable minimum requirement provided little or no marginal value in terms of improved reliability (as reflected in resulting changes to LOLE). However, the analyses differed in two key respects. First, the underlying MARS modeling used in the FTI analysis was based on "shifts" in capacity from the Localities to the NYCA. In contrast, the modeling used by the MMU relied on adding incremental capacity to each Locality and NYCA. Second, FTI relied on judgement to determine the ZCP – that is, relying on visual inspection to determine the point at which incremental value was near zero. The MMU quantitatively fit curves through scenarios outcomes to determine where the change in LOLE became zero.

[95] When referencing the ZCP in percentage terms relative to applicable IRM or LCR, AG uses the term zero crossing point ratio (ZCPR).
[96] NERA Economic Consulting, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, report for NYISO, August 2, 2013, pp. 14-15.
[97] The MMU analysis was presented at the August 22, 2013 ICAPWG meeting. Potomac Economics, "Preliminary Recommend Zero Crossing Points for the 2014-17 New York ISO Demand Curves," presentation to the NYISO ICAP Working Group, August 22, 2013.

Since the 2014-2017 DCR, no additional studies have been conducted to specifically inform the determination of ZCPs for the ICAP Demand Curves. Considering these factors, AG recommends that the current ZCPs remain unchanged for this DCR.

2. Seasonal Capacity Availability

The expected seasonal capacity availability ratios (i.e., the winter-to-summer ratio (WSR) and summer-to-winter (SWR) ratio) capture differences in the expected quantity of capacity available between winter and summer seasons given differences in seasonal operational capability. The ICAP Demand Curves account for differences in the prices that would prevail, all else equal, between seasons due to these seasonal differences in capacity.

The WSR is calculated as the ratio of total winter ICAP to total summer ICAP in each year. The SWR is calculated as the ratio of total summer ICAP to total winter ICAP in each year. 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 by using the applicable NYCA or Locality translation factor, which consider CAFs and unit specific derating factors for all relevant resources. These totals are adjusted for certain resource entry and exit circumstances.[98] 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.

Table 51 provides the WSR values for the 2024-2025 Capability Year used in producing the preliminary results in this Draft Report and reflect data for the period September 1, 2020 through August 31, 2023. **Seasonal capacity availability values (i.e., WSR and SWR) will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.**

Table 51: 2024-2025 Capability Year WSR by Location

Capacity Region	Capability Year	Winter-Summer Ratio
NYCA	2024-2025	1.033
G-J Locality	2024-2025	1.058
New York City	2024-2025	1.067
Long Island	2024-2025	1.072

3. Level of Excess Criterion

The LOE for each peaking plant 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.

[98] 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 out of 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 that retire, mothball, or enter an ICAP Ineligible Force Outage state.

The LOE is expressed in percentage terms and defined by the following equation, where all capacities are expressed in MW.

$$LOE = \frac{IRM\ (or\ LCR) + peaking\ plant\ capacity}{IRM\ (or\ LCR)} \quad (6)$$

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 ICR/LCR values are based on the peak load forecasts and the IRM/LCR values for the 2024/2025 Capability Year. Table 52 and Table 53 provides 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 52: Fossil Peaking Plant Technology Options Level of Excess by Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2024)	IRM/LCR	LOE (%) by Technology	
			GE 7HA.03	GE 7HA.02
NYCA	31,542	122.00%	101.04%	100.86%
G-J	15,220	81.0%	103.22%	102.66%
NYC	11,168	80.40%	104.50%	-
LI	5,043	105.30%	107.61%	-

Note:
[1] Average degraded net capacity by technology is provided in Table 33.

Table 53: BESS Options Level of Excess by Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2024)	IRM/LCR	LOE (%) by Battery Duration			
			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	81.0%	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%

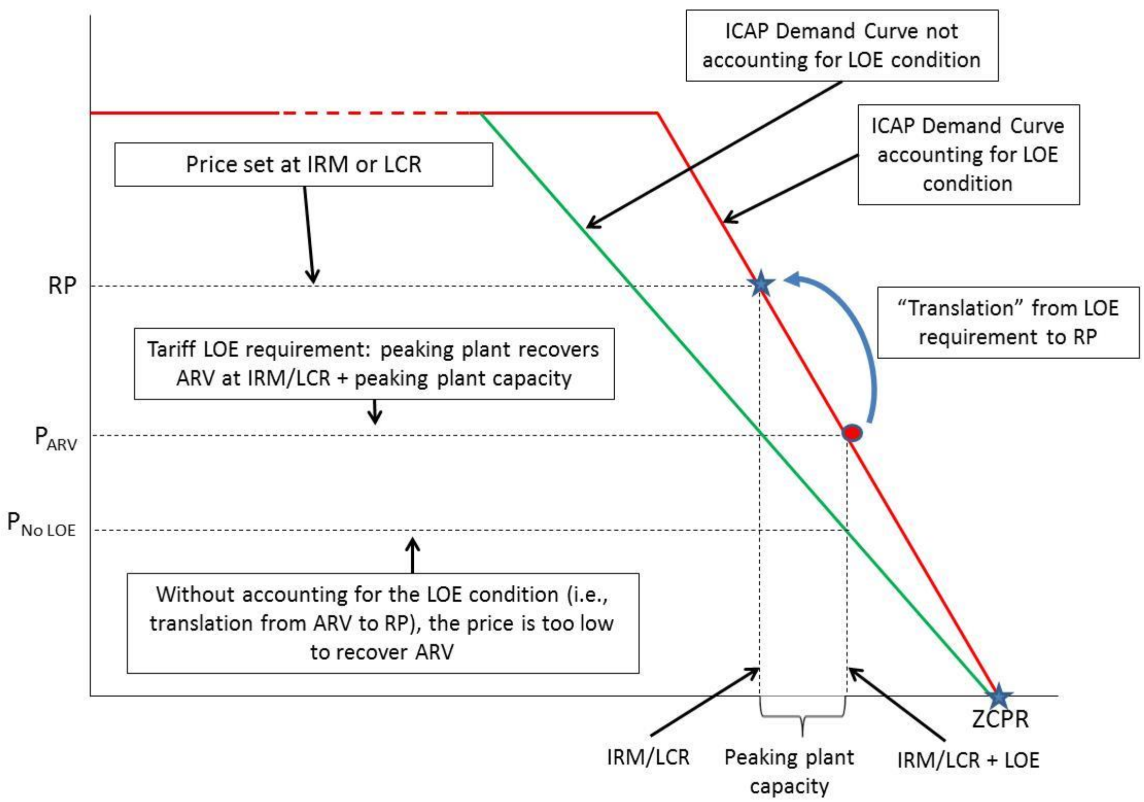
Note:
[1] Refer to Table 35. BESS is sized for 200 MW net at the POI. Energy discharge capability is maintained through capacity augmentation throughout the assumed project life.

D. Reference Point Price Calculations

Figure 20 illustrates the “geometry” of a generic, annual ICAP Demand Curve and the LOE requirements, which in turn determine the RP. The ICAP Demand Curve slope is determined by two conditions: (1) the requirement that peaking plant earns its revenue requirement at the LOE, illustrated by the red dot in Figure 20, with the price P_{ARV} and the quantity equal to the applicable seasonal level of excess conditions; and (2) the ZCPR. These two points define the red line in Figure 20, which is the ICAP Demand Curve slope. Having defined the ICAP Demand Curve slope, the seasonal RP can be calculated at the appropriate quantity for each capacity region. This calculation requires a translation that is defined below.

Figure 20 also generically illustrates the ICAP Demand Curve slope absent the LOE requirement (the green line, set so that the peaking plant recovers its ARV at the IRM/LCR). When the RP is calculated *without* an adjustment to account for the tariff prescribed seasonal LOE conditions, the price earned by the hypothetical peaking plant at the LOE (i.e., $P_{No\ LOE}$ in Figure 20) would be insufficient to recover ARV.

Figure 20: Illustration of the Reference Point Price and Level of Excess Requirement



Equations (7) and (8) define the summer reference point price (SRP) and winter reference point price (WRP) as a function of both the seasonal capacity adjustment (WSR and SWR), relative seasonal reliability risk (SLOLE and WLOLE) and the seasonal level of excess requirement:

$$SRP_z = \frac{ARV_z * AssmdCap_z * max\ [min(CPMax, SLOLE), CPMin]}{6 * \left[SDMNC_z * \left(1 - \frac{(SLOE_Z - 1) + max(0, SWR_Z - 1)}{ZCPR - 1}\right)\right]} \quad (7)$$

$$WRP_z = \frac{ARV_z * AssmdCap_z * max\ [min(CPMax, WLOLE), CPMin]}{6 * \left[WDMNC_z * \left(1 - \frac{(WLOE_Z - 1) + max(0, WSR_Z - 1)}{ZCPR - 1}\right)\right]} \quad (8)$$

Where:

- *CPMax* is the maximum percentage of the Annual Reference Value (ARV_z) to be recovered by the peaking plant in one Capability Period
- *CPMin* is the minimum percentage of the Annual Reference Value (ARV_z) to be recovered by the peaking plant in one Capability Period (equal to 1 minus *CPMax*)
- *SLOLE* is the percentage of the annual loss of load expectation expected to occur in the Summer Capability Period 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
- *WLOLE* is the percentage of the annual loss of load expectation expected to occur in the Winter Capability Period 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 (equal to 1 minus *SLOLE*)
- SWR_z is the ratio of the amount of ICAP available in the ICAP Spot Market Auctions in the Summer Capability Period to the amount of ICAP available in the ICAP Spot Market Auctions for the Winter Capability Period for location *z* (equal to 1 divided by WSR_z)
- *ARV* is the annual reference value for the relevant peaking plant ($/kW-year)
- $SDMNC_z$ is the summer dependable maximum net capability for the relevant peaking plant (MW)
- $WDMNC_z$ is the winter dependable maximum net capability for the relevant peaking plant (MW)
- *AssmdCap* is the average degraded net plant capacity for the relevant peaking plant
- $SLOE_z$ is the ratio of level of excess that would occur in the Summer Capability Period (i.e., the applicable minimum ICAP requirement, plus $SDMNC_z$) to the applicable minimum ICAP requirement for location z
- $WLOE_z$ is the ratio of level of excess that would occur in the Winter Capability Period (i.e., the applicable minimum ICAP requirement, plus $WDMNC_z$) to the applicable minimum ICAP requirement for location z
- WSR_z is the ratio of total winter ICAP to total summer ICAP, as calculated by the NYISO for the relevant capacity region
- $ZCPR_z$ is the ZCP ratio of the ICAP Demand Curve for the relevant capacity region
- *SRP* is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region for the summer
- *WRP* is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region for the winter

Along with accounting for the seasonal level of excess requirement, Equations (7) and (8) also account for differences in the capacity market revenue and peaking plant capacity between Summer and Winter Capability Periods. Thus, the plant's ARV (defined in $/kW-year) is met through different revenue streams in each season – that is:

$$ARV * AssmdCap = 6 * SP * SDMNC + 6 * WP * WDMNC \qquad (8)$$

Where:

- *SP* and *WP* represent the assumed summer and winter capacity prices at the seasonal level of excess conditions.

E. ICAP Demand Curve Parameters

AG has applied the methods, models and equations described in this Draft Report to identify preliminary RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2025-2026. These values are presented in Table 2, below.

To arrive at these results, AG and 1898 & Co. considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the RP values provided herein. **Note that all numerical results presented below will be updated in September 2024 to use the finalized data as required for the estimation of net EAS revenues and escalation of capital costs.** Specifically, AG and 1898 & Co. conclude the following:

- The two-hour BESS represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a BESS would use lithium-ion technology and a modular, PBE form factor.
- For the two-hour BESS, we assume a fifteen-year amortization period, and incorporate additional costs for capacity augmentation to ensure consistent performance and nominal capacity value over the assumed life of the resource. Capacity augmentation costs are included in the two-hour BESS' VOM costs, reflecting the fact that capacity augmentation costs are related to the total throughput of the battery.
- The appropriate method to evaluate the peaking plant technology is to identify the technology that minimizes the cost of UCAP. An economic evaluation focused solely on the cost of ICAP would fail to account for variation in CAFs and derating factors across technology options.[99]
- The state of New York has begun a process to decarbonize the power sector over the next couple of decades, including passage of the CLCPA in 2019. The CLCPA does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology during the 2025-2029 DCR period. It does, however, affect the development and operation of such facilities, which could in turn affect present-day financial analysis parameters (e.g., the appropriate amortization period). For this DCR, our review included two categories of units that at least initially were powered using fossil fuels. First, we reviewed installation and operation of a fossil unit in each location designed to exclusively run on fossil fuels (and thus assumed to not operate in 2040 or beyond). Second, we reviewed installation and operation of a unit initially operating on fossil fuels, but retrofitted to operate on hydrogen fuel beginning in 2040. For the fossil-only unit, we applied a 13-year amortization period to reflect CLCPA's requirement for 100% of load to be served by zero-emissions resources by 2040, and consistent with the decisions by FERC accepting this amortization period method in the 2021-2025 DCR.[100] For the fossil-hydrogen unit,

[99] AG acknowledges that, on June 4, 2024, the NYISO presented a proposal for revising the 2024-2025 Capability Year CAFs beginning November 1, 2024. AG will continue to monitor the status of this proposal for purposes of its assessment for this study.
[100] New York Independent System Operator, Inc., 183 FERC ¶ 61,130 (May 19, 2023); and New York Independent System Operator, Inc., 185 FERC ¶ 61,010 (October 4, 2023).

we studied the potential costs associated with retrofitting a turbine to run on hydrogen fuel, and the costs of storing associated hydrogen fuel onsite.

- For the fossil-fuel fired unit analysis, the GE 7HA.03 frame turbine represents the highest variable cost, lowest fixed cost SCGT peaking plant option that is economically viable. To be economically viable and practically constructible, a 7HA.03 SCGT would be built with SCR emission control technology in all locations, whether constructed as gas-only or dual-fuel.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures related to capacity accreditation, consideration of applicable reliability and LDC retail gas tariff requirements, and developer expectations, we expect that developers would include dual fuel capability in all locations.
- The WACC used to develop the levelized gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 14.0% cost of equity, for a WACC of 9.99%. Based on current tax rates in NY State and New York City, this translates to a nominal ATWACC of 9.02% for all locations other than Load Zone J and 8.76% for Load Zone J.
- For the purposes of modeling net EAS revenues for BESS technologies in the RTM, it is appropriate to use RTD prices transacting on a nominal 5-minute basis. Consistent with the 2017-2021 and 2021-2025 DCRs, we continue to model net EAS revenues for fossil peaking plant options in the RTM using average hourly prices.
- The ICAP Demand Curves should maintain the current ZCP values. The ZCPs should remain 112% for the NYCA ICAP Demand Curve, 115% for the G-J Locality ICAP Demand Curve, and 118% for the NYC and LI ICAP Demand Curves.

Table 54 provides parameters for the 2025/2026 Capability Year ICAP Demand Curves for each location, consistent with the conclusions and technology findings described above. Table 55 through Table 57 provide additional information for the other technologies evaluated. For all locations, the appropriate peaking plant technology and design, as well as the net EAS model structure (including the granularity of real-time prices used by such models) selected as the basis for the 2025/2026 Capability Year ICAP Demand Curves remain fixed for the four-year duration of the reset period.

Table 54: Preliminary ICAP Demand Curve Parameters ($2024 ICAP)

2-Hour BESS (RTD interval pricing net EAS Model)

Parameter	Source	C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
		Current Year (2025-2026)					
Gross Cost of New Entry ($/kW-Year)	[1]	$125.81	$126.49	$128.85	$125.85	$182.78	$127.04
Net EAS Revenues ($/kW-Year)	[2]	$61.58	$78.78	$69.33	$70.39	$74.00	$98.87
Annual Reference Value ($/kW-Year)	[3]=[1]-[2]	$64.23	$47.71	$59.53	$55.47	$108.78	$28.17
ICAP DMNC (MW)	[4]	200	200	200	200	200	200
Annual Reference Value	[5]=[3]*[4]	$12,846	$9,543	$11,905	$11,093	$21,756	$5,633
Level of Excess (%)	[6]	100.52%	100.52%	101.62%	101.62%	102.23%	103.77%
Ratio of Summer to Winter DMNCs	[7]	1.033	1.033	1.058	1.058	1.067	1.072
Summer DMNC (MW)	[8]	200	200	200	200	200	200
Winter DMNC (MW)	[9]	200	200	200	200	200	200
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$6.96	$5.17	$6.45	$6.01	$11.78	$3.05
Winter ($/kW-Month)	[11]	$3.75	$2.78	$3.47	$3.24	$6.35	$1.64
Monthly Revenue (Summer)	[12]=[10]*[8]	$1,392	$1,034	$1,290	$1,202	$2,357	$610
Monthly Revenue (Winter)	[13]=[11]*[9]	$749	$557	$694	$647	$1,269	$329
Seasonal Revenue (Summer)	[14]=6*[12]	$8,350	$6,203	$7,738	$7,211	$14,141	$3,662
Seasonal Revenue (Winter)	[15]=6*[13]	$4,496	$3,340	$4,167	$3,883	$7,615	$1,972
Total Annual Reference Value	[16]=[14]+[15]	$12,846	$9,543	$11,905	$11,093	$21,756	$5,634
ICAP Demand Curve Parameters							
Summer ICAP Monthly Reference Point Price ($/kW-Month)		$7.27	$5.40	$7.23	$6.74	$13.45	$3.86
Winter ICAP Monthly Reference Point Price ($/kW-Month)		$5.50	$4.08	$6.87	$6.40	$12.59	$4.20
Summer ICAP Maximum Clearing Price ($/kW-Month)		$21.37	$21.49	$23.48	$22.93	$33.90	$26.11
Winter ICAP Maximum Clearing Price ($/kW-Month)		$16.15	$16.24	$22.32	$21.80	$31.73	$28.45
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS. [2] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023 and the seasonal capacity availability values are based on data for the same period. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** [3] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [4] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.**

Table 55: Comparison of UCAP Preliminary Reference Point Prices by Technology

($2024 UCAP/kW-Month)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026)					
		C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
Summer Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$22.89	$19.67	$29.48	$27.54	$36.33	$29.47
	Gas Only, with SCR	$21.49	$18.38	$29.01	$26.99	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$26.17	$25.05	-	$29.45	-	-
	Gas Only, no SCR	$24.50	$23.35	-	$28.90	-	-
2-hour BESS	Battery Storage	$13.39	$9.95	$13.14	$12.24	$24.54	$7.46
4-hour BESS	Battery Storage	$22.76	$19.33	$22.96	$21.87	$36.85	$14.87
6-hour BESS	Battery Storage	$25.61	$23.09	$27.65	$26.44	$41.99	$24.15
8-hour BESS	Battery Storage	$32.51	$30.42	$35.39	$33.98	$51.35	$33.36
Winter Reference Point Prices (UCAP Basis)							
1x0 GE 7HA.03	Dual Fuel, with SCR	$16.71	$14.40	$30.48	$28.47	$38.02	$59.74
	Gas Only, with SCR	$15.69	$13.46	$30.00	$27.91	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$18.67	$17.87	-	$29.98	-	-
	Gas Only, no SCR	$17.48	$16.66	-	$29.42	-	-
2-hour BESS	Battery Storage	$10.12	$7.52	$12.49	$11.64	$22.97	$8.13
4-hour BESS	Battery Storage	$17.20	$14.61	$21.83	$20.79	$34.49	$16.21
6-hour BESS	Battery Storage	$19.35	$17.45	$26.29	$25.14	$39.31	$26.32
8-hour BESS	Battery Storage	$24.56	$22.99	$33.64	$32.30	$48.07	$36.35

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm and the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 15 ppm. [3] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023 and the seasonal capacity availability values are based on data for the same period. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** [4] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [5] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.** [6] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

Table 56: Comparison of Preliminary Gross CONE by Technology ($2024/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026) C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$260.72	$257.63	$274.05	$258.67	$321.70	$285.06
	Gas Only, with SCR	$249.23	$246.47	$262.80	$247.43	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$274.58	$271.21	-	$270.83	-	-
	Gas Only, no SCR	$260.66	$257.70	-	$257.21	-	-
2-hour BESS	Battery Storage	$125.81	$126.49	$128.85	$125.85	$182.78	$127.04
4-hour BESS	Battery Storage	$198.67	$199.65	$203.01	$198.75	$282.74	$202.50
6-hour BESS	Battery Storage	$279.12	$280.51	$285.27	$279.24	$385.42	$286.70
8-hour BESS	Battery Storage	$358.73	$360.53	$366.73	$358.86	$492.46	$370.12

Note: [1] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [2] As discussed in Section II, the 1x0 GE 7HA.03 is tuned to NOx emissions rate of 25 ppm and the 1x0 GE 7HA.02 is tuned to NOx emissions rate of 15 ppm.

Table 57: Comparison of Preliminary Net EAS by Technology ($2024/kW-year)

Technology	Fuel Type/ Emission Control	Current Year (2025-2026) C - Central	F - Capital	G - Hudson Valley (Rockland)	G - Hudson Valley (Dutchess)	J - New York City	K - Long Island
1x0 GE 7HA.03	Dual Fuel, with SCR	$72.82	$96.37	$67.86	$66.07	$80.40	$134.16
	Gas Only, with SCR	$72.82	$95.76	$59.89	$58.64	-	-
1x0 GE 7HA.02	Dual Fuel, no SCR	$56.16	$62.41	-	$54.78	-	-
	Gas Only, no SCR	$56.16	$63.04	-	$45.23	-	-
2-hour BESS	Battery Storage	$61.58	$78.78	$69.33	$70.39	$74.00	$98.87
4-hour BESS	Battery Storage	$71.68	$91.81	$77.13	$78.83	$81.68	$118.50
6-hour BESS	Battery Storage	$75.74	$97.15	$80.20	$83.15	$84.52	$128.55
8-hour BESS	Battery Storage	$77.41	$97.24	$81.24	$84.71	$85.41	$132.17

Note: [1] The net EAS revenues are estimated using data for the three-year period September 1, 2020 to August 31, 2023. **The values will be updated in September 2024 to reflect data for the period September 1, 2021 through August 31, 2024.** .[2] The net EAS revenues for BESS options reflect the net EAS model using RTD interval prices. Results for BESS options for a net EAS model using hourly real-time prices are provided in Appendix E. [3] The peaking plant technology choice in all locations is a 2-hour, lithium-ion BESS, which is highlighted in green. [4] Assumes a preliminary $2.48/kW-year voltage support service (VSS) revenues, based on settlement data analyzed by NYISO using the methodology from the 2021-2025 DCR. **This methodology and resulting VSS revenue value for each peaking plant technology option remain under review and subject to change.** [5] Runtime limits were applied based on New Source Performance Standards. All combustion turbines units with SCRs were limited to 3,504 hours of runtime in each modeled year (September 1, 2020 to August 31, 2021; September 1, 2021 to August 31, 2022; September 1, 2022 to August 31, 2023). All units without SCRs were limited to 200,000 lbs of NOx emissions in each modeled year.

VI. Annual Updating of ICAP Demand Curve Parameters

As described above, AG's demand curve model calculates the seasonal RPs for each Locality and NYCA based on input values for revenue requirements (i.e., ARV), financial parameters, "shape" parameters and other parameters (seasonal capacity availability, relative seasonal reliability risks, and various capacity values). Outputs of the demand curve model provide the applicable ICAP Demand Curve parameters for the Capability Year in question and associated financial metrics. These outputs include the gross CONE ($/kW-year), net EAS revenues ($/kW-year), ARV ($/kW-year and total $/year), seasonal ICAP monthly RP ($/kW-Month), seasonal ICAP Demand Curve maximum clearing price ($/kW-Month), and ICAP Demand Curve length (%).

ICAP Demand Curves will be updated annually based on the updating of (1) gross CONE, (2) net EAS revenues, (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 will be based on the data and models discussed in Sections III and IV, and described in greater detail below.

Table 58 contains a summary of the factors used in the ICAP Demand Curve calculations, with an indication of data source and whether or not they are updated annually (items in BOLD are updated annually).

Table 58: Overview of ICAP Demand Curve Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	Type of Value
ICAP Demand Curve Values	
Zero-crossing point	Fixed for Quadrennial Reset Period
Reference Point Price Calculation	
Peaking Plant Net Degraded Capacity	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Summer Capability Period Dependable Maximum Net Capability (DMNC)	Fixed Value (Fixed for Quadrennial Reset Period)
Peaking Plant Winter Capability Period DMNC	Fixed Value (Fixed for Quadrennial Reset Period)
Installed Capacity Requirements (IRM/LCR)	Fixed Value (Fixed for Quadrennial Reset Period)
Monthly Available Capacity Values for Use in Calculating Seasonal Capacity Availability (SWR and WSR)	**NYISO Published Values**
Relative Seasonal Reliability Risk (SLOLE and WLOLE)	**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

The NYISO will post updated ICAP Demand Curve values on or before November 30th of the calendar year immediately preceding the beginning of the Capability Year for which the updated ICAP Demand Curves will apply.

A. Annual Updates to Gross CONE

An element of annual updates is the update of gross CONE. In each year, the gross CONE of each peaking plant 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 or storage batteries, materials and components, and other costs. The growth rate for all indices is a ratio of (1) the most recently available 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.[101]

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 same weighting factors and indices will be used over the reset period, but the values resulting from the indices will be updated annually.

The composite escalation rate (and the rate associated with the general component thereof) will be updated annually using data published by indices as of October 1st of the year prior to the start of the Capability Year to which the relevant ICAP Demand Curves will apply. For future annual updates, gross CONE values are adjusted 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). **AG currently anticipates employing the same composite escalation rate indices as the 2021-2025 DCR. This section will be updated to include the final recommended indices and components weights for each peaking plant technology option applicable for the 2025-2029 DCR.**

B. Annual Updating of Net EAS

1. Updating Approach and Timing

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, but model inputs would include the most recent three-year data available for Energy and reserve market prices, fuel prices, emission allowance prices, and Rate Schedule 1 charges. Other peaking plant costs and operational parameters (e.g., heat rate, variable O&M costs) needed

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[101] Services Tariff, Section 5.14.1.2.2.1. *See,* FERC Docket No. ER20-1049-000, *New York Independent System Operator, Inc.*, Proposed Enhancements to the ICAP Demand Curve Annual Update Procedures (February 21, 2020); and FERC Docket No. ER20-1049-000, *New York Independent System Operator, Inc.*, Letter Order (April 3, 2020).

to run the model and the LOE-AFs would not be updated for the purposes of annual recalculation of net EAS revenues.

Table 59 contains a summary of the factors used in the net EAS calculation, with an indication of data source and whether or not they are updated annually (items in **bold** are updated annually).

Table 59: Overview of Treatment of Net EAS Model Parameters for Annual Updating

(Items in **bold** print are to be updated during each Annual Update)

Factor Used in Annual Updates for Each ICAP Demand Curve	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 other ancillary services not determined by net EAS Model (*e.g.*, voltage support service)	Fixed Value (Fixed for Quadrennial Reset Period)
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 CO_2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)

CO_2 Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant NO_x Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
NO_x Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
Peaking plant SO_2 Emissions Rate	N/A for BESS; Fixed Value (Fixed for Quadrennial Reset Period)
SO_2 Emission Allowance Cost	N/A for BESS; **Subscription Service Data Source or Publicly Available Data Source**
NYISO Rate Schedule 1 Charges	**NYISO Published Values**
Transmission Service Charges for BESS Charging Withdrawals	**NYISO Published Values**

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

Updated net EAS revenues values would be combined with updated gross CONE values to establish the seasonal RPs and ICAP Demand Curve parameters for NYCA and each Locality by November 30th of the year preceding the beginning of the Capability Year to which the updated ICAP Demand Curves will apply.

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