Attachment III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER21-____-000**

AFFIDAVIT OF PAUL J. HIBBARD, DR. TODD SCHATZKI, CHARLES WU, AND CHRISTOPHER LLOP

I. Qualifications

A. Paul Hibbard

1. My name is Paul J. Hibbard. I am a Principal at Analysis Group, Inc. (AGI), an economic, finance and strategy consulting firm headquartered in Boston, Massachusetts, where I work on energy and environmental economic, policy, and strategy consulting. My business address is 111 Huntington Avenue, 14th Floor, Boston, Massachusetts 02199.

2. I have been with AGI for fourteen years since 2003. First, from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010 I served as Chairman of the Massachusetts Department of Public Utilities (DPU, or Department). While Chairman, I served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the National Association of Regulatory Utility Commissioners (NARUC) Electricity Committee and Procurement Work Group. I also served as State Manager for the New England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnection States' Planning Council.

3. I worked in energy and environmental consulting with Lexecon, Inc. from 2000 to 2003. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, State Implementation Plans and emission control programs for the electric industry, with a

focus on criteria pollutants and carbon dioxide (CO_2), as well as various policy issues related to controlling pollutants from electric power generators within the Commonwealth. From 1991 to 1998, I worked in the Electric Power Division of the DPU on the restructuring of the electric industry in Massachusetts, the setting of company rates, the quantification of environmental externalities, integrated resource planning, energy efficiency, utility compliance with state and federal emission control requirements, regional electricity market structure development, and coordination with other states on electricity and gas policy issues through the staff subcommittee of the New England Conference of Public Utility Commissioners.

4. I hold an M.S. in Energy and Resources from the University of California, Berkeley, and a B.S. in Physics from the University of Massachusetts at Amherst. My curriculum vitae is attached as Exhibit A.

B. Dr. Todd Schatzki

5. My name is Todd Schatzki. I am a Principal at AGI in its Boston office.

6. I have been with AGI since 2005. I have extensive experience in wholesale power markets in many regions of North America, including work in markets for capacity, energy and ancillary services. I have helped in the review and redesign of market rules used in organized wholesale markets, performed economic analysis of the impacts of proposed market rules, evaluated the rules and procedures for monitoring and mitigation by market monitors in organized markets, evaluated the conduct of market participants with respect to allegations of market manipulation, and assessed economic damages associated with disputes regarding wholesale power contracts. I have performed work for ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) on a variety of issues related to market design, market monitoring, and the impact of market rule changes under consideration. More broadly, my work has involved many organized wholesale markets, including Alberta Electric System Operator, California Independent System Operator Corporation (California ISO), ISO-NE, Midcontinent Independent System Operator, Inc. (MISO), NYISO, PJM Interconnection, L.L.C. (PJM) and Southwest Power Pool, Inc. (SPP). Across engagements, I have worked on behalf of system and market

operators, market monitors, and market participants. I have submitted testimony to federal, state and provincial (Canada) regulatory commissions.

7. Prior to joining AGI, I held research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis, and was an economist at both LECG, LLC, and National Economic Research Associates.

8. I hold a Ph.D. in Public Policy from Harvard University, an M.C.P. from the Massachusetts Institute of Technology in Environmental Policy, and a B.A. in Physics from Wesleyan University. My curriculum vitae is attached as Exhibit B.

C. Charles Wu

9. My name is Charles Wu. I am a Manager at AGI, also in its Boston office.

10. I have been with AGI for 6 years, since 2012. First, from January 2012 to July 2015, and most recently, from July 2017 to the present. During that period, I have worked on economic analyses of energy, electricity, and carbon allowance markets, and have designed and run models of large-scale electrical systems to simulate operations during stressed conditions. I have also provided litigation support in cases related to trade disputes, mergers and acquisitions, and statistical sampling.

11. I hold a M.B.A. from the MIT Sloan School of Management, a M.A. in Economics from Northwestern University, and an S.B. in Economics from the Massachusetts Institute of Technology. My curriculum vitae is attached as Exhibit C.

D. Chris Llop

12. My name is Christopher Llop. I am a Manager at AGI, also in its Boston office. I have been with AGI for approximately nine years, working on technology, software, and energy assignments.

13. I have extensive experience in litigation source code analysis, software development, energy market modeling, and policy and governance studies. I have supported experts in technology-related litigation, from assessments of cybersecurity issues to detailed competitor analyses of the antitrust implications of high-tech product lines. In the energy

sector, I have been responsible for capacity demand curve analytics, economic modeling of proposed electricity market rule impacts, and the analysis of industry rate structures.

14. I also have experience in studies related to artificial intelligence and algorithms, and analysis of health care claims and medical records, and am a virtual lecturer on Python Fundamentals for Data Science, a highly rated class at the University of California, Berkeley.

15. I hold an M.I.D.S. in information and data science from the University of California Berkeley School of Information, and a B.S. in electrical engineering from the State University of New York at Buffalo. My curriculum vitae is attached as Exhibit D.

II. Purpose and Summary of Affidavit

16. Section 5.14.1.2.2 of the NYISO Market Administration and Control Area Services Tariff (Services Tariff) requires that the ICAP Demand Curves be comprehensively evaluated every four years through a review of the ICAP Demand Curve parameters. An independent consultant assists with conducting the periodic reviews.[1] In order to develop recommended ICAP Demand Curve parameters, the independent consultant develops the initial assumptions and analysis, and reviews these with the NYISO and stakeholders through a stakeholder process. This process culminates in the filing with the Federal Energy Regulatory Commission (FERC or Commission) of the ICAP Demand Curves approved by the NYISO Board of Directors. This process is commonly referred to as the ICAP Demand Curve reset (DCR).

17. AGI was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2021/2022 Capability Year. AGI worked with Burns & McDonnell Engineering Company, Inc. (BMCD) to complete the tariff-required periodic review process (together, AGI and BMCD are referred to in this Affidavit as the "Independent Consultant").

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[1] Capitalized terms that are not specifically defined in this Affidavit shall have the meaning set forth in the filing letter to which this Affidavit is attached or, if not defined therein, the meaning set forth in the Services Tariff.

18. The purpose of this affidavit is twofold. First we provide a summary of the Final Report completed by AGI and BMCD for the 2021-2025 DCR,[2] including a description of the analytic framework and stakeholder process, and our recommendations on ICAP Demand Curve parameters and related issues. The Final Report is attached hereto as Exhibit E. Second, we describe our evaluation of certain key issues, all of which are described more fully in the Final Report – namely, (1) items related to *technology design* (in particular, the recommendations related to emissions controls and dual fuel capability to be used in each location evaluated as part of the DCR); (2) items related to the *net Energy and Ancillary Services (EAS) revenues model* (in particular, selection of pricing indices for natural gas for each location evaluated, and the selection of reserve offer costs for dual fuel versus gas-only units); and (3) items related to the *financial parameters* used in establishing levelized localized embedded costs for the peaking plants.

III. Overview and Summary of the Final Report

19. The creation of ICAP Demand Curves for NYCA and each Locality (*i.e.*, the G-J Locality, New York City (NYC), and Long Island (LI)) generally includes five specific tasks, our assessment of which is described in detail in the Final Report and summarized below:

- *Assessment of the peaking plant technology* – selection of the peaking plant representing the technology with the lowest fixed and highest variable costs that is economically viable, considering how the peaking plant could be practically constructed within each location, and how a potential developer would choose amongst various design capabilities and environmental control technologies when making investment decisions given applicable laws and regulations, project development and operational risk, and opportunities for revenues over the economic life of the project.[3]

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[2] Hibbard, Schatzki, Wu, Llop, Lind, McInerney, and Villarreal, *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years - Final Report*, September 9, 2020 (hereafter, the "Final Report" or "Independent Consultant Report").

[3] Services Tariff, Section 5.14.1.2.2. In 2011, FERC found that only peaking plants which "could be practically constructed should be considered" (*See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,058 at P 37 (2011)). In the DCR which resulted in the establishment of ICAP Demand Curves for the 2014/2015, 2015/2016, and 2016/2017 Capability Years (2014-2017 DCR), FERC found 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 (2014)).

- *Estimation of the gross cost of new entry* – the gross cost of new entry (CONE) is the fixed annual costs of the peaking plant, including the recovery of and return on upfront capital costs, taxes, insurance and fixed operations and maintenance (O&M), resulting in a levelized fixed charge 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* – expected EAS revenues for the peaking plants, net of operating costs, are estimated using models we constructed for this purpose (one for fossil-fueled technologies, and one for battery storage technologies). The net EAS model used for the peaking plant includes an adjustment of historic locational based marginal prices (LBMPs) and reserve prices to reflect market conditions at the Services Tariff-prescribed level of excess (LOE) conditions assumed for purposes of the DCR.[4]

- *Determination of a reference point price and ICAP Demand Curve in NYCA and each Locality* – combining gross CONE estimates and expected net EAS revenues to calculate a reference point price for each ICAP Demand Curve, and establishing the shape and slope of the ICAP Demand Curves in consideration of the zero-crossing points (ZCP) and other factors including the winter-to-summer ratio (WSR) and the LOE.[5]

As noted in the accompanying *Affidavit of Matthew E. Lind and Kieran McInerney* (BMCD Affidavit), we have applied the following criteria in this DCR to inform our decisions regarding the appropriate technology and associated plant design: (i) whether the technology is generally available to most market participants; (ii) whether the technology has sufficient operating experience to demonstrate that it is proven; (iii) whether the technology is capable of being cycled to provide peaking service; and (iv) whether the technology is capable of complying with applicable environmental requirements. These factors are consistent with the technology screening criteria used in prior DCRs.

[4] *See* Services Tariff, Section 5.14.1.2.2. The Services Tariff requires that net EAS revenues be estimated for each peaking plant under system conditions that reflect the applicable minimum Installed Capacity requirement (ICR) plus the capacity of the peaking plant, which we define as the LOE. The derivation of LOE adjustment factor values and how LBMPs and reserve prices are adjusted to reflect LOE conditions are described in detail in Section IV of the Final Report.

[5] 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 WSR is used to account for the differences in capacity available. The WSR is discussed in detail in Section V of the Final Report.

- *Annual updating* – as required by the Services Tariff, the ICAP Demand Curve parameters are to be updated annually based on escalation of installed capital costs, recalculation of net EAS revenues using updated electricity price and fuel/emission cost data, and updated WSR values.

20. The steps described above involve a complex mix of historical data, forecasts, and modeling techniques geared towards developing an accurate representation of New York's 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 alternatives based on the application of decision criteria and professional judgment.

21. The Final Report, and the analyses and conclusions contained therein, were developed by AGI and BMCD in an open and transparent process in consultation with the NYISO and stakeholders over a roughly one-year period beginning in August 2019 and ending with the issuance of the Final Report in September 2020. Throughout, we developed quantitative and qualitative analyses, proposed and finalized recommendations, and presented and discussed the analyses and recommendations with stakeholders across numerous stakeholder meetings.[6] To assist in completion of the DCR, we: (1) established guiding principles for evaluating DCR alternatives; (2) evaluated approaches taken in past DCRs, as well as capacity markets in other relevant ISO/RTO jurisdictions; (3) highlighted key issues related to technology costs, net EAS modeling, financial parameters, and ICAP Demand Curve reference point price calculations; and (4) presented analyses on and discussed potential benefits and drawbacks of each issue considered. Our final analyses and recommendations, as comprehensively documented in the Final Report, were greatly aided and improved by the full scope of comments and opinions heard throughout the stakeholder process.

22. In the end, however, the conclusions and recommendations in the Final Report represent our independent views, consistent with our assignment, the requirements of the Services

[6] *See* Independent Consultant Report at 3-4. Table 1 of the Final Report identifies the meetings held as well as the topics discussed in each meeting.

Tariff and the structures and rules of the New York markets. The process of establishing ICAP Demand Curve parameters requires analysis of a wide array of quantitative market, financial, and economic data and factors, as well as the application of reasoned judgment where the empirical evaluation is limited by sparse, uncertain, and variable historical data or forecast assumptions. The viewpoints of NYISO and stakeholders were important inputs to the analyses, but, in the end, our final recommendations reflect a combination of factors, including these viewpoints, our empirical evaluation, and our knowledge and judgment. The analyses were conducted with a set of objectives and criteria which were developed to help guide the analysis and provide a framework for the evaluation of process and analytic alternatives.

23. Specifically, we evaluated DCR-related matters applying, where relevant, the following objectives and criteria:

- *Economic Principles* – proposed 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 net cost of new entry in New York with as much certainty as 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.
- *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 (with particular focus on the capacity markets administered by the NYISO, ISO-NE, and PJM). Consistency between DCRs also promotes market stability, which in turn reduces financial risk to developers.

24. We applied the methods, models and equations summarized herein and described in detail in the Final Report to identify recommended reference point prices and other ICAP Demand Curve parameters for the 2021/2022 Capability Year, as well as the methodologies and inputs to be used in the annual updates to determine the ICAP Demand Curves for the 2022/2023 through 2024/2025 Capability Years. This information is presented in the Final Report.[7]

25. Our recommendations and results reflect a number of conclusions on key market and technology issues that we comprehensively evaluated throughout the DCR including:

- The GE 7HA.02 (H-class frame turbine) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a dual fuel H-class frame machine would be built with selective catalytic reduction (SCR) emissions control technology in Load Zone J, Load Zone K, Load Zone G (Rockland County), and Load Zone G (Dutchess County), and a gas only H-class frame machine would be constructed without SCR emissions control technology in Load Zone C and Load Zone F.

- Based on market expectations for fuel availability and fuel assurance, changes in market structures, consideration of applicable reliability and Local Distribution Company (LDC) tariff requirements, and developer expectations, the H-class frame machine should include dual fuel capability in Load Zone G (Rockland County), Load Zone G (Dutchess County), Load Zone J, and Load Zone K. AGI and BMCD recommend a gas-only (without dual fuel capability) design in Load Zone C and Load Zone F.

- The state of New York has begun a process to decarbonize the power sector over the next couple decades, including passage of the Climate Leadership and Community Protection Act (CLCPA).[8] This does not eliminate consideration of a

[7] Independent Consultant Report, p. 9 and Section VI.

[8] New York State, Chapter 106 of the Law of 2019. Requirements established by the CLCPA include: (1) a goal to reduce economy wide 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-

fossil-fueled plant as the potential peaking plant technology. It does, however, suggest review of the ways in which these efforts affect the development and operation of such facilities, which could in turn affect the present-day financial analysis parameters (*e.g.*, the appropriate amortization). For this DCR, we recommend a 17-year amortization period for fossil-fueled plants in consideration of the CLCPA's restrictions on fossil fuel operations for electric generation past 2039 and the current status of regulations and program rules to define how New York will meet the emission requirements in the CLCPA.

- Based on our review, battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time. We come to this conclusion based primarily on our estimates of the net CONE for the battery storage options evaluated in this DCR and the availability of lower cost viable technology options.

- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 13.0% return on equity, for a WACC of 9.54%. Based on current tax rates in New York State and New York City, this translates to a nominal after tax WACC (ATWACC) of 8.52% and 8.20%, respectively.

- Net EAS revenues are estimated for the peaking plants using gas hubs that reflect consideration of a number of factors, including consistency of gas prices with LBMPs within each Load Zone, liquidity of trading, geographic consistency with the locations evaluated, and precedence of use in other studies/analyses. To that end, net EAS revenues are estimated using the following gas hubs, which remain fixed for the four year duration of the reset period:

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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.

- Load Zone C: TGP Zone 4 (200L)[9]
- Load Zone F: Iroquois Zone 2
- Load Zone G (Dutchess County): Iroquois Zone 2
- Load Zone G (Rockland County): TETCO M3
- Load Zone J: Transco Zone 6 New York
- Load Zone K: Iroquois Zone 2

- 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.

- For the NYCA ICAP Demand Curve and the G-J Locality ICAP Demand Curve where more than one potential peaking plant location was evaluated, the location resulting in the lowest reference point price for the 2021/2022 Capability Year ICAP Demand Curve should serve as the basis for each ICAP Demand Curve and remain fixed for the four year duration of the reset period. Based on our recommendations, Load Zone C should serve as the basis for the NYCA ICAP Demand Curve and Load Zone G (Rockland County) should be selected as the basis for the G-J Locality ICAP Demand Curve.

26. The Final Report contains an organized and detailed presentation on these and other issues and conclusions. Section II of the Final Report contains our assessment of the peaking plant technology options and costs. Section III of the Final Report contains our estimation of gross CONE. Section IV of the Final Report contains our method for estimating the net EAS revenues of the peaking plants. Section V of the Final Report contains our method for determining the ICAP Demand Curve parameters, including reference point prices. Finally, Section VI of the Final Report describes the process by which ICAP Demand Curve parameters will be updated annually for the subsequent three Capability Years covered by this reset period (*i.e.*, the 2022/2023 through 2024/2025 Capability Years).

[9] AGI acknowledges that the NYISO proposes to adopt the recommendation of the Market Monitoring Unit (MMU) that was provided after we finalized our recommendation for Load Zone C. Based on additional analysis completed by the MMU subsequent to finalizing our recommendations, the NYISO proposes to use the TGP Zone 4 (200L) hub for non-winter months (April-November) and the Niagara hub for the winter period (December-March).

27. In the remainder of this affidavit, we provide further explanation of our review and conclusions on certain key items. Specifically, in Section IV, we discuss issues related to technology and capital costs. In Section V, we discuss the method for and issues related to calculation of net EAS revenues. Finally, in Section VI, we discuss items related to the financial parameters used in establishing levelized localized embedded costs for the peaking plants.

IV. Technology Costs

28. The Services Tariff specifies that the DCR shall assess "…the current localized levelized embedded cost of a peaking plant in each NYCA Locality, [and] the Rest of State …." In the Final Report, we evaluate a number of factors that go into the calculation of gross CONE for each peaking plant. The accompanying BMCD Affidavit discusses a number of the technology and cost factors related to the identified peaking plants, including their assessment related to the need and costs of SCR emissions control technology. In this section, we supplement BMCD's discussion with an explanation of our findings with respect to emissions controls and dual fuel capability (*i.e.*, whether or not SCR emissions control technology and/or dual-fuel capability should be included in the peaking plant design for each location evaluated during the DCR).

29. While our study reflects generic sites within each Load Zone, we did develop separate estimates for both Rockland County (west of the Hudson River) and Dutchess County (east of the Hudson River) for Load Zone G. This is consistent with the last reset that addressed the ICAP Demand Curves for the 2017/2018 through 2020/2021 Capability Years (the 2017-2021 DCR), and the use of these two locations provides for a consideration of differences in environmental requirements that apply throughout the lower Hudson Valley (*i.e.*, Load Zones G, H, and I).

30. In this DCR we expanded the set of technologies evaluated to include battery storage technology. Specifically, we identified battery energy storage systems (BESS) based on lithium-ion battery technology as the most likely candidates for new energy storage plants at this time, and specifically evaluated the following systems for comparison to traditional simple cycle gas turbine technologies:

- 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

31. We conclude that battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time, based upon our estimates of net CONE for these battery storage facilities, in comparison to alternative, lower cost viable technology options.

A. Dual Fuel Capability

32. The recommended technology choice requires determining for each location whether the peaking plant should be a natural gas-only resource or have the capability to operate on both natural gas and oil (dual fuel). For the 2017-2021 DCR, FERC approved peaking plants with dual fuel capability for the G-J Locality, NYC, and LI ICAP Demand Curves, and a gas-only peaking plant design for the NYCA ICAP Demand Curve.[10] FERC recognized that dual fuel capability is mandatory in NYC and LI.[11] With respect to dual fuel capability in Load Zone G, FERC agreed that "dual fuel capability comes with increased revenue potential, siting benefits, and reliability benefits, plus it can serve as a hedge to mitigate electricity price spikes during times of high natural gas prices."[12] FERC also agreed that "the G-J Locality is a relatively geographically constrained region; therefore, the inclusion of dual fuel capability is important for providing increased siting flexibility," and that "current concerns regarding the ability to expand natural gas pipeline infrastructure and capacity in New York underscore the reliability benefits gained from dual fuel capability in the G-J Locality."[13] FERC's acceptance of dual fuel capability for NYC, LI, and the G-J Locality as part of the 2014-2017 DCR was based on similar reasons.[14]

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[10] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028 at ¶ 91-96 (2017) (2017-2021 DCR Order).

[11] 2017-2021 DCR Order at ¶ 91.

[12] *Id*.

[13] *Id*.

[14] *See, e.g.*, 2017-2021 DCR Order at ¶ 92-93.

33. In accepting a gas-only design for the NYCA ICAP Demand Curve as part of the 2017-2021 DCR, FERC noted that Load Zones C and F are "far less geographically constrained than the G-J Locality" and that "natural gas supply conditions in load zones C and F are more favorable than in the G-J Locality because this region is generally located upstream of interstate natural gas pipeline constraints and has connections to natural gas supplies from the nearby shale gas producing regions."[15]

34. In this DCR, we again evaluated whether to recommend including dual fuel capability in all locations. In the case of NYC and LI, dual fuel capability remains mandatory due to existing local electric reliability rules and LDC tariff requirements. For all other locations where dual fuel capability is not mandatory, we evaluated potential recommendations through a review of relevant data and considerations tied to what developers are most likely to include in development projects, in consideration of costs, potential revenues, technology optionality, and development and operational risks.

35. Based on our evaluation, AGI recommends that the peaking plant design should continue to include dual fuel capability in Load Zones G, J, and K. Consistent with the current design for the NYCA ICAP Demand Curve, AGI recommends continued use of a gas-only design for Load Zones C and F. 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 that the answer to this question is yes in Load Zones G, J, and K, and no in Load Zones C and F:

- There are local electric reliability rules applicable to NYC and LI that require dual fuel capability. Additionally, nearly all gas fired generation in Load Zones J and K is connected to the LDC gas system, and LDC gas tariffs require dual fuel capability for generators. LDC gas tariff requirements for dual fuel capability also exist in locations outside NYC and LI. Such LDC requirements are in place for

[15] 2017-2021 DCR Order at ¶ 95.

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 or become uneconomic (such as during certain winter periods when gas supplies may be scarce due to higher demand for all end uses). Moreover, the value of dual fuel optionality may be greater under the LOE conditions prescribed by the tariff for use during the DCR, particularly to the extent that such conditions arise due to shifts in generation resources that increase reliance on gas-fired resources. These factors are particularly true in Load Zones G, J, and K, where there are potentially more meaningful constraints on natural gas availability in winter months than in the rest of the state.

- Potential peaking plant developers would also consider various risks and benefits associated with project development and siting. Specifically, on the one hand adding dual fuel capability would expand the geographical flexibility for power plant siting, by supporting the siting of plants on (and obtaining gas supply from) the distribution systems of LDCs. Expanding such geographic flexibility increases the potential of finding sites that coincidentally minimize the costs to obtain both natural gas and electrical interconnections. On the other hand, the addition of oil-fired capability can complicate the process of successfully siting and permitting the facility.

- Finally, in the downstate regions a developer would likely view the addition of dual fuel capability favorably in light of New York State’s reliance on natural gas for power generation which is expected to continue in the coming years, as well as in recognition of constraints on the use of natural gas that arise, particularly during winter months.

B. SCR Emissions Control Technology

36. The accompanying BMCD Affidavit discusses a number of the technology and cost factors related to the peaking plants evaluated in this DCR, including their assessment related to the need and costs of SCR emissions control technology. In this section, we supplement BMCD's discussion of whether a developer would likely include SCR emissions control technology.

37. We conclude that to be economically viable and practically constructible, the peaking plant technology would be built with SCR emission control technology in Load Zone J, Load Zone K, Load Zone G (Rockland County), and Load Zone G (Dutchess County), and would be constructed without SCR emissions control technology in Load Zone C and Load Zone F.

38. Our recommendation regarding the installation of SCR emissions control technology balances several factors a developer would consider, including applicable environmental requirements, the economics of installing and operating with SCR emissions control technology, and risks associated with the permitting and siting process in New York State.

39. Including SCR emissions controls on a simple cycle plant increases costs, but it also can serve to mitigate certain siting, permitting, and future market risks which are considered by power plant project developers. In addition to the specific environmental requirements discussed in the accompanying BMCD Affidavit, 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 the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[16]

[16] 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…"

40. Considering the balance of risks and costs a developer would face in each location, AGI and BMCD conclude that the developer of a new plant in Load Zones C and F would not seek to include SCR emissions control technology for a gas only plant at the time of construction due to economic considerations. Instead, for these locations, it is assumed that the developer of a gas-only peaking plant would accept and adhere to the applicable annual emissions limit necessary to become a synthetic minor source.[17] As further described in the accompanying BMCD Affidavit, this approach would permit a gas-only H-class frame turbine to operate for approximately 1,060 hours annually in Load Zones C and F.

41. For Load Zone G (Dutchess County), which is subject to the less restrictive environmental requirements that also apply for Load Zones C and F, AGI and BMCD determined that the balance of considerations supported the inclusion of SCR emissions control technology during construction for a dual fuel plant design. Based on prices from a three-year historical period (2016/2017 to 2018/2019), the GE 7HA.02 unit without SCR emissions control technology could emit less than its annual NO_x emissions limit by implementing an emissions limit that curtailed relatively few hours of operation. However, we assume that a developer would choose to build a dual fuel unit with SCR emissions controls, reflecting several considerations. First, in terms of historical precedent, past DCRs have not included a recommendation for a peaking unit with dual fuel capability without also recommending inclusion of SCR emissions controls. This primarily reflects the potential restriction to annual operating hours that arises from operation on oil. As further described in the accompanying BMCD Affidavit, application of an emissions limit to a dual fuel plant could significantly reduce the allowable hours of operation for a GE 7HA.02 plant. At the extreme, this limitation would restrict operation to as few as 312 hours in Load Zone G (Dutchess County), if the unit were to operate only on oil. Second, SCR emissions control technology provides optionality to operate above the synthetic minor operating limit, which could be financially valuable in the future. Our three-year analysis does not fully capture the value of this optionality. Future net EAS revenues may be greater than net revenues in

[17] As described in Section IV.B.2.a of the Independent Consultant Report, the emissions 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. Units without SCR emissions controls in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions.

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 New York State Department of Environmental Conservation's recently implemented "peaker rule."[18] Third, the installation of SCR emissions control technology could mitigate potential permitting and siting risk associated with building a new dual fuel unit in the lower Hudson Valley without back-end emissions control technology. Within this context, a potentially relevant consideration is that the lower Hudson Valley also contains severe non-attainment areas and that selecting a plant without SCR emissions controls would not accommodate potential new plants throughout the region.

V. Net EAS Revenues Model

42. Net EAS revenues are estimated based on the simulated dispatch of each peaking plant using a rolling 3-year historical sample of LBMPs and reserve prices (both adjusted for LOE conditions), the applicable fuel and emission allowance prices, and data on the non-fuel variable costs and operational characteristics of the peaking plant technology. Our 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 ICAP Demand Curve parameters evolve (with a lag) consistent with actual EAS market outcomes (as adjusted for LOE conditions).

43. To model the different market behavior and input costs of fossil fuel peaking plants and battery storage plants, we created separate models for each. Throughout the stakeholder process, we solicited feedback on the model logic used to estimate net EAS revenues and the choice of gas hubs used to price fuel inputs in the fossil model. In this section, we first discuss the net EAS revenues model logic for fossil fuel peaking plants. We then discuss the net EAS revenues model logic for battery storage plants. Finally, we discuss our choice and selection of the relevant natural gas hubs for the fossil model.

[18] 6 NYCRR Subpart 227-3.

1. Net EAS Revenues Fossil Model Logic

44. Our simulated net EAS revenues fossil model estimates the net EAS revenues earned by a peaking plant on an hourly basis assuming dispatch of the plant and the variable operating cost of producing energy or providing reserves. In the model, the peaking plant can earn revenues through supplying in one of four markets: (1) Day-Ahead Market (DAM) commitment for energy, (2) DAM commitment for reserves, (3) Real-Time Market (RTM) dispatch for energy, or (4) RTM supply of reserves. Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual fuel 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.

45. In addition, a unit maintains the ability to buy out of either DAM energy or reserves commitments, based on real-time prices and whether or not a change in operating status is sufficiently profitable, after accounting for real-time fuel costs. Real-time fuel costs reflect a premium for purchases and discount for sales relative to day-ahead gas prices, which vary by Load Zone. 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. This additional cost is incorporated into RTM buy out decisions for all units.

46. Similarly, when evaluating a reserves commitment in either the DAM or RTM, the model assumes that each peaking plant bids into non-spinning reserve markets at an assumed cost for taking a 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 (*i.e.*, ULSD), 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.[19] 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, that is, 10% of the natural gas fuel cost for that day.

47. If the generator 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 when buying or discount when selling natural gas. Dual fuel units do not face a cost to provide reserves when ULSD costs are lower than natural gas costs.

48. The net EAS revenues model uses historical LBMPs, which reflect actual system conditions, including levels of historical surplus capacity. To address the Services Tariff requirement that reference point prices reflect system conditions at the prescribed LOE conditions, and consistent with the 2017-2021 DCR, we developed 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. Specifically, we developed adjustment factors for each month and capacity zone, with unique factors for on-peak hours, high on-peak hours (defined as a subset of on-peak hours, for both summer and winter periods), and off-peak hours.

49. We developed these LOE-AFs by comparing forecasted hourly energy prices at current (or "as found") conditions and at the tariff-prescribed LOE conditions. Hourly prices for each of these two modeling cases were developed using the NYISO 2019 Congestion Assessment Resource Integration Study (CARIS) Phase 1 base case dataset. The tariff-prescribed LOE conditions were estimated by adjusting system loads in each Load Zone so that the resulting ratio of peak load to available resources equaled the reserve margin consistent with the required LOE conditions. LOE-AF values were developed as the ratio of average LBMPs in the base case (*i.e.*, "as found" system conditions) to average LBMPs in the LOE conditions case for each Load Zone. LBMPs were first averaged within each

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[19] 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," August 5, 2020, pp. 7-10, available at: https://www.nyiso.com/documents/20142/13609298/MMU-2020-DCR-Draft-Report-Comments.pdf.

month and period across all of the modeled years 2021 to 2025. The resulting average LOE-AF values across all months and periods ranged from 1.02 in Load Zone F and J to 1.06 in Load Zone C. Pursuant to the Services Tariff, the set of LOE-AF values, calculated at the time of the DCR, will remain set for the duration of the reset period, and will be applied to historical LBMPs and reserve prices used in each subsequent Capability Year's net EAS revenues calculation as part of the annual updates during the reset period.

50. Finally, hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, with the applicable and relevant amortization schedule for each unit based on its startup time and consideration of whether the unit is committed/dispatched in the DAM or RTM. Dual fuel capability (if applicable) is accounted for through the option to generate on natural gas or ULSD based on a comparison of fuel prices. Total annual net EAS revenues are the sum of all hourly revenues, derated by the peaking plant's technology-specific Equivalent Demand Forced Outage Rate (EFORd). Environmental operating limits are modeled 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 applicable maximum for each peaking plant. For Load Zones C and F where the recommended peaking plant design is a gas-only plant without SCR emissions control technology, the applicable NO_x maximum emissions is set at the 100 tons/year limit that would apply to a synthetic minor source in these locations. Finally, total net EAS revenues include an incremental adder of $2.04/kW-year for combustion turbines, which is based on historical data provided by NYISO and included to account for voltage support service (VSS) revenues that are not accounted for in the model.

51. The net EAS revenues model used in the 2017-2021 DCR included logic for the timing of natural gas prices that was based on an understanding that the gas prices published by the data vendor (S&P Global Market Intelligence (S&P)) represented the "trade day" price (or the day before the generator would take delivery of and use the gas to produce electricity). AGI has confirmed with S&P that the published data represents the "flow day" price (or the day the generator would take delivery of and use the gas to produce electricity). The

timing of the natural gas prices used in the net EAS revenues fossil model logic for the 2021-2025 DCR was modified accordingly.

52. The net EAS revenues fossil model logic is designed to provide an appropriate balance with respect to our evaluation criteria, and in particular, to provide an accurate and transparent model, which can reasonably and feasibly be updated by any interested stakeholders on an annual basis. In practice, however, an individual unit's historical and actual net EAS revenues may differ from the modeled revenues of the hypothetical peaking plants considered in the DCR. Actual revenues could be higher or lower than modeled revenues for various reasons related to unit-specific cost, operational, and fuel portfolio management factors that vary from those assumed for the hypothetical peaking plants.

2. Net EAS Revenues Battery Model Logic

53. Like the fossil model, AGI developed a model that estimates net EAS revenues for battery storage plants evaluated as part of this DCR based on a simulated dispatch of the plants in the NYISO energy and ancillary services markets. Like the fossil plant, net EAS revenues are earned by the battery on an hourly basis in the RTM and DAM energy and reserve markets. The model's logic 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.

54. Within the model, the battery's operations, including its supply and purchases of energy, are constrained by the battery's physical storage and charge/discharge capabilities. These physical realities include energy losses in round-trip charge/discharge of the battery, the need for balancing between energy inflows and outflows while maintaining stored energy amounts ranging between zero and the battery's maximum storage capacity, charge/discharge sequencing that is feasible given storage limits and flow capabilities, and certain limits to operations to avoid excessive battery wear-and-tear.

55. Battery storage dispatch is split into three steps: (1) daily DAM commitments, (2) multi-day DAM revisions (to maximize revenues from days where the battery is idle and does not charge or discharge), and (3) daily RTM dispatch (to capture profitable opportunities for

charging and discharging given DAM commitments). Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for LBMP uncertainty in the real-time market.

56. Along with consuming and supplying energy, the model assumes that the battery can also supply reserves. The supply of energy and reserves (and consumption of energy) is consistent with NYISO market rules for battery resources, allowing the battery reserve supply amounts to reflect its capacity, stored energy and day-ahead commitments to consume energy, which can be foregone physically.[20]

57. As with the fossil model, the battery model uses historical LBMPs and reserve prices, as modified using the LOE-AFs to approximate prices under the tariff-prescribed LOE conditions. The model calculates the annual average net EAS revenues as the simple average of all energy and reserves revenues over the three-year period, derated by the plant's assumed unavailability factor of 3 percent. Total net EAS revenues include an incremental VSS adder of $2.04/kW-year.

58. The net EAS revenues battery model logic is designed to provide an appropriate balance with respect to our evaluation criteria, and in particular, to provide an accurate and transparent model to stakeholders.

3. Net EAS Revenues Model Natural Gas Pricing Locations

59. A key consideration with respect to the net EAS revenues model for the fossil peaking plants is the choice of natural gas pricing points (gas hubs) for each location. Despite the existence of numerous pricing hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a peaking plant in a given Load Zone. Individual gas indices reflect a number of factors, including existing and future contracts from LDCs and merchant generators, wholesale gas market conditions, and expectations about potential supply expansions (or lack thereof). Therefore, we developed

[20] The model assumes the battery can supply 10-minute spinning reserves when it has no DAM or RTM energy discharge position but has at least one hour capability of stored energy or is charging. The battery can supply reserves up to the lesser of its full capacity or the amount of stored energy. When the battery is charging, the model assumes 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.

our recommendations for the appropriate gas hub pricing points for each location based on a consideration of multiple factors, including market dynamics, gas hub liquidity, geography, and precedent and continuity for the use of similar hubs in other NYISO studies and assessments, including assessments by the MMU.

60. One factor in our identification of an appropriate gas hub was the historical relationship between gas prices and LBMPs. In some cases, it is apparent from comparison of gas hub prices and zonal LBMPs that during certain periods (particularly winter months) zonal LBMPs do not reflect marginal supply from facilities relying on fuel prices at certain gas price indices nearby to that Load Zone. To the extent that a peaking plant could receive delivery of gas at these prices during these period, these price differentials suggest a potentially profitable opportunity for arbitrage between natural gas and electricity markets. However, these arbitrage opportunities may not necessarily reflect a long-run equilibrium given the potential that increasing demands over time on these gas delivery lines and other factors that may bring these markets into equilibrium. In addition, because gas hubs capture pricing over broad geographic areas, a hub may not capture variation in pricing within these zones, particularly in more constrained areas.

61. For Load Zone J, AGI recommends the use of Transco Zone 6 NY as the natural gas hub. Transco Zone 6 NY represents a highly liquid trading hub with immediate proximity to this zone and with pricing consistent with a reasonable expectation of the long-run equilibrium between gas and electricity markets.

62. For Load Zone F, Load Zone G (Dutchess County), and Load Zone K, AGI recommends the use of Iroquois Zone 2 as the natural gas hub. These recommendations reflect a balance of considerations, particularly market dynamics and geography. For Load Zone K in particular, Iroquois Zone 2 provides a better proxy for gas prices during constrained conditions than other alternatives considered. This suggestion is consistent with the use of the Iroquois Zone 2 hub for these locations in other assessments including the MMU's State of the Market Report.

63. For Load Zone G (Rockland County), AGI recommends the use of TETCO M3 as the natural gas hub. Certain hubs with geographic proximity did not provide a reasonable

expectation of the long-run expectations between gas and electricity markets or exhibited other concerns such as liquidity. In particular, the Millennium pipeline crosses the zone through Rockland County, but it may not have the required flexibility of supply for a peaking generator 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, TETCO M3 is a liquid trading hub which reasonably reflects the fuel cost of a generator such as the peaking plant that is expected to operate intermittently throughout the year. While TETCO M3 delivery points are outside Rockland County, TETCO M3 delivers to points proximate to Rockland County and the transportation costs assumed in the model provide a reasonable proxy for the incremental costs needed to obtain fuel in Rockland County relative to points in Northeast New Jersey.

64. In Load Zone C, a number of pipelines, including those owned by Tennessee Gas Pipeline (TGP), Dominion, and Millennium, cross the zone. The MMU conducted analyses which found that historical energy price patterns best matched simulated operations of gas-fired generators in Load Zone C based on the use of the TGP Zone 4 (200L) gas hub as the assumed gas cost for such generators.[21] Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, we recommend the use of TGP Zone 4 (200L) as the natural gas index for Load Zone C. We recognize that the NYISO proposes a slightly different assumption for Load Zone C in response to certain availability considerations identified by the MMU related to the use of TGP Zone 4 (200L) during winter months. Based on the MMU's additional analysis, the NYISO proposes to use the TGP Zone 4 (200L) hub during most of the year (April-November) and the Niagara hub during the winter period (December-March) when the availability considerations identified by the MMU are most likely to arise.

VI. Financial Parameters

65. The development of a new generation facility requires the upfront capital investment costs for the construction of the facility. We developed financial parameters to translate these

[21] Potomac Economics, "Memorandum re: MMU Comments on Independent Consultant Interim Final Draft ICAP Demand Curve Reset Report and NYISO Staff DCR Draft Recommendations," August 24, 2020, available at https://www.nyiso.com/documents/20142/14871137/MMU-2020-DCR-Draft-Report-Comments-08-24-2020.pdf

upfront technology and development costs into an annualized value that is an element of gross CONE for each Load Zone. The parameters used in this translation include:

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

66. We developed the parameters to reflect the particular financial risks faced by the developer given the nature of the project, its technology, and the New York electricity market context. They were chosen in an integrated fashion to properly account for the interrelationships among the financial parameters. Many factors can affect the risks to development of a new peaking plant, including: uncertainty and variability in fuel prices and demand for capacity and energy; changes in market infrastructure (generation and transmission) over time; energy and environmental policies with implications for industry demand, resource mix and infrastructure, costs, and revenues; and the pace and nature of technological change. Our selections reflect available data on individual components of the WACC and the AP, recognizing that the values for these components vary with features 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.

67. Ultimately, the recommended WACC and 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. Our recommendations are based on our professional judgment, reflecting the particular circumstances of merchant development of a peaking plant in the NYISO market context; the many sources of information identified and described below; professional experience, including conversations with developers and the finance community; and our view of current industry conditions and market factors, including past experience with merchant generation development in wholesale markets.

1. Amortization Period

68. The AP is the term over which the project developer expects to recover upfront capital costs, including the return on investment. This period is the project's "economic life," which can differ from the potential physical life of the unit, due to financial considerations, particularly risks associated with assuming revenue streams far into the future. The AP reflects a balance of factors. On the one hand, plant owners will earn net revenues over the full physical life of the unit, which is reasonably estimated as approximately thirty years for a peaking plant absent factors that may otherwise restrict operation for this full physical life. On the other hand, many factors create risks to future cash flows, including changes in markets, technologies, regulations, policies, and underlying demand from consumers. To account for these risks, investors typically assume an economic life less than the plant's physical life. Notably, units may require significant capital expenditures to retrofit or upgrade the unit to maintain its ability to operate efficiently or in compliance with applicable laws and regulations. Consistent with our assumption for a shorter economic life than physical life, our analysis does not consider these incremental investments in the discounted cash flow analysis.

69. Given these factors, we recommend an AP of 17 years for all gas-fired technologies and Load Zones. This value is less than the 20 year AP used for the last DCR. This value accounted for a balance of considerations between a shorter and longer period. A primary consideration of the change in recommended AP is the enactment of the CLCPA, which requires all electricity be supplied by zero-emission resources beginning in 2040. This legislation imposes the substantial risk that the recommended peaking plant may be unable to supply energy starting in 2040. If a peaking plant is unable to supply energy in 2040, its economic life would range from 15.2 to 19.2 years depending on when during the upcoming 4-year period covered by this DCR the plant is constructed. An AP of 17 years reasonably accounts for this range of expected economic lifetimes. Our recommended AP also avoids speculative assumptions regarding: (1) future regulations and programs rules to be developed in the coming years to define how New York will meet the emission requirements in the CLCPA; and (2) the emergence of commercially available technologies that may allow the plant to continue operations beyond 2040 in compliance with the CLCPA. While this may be possible, it is far too early to assume that is the case and, in

any event, such technologies may require incremental one-time capital costs (or higher fuel and operations costs) that are not otherwise accounted for in our plant cost estimates or estimated net EAS revenues.

2. Weighted Average Cost of Capital

70. The WACC for use in the DCR reflects the project-specific risks associated with the development of a new peaking plant by a merchant developer within New York. The WACC, reflecting both the "cost" of different sources of capital – that is, the required return on equity and the cost of debt – and the proportion of each type of capital in the project's capital structure, are developed in tandem because of the interrelationship between these elements.

71. We developed our recommended cost of capital based on data from a number of different sources, including: (i) financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets, including cost of debt, return on equity and debt-to-equity ratios; and (ii) independent assessments developed by financial analysts, including so-called "fairness opinions" and assessments of the costs of merchant power plant development, including assessments of plants financed through a so-called "project finance" approach. Our recommendations also reflect: (i) the information and data identified below; (ii) our professional experience, including conversations with developers and other professionals in the finance community; and (iii) an appropriate balancing of these various sources of information and experiences considering the market risks that would be faced by a new merchant peaking plant being developed within New York and operating in the NYISO markets.

72. When developing our recommended financial parameters, we assume the peaking plant is likely to be developed through a project financing approach. Given this assumption, we view the appropriate WACC for the peaking plant as bounded from below by the company-wide WACCs typical of established independent power producers (IPPs). Project-specific risk is greater than the risks associated with the company or investors that are considering the development of that project because these companies tend to have portfolios of assets that balance and mitigate risks. 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.

73. Below, we describe information used in developing the individual financial parameters that bear on the recommended WACC, recognizing the interrelationships among these parameters in determining the WACC.

a) Cost of Debt

74. The cost of debt reflects a project developer's ability to raise funds on debt markets. Our recommended cost of debt reflects both the risks particular to peaking plant development and conditions in debt markets. Evaluation of debt market conditions is complicated by the COVID-19 pandemic, which caused substantial disruption to debt markets starting in the second quarter of 2020.

75. We assume credit quality for the project comparable to that of a B rated firm, given the non-recourse nature of the project financing, the absence of an explicit cost assumption for the potential need to execute a financial hedge to secure debt financing, and underlying creditworthiness of the corporate entities developing these types of projects (notably, publicly-traded IPPs generally have below-investment grade credit ratings). The generic debt costs for B rated firms has declined from highs of 12.4 percent in March 2020 to 6.6 percent in July 2020, at the time we made final recommendations for this DCR. At the time of finalizing our recommendations, we anticipated possible further declines as the financial markets continue to adjust to the COVID-19 pandemic. In fact, the cost of B-rated debt was 5.7 percent as of the end of October 2020.[22] Our research also found that debt costs for relevant publicly-traded IPPs since 2017 have ranged from approximately 4 percent to 8 percent. Based on these factors, we recommend a COD of 6.7 percent. This recommendation reflects multiple considerations, including past debt costs for IPPs and generic B-rated corporate debt, the observation that IPP debt costs often somewhat exceed contemporaneous cost of debt indices, the non-recourse nature of project finance debt, and

[22] Average of B-rated bond yield over all trading days in October 2020. St. Louis Federal Reserve Bank of St. Louis, FRED, ICE BofA Single-B US High Yield Effective Yield Index (BAMLH0A2HYBEY)

the absence of an explicit costing of a potential financial hedge that may be needed to secure debt financing of a peaking plant in New York.

b) Return on Equity

76. Our recommended ROE is developed using data from several sources, including estimates for the return on equity for publicly traded IPPs and other independent studies. Our analysis of the return on equity for two IPP companies based on the capital asset pricing model (CAPM) found ROEs ranging from 6.6 to 10.5 percent. However, as these companies hold many less-risky assets, such as regulated utilities and generation assets with multi-year purchase power agreements, these ROE values understate the ROE appropriate for a peaking plant. An independent study by the US Environmental Protection Agency (EPA) assumed a return on equity for new combustion turbines developed by IPPs of 12 percent, while industry sources report project finance return on equity values that range from approximately 13% to 20%, although public reporting of such values is limited.[23]

77. Based on this information, we recommend a ROE of 13.0 percent. This reflects a balance between the lower IPP values (which range up to 10.5 percent) and higher project finance values (some of which may not solely reflect the non-diversifiable component of risk that is the appropriate basis for determining return on equity).

c) Debt to Equity Ratio

78. 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 could reasonably be developed through a range of capital structures. We

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[23] EPA, Integrated Planning Model v6, November 2018 Reference Case, Documentation for Chapter 10: Financial Assumptions, p. 10-7, , which reports a 12.16% ROE at a 55% target debt ratio and 3.45% risk free rate for merchant projects; Chadbourne, "Merchant Gas Projects: How Many More?" Project Finance NewsWire, August 2016, p. 40. *See also* DOE National Energy Technology Laboratory (NETL) (2011), which indicates that a 15 to 20 percent ROE is common for low and high risk power projects at debt ratios of 50 to 70 percent (DOE-NETL, "Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects", September 2008).

recommend a D/E ratio of 55 percent debt to 45 percent equity given a balance of tradeoffs involved with greater or lesser leverage. This ratio is in line with the capital structure of IPP companies (at the corporate, not the project level), although we recognize that current *corporate* level capital structure may not fully reflect *project-level* capital structure for a new development going forward.[24] While some independent sources report comparable capital structures for merchant generation developments and combustion turbine projects similar to the peaking plant (*e.g.*, EPA assumes a D/E ratio of 55/45 for merchant projects) other report lower levels of debt (*e.g.*, NETL assumes 30 to 40 percent debt levels for IPP combustion turbines, although at a point in history in which the market-wide cost of debt was higher than currently observed debt costs, particularly relative to the return on equity).[25] Thus, given this balance of considerations, our selection of a 55/45 D/E equity ratio appears reasonable.

d) WACC

79. Our assessment of factors related to the calculation of the WACC has considered: (i) the data on return on equity, cost of debt and debt-to-equity ratio described above; (ii) facts and circumstances unique to New York and the NYISO markets, including the extent of past experience with merchant development; (iii) the rapidly changing nature of federal and state energy and environmental policies; and (iv) likely project/ownership structures for new peaking plant development in New York.

80. The resulting WACC consistent with the recommended values for return on equity, cost of debt and debt-to-equity ratio is 9.54 percent.

81. The calculation of an after-tax WACC reflects common tax treatments and appropriate tax rates for applicable taxes, including Federal income taxes (assumed to be 21 percent),

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[24] Note that a desire by these companies to deleverage (*i.e.*, lower debt share), which has been expressed by the companies themselves and analysts, may place pressure to lower the debt levels of individual projects. *See*, e.g., UBS Financial ("We believe all IPPs will accelerate their debt paydown efforts…") (How to Value Power? December 8, 2015.)

[25] CEC 2010 Study, p. 59, Table 18; NETL 2010 Study, p III-18, Exhibit 3-2.

corporate New York State taxes (6.5 percent),[26] and the New York City business corporation taxes (8.85 percent).[27] These result in composite income tax rates of 36.35 percent for NYC and 27.5 percent for all other locations. Using these values, the nominal ATWACC is 8.52 percent in Load Zones C, F, G, and K and 8.2 percent in NYC.

82. The recommended ATWACC is slightly higher than currently approved capital cost values in other neighboring markets (*e.g.*, ISO-NE and PJM) for similar capacity market cost evaluations. The current ATWACC in ISO-NE and PJM is 8.1 percent and 7.5 percent, respectively. The ATWACC recommended for this DCR is slightly higher than values adopted in other neighboring markets reflecting, among other things, that developers within New York may face greater project-specific risk that arise from the lack of long-term contracts (as compared to ISO-NE) and less experience with merchant development (as compared to PJM). Relative to the last reset (*i.e.*, the 2017-2021 DCR), the ATWACC is slightly lower due to, among other things, more favorable debt markets that lowers both the cost of debt and the return on equity for the merchant peaking plant.

VII. Conclusion

83. AGI was hired as the independent consultant for review of the ICAP Demand Curves to be used starting in the 2021/2022 Capability Year. AGI worked with BMCD to complete the tariff-required periodic review.

84. Our final analyses and recommendations are presented in Sections IV, V, and VI above, and comprehensively documented in the Final Report.

85. This concludes our affidavit.

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[26] *See* New York Department of Taxation and Finance, Form CT-3/4-I.

[27] *See* http://www1.nyc.gov/site/finance/taxes/business-business-corporation-tax.page.

Respectfully submitted,

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Principal
Analysis Group, Inc.

/s/ Todd Schatzki
Dr. Todd Schatzki
Principal
Analysis Group, Inc.

/s/ Charles Wu
Charles Wu
Manager
Analysis Group, Inc.

/s/ Christopher Llop
Christopher Llop
Manager
Analysis Group, Inc.

Exhibit A

EXHIBIT A
PAUL J. HIBBARD
Principal

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paul.hibbard@analysisgroup.com

111 Huntington Avenue
14th Floor
Boston, MA 02199

Mr. Hibbard is an expert on economics, strategy, regulation, and policy in the electric and natural gas industries. He has a comprehensive background merging business development, technical analysis, resource planning and development modeling, economics, and public policy in the energy and environmental fields. Throughout his career, he has administered and promoted an agenda of advanced ratemaking and policy initiatives for energy companies. Mr. Hibbard has also provided technical and strategic advice to government, industry, business, public interest groups, and trade organizations on energy market structure, electric and natural gas infrastructure planning and siting, utility resource solicitation and procurement, emission allocation and environmental policy, renewable resource program design and administration, transmission pricing, climate change policy, utility ratemaking practices, and the transfer of US federal and state emission control programs to other countries.

Prior to joining Analysis Group, Mr. Hibbard was chairman of the Massachusetts Department of Public Utilities. During his tenure, he carried out a forward-looking ratemaking and policy agenda to advance energy efficiency and renewable resources, coordinate regional efforts in the development of energy resources and associated infrastructure, and promote the administration of fair and efficient transmission pricing models in regional and national contexts. He also provided testimony on resource planning, competitive electricity markets, and transmission pricing in hearings before committees of the Massachusetts legislature and the US House of Representatives, the Federal Energy Regulatory Commission (FERC), and state and regional planning councils. Mr. Hibbard has also served as a member of many energy-related boards and committees.

EDUCATION

M.S.	Energy and resources, University of California, Berkeley *Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs* *(completed Ph.D. coursework in nuclear engineering)*
B.S.	Physics, University of Massachusetts Amherst

PROFESSIONAL EXPERIENCE

2010–Present	**Analysis Group, Inc.** *Principal (2015–Present)* *Vice President (2010–2015)*
2007–2010	**Massachusetts Department of Public Utilities** *Chairman* *Member, Energy Facilities Siting Board* *Manager, New England States Committee on Electricity* *Treasurer, Executive Committee, Eastern Interconnect States' Planning Council*

2007–2010 **Massachusetts Department of Public Utilities** (continued)
Representative, New England Governors' Conference (NEGC)
Power Planning Committee
Member, National Association of Regulatory Utility Commissioners (NARUC)
Electricity Committee, Procurement Work Group

2003–2007 **Analysis Group, Inc.**
Vice President (2005–2007)
Manager (2003–2005)

2000–2003 **Lexecon Inc.**
Senior Consultant (2002–2003)
Consultant (2000–2002)

1998–2000 **Massachusetts Department of Environmental Protection**
Environmental Analyst

1991–1998 **Massachusetts Department of Public Utilities**
Senior Analyst, Electric Power Division

1988–1991 **University of California, Berkeley**
Research Assistant, Safety/Environmental Factors in Nuclear Designs

SELECTED PUBLIC SECTOR EXPERIENCE (MASSACHUSETTS)

- ***Chairman, Department of Public Utilities***
  - Chaired the state's public utilities commission during a period of aggressive change in state policies affecting electricity and natural gas industries, including initial implementation of several new state energy laws and initiatives restructuring the setting of utility rates, promoting the expansion of energy efficiency and demand response, facilitating the retail and wholesale market integration of renewable and low-carbon resources, and revising state policy on the siting of major generation and transmission infrastructure.
  - Oversaw the issuance of initial regulations and policy related to revenue decoupling, net metering, long-term contracting for renewables, and power system emergency planning and outage restoration.
  - Led Massachusetts's work with regulators across the Northeast to pursue large-scale renewable resource development through coordinated procurement strategies, to develop coordinated positions related to national transmission development proposals and establish a regional presence on transmission-related provisions in federal legislation.
  - As chairman, served as administrative and policy head of an agency of nearly 150 employees, responsible for agency management and growth, budgeting, legislative matters, press inquiries, and policy agenda-setting.
  - Oversaw completion of all dockets jurisdictional to the department, including rate cases and associated tariff matters, forecast and supply planning for electric and natural gas industries, and state oversight of natural gas pipeline safety and public transit authorities.
  - Responsible for all interaction with the governor's office, legislature, and Executive Office of Energy and Environmental Affairs, as well as representing the state in regional deliberations related to electric and natural gas utility policy, electricity market design and oversight, and regional power system reliability issues.

- ***Member, Energy Facilities Siting Board***
  Sitting member of state board with responsibility to review all proposals for major generation and transmission infrastructure projects within the state, as well as state intervention in federal review of natural gas pipeline infrastructure. Review involved technical, environmental, and economic review of jurisdictional power plants, transmission lines, and other energy infrastructure, as well as ruling on proposals for exemption from state and local zoning ordinances.

- ***Manager, New England States Committee on Electricity***
  State representative on regional group chartered to develop New England regional policy positions on electricity market and transmission planning issues. Included consideration of group development issues, input into regional determinations of installed capacity requirement, consideration of regional approaches to transmission planning and the consideration of non-transmission alternatives, and coordinated development of a regional RFP/RFI for the solicitation of renewable power under long-term contracts for the New England states.

- ***Treasurer, Executive Committee, Eastern Interconnection States' Planning Council***
  Elected treasurer of steering committee for state council formed under a US Department of Energy (DOE) grant to coordinate with power system operators on developing long-range plans for transmission system spanning 41 states in the Eastern US. Coordinated New England states' approach to policy issues stemming from council efforts.

- ***Representative, NEGC Power Planning Committee***
  Represented governor's office in all discussions related to regional energy/environmental issues, including transmission cost allocation, regional energy policy coordination, and development of mechanisms for and approaches to procurement of renewable power through long-term contracts with sources in New England and Eastern Canada. Engaged in collaborative discussions with counterparts representing the Eastern Canadian Premiers.

SELECTED CONSULTING EXPERIENCE

Government, Foundations, Commissions, Cooperatives

- ***For the Advanced Energy Economy Institute (AEE Institute)*** – Coauthored a public report on the economic impact of potential stimulus spending on clean and advanced energy resources. (2020)
- ***For a Municipal Association*** – Drafted a white paper related to the fuel mix and emission characteristics of the portfolio of generating assets and power contracts used by municipal electric light companies in Massachusetts (2020).
- ***For the Wellesley Municipal Light Plant (WMLP)*** – Coauthored two white papers on the greenhouse gas (GHG) impacts of the WMLP power portfolio, and considerations for the WMLP associated with achieving continued reductions in carbon emissions over the ensuing decades (2020).
- ***For the Georgetown Climate Center*** – Conducted a bill impact analysis related to Virginia's proposed implementation of a carbon cap and trade program (2018).
- ***For Energy New England*** – Provided strategic assistance on energy market and public policy issues in New England (2017).
- ***For the Environmental Defense Fund*** – Coauthored a white paper related to historical power system emission trends (2015).
- ***For the Massachusetts Attorney General*** – Coauthored a report evaluating electric and natural gas infrastructure in New England from the perspectives of reliability, cost, and GHG emissions (2015).

- ***For the Advanced Energy Economy Institute*** – Coauthored a report on the status of the electric industry in the State of Ohio, and developed recommendations on state energy policy in consideration of the state's market and technological circumstances at the time.
- ***For the Energy Foundation and industry groups*** – Coauthored multiple white papers on the reliability, cost, and market efficiency impacts of US Environmental Protection Agency's (EPA's) proposed regulations to control emissions of carbon dioxide from existing electric generating facilities. Presented results in numerous conference, stakeholder, and regulatory settings.
- ***For a foundation*** – Led a study of the economic impacts of a state clean energy policy (2013–2014).
- ***For the Massachusetts Department of Energy Resources –*** Provided testimony on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013).
- ***For the Advanced Energy Economy Institute*** – Facilitated a regional symposium for New England Conference of Public Utility Commissioners and staff related to advanced energy technology development and commercialization, and the legal and regulatory structures needed to facilitate integration of emerging technologies (2013).
- ***For the Regional Greenhouse Gas Initiative (RGGI)*** – Conducted a bill impact analysis related to changes to retail customer electric bills in New England, New York, and RGGI PJM states associated with various changes considered by RGGI to program cap level and use of allowance revenues (2012).
- ***For the AEE Institute*** – Participated in a project advising the AEE Institute with respect to its national program to support public utility commission consideration of policies and regulations related to the development and integration of advanced energy technologies (2012–2013).
- ***For the Merck Family Fund*** – Developed an interactive tool to compare the impacts of energy, economic, environmental, legislative, and regulatory policies and programs across the US states (2012).
- ***For the AEE Institute*** – Coauthored a report on the perspectives of CEOs at advanced energy companies doing business in California on California's energy policies. Conducted over 30 interviews with energy business leaders to get perspectives and recommendations for policy changes (2012).
- ***For the Barr Foundation*** – Coauthored a report on the benefits and costs associated with reducing natural gas leaks on natural gas distribution systems through implementation of targeted infrastructure replacement ratemaking mechanisms in Massachusetts, Rhode Island, and Ohio. Developed a cost-benefit model to quantify the impacts of such programs (2012–2013).
- ***For the American Clean Skies Foundation*** – Developed a dispatch price and emissions model to forecast power system outcomes in the PJM Interconnection, Midwest Independent System Operator, and Southwest Power Pool regions (2012).
- ***For a national environmental organization*** – Conducted a comprehensive national review of energy efficiency monitoring and verification programs, in order to support development of a protocol that could be used to allow energy efficiency to be used as a compliance tool in national carbon emission control regimes (2012–2013).
- ***For the Merck Family Fund –*** Co-led a project to carry out an analysis of the economic impacts of the Northeast States' use of revenues collected from the auctioning of carbon allowances associated with RGGI (2011).
- ***For Advanced Energy Economy (AEE) –*** Developed background on electric industry structure, regional planning and market structures and operations, and state energy policy organization and initiatives. Assisted with the development of web-based information platform (2011).

- ***For the American Clean Skies Foundation –*** Authored a paper on the redesign of wholesale electricity market structures to efficiently integrate a higher level of variable resources (2012). Coauthored a white paper examining electric reliability and air emission issues associated with the potential retirement of the Potomac River Generating Station in Alexandria, Virginia (2011).
- ***For the Public Service Commission of Colorado –*** Coauthored a white paper on the design of incentives for the photovoltaic (PV) solar energy market (2011).
- ***For a national environmental organization*** – Conducted an economic analysis of key US cities that were or had been in nonattainment under the National Ambient Air Quality Standards, to explore relationships between air quality control requirements and the local economy (2011).
- ***For a national environmental organization*** – Completed a comprehensive report on the full scope of energy efficiency and demand response programs administered by New York electric utilities and the New York Independent System Operator (NYISO). Assessed the potential for additional innovative programs to improve energy efficiency and demand response in New York City (2010).
- ***For the North Carolina Attorney General –*** Managed project in support of expert testimony on the economic and financial feasibility of requiring the installation of controls to reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from coal-fired power plants owned by the Tennessee Valley Authority (TVA). Project was in the context of a public nuisance lawsuit brought by the North Carolina Attorney General against TVA (2006).
- ***For the National Commission on Energy Policy –*** Authored white papers on (1) the implications for US energy infrastructure of the damage to Gulf Coast energy facilities from Hurricanes Katrina and Rita (2006); (2) the practical and economic implications of various mechanisms for the allocation of carbon dioxide emission allowances to the electric sector under potential federal carbon control regimes (2005); and (3) national energy infrastructure needs for the electricity, natural gas, and petroleum industries, and for addressing the long-term impacts of energy production and use associated with spent nuclear fuel and carbon dioxide (2004).
- ***For the Energy Foundation*** – Coauthored a report (with Dr. Susan Tierney) documenting best practices in energy facility siting regulations in the US, and analyzing in particular the impact of California's energy facility siting process on that state's electricity crisis (2002). Supported a foundation-based program to provide international assistance to China's efforts to privatize and restructure its electric industry, and to develop regulations to control air emissions from power plants in that country (2000–2003).
- ***For the Massachusetts Technology Collaborative (MTC) –*** Managed projects in support of the MTC's renewable and premium power programs, including (1) creation of a standard financial pro-forma for wind and landfill gas technologies in New England under various assumptions related to capital and operating costs, financing, discount rates, and the impact of state and federal policies to support renewable development; (2) development of an economic model to determine the financial impact on potential wind and combined heat and power facilities of proposed changes to utility standby service tariffs; and (3) research, strategic, and regulatory support of MTC's efforts to advance distributed generation in Massachusetts to promote renewable resources and improve power reliability for commercial and industrial customers (2000–2002).
- ***For the Massachusetts Health and Educational Facilities Authority (MHEFA) PowerOptions Program*** – Managed several projects providing regulatory, economic, and strategic advice to PowerOptions to assist in their selection and pricing of retail electricity products from competitive electricity suppliers. Over a three-year period projects included analyses of forward prices and wholesale markets for capacity and reserves; analysis of contract price options, terms, and conditions; and analysis of congestion pricing implications for retail supply (2002–2004).

ENERGY INDUSTRY STAKEHOLDERS

- ***For the Hingham Municipal Lighting Plant (HMLP)*** – Conducted an internal evaluation of the impact of decarbonization of residential and commercial energy use in the town, and its effect on HMLP's investments and operations (September 2020).
- ***For a natural gas interstate pipeline company*** – Coauthored a white paper and presention showing options to decarbonize the company's operations. The study included an analysis of its GHG footprint, identification of options and pathways to reduce net GHG emissions from operations to zero over time, and the development of recommendations for senior management (August 2020).
- ***For Oracle Corporation*** – Conducted an analysis of and report on the GHG emission reduction impacts of various types of energy efficiency programs and measures, with a focus on the comparison of structural and behavioral energy efficiency programs (August 2020).
- ***For NYISO*** – Conducted a study of the parameters used as the basis to set the NYISO's installed capacity demand curves for the four capability years beginning with the summer 2021 capability period (August 2020).
- ***For NYISO*** – Conducted an internal study of the potential reliability impacts on the electric grid due to changes in system mix and operations associated with a changing climate and with state programs to address climate change (August 2020).
- ***For NYISO*** – Conducted a study of the potential risks to New York power system operations associated with an increased reliance on natural gas for power generation (2020).
- ***For Commonwealth Edison*** – Provided testimony on issues associated with a request for a certificate of public convenience and necessity by NextEra related to the proposed acquisition of the transmission assets of Rochelle Municipal Utilities (2020).
- ***For Repsol Energy North America*** – Provided strategic assistance related to the potential impacts of electric system market rules and public policy on the potential marketability of liquefied natural gas (LNG) in New England (2020).
- ***For Liberty Utilities*** – Provided testimony on the need for and economic and environmental impacts of the proposed Granite Bridge pipeline and LNG project in the state of New Hampshire (2020).
- ***For NYISO*** – Coauthored a white paper for NYISO on the potential impacts of a proposed carbon pricing mechanism in New York on power prices; energy policy; and economic, environmental, and public health impacts in New York (2020).
- ***For NTE Energy*** – Provided testimony before the Connecticut Siting Council on the need for and potential benefits associated with a proposed new natural gas-fired power plant in the state of Connecticut (2020).
- ***AltaGas*** – Provided testimony before the Maryland and District of Columbia public utility commissions on the potential environmental impacts of a proposed merger between AltaGas and Washington Gas (2017–2018).
- ***For Calpine Corporation*** – Coauthored a white paper on the design of a proposed carbon trading mechanism in Massachusetts (2017).
- ***For Vermont Gas*** – Provided testimony on the prudence of Vermont Gas' decisions and investments with respect to the Addison natural gas project (2017).
- ***For the Vermont Electric Power Company*** – Coauthored a white paper on Vermont Electric Power Company's capital structure associated with its transmission assets and operations (2016).
- ***For the Merck Family Fund*** – Coauthored a white paper on economic principles associatied with the trading of emission allowances associated with RGGI. (2016)

- ***For a consortium of solar companies*** – Developed a white paper on the appropriate evaluation and treatment of behind-the-meter solar PV generation from the perspective of net metering policies in Massachusetts (2015).
- ***For a group of owners of electric generating facilities*** – Developed a comprehensive quantitative and qualitative critique of a utility proposal to invest in electricity storage capability in the State of Texas. Drafted a report for circulation to legislative, regulatory, and market interests reporting the results of the critique and analysis (2015).
- ***For an energy resource developer*** – Conducted a financial and ratepayer analysis of the benefits of a project to develop a power plant and natural gas pipeline in the State of Maine. Submitted testimony to the Maine Public Utilities Commission describing the results (2014–2015).
- ***For an energy storage company*** – Developed an optimization analysis to evaluate the security, reliability, economic, and environmental benefits and costs of multiple battery storage installations across the Hawaiian Islands in different industry settings (renewable generator, island utility, military base, hotel/resort). Drafted a report presenting the results, considering the state's unique energy price and fuel security context (2014–2015).
- ***For NYISO*** – Developed a model to compare cost, resource, and emission outcomes of alternative designs for a capacity market in the State of New York. Coauthored a report presenting the results of the analysis and a comprehensive review of the benefits and drawbacks of moving from a spot to a forward capacity market structure. Presented results to NYISO senior management and several meetings of New York electricity market participants and stakeholders (2014–2015).
- ***For multiple regional transmission organizations*** – Provided board of director- and senior management-level strategic support for considering the changing structures of retail regulation and wholesale market incentives within their regions (2014–2015).
- ***For Calpine Corporation*** **–** Provided testimony on the costs and benefits of different proposals for generation capacity in Florida (2014).
- ***For a regional transmission operator*** – Conducted an internal analysis of the financial risk associated with the RTO's position in administering the trading of power system transmission rights (2014).
- ***For a regional transmission operator*** – Conducted a top-to-bottom review of the content and design of the RTO's Rate Schedule 1 tariff for the collection of operational costs from market participants. Presented results of the analysis to the RTO's board of directors and senior management (2014).
- ***For a retail electricity supplier*** – Provided analytic and strategic support with respect to the supplier's participation in a state regulatory proceeding related to changing the nature of and rate structure for electric distribution service (2014).
- ***For Ambri Inc.*** **–** Led a study of the economic feasibility of using battery storage in conjunction with wind and solar for a micro-grid application (2013–2014).
- ***For Calpine Corporation*** **–** Provided testimony on the costs and benefits of different proposals for generation capacity in Minnesota (2013).
- ***For the New England Independent System Operator (ISO-NE)*** **–** Assisted on several projects related to addressing the co-dependence of electric and natural gas systems in New England through a mix of short- and long-term market rule changes and administrative actions. Assistance included review of market structures to improve unit performance, particularly under stressed natural gas system conditions; quantification of the costs of potential natural gas and electric system infrastructure, and contractual responses to market rules and administrative actions (e.g., dual-fuel capability, new pipeline investment, LNG purchasing, and firm natural gas transportation agreements); and assistance with a series of discussions between ISO-NE and regional electricity and

natural gas market participants. Also quantified the potential benefits of improved performance associated with reduced system interruptions (2012–2013).

- ***For ISO-NE*** – Developed an economic supply/demand model of the forward capacity market (FCM) to estimate the cost impact of integrating a new long-term performance incentive design element into the FCM auctions and pricing structure (2012–2013).
- ***For Calpine Corporation*** – Filed a report with EPA on the impact of emergency generation demand response programs on the costs and emissions associated with power system dispatch in the PJM electricity market (2012).
- ***For ISO-NE*** – Organized and helped lead a strategic planning initiative to address unit retirement, fuel mix, operational performance, and wind resource integration issues. Oversaw comprehensive generating unit performance analysis and electric-gas system risk review. Conducted a thorough internal risk assessment and key-challenge solution development. Facilitated meetings and developed organizational and concept documents to explore outcomes and assist in deliberations with states and regional industry stakeholders, and participated in external meetings to gain input and feedback (2010–2012).
- ***For a regional transmission organization*** – Conducted a top-to-bottom review of its external market monitoring function and a comprehensive best-practices survey of all internal and external market monitoring functions at US Regional Transmission Organizations and Independent System Operators (2012).
- ***For a wind power development company*** – Conducted a regional review of wind power development projects and an assessment of potentially valuable projects for acquisition based on power system location and siting viability (2012).
- ***For an energy services company –*** Oversaw and conducted an analysis of business, legal, and regulatory conditions related to a legal dispute over the legitimacy of a contract for energy and water management services. Coauthored a report to be used in the development of legal strategy and legal proceedings (2012).
- ***For an international power company*** – Conducted a review of a regional utility's compliance with FERC requirements for transmission open access, and developed strategies for the filing of complaints of anticompetitive conduct before FERC (2011–2012).
- ***For a regional transmission organization*** – Comprehensively reviewed and suggested changes to the design of regional market structures; oversaw data review and analysis related to key market design features and asset performance (2011).
- ***For Direct Energy*** – Assisted with the development of strategies to increase retail choice in Pennsylvania, including the design of an opt-in descending-clock auction to increase migration from default service to competitive supply. Prepared comments and analysis on utility contract structures. Provided testimony before the Pennsylvania Public Utilities Commission (2011).
- ***For Algonquin Gas*** – Submitted affidavits and testified in bankruptcy court on the impact on power plant value of changes in market rules related to the forward capacity market in New England. Also provided testimony on the impact on power system reliability of the availability of firm transportation contracts for natural gas supplied to power plants in New England (2010).
- ***For an independent system operator*** – Conducted a best-practices and performance metrics analysis to benchmark the ISO's performance against industry peers with respect to responsiveness to consumers, stakeholders, and policymakers. Drafted a report with comprehensive benchmarking and performance metric recommendations; participated in stakeholder discussions (2010).
- ***For a power generators trade association*** – Developed and facilitated an all-day group discussion concerning key economic, environmental, legal, and policy challenges to the economic viability of existing and new power generation capacity in regional wholesale electricity markets (2010).

- ***For a coalition of electric companies*** – Coauthored a report, "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," reviewing the impact on power plant operations of proposed EPA rules to reduce emissions of sulfur dioxide, nitrogen oxides, mercury, and other hazardous air pollutants. Presented findings to numerous regional and national industry and regulatory groups (2010).
- ***For an industry coalition*** – Conducted a study and coauthored a white paper (with Dr. Susan Tierney) for the New England Energy Alliance on New England energy infrastructure needs and policy issues (e.g., facility siting policies, RGGI/climate change) influencing the future addition of energy infrastructure in the region (2006).
- ***For an interstate pipeline company and offshore LNG developer*** – Authored a report related to recent developments in the supply and demand for natural gas in New England, and surveyed the development, regulatory and commercial status of proposed LNG projects across the US (2006); coauthored a Report (with Susan Tierney) providing an overview of Northeastern natural gas markets and conditions, and an assessment of natural gas supply and demand conditions (2005).
- ***For independent system operators*** – Managed several projects and coauthored reports or analyses for the Northeast region's ISOs/RTOs, related to ISO/RTO annual strategic plans; market monitoring and mitigation best practices; and the links between wholesale electricity markets and local distribution company retail prices (2002–2006).
- ***For electric utilities*** – Managed or participated in numerous engagements with wires-only as well as vertically integrated electric utilities within New England and across the country related to rate case strategy and regulatory support; strategic planning; power supply resource planning and procurement (including the role of independent monitor of utility procurements); price and environmental analyses related to the siting of new high-voltage transmission lines; and evaluation of the allocation of SO_2 and NO_x emission allowances under the EPA Clean Air Interstate Rule (CAIR) program (2001–2006).
- ***For a developer of a land-based LNG facility –*** Assisted in the preparation of confidential reports on US natural gas supply/demand conditions, market pricing indices, US LNG facilities' status, Northeast interstate and intrastate pipeline infrastructure conditions and prospects, and LNG supply contract prices, terms, and conditions (2006).
- ***For retail energy providers*** – Managed projects and authored or coauthored confidential reports on the experience with retail competition in the US, a benefit/cost analysis of wholesale electricity competition, and comparative analyses of retail electricity prices for utility and competitive retail suppliers in select states (2004–2006).
- ***For merchant generating companies/coalitions*** – Managed production cost dispatching analyses for strategic planning related to the construction of new generating capacity in New England; assisted in the development of regulatory proposals for new wholesale market organizations and policies in New England (2001–2002).
- ***For a renewable power developer association*** – Provided testimony on the potential negative effects – and remedial policy options – related to the impact of locational marginal pricing on the development and operation of renewable generating resources in New England (2001).
- ***For a major interstate pipeline owner/operator –*** Modeled the electrical load characteristics of pipeline operations and utility rate structures to quantify the extent to which the company was being overcharged for electricity services. Supported company intervention in public utility commission proceedings and with analytical support in settlement negotiations (2002).

OTHER PROFESSIONAL ACTIVITIES

Advanced Energy Economy
Advisory Board (2011)

SELECTED REPORTS, TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Paul J.Hibbard, Todd Schatzki, Charles Wu, Christopher Loop, Matthew Lind, Kiernan McInerney and Stephanie Villarreal, *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report,* September 9, 2020.

"Energy Efficiency for Climate, Not Ratepayers" presentation on a plenary panel to the American Council for an Energy-Efficient Economy (ACEEE) Summer Study session, August 19, 2020.

Testimony of Paul J. Hibbard before Commonwealth Edison on issues associated with a request for a certificate of public convenience and necessity by NextEra related to the proposed acquisition of the transmission assets of Rochelle Municipal Utilities (2020).

For the New England Power Generators Association (NEPGA), coauthored a report assessing the potential use of carbon pricing in New England. The analysis applied tested industry models to identify effective and efficient economy-wide pricing of carbon dioxide (CO_2) emissions consistent with New England states' GHG emission reduction targets, June 23, 2020.

Joseph Cavicchi and Paul J. Hibbard, *Carbon Pricing for New England: Context, Key Factors, and Impacts*, June 2020.Paul J. Hibbard, Jonathan Baker, Mona Birjandi-Feriz and Hannah Krovetz, *Utility energy efficiency program performance from a climate change perspective: A comparison of structural and behavioral programs*, 2020.

Pavel G. Darling and Paul J. Hibbard, *Economic Impact of Stimulus Investment in Advanced Energy, 2020.*

Paul J. Hibbard, Charles Wu, Hannah Krovetz, Tyler Farrell and Jessica Landry, *Climate Change Impact and Resilience Study – Phase II: An Assessment of Climate Change Impacts on Power System Reliability in New York State*, 2020.

"Decarbonization and Wholesale Markets in New England – Looking Ahead: Achieving 80% GHG Reduction by 2050," presented on a plenary panel to the Association of Energy Engineers Conference, "ISO-NE in 2050: Getting to an advanced energy future in New England," Boston, MA, March 18, 2020.

"Decarbonization and Natural Gas in the Northeast," moderated panel and presented at EUCI conference on Natural Gas Decarbonization, Greenwood Village, Denver, CO, January 22–23, 2020.

Paul J. Hibbard and Charles Wu, *Fuel and Energy Security in New York State: An Assessment of Winter Operational Risks for a Power System in Transition*, November 2019.

Susan F. Tierny and Paul J. Hibbard, *Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets*, October 2019."Natural Gas in Power Generation: Role Going Forward" participated on a panel of industry experts at the 7th Annual Maine Natural Gas Conference to discuss power generation in the New England region. The panel focused on the role of natural gas, particularly in light of strong state policy initiatives to reduce GHG emissions. Falmouth, ME, October 3, 2019.

Rebuttal Testimony on Reopening of Paul J. Hibbard before the Illinois Commerce Commission on Behalf of Commonwealth Edison, Docket No. 18-0843, May 31, 2019.

Direct and rebuttal testimonies of Paul J. Hibbard before the New Hampshire public Utility Commission on the need for and economic and environmental impacts of proposed Liberty Utilities Granite Bridge pipeline and LNG project (2019).

Pre-filed Testimony of Paul J. Hibbard before the Connecticut Siting Council on behalf of NTE Connecticut LLC, Docket No. 470, January 18, 2019.

Susan F. Tierney, Paul J. Hibbard with Benjamin Dalzell, Grace Howland, Jonathan Baker, Tom Beckford, Sarah Centanni, Asie Makarova, and Scott Ario, "*Vehicle Fuel-Economy and AirPollution Standards: A Literature Review of the Rebound Effect*," June 28, 2018.

Paul J. Hibbard, Susan F. Tierney, and Pavel G. Darling, "An Expanding Carbon Cap-and-trade Regime? A Decade of Experience with RGGI Charts a Path Forward," *The Electricity Journal*, June 2018.

Paul J. Hibbard., Susan F. Tierney, Pavel G. Darling, and Sarah Cullinan, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States*, review of RGGI's third three-year compliance period (2015–2017), April 2018.

Post-Settlement Testimony of Paul J. Hibbard before the Maryland Public Service Commission on behalf of AltaGas, Case No. 9449, January 5, 2018.

Rebuttal and post-settlement testimonies of Paul J. Hibbard before District of Columbia and Maryland public service commissions on the potential environmental impacts of the proposed merger between AltaGas and WGL Holdings (2017-2018)

Rebuttal Testimony of Paul J. Hibbard before the Public Service Commission of the District of Columbia on behalf of AltaGas, Formal Case No. 1142, October 27, 2017.

Paul J. Hibbard, Todd Schatski, and Sarah Bolthrunis, *Capacity Resource Performance in NYISO Markets: An Assessment of Wholesale Market Options*, November 2017.

Paul J. Hibbard and Ellery Berk, *RGGI and Emissions Allowance Trading: Options for Voluntary Cooperation Among RGGI and Non-RGGI States*, July 2017.

"Analytical Issues in Linking," presentation to *Virginia and the Regional Greenhouse Gas Initiative*, Virginia Commonwealth University, Richmond, VA, July 12, 2017.

Paul Hibbard, Susan Tierney, and Katherine Franklin, *Electricity Markets, Reliability and the Evolving U.S. Power System*, June 2017.

Testimony of Paul J. Hibbard before Vermont Gas on the prudence of Vermont Gas' decisions and investments with respect to the Addison natural gas project (2017).

Paul Hibbard, "Storage and Microgrids – New Applications," panel presentation during the Electricity Advisory Committee's Energy Storage Session, Arlington, VA, June 8, 2017.

Paul Hibbard, Craig Aubuchon, and Mike Cliff, *Evaluation of Vermont Transco, LLC Capital Structure*, October 2016.

Rebuttal Testimony of Paul J. Hibbard before the State of Vermont Public Service Board on behalf of Vermont Gas Systems Inc., Docket Nos. 8698 and 8710, September 26, 2016.

Susan Tierney, Paul Hibbard, and Ellery Berk, *RGGI and CO_2 Emissions Trading Under the Clean Power Plan: Options for Trading Among Generating Units in RGGI and Other States*, July 12, 2016.

Affidavit of Paul J. Hibbard before the FERC, Docket No. ER16-1751-000 on behalf of the NYISO, May 20, 2016.

Declaration of Paul J. Hibbard and Andrea M. Okie in the US Court of Appeals for the District of Columbia Circuit, Case No. 15-1363 (and consolidated cases) on behalf of multiple parties, December 8, 2015.

Paul Hibbard and Craig Aubuchon, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*, report for the Massachusetts Office of the Attorney General, November 2015.

Testimony of Paul J. Hibbard before the Senate Committee on Global Warming and Climate Change, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas*, November 24, 2015.

Paul Hibbard, Andrea Okie, Susan Tierney, and Pavel Darling, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Altantic States*, review of RGGI's Second Three-Year Compliance Period (2012–2014), July 14, 2015.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: The Case of MISO*, report for the Energy Foundation, June 8, 2015.

Paul Hibbard, *Net Metering in the Commonwealth of Massachusetts: A Framework for Evaluation*, May 2015.

Paul Hibbard, Todd Schatzki, Craig Aubuchon, and Charles Wu, *NYISO Capacity Market: Evaluation of Options*, report for the NYISO, May 2015.

Paul Hibbard and Andrea Okie, *Ohio's Electricity Future: Assessment of Context and Options*, report for Advanced Energy Economy, April 2015.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: The Case of PJM*, report for the Energy Foundation, March 16, 2015.

Susan Tierney, Paul Hibbard, and Craig Aubuchon, *Electric System Reliability and EPA's Clean Power Plan: Tools and Practices*, report for the Energy Foundation, February, 2015.

Andrea Okie, Paul Hibbard, and Susan Tierney, *Tools States Can Utilize for Managing Compliance Costs and the Distribution of Economic Benefits to Consumers Under EPA's Clean Power Plan*, Electricity Forum, February 2015.

Paul Hibbard, Katherine Franklin, and Andrea Okie, *The Economic Potential of Energy Efficiency*, report for the Environmental Defense Fund, December 2014.

Paul Hibbard, Andrea Okie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels*, report for the Environmental Defense Fund and National Resources Defense Council, December 2014.

"EPA's Proposed Clean Power Plan and States' Planning for Implementation," presentation to the Power-Gen International Annual Conference, December 2014.

"Storage/Renewables Valuation: A Case Study Hitting Multiple Perspectives," presentation to the Caribbean Renewable Energy Forum 2014, October 2014.

"Electric Industry Transformation: A New World, or a Step Through the Looking Glass?" presentation to the New England Independent System Operator Quarterly Meeting, September 2014.

"Consumers, Markets, and Infrastructure: New England at a Crossroads," presentation to the New England Consumer Liaison Group, September 2014.

"Columbia River Treaty Hydropower: Perspectives on Power Benefits," presentation to the LSI Conference on the Columbia River Treaty, September 2014.

Direct Testimony of Paul J. Hibbard on Behalf of Calpine Construction Finance Company, L.P. before the Florida Public Service Commission, Docket No. 140110-E1, July 2014.

"States in Control: EPA's Clean Power Plan and State Implementation," presentation at the National Association of Regulatory Utility Commissioners Summer Meetings, July 2014.

Paul Hibbard, Andrea Okie and Susan Tierney, "EPA's Clean Power Plan: States' Tools for Reducing Costs and Increasing Benefits to Consumers," *The Electricity Journal*, July 2014.

Direct Testimony of Paul J. Hibbard on behalf of Calpine Construction Finance Company, L.P. before the Florida Public Service Commission , Docket No. 140110-E1, July 14, 2014.

"Project Vigilance: Value of Ambri Batteries at Joint Base Cape Cod," presentation to Raab Restructuring Roundtable, Boston MA, June 2014.

Paul Hibbard and Todd Schatzki, *Further Explanation on Rate Calculations*, memo to the New England Independent System Operator Markets Committee on setting the compensation rate for the ISO Winter Program, May 28, 2014.

"Markets, Infrastructure, and Policy: New England at a Crossroads," presentation to the US/Canada Cross-Border Power Summit, April 2014.

"Siting Infrastructure: Economic and Siting Hurdles," presentation to the US/Canada Cross-Border Power Summit, April 2014.

Paul Hibbard, Susan Tierney, and Pavel Darling, *Economic Impact of the Green Communities Act in the Commonwealth of Massachusetts: Review of the Impacts of the First Six Years*," March 4, 2014.

Paul Hibbard and Andrea Okie, *Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments: Recommended Framework for Proposed Guidance on Quantifying Energy Savings and Emission Reductions in Section 111(d) State Plans Implementing the Carbon Pollution Standards for Existing Power Plants*, report for the Environmental Defense Fund, March 2014.

"Climate Policy and the Economy," presentation to the 2014 Joint Institute for Strategic Energy Analysis Annual Meeting, NREL, Golden CO, March 2014.

Testimony of Paul Hibbard and Todd Schatzki on behalf of the New England Independent System Operator before the Federal Energy Regulatory Commission, Docket Nos. ER14-1050-000 and ER14-1050-001, February 12, 2014.

Paul Hibbard, Steve Carpenter, Pavel Darling, Margaret Reilly, and Susan Tierney, *Project Vigilance: Functional Feasibility Study for the Installation of Ambri Energy Storage Batteries at Joint Base Cape Cod*, report for demonstration project under the MassInnovate Program of the Massachusetts Clean Energy Center, February 2014.

Testimony of Paul J. Hibbard before the Maine Public Utilities Commission on behalf of Loring Holdings LLC. Testimony described the results of a financial and ratepayer analysis of the benefits of a project to develop a power plant and natural gas pipeline in the State of Maine, 2014–2015.

Rebuttal Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240, October 18, 2013.

Direct Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240, September 27, 2013.

Paul J. Hibbard and Todd Schatzki, *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives,* September 2013.

"Market Monitoring at US RTOs," presentation to the 12th Annual Gas and Power Institute, Houston, TX, August 2013.

Testimony of Paul J. Hibbard before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Department of Energy Resources, DPU 13-07, May 31, 2013.

Testimony of Paul Hibbard before the House Committee on Energy and Commerce, Subcommittee on Energy and Power, *The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges*, March 19, 2013.

Testimony of Paul J. Hibbard on behalf of the Massachusetts Department of Energy Resources, on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013).

Paul Hibbard, Andrea Okie, and Susan Tierney, *California's Advanced Energy Economy – Advanced Energy Business Leaders' Perspectives and Recommendations on California's Energy Policies*, report prepared for the Advanced Energy Economy Institute, February 2013.

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Craig Aubuchon and Paul Hibbard, *Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs*, report for the Barr Foundation, January 2013.

Paul Hibbard, Andrea Okie, and Pavel Darling, "Demand Response in Capacity Markets: Reliability, Dispatch and Emission Outcomes," *The Electricity Journal*, November 2012.

"The Electric Generation Landscape – A Marathon of Challenges," presentation to SNL Generation Landscape, Chicago IL, October 2012.

"Economics, EPA, and Old Capacity – Bring Out Your Dead," presentation to LSI Energy in the Northeast, Boston MA, September 2012.

Paul Hibbard, *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, report to the EPA on behalf of Calpine Corporation, August 2012.

"Uncertainty in Electricity Infrastructure Development – Key Drivers, International Context," presentation to NCEA Annual Conference, Brainerd, MN, June 2012.

Paul Hibbard and Todd Schatzki, "The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," *The Electricity Journal*, May 2012.

"Economic Impacts of RGGI," presentation to the New Hampshire Environmental Business Council, April 2012.

Testimony of Paul Hibbard before the California Legislature, *The Economic Impacts of RGGI's First Three Years*, California Select Committee on the Environment, the Economy, and Climate Change, March 27, 2012.

Testimony of Paul Hibbard before the New Hampshire Legislature, *RGGI and the Economy – Following the Dollars*," New Hampshire House Committee on Science, Technology, and Energy, February 14, 2012.

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"Public Policy Transmission: Competition and Cooperation," presentation to the Energy Bar Association Renewables Subcommittee, Washington, DC, November 2011.

"Competitive Markets and Wind Power: Challenge and Opportunity," presented to the Governors' Wind Energy Coalition, Washington, DC, November 2011.

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Testimony before the Pennsylvania Public Utilities Commission on retail opt-in auctions, November 10, 2011.

"Interdependence and Opportunity: The Growing Link Between Electricity and Natural Gas," presentation to the Colorado Oil & Gas Association Energy Epicenter Conference, Denver, August 2011.

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Paul Hibbard, Susan Tierney, and Andrea Okie, *Solar Development Incentives: Status of Colorado's Solar PV Program, Practices in Other States, and Suggestions for Next Steps*, June 30, 2011.

"The Balancing Act: Challenges in Traversing the Modernization of New England's Infrastructure," presentation to the NECA Annual Conference, Mystic, CT, May 2011.

"Renewables v. Gas: The Future of New England Infrastructure," presentation to the EBC Energy Seminar, Waltham, MA, April 2011.

"Upcoming Power Sector Environmental Regulations: Framing the Issues About Potential Reliability/ Cost Impacts," presentation to the Raab Restructuring Roundtable, Boston, MA, October 2010.

"Carbon Regulation: Action and Convergence Spanning the Pond," presentation to the Energy Smart Conference, Boston, MA, October 2010.

"Renewables Development – A Tricky Time to be Placing Bets," presentation to the NECA Renewables Committee, Boston, MA, October 2010.

"Energy Infrastructure Challenges in the Current Policy Environment, A Wide Angle Point of View," presentation to NARUC, Providence, RI, September 2010.

Susan F. Tierney, Paul J. Hibbard, Michael J. Bradley, Christopher Van Atten, Amlan Saha, and Carrie Jenks, *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*, August 2010.

"Renewables Development – National Policies, New England Progress," presentation to the National Association of State Energy Officials Annual Meeting, Boston, MA, September 2010.

"Northeast US and Eastern Canada – Competitive Markets and Renewable Resource Development," presentation to LSI Conference on US/Canada Energy Transactions, Vancouver, BC, August 2010.

"Renewables in the Northeast – Local Opportunities, National Context," presentation to Council of State Governments, Portland, ME, August 2010.

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"Federal Transmission Legislation," comments to Capitol Hill briefing of the Coalition for Fair Transmission Policy, Washington, DC, April 2010.

"Transmission Planning & Cost Allocation Alternatives under Order 890," comments to the Energy Bar Association's 64th Meeting, Washington, DC, April 2010.

"Deregulation and Sustainable Energy," class lecture, MIT (Jonathan Raab Energy Course), Cambridge, March 2010.

"Transmission for Renewables," presentation to the Raab Restructuring Roundtable, Boston, MA, March 2010.

"US Electric Power Transmission: The Battle of the Jurisdictions," comments to CERAWeek 2010, March, 2010.

"New England Blueprint and the Federal Context," presentation to the New England Independent System Operator Consumer Liaison Group Meeting, Westborough, MA, February 2010.

"Interconnection-Wide Planning and Renewable Energy," comments to the National Wind Coordinating Collaborative, Transmission Update Briefing, December 2009.

"Infrastructure Planning," comments to the Northeast Energy and Commerce Association Power Markets Conference, Westborough, MA, November 2009.

"Transmission for Renewables - Risks and Opportunities for the Northeast," presentation to the Governor's Clean Energy Innovation Forum, New Brunswick, NJ, October 2009.

"Renewable Energy Development – The Role of Markets and Planning," presentation to the Northeast Power Planning Council General Meeting, Cambridge, MA, September 2009.

"Transmission Planning," comments to the Federal Energy Regulatory Commission Technical Conference on Transmission Planning Processes Under Order No. 890, Docket No. AD09-8-000, Philadelphia, PA, September 2009.

"New England Governors' Blueprint – Purpose and Context," presentation to the Raab Restructuring Roundtable, Boston, MA, September 2009.

"Wind, Transmission, and Federal Legislation," comments to the MIT Wind Group, Cambridge, MA, Fall 2009.

"National Transmission Policy," comments to The Energy Daily's Transmission Siting Policy Summit, Washington, DC, September 2009.

Testimony before the Massachusetts Joint Committee on Telecommunications, Utilities and Energy Hearing to Review Implementation of the Green Communities Act, Boston, MA, July 8, 2009.

"Federal Transmission Legislation," comments to the National Association of State Utility Consumer Advocates, Boston, MA, July 2009.

"Renewable Energy Development – The Role of Markets and Planning," presentation to the Governor's Wind Energy Coalition, Washington, DC, July 2009.

"Transmission and Renewables: ISO and Regulator Perspectives" comments to the Raab Restructuring Roundtable, Boston, MA, June 2009.

"Renewable Development in and for New England: Massachusetts' Perspective," presentation to Law Seminars International, Boston, MA, June 2009.

"Roadmap to New Renewable Resources in New England," comments on the New England Governors' Blueprint to the New England Conference of Public Utilities Commissioners Annual Symposium, Newport, RI, May 2009.

"Comments of Chairman Paul Hibbard," presentation to the EBC Energy Seminar: New Transmission – The Key to Renewable Resource Integration in New England, Boston, MA, April 2009.

"Coordinating Wind and Transmission Development – Who Pays?" comments to the 2009 Platts Wind Power Development Conference, Chicago, IL, March 2009.

"Integrating Energy and Environmental Regulations in Massachusetts," presentation to the Northeast Sustainable Energy Association Building Energy Conference, Boston, MA, March 2009.

"One Reason for the GCA: Energy Pricing in Massachusetts," presentation to the South Shore Coalition, Hingham, MA, January 2009.

"Non-Reliability Transmission: State Choice and Control," presentation to the New England Conference of Public Utility Commissioners Transmission Group, Chelmsford, MA, January 2009.

"Regulation and Renewable Energy Policy," panel moderator, Center for Resource Solutions National Renewable Energy Marketing Conference, Denver, CO, October 2008.

"Energy Pricing in Massachusetts (… and What We Should Do About It)," presentation to the Berkshire Gas Large Commercial and Industrial Customer Annual Meeting, Lenox, MA, October 2008.

"Conversation with Chairman Hibbard," presentation to the New England Energy Alliance, Boston, MA, September 2008.

"Creating the Path: Delivering Clean Energy through Transmission Improvements," presentation to the New England Independent System Operator Lights, Power, Action Conference, Boston, MA, September 2008.

"Distributed Resources, the Decoupling Model, and the Green Communities Act," presentation to the Raab Restructuring Roundtable, Boston, MA, September 2008.

"Resource Planning: The Contribution of Efficiency and Renewables in Massachusetts," presentation to the Law Seminars International Renewable Energy in New England Conference, Boston, MA, September 2008.

"Remarks to Economic Studies Working Group," ESWG Committee Meeting, Westborough, MA, July 2008.

"Power Trade: Market Context and Opportunities," presentation to the New England Governors' Council/Eastern Canadian Premiers' Energy Dialogue, Montreal, Canada, May 2008.

"New England Transmission Investment," presentation to the Municipal Electric Association of Massachusetts Annual Business Meeting, North Falmouth, MA, April 2008.

"Bringing Power from the North," presentation to the Raab Restructuring Roundtable, Boston, MA, February 2008.

"Natural Gas: Drivers of Supply, Demand, and Prices," comments to the Guild of Gas Managers, November 2007.

"Generation and Demand Outlook for New England," presentation to NECA Dinner Meeting, Cambridge, MA, September 2007.

"Comments on ISO's Draft Regional System Plan," presentation to the Independent System Operator Planning Advisory Committee, Boston, MA, September 2007.

"Regulatory Pressures, Policy Opinions," presentation to the Environmental Business Council, Boston, MA, July 2007.

"Is New England Ensuring the Adequacy and Cost Effectiveness of the Region's Transmission Grid?" panel moderator, New England Conference of Public Utility Commissioners Annual Symposium, Mystic, CT, June 2007.

"Energy Regulation in Massachusetts – Concerns and Options," presentation to the Raab Restructuring Roundtable, Boston, MA, June 2007.

"View From the Regulatory Bench," comments to the New England Energy Conference and Exposition, Groton, CT, May 2007.

"Energy for New England – The Demand, Supply and Price Context," presentation to Massachusetts Municipal Wholesale Electric Cooperative Annual Meeting, Boylston, MA, May 2007.

"Demand Resources in New England: New Opportunities and Future Directions," presentation to the New England Independent System Operator Annual Demand Resources Summit, Westborough, MA, May 2007.

"Power Supply for the New England Region," presentation to the Boston Bar Association, Boston, MA, March 2007.

"Fuel Supplies and the Need for Fuel Diversity: Forecast for Global Fuel Markets and the Likely Impact on Electric Generation in the Northeast," presentation to the Law Seminars International Seminar on Resource Adequacy and Reliability in the Northeast, October 16, 2006.

"Consumers and Politicians Claim They Want Cheap, Reliable and Clean Energy – Do They Have the Will to Make That Happen?" presentation to the National Association of Energy Service Companies New England Regional Meeting, September 28, 2006.

"The Need for New LNG Infrastructure in Massachusetts and New England: An Update," report prepared for Northeast Gateway Energy Bridge, LLC and Algonquin Gas Transmission, LLC, August 2006.

"Natural Gas & LNG for New England: What's Needed & How To Get It," presentation to the Foundation for American Communications Meeting on *New England's Energy Needs – Who Pays and Who Suffers?*" May 17, 2006.

Susan F. Tierney and Paul J. Hibbard, in cooperation with the Ute Indian Tribe of the Uintah and Ouray Reservation, *Energy Policy Act Section 1813 Comments: Report of the Ute Indian Tribe of the Uintah and Ouray Reservation for Submission to the US Departments of Energy and Interior*, May 15, 2006.

"US Energy Infrastructure Vulnerability: Lessons From the Gulf Coast Hurricanes," report to the National Commission on Energy Policy, March 2006.

Paul Hibbard and Susan Tierney, "New England Energy Infrastructure – Adequacy Assessment and Policy Review" prepared for the New England Energy Alliance, November 2005.

"Federal Legislative Developments in Energy," presentation to the Law Seminars International Seminar on Energy in the Northeast, October 2005.

Paul Hibbard and Susan Tierney, "The Benefits of New LNG Infrastructure in Massachusetts and New England: The Northeast Gateway Project," prepared for Northeast Gateway Energy Bridge, LLC and Algonquin Gas Transmission, LLC, June 2005.

"Climate Change Policy – New Business and Regulatory Risks," presentation to EnviroExpo & Conference, May 2005.

"Carbon Cap & Trade Allocation Options – Practical Considerations," "Carbon Trading Program Emission Allowances: Practical Considerations for Allocation," and "Allocation of Carbon Allowances to Mitigate Electric Sector Costs," reports to the National Commission on Energy Policy, May 2005.

"U.S. Energy Infrastructure: Demand, Supply and Facility Siting," report to the National Commission on Energy Policy, November 2004.

Comments of Susan F. Tierney and Paul. J. Hibbard on their own behalf before the Federal Energy Regulatory Commission, in the Matters of Solicitation Processes for Public Utilities (Docket No. PL04-6-000) and Acquisition and Disposition of Merchant Generation Assets by Public Utilities (Docket No. PL04-9-000), on the role of independent monitors and independent evaluators in public utility resource solicitations, July 1, 2004.

Paul Hibbard and Susan Tierney, "Energy and Environmental Policy in the United States: Synergies and Challenges in the Electric Industry," prepared for Le Centre Français sur les Etats-Unis (The French Center on the United States), July 2003.

P. Hibbard, B.A. Finamore, N. Seidman, and T. Szymanski,"Controlling China's Power Plant Emissions after Utility Restructuring: The Role of Output-Based Emission Controls," *The Sinosphere Journal*, July 2002.

Paul Hibbard and S. Tierney, "Siting Power Plants in the New Electric Industry Structure: Lessons from California and Best Practices for Other States," *The Electricity Journal*, June 2002.

Paul Hibbard and Susan Tierney, "Siting Power Plants: Recent Experience in California and Best Practices in Other States," prepared for The Hewlett Foundation and The Energy Foundation, February 2002.

Paul Hibbard, N. Seidman, and B. Finamore, "Setting and Administering Output-Based Emission Standards for the Power Sector: A Case Study of the Massachusetts Output-Based Emission Control Programs," prepared for the China Sustainable Energy Program, October 2001.

P. Hibbard and J. Besser, Joint Affidavit before the Federal Energy Regulatory Commission, New England Power Pool and ISO New England, Inc., Docket No. ER01-2329, on behalf of the New England Renewable Power Producers Association, July 3, 2001.

Paul Hibbard, N. Seidman, B. Finamore, and D. Moskovitz, "Output-Based Emission Control Programs – U.S. Experience," prepared for the China Sustainable Energy Program, May 2000.

"P2 and Power Plants: The Massachusetts Allowance Trading Program," in *Proceedings of the National Pollution Prevention Roundtable*, March 2000.

Paul Hibbard, A.P. Kinzig, and J.P. Holdren, "Safety and Environmental Comparisons of Stainless Steel with Alternative Structural Materials for Fusion Reactors," *Fusion Technology*, August 1994.

"Utility Environmental Impacts: Incentives and Opportunities for Policy Coordination in the New England Region," US EPA CX817494-01-0, RCEE Core Group, June 1994.

"Final Report: Code Development Incorporating Environmental, Safety, and Economic Aspects of Fusion Reactors," UC-BFE-027, Fusion Environmental and Safety Group, University of California, Berkeley, 1991.

Exhibit B

Exhibit B
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Dr. Schatzki has a broad range of expertise in energy, environment, finance, and competition matters. He supports clients in a range of contexts, including strategic and financial advice, policy analysis, regulatory and rulemaking proceedings, and litigation.

Dr. Schatzki has deep experience in electricity, natural gas, petroleum, and renewable energy. His expertise in the electricity sector includes wholesale energy and capacity market design; utility regulation and ratemaking; economic impact analysis of new market rules, regulations, and generation and transmission investments; contract analysis and disputes; financial valuation; and options analysis. Dr. Schatzki has testified before US state and federal, as well as Canadian provincial, regulatory commissions. He has supported the analysis of alleged market manipulation and damages in high-profile litigations such as *FERC v. Barclays* and lawsuits following the California electricity crisis.

Dr. Schatzki works extensively on environmental economics, policy, and regulation. Recently, he has focused on the intersection of climate policy and energy markets, and disputes involving water resources and environmental contamination. His research has been published in distinguished energy- and environment-related publications, and he has provided research for prominent organizations such as the Electric Power Research Institute, the Edison Electric Institute, and the Federal Energy Regulatory Commission.

In finance and competition matters, Dr. Schatzki has worked with clients on litigation and non-litigation projects in many sectors, including energy, financial instruments, foreign exchange, insurance, airlines, and retail products.

EDUCATION

1998	Ph.D., public policy, Harvard University Specialized fields: Microeconomics, econometrics, industrial organization, natural resources, and environmental economics - Doctoral Fellow, Harvard University (1993–1995) - Crump Fellowship, Harvard University (1995–1996) - Pre-doctoral Fellow, Harvard Environmental Economics Program
1993	M.C.P., environmental policy and planning (urban studies and planning), Massachusetts Institute of Technology
1986	B.A., physics, Wesleyan University

PROFESSIONAL EXPERIENCE

2005–Present	Analysis Group, Inc. *Principal*
2001–2005	LECG, LLC *Managing Economist*

1998–2001	National Economic Research Associates, Inc. *Senior Consultant*
1997–1998	Harvard Institute for International Development *Consultant*
1996–1997	Department of Economics, Harvard University *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987–1991	Tellus Institute *Research Associate*

SELECTED CONSULTING EXPERIENCE

Energy

- **Continental Buchanan**
  Analysis regarding contractual dispute over synthetic gypsum produced at coal-fired power generation facilities.
- **Singapore**
  Analysis of need for and design of proposed capacity market for Singapore.
- **Ameren Missouri**
  Assessment of reliability and accuracy of Evaluation, Measurement and Verification (EM&V) analysis performed by a third-party consultant.
- **ISO New England**
  Assessment of the economic and operational impact of proposed Energy Security Improvements, market rule changes designed to address energy security concerns.
- **Ameren Missouri**
  Assessment of economic issues associated with participation of baseload (coal-fired) power plants in RTO/ISO markets, including self-commitment and incremental energy offers.
- **ISO New England**
  Analysis of costs of securing energy inventory, including forward LNG contracts, for purposes of establishing the rate for ISO New England’s inventoried energy program.
- **Capital Power**
  Analysis of design of proposed capacity market for Alberta, Canada.
- **New England Electricity Markets**
  Confidential analyses related to natural gas supply contracts, including contracts from liquefied natural gas terminals, and market rules to mitigate fuel security challenges.
- **Global Crude Oil Producer**
  Analysis of alternative approaches and contractual structures for marketing crude oil, including econometric analysis of customer price responsiveness.
- **New York Independent System Operator (New York ISO)**
  Evaluation of performance issues associated with capacity market resources and potential changes to market designs.
- ***Merced v. Barclays***
  Analysis of alleged monopolization of western US electric power markets.

- **ISO New England**
  For the New England Power Pool (NEPOOL) 2016 Economic Analysis, analysis of Forward Capacity Market implications of alternative scenarios with varying assumptions about retirements and clean energy resources.
- **New England Electricity Markets**
  Confidential assessment of interactions between state policies affecting electric power resources, including long-term contracts, and wholesale electricity markets.
- ***FERC v. Barclays***
  Analysis of alleged manipulation of western US electric power exchange markets.
- **New York ISO**
  Demand curve reset for the New York ISO ICAP market including development annual updating process between resets and ICAP Demand Curve parameters.
- **Confidential Client**
  Analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suit.
- **ISO New England**
  Assessment of framework for evaluating capacity market offers from elective transmission projects for market mitigation.
- **Southwest Power Pool Power Suppliers**
  Analysis and testimony related to the types of costs are appropriately short-run marginal costs and thereby should be incorporated into energy market resource offers.
- **New York ISO**
  Evaluation of capacity market rule changes including a forward market structure and multi-year price lock-in, including quantitative economic analysis of changes in market outcomes under alternative market structures.
- **Ameren Missouri**
  Analysis of the economic impact of the Mark Twain Project, a new transmission project designed to support renewable energy requirements and other objectives (using PROMOD).
- **ISO New England**
  Assistance to the ISO New England market monitor in the development of a de-list offer model consistent with new market rules.
- ***Zaremba v. Encana***
  Evaluate operating agreements, the structure of the oil and gas industry, and trends in gas pricing in regards to antitrust claims in the market for oil and gas leases.
- **ISO New England**
  Assistance in the development of winter fuel assurance programs for 2013/2014, 2014/2015 and 2015/2016, including oil inventory, dual fuel, liquefied natural gas and demand response programs
- **Ameren Transmission**
  Analysis of the impact of Multi Value Project No. 16, a new transmission project, on energy market competition in Illinois (using PROMOD).
- **Vancouver Energy**
  Assessment of economic impacts of a new energy distribution terminal, including change in economic activity, property value impacts, and changes in rail congestion.
- **ISO New England**
  Assessment of the economic costs associated with winter 2013/2014 reliability programs, including oil inventory, dual fuel, liquefied natural gas, and demand response programs.

- **ISO New England**
  Assessment of and testimony regarding the economic and reliability impacts of proposed capacity market rules introducing new performance incentives.
- **ITC Midwest**
  Analysis of and testimony regarding the LMP and production cost impacts of new transmission infrastructure (using PROMOD).
- **Entergy**
  Evaluation of economic damages associated with an alleged contract breach.
- **Ameren Transmission**
  Analysis of the impact of the Illinois River Project, a new transmission project, on energy market competition in Illinois (using PROMOD).
- **Dayton Power and Light**
  Evaluation of the aggregate benefits created by a proposed rate plan.
- **Corporation with Distribution Companies Across Multiple Jurisdictions**
  Regulatory assessment considering current ratemaking models, regulatory environment, and alternative ratemaking structures.
- **ISO New England**
  Assessment of the costs, feasibility, and effectiveness of technical options to securing fuel supply for gas-fired generators.
- **ISO New England**
  Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies.
- **Pacific Gas and Electric**
  Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **Confidential Technology Company**
  Analysis of the regional economic impacts of a prototype biofuels production facility at two potential development sites (using the IMPLAN model).
- **ISO New England**
  Statistical analysis of the performance of resources responding to system contingencies.
- **Direct Energy**
  Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions.
- **ISO New England**
  Assistance developing design enhancements for the region's Forward Reserve Markets.
- **Confidential Client**
  Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software).
- **Confidential Client**
  Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software).
- **Confidential Regulated Utility**
  Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development.
- **Commonwealth Edison**
  Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements.

- **New England Power Generators Association**
  Analysis of impacts of proposed electric power company merger.
- **Confidential Technology Company**
  Development of a quantitative model of energy savings associated with end-use technological modifications.
- **National Grid**
  Development of an internal white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load, and service challenges.
- **EDF Group**
  Analysis of financial and credit implications of the sale of a portion of power generation assets.
- **New England States Committee on Electricity**
  Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy.
- **National Grid Utilities**
  Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC**
  Analysis of "best practices" in state policies for competitive procurement of retail electricity supply.
- **New York ISO**
  Analysis of single-clearing-price versus pay-as-bid market designs.
- **Confidential System Operator**
  Analysis of metrics for characterizing the economic value provided by regional transmission organizations.
- **TransCanada**
  Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts.
- **New York ISO**
  Analysis of market implications of fuel diversity issues.
- ***Vitol S.A. Inc. vs. BP Products North America, Inc.***
  Analysis of damages from breach of commodity swap contract (petroleum).
- **Confidential**
  Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding.
- **Confidential**
  Financial and strategic analysis of gas supply contracting alternatives.
- **Confidential**
  Analysis of value of generating assets using real options analysis.
- **Confidential**
  Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts.
- **Confidential**
  Financial and strategic analysis of renewable generation technologies.

Environment

- **Western States Petroleum Association**
  Analysis of approaches to transitioning to long-run efficient climate policies.
- **Western States Petroleum Association**
  Analysis of the implications of a GHG cap-and-trade market rule for other climate policies for the state of Oregon.
- **Greater Boston Real Estate Board**
  Development of a white paper evaluating mandatory residential energy labeling/benchmarking policies.
- **Western States Petroleum Association**
  Analysis of key changes to California's GHG cap-and-trade market rule for the 2021–2030 compliance period.
- ***Florida v. Georgia***
  Analysis of economic issues related to current and proposed alternative apportionment of water between the states of Florida and Georgia before the US Supreme Court.
- **Western States Petroleum Association and Chevron**
  Analysis of key regulatory issues in the design of California's GHG cap-and-trade system for the 2021–2030 period
- ***New Jersey DEP v. Occidental Chemical Corp., et al.***
  One behalf of Maxus, assessment of reliability of analyses and conclusions reached regarding settlement of claims related to environmental contamination.
- **Chevron**
  Development of a white paper on post-2020 climate policy for California.
- ***C&A Carbone v. County of Rockland***
  Support of expert testimony regarding a violation of the dormant commerce clause.
- ***New Jersey DEP v. ExxonMobil***
  Assessment of methods for valuation of environmental contamination.
- **American Petroleum Institute**
  Assessment of issues related to the impact of changes to National Ambient Air Quality Standard Requirements on oil and gas exploration and production.
- **Greater Boston Real Estate Board**
  Development of a white paper on mandatory building energy labeling/benchmarking policies.
- **Little Hoover Commission**
  Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system.
- **Exelon**
  Analysis of the economic and market consequences of EPA's Clean Air Transport Rule.
- **Chevron**
  Assessment of lessons learned from federal requirements for regulatory review for the potential development of state requirements.
- **Western States Petroleum Association and Chevron**
  Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board.
- **Honeywell**
  Analysis of proposed limits on HFC consumption under domestic climate policy.

- **Electric Power Research Institute**
  Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006).
- **Confidential**
  Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs.
- **Confidential**
  Quantitative analysis of the impacts for technology, consumers, and asset owners of a market-based domestic climate policy.
- **Toyota**
  Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements.
- **Barajas Airport**
  Evaluation of the regional economic impacts of runway expansions at the Barajas airport in Spain.

Finance and Commercial Damages

- ***Anderson, et al. v. American Family Insurance***
  Analysis of reliability of methodologies to estimate diminution in property value associated with remediated property damage.
- **Confidential Client**
  Support during settlement, including analysis of factors contributing to assessment of fines associated with an operational incident in the context of a shareholder derivative suite.
- ***In the Matter of Current and Future Conditions of Baltimore Gas and Electric Company***
  Analysis of financial and credit implications of the sale of a portion of power generation assets.
- ***Becarra, et al. v. The Argentine Republic***
  Analysis of bond pricing, transactions, and holdings related to default of sovereign bonds.
- ***Capital One Financial v. Commissioner of Internal Revenue***
  Analysis of transfers between financial institutions within credit card networks.
- **Confidential Client**
  Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement.
- ***Kourosh A. Dastgheib v. Genentech***
  Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product.
- **Confidential Client**
  Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution.

Antitrust

- **BlackRock**
  Analysis of potential impact of common ownership on competition, including econometric analysis of such impacts in the commercial airline industry.
- **Confidential Client**
  Analysis of alleged monopolization of energy price indices.
- ***Central Garden & Pet v. Monsanto***
  Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement.

- ***In re: Vitamins Antitrust Litigation***
  In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data.
- **Confidential Retail Consumer Product Company**
  Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement.
- ***Michlin Diazo Products v. Oce-USA and Oce Printing Systems***
  Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages.
- **Confidential Petrochemical Company**
  Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by the Department of Justice (DOJ) and private parties.
- **Confidential Scientific Equipment Company**
  Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents.
- ***Endobionics, Inc. v. Medtronic, Inc.***
  Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement.
- **Confidential Scientific Equipment Company**
  Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent.

TESTIMONY AND OTHER FILINGS

- **Affidavit on Behalf of ISO New England**
  Federal Energy Regulatory Commission, Docket No. EL18-182-000
  April 14, 2020
- **Expert Report**
  Continental Buchanan, LLC v. GenOn Mid-Atlantic LLC, American Arbitration Association, Case No. 01-19-0002-8683
  April 3, 2020
- **Rebuttal Testimony on Behalf of Ameren Missouri**
  Missouri Public Service Commission, Case No. ER-2019-0335
  January 21, 2020
- **Additional Evidence Regarding the Design for Alberta's Capacity Market**
  Alberta Utilities Commission, Proceeding No. 23757
  April 4, 2019
- **Testimony on Behalf of ISO New England**
  Federal Energy Regulatory Commission, Docket No. ER19-1428-000
  March 25, 2019
- **Evidence Regarding the Design for Alberta's Capacity Market**
  Alberta Utilities Commission, Proceeding No. 23757
  February 28, 2019
- **Direct Testimony on Behalf of Ameren Transmission Company of Illinois**
  Missouri Public Service Commission, Case No. EA-2017-0345
  September 14, 2017

- **Supplemental Affidavit on Behalf of New York Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER17-386-000
  December 21, 2016
- **Affidavit on Behalf of New York Independent System Operator**
  Federal Energy Regulatory Commission, Docket No. ER17-386-000
  November 18, 2016
- **Pre-Filed Testimony on Behalf of Vancouver Energy**
  Washington Energy Facilities Site Evaluation Council, Case No. 15-001
  May 2016
- **Surrebuttal Testimony on Behalf of Ameren Transmission Company of Illinois**
  Missouri Public Service Commission, Case No. EA-2015-0146
  November 16, 2015
- **Affidavit on Behalf of Joint Filing Group, Southwest Power Pool**
  Federal Energy Regulatory Commission, Docket No. ER15-2268-000
  August 31, 2015
- **Direct Testimony on Behalf of Ameren Transmission Company of Illinois**
  Missouri Public Service Commission, Case No. EA-2015-0146
  May 29, 2015
- **Rebuttal Testimony on Behalf of Ameren Transmission Company of Illinois**
  Illinois Commerce Commission, Docket No. 14-0514
  March 5, 2015
- **Rebuttal Testimony on Behalf of MidAmerican Transmission Company**
  Illinois Commerce Commission, Docket No. 14-0494
  March 5, 2015
- **Direct Testimony on Behalf of Ameren Transmission Company of Illinois**
  Illinois Commerce Commission, Docket No. 14-0514
  August 21, 2014
- **Direct Testimony on Behalf of MidAmerican Transmission Company**
  Illinois Commerce Commission, Docket No. 14-0494
  August 4, 2014
- **Rebuttal Testimony on Behalf of ITC Midwest LLC**
  Minnesota Public Utilities Commission, Docket No. CN-12-1053
  April 25, 2014
- **Direct Testimony on Behalf of ITC Midwest LLC**
  Minnesota Public Utilities Commission, Docket No. CN-12-1053
  February 24, 2014
- **Testimony on Behalf of ISO New England**
  Federal Energy Regulatory Commission, Docket No. ER14-1050-001
  February 12, 2014
- **Affidavit on Behalf of ISO New England, Performance Incentives Market Rule Changes**
  Federal Energy Regulatory Commission, Docket No. ER14-1050-001
  January 14, 2014
- **Comments Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program (with Robert N. Stavins)**
  California Air Resources Board
  August 2011

- **Comments Submitted to the Little Hoover Commission's Study of Regulatory Reform in California (with Robert N. Stavins)**
  January 2011
- **Comments Regarding on the Proposed Regulation to Implement the AB 32 Cap-and-Trade Program**
  California Air Resources Board
  December 2010
- **Comments Regarding Cost Containment Provisions of Preliminary Draft Cap-and-Trade Regulation**
  California Air Resources Board
  July 2010
- **Comments Regarding the Draft Report "Allocating Emissions Allowances Under California's Cap-and-Trade System" (with Robert N. Stavins)**
  Economics and Allocation Advisory Committee, California Air Resources Board
  December 1, 2009

ARTICLES AND PAPERS

"GHG Cap-and-Trade: Implications for Effective and Efficiency Climate Policy in Oregon," with Robert N. Stavins, The Harvard Project on Climate Agreements, Discussion Paper 18-92, November 2018.

"Key Issues Facing California's GHG Cap-and-Trade System for 2021-2030," with Robert N. Stavins, M-RCBG Faculty Working Paper 2018-02, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, July 2018.

"Beyond AB 32: Post-2020 Climate Policy for California," with Robert N. Stavins, Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2014.

"Three Lingering Design Issues Affecting Market Performance in California's GHG Cap-and-Trade Program," with Robert N. Stavins, Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2013.

"Using the Value of Allowances from California's GHG Cap-and-Trade System," with Robert N. Stavins, Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"Implications of Policy Interactions for California's Climate Policy," with Robert N. Stavins, Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," with Paul Hibbard, *The Electricity Journal*, May 2012.

"California's Cap-and-Trade Decisions," *Forbes.com*, August 19, 2010.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," with Susan F. Tierney, *The Electricity Journal*, March 2009.

"Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation," with Susan F. Tierney and Rana Mukerji, *Public Utilities Fortnightly*, March 2008.

"Free Greenhouse Gas Cuts: Too Good to Be True?" with Judson Jaffe and Robert Stavins, VoxEU.org, January 3, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy," with Robert N. Stavins and Judson Jaffe, AEI-Brookings Joint Center for Regulatory Studies, Related Publication 07-01. Jan 2007.

"Options, Uncertainty and Sunk Costs: An Empirical Analysis of Land Use," Journal of Environmental Economics and Management, Vol. 46, p. 86-105, 2003.

"The database on the economics and management of endangered species (DEMES)," with David Cash, Andrew Metrick, and Martin Weitzman, in *Protecting Endangered Species in the United States: Biological Needs, Political Realities, Economic Choices*. Cambridge University Press, 2001.

"The Issue of Climate," *Fundamentals of the Global Power Industry, Petroleum Economist*, 2000.

"Review of "Sustainable Cities: Urbanization and the Environment in International Perspective," *Environmental Impact Assessment Review*, (Vol. 12, No, 4), 1993.

"Bottle Bills and Municipal Recycling," *Resource Recycling*, June 1991.

WORKING PAPERS

Reassessing Common Ownership: Corrections to Azar, Schmalz, and Tecu, with Mark Egland, Owen Hearey, and Channing Verbeck, October 2, 2019.

Quality and *Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes*, June 23, 2014.

Reliability and Resource Performance, May 16, 2012.

Can Cost Containment Raise Costs? Allowance Reserves in Practice, March 2012.

Generation Fleet Turnover in New England: Modeling Energy Market Impacts, with Paul Hibbard, Pavel Darling, and Bentley Clinton, June 2011.

A Hazard Rate Analysis of Mirant's Generating Plant Outages in California, with William Hogan and Scott Harvey, presented at the IDEI Conference on Competition and Coordination in the Electricity Sector, Toulouse, France, January 16–17, 2004.

The Pollution Control and Management Response of Thai Firms to Formal and Informal Regulation, with Theodore Panayotou, 1999.

Differential Industry Response to Formal and Informal Environmental Regulations in Newly Industrializing Economies: The Case of Thailand, with Theodore Panayotou and Qwanruedee Limvorapitak, presented at Harvard Institute for International Development 1997 Asia Environmental Economics Policy Seminar, Bangkok, Thailand, February 1997.

The Effects of Uncertainty on Landowner Conversion Decisions, John F. Kennedy School of Government, Center for Science and International Affairs, Environment and Natural Resources Program, Discussion Paper 95-14, December 1995.

REVIEW OF ACADEMIC ARTICLES

Economics of Energy & Environmental Policy

Ecological Economics

Journal of Environmental Economics and Management

Transportation Research

SELECTED PRESENTATIONS

"Market Implications of Evolving 'Cleaner,' 'Greener' Resource Mixes," 2020 Energy Bar Association Midwest Chapter Annual Meeting, March 10, 2020.

"Regional Generation Trends – State Policy Drivers and Responses," EBA Energizer, Energy Bar Association Power Generation and Marketing Subcommittee, December 3, 2019.

"Cost Containment – Which Cap-and-Trade Features Matter Most?" Climate Forum on California's Cap-And-Trade Program, International Emissions Trading Association, Carbon Market Compliance Association, Latham and Watkins, LLC, September 19, 2018.

"Northeast Power Markets Outlook: Addressing the Capacity and Reliability Crunch" and "Natural Gas: Cross-Border Trade, Market Dynamics, and Infrastructure Woes," EUCI 4TH Annual US Canada Cross-Border Energy Summit, March 12–13, 2018.

"Implications of the Expansion of "Non-Traditional" Resources for the Northeast Power Markets," Northeast Energy and Commerce Association's Power Markets Conference, November 14, 2017.

"The FERC's Anti-Market Manipulation Rule: Trends and Developments," webinar, The Knowledge Group, April 12, 2017.

"State Policy and Wholesale Power Markets: Emerging Issues Across the Markets," Northeast Energy and Commerce Association, Power Markets Conference, November 1, 2016.

"Net Metering," workshop, EUCI, Residential Demand Charges, October 20, 2016.

"Evaluating Carbon Risk Measures Under Policy Uncertainty," workshop, EUCI U.S./Canada Cross-Border Power Summit, March 14–15, 2016.

"Implications of Policy Initiatives for Wholesale Markets," Northeast Energy and Commerce Association, Power Markets Conference, November 17, 2015.

"The Western United States' Impact On Global Climate Change Policy," 2015 WSPA Issues Conference, September 30, 2015.

"Capacity Performance (and Incentive) Reform" and "Out of Market Actions," EUCI Conference: Capacity Markets: Gauging Their Real Impact on Resource Development & Reliability, August 31–September 1, 2015.

"California Climate Goals for 2030 to 2050," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Local and Regional Climate Protection Efforts," California Council on Environmental and Economic Balance, Summer Issues Seminar, July 14, 2015.

"Current Regional Transmission Planning and Issues in New England," Law Seminar International Transmission in the Northeast, March 19, 2015.

"Stakeholder Assessment and Outlook for the Markets," Power Markets Conference, Northeast Energy and Commerce Association, October 20, 2014.

"Market Changes to Promote Fuel Adequacy – Capacity Markets to Promote Fuel Adequacy," moderator of panel discussion, Northeast Energy Summit 2014, September 17–19, 2014.

"Quality *and* Quantity: Alternatives for Addressing Reliability Concerns from Shifting Resource Mixes," Center for Research In Regulated Industries 27th Annual Western Conference June 26, 2014.

"Climate Policy Choices – RPS, Cap-and-Trade & the Implications for Actions (and Exits) that Affect Emissions," Electric Utilities Environmental Conference, February 4, 2014.

"Multiple Dimensions of Gas-Electric Coordination Concerns," Electric Utilities Environmental Conference, February 3, 2014.

"The Economics of Cap-and-Trade in the California Power Markets," EUCI Conference, California Carbon Policy Impacts on Western Power Markets, January 27, 2014.

"An Economic Perspective on Building Labeling Policies," Greater Boston Real Estate Board, April 26, 2013.

"Market-Based Policies to Address Climate Change," Sustainable Middlesex, May 4, 2013.

"Market Forces and Prospects/Economic Ripple Effects, 5-10 Years Ahead," Air & Waste Management Association, New England Section, October 12, 2012.

"Gas and Electric Coordination: Is It Needed? If So, To What End?" Harvard Electric Policy Group, Cambridge, MA, October 11, 2012.

"Reliability and Resource Performance," Center for Research In Regulated Industries 31st Annual Eastern Conference May 16, 2012.

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," International Industrial Organization Conference, Boston, MA, April 9, 2011.

"Ratemaking Mechanisms/Tools as Carrots for Achieving Desirable Regulatory Outcomes," Conference on Electric Utility Rate Cases, Law Seminars International, Boston, Massachusetts, November 9, 2010.

"Evolving Issues in Revenue Decoupling: Designs for an Era of Rising Costs," Center for Research In Regulated Industries 29th Annual Eastern Conference May 19, 2010.

"Aligning Interest with Duty: Revenue Decoupling as a Key Element of Accomplishing Energy Efficiency Goals," National Conference of State Legislatures, Fall Forum, December 8, 2009.

"Federal Proposals to Limit Carbon Emissions and How They Would Affect Market Structures – Regional Trading Programs' Futures in Light of New Federal Interest in Reducing GHG Emissions," Energy in California, Law Seminars International, San Francisco, California, September 15, 2009.

"Current Market, Technology and Regulatory Risks: Impact on Investment and Implications for Policy," Utility Rate Case, Issues and Strategy 2009, Law Seminars International, Las Vegas, Nevada, February 9, 2009.

"An Economic Perspective on the Benefits of Going Green," Harvard Electricity Policy Group, Atlanta, Georgia, December 11–12, 2008.

"Implications of Current Regulatory, Technology and Market Risks," Energy in California, Law Seminars International, San Francisco, California, September 22–23, 2008.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," National Association of Regulatory Utility Commissioners Summer Committee Meetings, Portland, Oregon, July 20, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy, Key Findings and Lessons Learned," POWER Research Conference on Electricity Markets and Regulation, University of California at Berkeley, March 21, 2008.

"Preliminary Findings: Study of Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," National Association of Regulatory Utility Commissioners Annual Meeting, Washington, DC, February 17, 2008.

"The ABC's of California's AB 32: Issues and Analysis, Cost Analyses and Policy Design," Environmental Market Association Webinar, April 12, 2007.

SELECTED CONSULTING REPORTS

Capacity Resource Performance in NYISO Markets, An Assessment of Wholesale Market Options, with Hibbard, P. and Bolthrunis, S., prepared for the New York Independent System Operator, October 2017.

Capacity Market Impacts and Implications of Alternative Resource Expansion Scenarios, An Element of the ISO New England 2016 Economic Analysis, with Llop, C., prepared for ISO New England, July 3, 2017.

Study to Establish New York Electricity Market ICAP Demand Curve Parameters, with Hibbard, P., Aubuchon, C., Berk, E., and Llop, C., prepared for the New York Independent System Operator, June 2016.

NYISO Capacity Market: Evaluation of Options, with Hibbard, P., Aubuchon, C., and Wu, C., prepared for the New York Independent System Operator, May 2015.

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives, with Hibbard, P., prepared for ISO New England, September 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis, with Frame, R. and Darling, P., Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, April 9, 2013.

LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project, with Frame, R., and Darling, P., Appendix M, ITC Midwest LLC, Application to the Minnesota Public Utilities Commission for a Certificate of Need, Docket No. ET6675/CN-12-1053, March 22, 2013.

Analysis of Reserve Resources: Activation Response following Contingency Events, prepared for ISO New England, May 29, 2012.

Economic and Environmental Implications of Allowance Benchmark Choices, with Stavins, R., prepared for the Western States Petroleum Association, October 2011.

Next Steps for California Climate Policy II: Moving Ahead under Uncertain Circumstances, with Stavins, R., prepared for the Western States Petroleum Association, April 2010.

Options for Addressing Leakage in California's Climate Policy, with Borck, J. and Stavins, R., prepared for the Western States Petroleum Association, February 2010.

Addressing Environmental Justice Concerns in the Design of California's Climate Policy, with Stavins, R., prepared for the Western States Petroleum Association and the AB 32 Implementation Group, November 2009.

Next Steps for California with Federal Cap-and-Trade Policy On the Horizon, with Stavins, R. and Borck, J., prepared for the Western States Petroleum Association, July 2009.

Evolving GHG Trading Systems Outside Its Borders: How Should California Respond? with Stavins, R. and Borck, J., prepared for the Western States Petroleum Association, July 2009.

Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices, with Tierney, S., prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008.

Uniform Pricing versus Pay-as-bid: Does it Make a Difference? with Tierney, S. and Mukerji, R., prepared for the New York Independent System Operator, March 2008.

Prospects for the U.S. Nuclear Industry, coauthor, prepared for a major Japanese electric power company, January 2001.

Costs and Benefits of Fish Protection Alternatives at Mercer Generating Station, with Harrison, D. and Lovenheim, M., prepared for Public Service Enterprise Group, September 2000.

Economic Evaluation of EPA's Proposed Rules for Cooling Water Intake Structures for New Facilities, with Harrison, H., prepared for the Utility Water Act Group, November 2000.

The Impacts of Revised Salem Refueling Schedules on the Wholesale and Retail Electric Market, with Harrison, D. and Meehan, G., prepared for Public Service Enterprise Group as a filing to New Jersey Department of Environmental Protection, September 2000.

Setting Baselines for Greenhouse Gas Credit Trading Programs: Lessons from Experience with Environmental and Non-Environmental Program, with Harrison, D., Electric Power Research Institute Report #1000147, December 2000.

Fueling Electricity Growth for a Growing Economy, Background Paper, with Harrison, D., prepared for the Edison Electric Institute, July 2000.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 2 Executive Report, contributor, Electric Power Research Institute, Technical Report 1000097, December 2000.

Economic Evaluation of Alternative Revised Refueling Outage Schedules for Salem Power Plant, with Harrison, D. and Murphy, J., prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, July 2000.

Critical Review of "Economic Impacts of On Board Diagnostic Regulations", with Harrison, D. and Chamberlain, S., prepared for Alliance of Automobile Manufacturers, January 2000.

Costs and Benefits of Alternative Revised Refueling Outage Schedules, with Harrison, D. and Murphy, J., prepared for Public Service Electric and Gas Company, July 1999.

Costs and Benefits of Fish Protection Alternatives at the Salem Facility, with Harrison, D. and Murphy J., prepared for Public Service Electric and Gas Company as a filing to New Jersey Department of Environmental Protection, March 1999.

Energy-Environment Policy Integration and Coordination Study (E-EPIC) Phase 1 Executive Report, contributor, Electric Power Research Institute, February 1999.

Economic Benefits of Barajas Airport to the Madrid Region and the Neighboring Communities, with Harrison, D., Garcia-Cobos J., and Rowland, D., prepared on behalf of the Spanish Government, January 1999.

Costs and Benefits of Alternatives for Modifying Cooling Water Intake at the Hudson Facility, with Harrison, D., Rowland, D., and Murphy, J., prepared for Public Service Electric and Gas Company, November 1998.

Disposal Cost Fee Study, with Ackerman, F., McClain, G., Peters, I., and Schall, J., prepared for the California Integrated Waste Management Board, 1991.

The Marginal Cost of Handling Packaging Materials in the New Jersey Solid Waste System, with Schall, J., prepared for The Council of State Governments and the New Jersey Department of Environmental Protection, 1990.

Energy Implications of Alternative Solid Waste Management Systems, with Becker, M., and White, A., prepared for the Northeast Regional Biomass Program, Coalition of Northeastern Governors Policy Research Center, 1990.

Exhibit C

Exhibit C
CHARLES WU
Manager

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Boston, MA 02119

Mr. Wu has broad experience consulting to clients on energy economics, securities, trade disputes, and mergers and acquisitions. He has conducted economic impact analyses related to energy, electricity, and carbon allowance markets, and has designed and run simulations of large-scale distributed networks to predict operational efficiency and costs to consumers, including operational models of power plant and natural gas availability to analyze fuel and energy security during extreme weather conditions. Mr. Wu has assisted market regulatory authorities with matters related to market and auction design. In litigation matters, he has supported academic affiliates with damages estimations based on lost royalties, critiques of statistical sampling for mortgage-backed securities, and Monte Carlo simulation modeling of statistical tests. Prior to joining Analysis Group, Mr. Wu worked at Microsoft, where he used order-level data from across Microsoft's hardware supply chain to visualize the timing of international distribution center inbound and outbound shipments.

EDUCATION

2017	M.B.A., enterprise management, MIT Sloan School of Management
2011	M.A., economics, Northwestern University
2010	S.B., economics, Massachusetts Institute of Technology

PROFESSIONAL EXPERIENCE

2012–Present	Analysis Group, Inc. *Manager (2020–Present)* *Associate (2015–2019)* *Senior Analyst (2012–2014)*
2016	Microsoft Corp. *Supply Chain Analytics Intern*

SELECTED CONSULTING EXPERIENCE

Electricity Operational Analysis

- **Analysis of Winter Operational Risks**
  Co-authored study on the impact of climate change on energy security in New York. Led team in modeling of system reliability across three seasons under multiple climate-change-related scenarios. Managed development of potential future resource sets, including modeling of New York transmission network

- **Analysis of Winter Operational Risks**
  Co-authored study on the impact of winter operational risks on fuel and energy security in New York. Led team in modeling of severe winter cold snap period under a variety of weather and fuel contingency scenarios with impacts on generation and load.

Economic Impact Analysis

- **Economic impact analysis of carbon trading program**
  Led team to quantify the economic and employment impacts of the nine-state Regional Greenhouse Gas Initiative (RGGI) carbon trading program. Coordinated team's collection and integration of data into multi-region model of hourly electricity prices.
- **Economic impact modeling for electrical distribution system**
  Led team to analyze economic impact on ratepayers of a potential change in ownership for a California electrical distribution system. Managed data collection and integration processes.
- **Supply and demand modeling for wholesale electricity markets**
  Designed and programmed predictive models for electricity supply and demand in New England and New York capacity markets using power plant-level cost data on hundreds of regional generation assets. Modeled outcomes used by regulatory clients to set electricity policy affecting 34.5 million consumers.

Other Energy Economics

- **Simulation analyses for electrical transmission infrastructure**
  Ran simulations of electrical transmission and analyzed results to show efficacy of proposed high-voltage transmission lines in the Midwest. Analyses were used to gain regulatory approval for five major projects valued at over $2 billion in capital investment.
- **Valuation for new power plant**
  Created dynamic discounted cash flow (DCF) model to predict revenues for proposed 85-megawatt gas turbine power plant in Maine under variety of fuel price and generation scenarios. Results were used by client to determine bid for 15-year power purchase agreement (PPA) worth $300 million.

Data Analytics for Litigation and Arbitration

- **Financial modeling for royalties**
  Led team of three analysts in construction of financial model based on sales invoices, used to calculate damages in international arbitration concerning natural gas royalties. Served as main point of contact with client on quantitative issues. Analyses led to award of $56.3 million to client.
- **Statistical sampling for mortgage-backed securities (MBS)**
  Designed and implemented analyses to support statistical expert evaluating sampling in MBS litigation.
- **Statistical analysis for trade dispute**
  Designed and led implementation of Monte Carlo statistical simulation model to support testifying expert in high-profile international tobacco trade litigation; work led to withdrawal of two opposing experts' testimonies.

SELECTED HONORS AND AWARDS

2010 Graduate Research Fellowship, National Science Foundation

Exhibit D

EXHIBIT D
CHRISTOPHER J. LLOP
Manager

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Mr. Llop specializes in information analyses in the technology, software, and energy sectors. His areas of expertise include managing analytics teams, energy market modeling, litigation source code analysis, software development, and policy and governance studies. Mr. Llop regularly supports experts in technology-related litigation matters, from assessments of cybersecurity issues to detailed competitor analyses of the antitrust implications of high-tech product lines. He works on many of Analysis Group's largest data cases and manages product teams responsible for developing applications to collect and securely store data from sources such as wearable technology. In the energy sector, Mr. Llop conducts economic modeling of proposed market rule impacts and has been involved in studying the competitiveness of rate structures. His experience in governance covers organizational reviews and policy studies related to artificial intelligence and algorithms. He also has experience in health care claims and medical records; his work in this area has been published in *Hospital Practice*. Mr. Llop is a virtual lecturer on Python Fundamentals for Data Science, a highly rated class at the University of California, Berkeley. He is an active participant in Analysis Group's pro bono work in Haiti, building methods to measure and optimize patient experiences in a clinic and the data connectivity in a lab.

EDUCATION

2016	M.I.D.S., information and data science, UC Berkeley School of Information
2010	B.S., electrical engineering, State University of New York at Buffalo

PROFESSIONAL EXPERIENCE

2011–Present	Analysis Group, Inc. *Manager (January 2019–Present)* *Associate (July 2016–December 2018)* *Analyst/Senior Analyst (2011–2016)*
2016–Present	University of California, Berkeley School of Information *Lecturer*

SELECTED CONSULTING EXPERIENCE

Energy

- Managed a team to conduct multiple analyses evaluating the capacity market impacts of various potential resource expansion scenarios in New England. Modeled market clearing under a variety of scenarios and elaborated on potential impacts. Produced a report for market participants.

- Managed a team in building a bespoke production cost model using linear programming to evaluate the impact of proposed Energy Security Improvement changes to the ISO New England energy markets, including the evaluation of new market products co-optimized with existing products.
- Assisted in an antitrust litigation matter dealing with the competitiveness of a specific utility rates structure. Spearheaded effort to reverse engineer the client's calculations and codes so that they could be defended in an expert report.
- Developed interactive models to assess the economic impact of performance incentives on New England's power capacity market. Modeled costs to comply with Environmental Protection Agency regulations, benefits of fuel types, and premium due to risk across asset portfolio.
- Used production models to determine the potential impacts of a proposed pipeline in New England for the Attorney General of Massachusetts. Compared the costs and impacts of the pipeline with other reliability solutions.
- Reviewed 43,000 pages of trial transcripts to develop analyses related to the "safety culture" of an international oil and gas company after an environmental disaster. Condensed information to assist an academic expert.

Software, Technology, and Cybersecurity

- Provided in-depth consulting support for early stages of a patent litigation matter, including assistance with the analysis of infringement contentions, creation and support of related non-infringement arguments, and technical guidance related to claim construction. Managed a team studying and providing evidence from over 70,000 code files for a distributed cloud computing infrastructure.
- Analyzed the source code for millions of files across programming languages for a multibillion-dollar tax litigation. Measured the similarity between pairs of files to understand how developers modified the source code over time. Critiqued methods of the opposing academic expert and developed modified analyses to more accurately reflect case issues.
- Performed detailed review of source code in an intellectual property dispute involving networking protocol, as implemented within software for a now bankrupt company. Identified the presence and use of specific third-party codes, assisted in identifying code versions active during product compilation, developed scripts to flag lines of code based on content, and compiled status for use in expert report.
- Analyzed technology logs from a malware attack causing millions of dollars to be transferred to hackers around the globe. Supported an affiliated expert in examining available anomaly detection methods and whether the defendant's fraud detection system met commercial industry standards.
- Provided analysis of the source code of systems alleged to be automated telephone dialing systems.
- Provided litigation analysis of the source code of systems implementing the SNMP networking protocol, and systems alleged to be telephone dialing systems.
- Led an organizational review of Security and Stability Advisory Committee (SSAC) for the Internet Corporation for Assigned Names and Numbers (ICANN).
- Performed research and analysis for technology companies such as Facebook and Google regarding the regulation and law around machine learning, artificial intelligence, and data privacy.
- Managed a team developing detailed case studies of competitors in the modem chip industry, and applied an industrial organization economics framework to understand the drivers of company success.

- Assisted in the development of cross-examination strategy related to the digital forensics of when an email was saved and whether it was viewed.
- Assisted in the development of an expert report related to matters of responsible disclosure in the face of cybersecurity vulnerability discovery.
- Regularly manage the preparation of "code rooms" for litigation expert work, ensuring that files and technology are properly in place for analyses.

Health Care and Finance

- Managed the development of a wearable device mobile application (iPhone and Apple Watch) for a pilot study investigating the capability of using digital health as a tool to assist in clinical trials. Oversaw development of front- and back-end infrastructure, application testing, and real-time data collection as the study progressed.
- Designed data intake systems for a large health care case involving tens of terabytes of undocumented data and non-data files. Led the process of organizing and classifying files, and preparing them for rigorous data analysis.
- Designed and implemented statistical analyses measuring health care claims and electronic medical records (EMRs) of antibiotic impacts on patients with community-acquired pneumonia. This work was featured at conferences and published in *Hospital Practice* (Llop, et al., 2017).
- Developed analyses modeling alleged overcharges to bank clients in a litigation matter involving foreign exchange trades of an international custodian bank. Streamlined codes for multi-person cleaning of a large amount of disorganized data.

COMMUNITY INVOLVEMENT

- GHESKIO Centers
- Public Service Economics

Exhibit E

ANALYSIS GROUP

Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report

Analysis Group, Inc.
Burns & McDonnell

September 9, 2020

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This Final Report provides values for the 2021/2022 Capability Year ICAP Demand Curves as well as methodologies and inputs to be used in determining the ICAP Demand Curves for the 2022/2023, 2023/2024, and 2024/2025 Capability Year. *All numerical results presented in this Final 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 2017 through August 2020.*

Legal Notice

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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
AF	Attachment Facilities
AP	Amortization Period
ARV	Annual Reference Value
ATWACC	After Tax Weighted Average Cost of Capital
BACT	Best Available Control Technology
BPCG	Bid Production Cost Guarantee
Btu	British Thermal Units
CAES	Compressed Air Energy Storage
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CSAPR	Cross State Air Pollution Rule
CSO	Capacity Supply Obligation
CSPP	Comprehensive System Planning Process
CT	Combustion Turbines
CTO	Connecting Transmission Owner
CY	Class Year
DAMAP	Day-Ahead Margin Assurance Payment
DCR	Quadrennial ICAP Demand Curve Reset Process
DMNC	Dependable Maximum Net Capability
DOL	NYS Department of Labor
EAS	Energy and Ancillary Services

Acronym or Abbreviation	Description
EFORd	Equivalent Demand Forced Outage Rate
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, Construction
ERC	Emission Reduction Credits
FERC	Federal Energy Regulatory Commission
FEMA	Federal Emergency Management Agency
FICA	Federal Insurance Contributions Act
FTE	Full Time Equivalent
GADS	Generating Availability Data System
GE	General Electric International, Inc.
GHG	Greenhouse Gases
HHV	Higher Heating Values
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
ICR	NYCA Minimum Installed Capacity Requirement (MW)
IRM	NYCA Installed Reserve Margin (%)
ISO	International Organization for Standardization
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
kW-mo.	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
LFG	Landfill Gas

Acronym or Abbreviation	Description
LHV	Lower Heating Value
LI	Long Island (Load Zone K)
LOE	Level of excess
LOE-AF	Level of excess adjustment factor
LOLE	Loss of Load Expectation
MHPS	Mitsubishi Hitachi Power Systems
MIS	Minimum Interconnection Standard
MMBtu	Million Btu
MMU	Market Monitoring Unit (Potomac Economics)
MPs	Market Participants
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGCC	Natural Gas Combined Cycle
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.
NYPA	New York Power Authority
NYSDEC	New York State Department of Environmental Conservation

Acronym or Abbreviation	Description
O_2	Oxygen
O&M	Operations and Maintenance
OTR	Ozone Transport Region
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection, L.L.C.
POI	Points of Interconnection
PPA	Power Purchase Agreement
ppb	Parts per billion
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
PV	Photovoltaic
P&W	Pratt & Whitney Power Systems
REV	New York Reforming the Energy Vision proceeding
RGGI	Regional Greenhouse Gas Initiative
RICE	Reciprocating Internal Combustion Engines
ROS	Rest of State (Load Zones A-F)
RP	Reference point price
RTO	Regional Transmission Organization
SCR	Selective Catalytic Reduction
SDU	System Deliverability Upgrades
SER	Significant Emission Rates
Siemens	Siemens Energy Inc.
SiPEP	Siemens Performance Estimating Program
SO_2	Sulfur Dioxide
SUF	System Upgrade Facilities

Acronym or Abbreviation	Description
UARG	Utility Air Regulatory Group
UCAP	Unforced Capacity
ULSD	Ultra-low Sulfur Diesel
U.S.	United States
USEPA IPM	United States Environmental Protection Agency Integrated Planning Model
VOC	Volatile Organic Compounds
VSS	Voltage Support Service
WACC	Weighted Average Cost of Capital
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 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 18, 2019, the NYISO contracted with Analysis Group Inc. (AGI) to conduct the independent review of ICAP Demand Curves, to be used starting in Capability Year 2021/2022. Analysis Group, Inc. (AGI) teamed with Burns & McDonnell (BMCD) to complete the development of ICAP Demand Curve parameters, described in this Final Report (Report).

B. Study Purpose and Scope

The purpose of this Report is to summarize the results of our study of the ICAP Demand Curve process and 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.[1] 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 over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[2]

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:

> "…[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…"[3]

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[1] NYISO, Market Services Tariff (hereafter "Services Tariff"), Section 5.14.1.2.
[2] Services Tariff, Section 5.14.1.2.
[3] Services Tariff, Section 5.14.1.2.

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, or 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.[4]

The Services Tariff also specifies the process for selecting the independent consultant, and sets forth 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, 2021).

C. Study Process

AGI and BMCD have conducted the ICAP Demand Curve review in an open and transparent process that involved the full vetting of issues raised by stakeholders. AGI and BMCD 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 AGI or BMCD participated, and the issues discussed with stakeholders in each meeting.

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

[4] Services Tariff, Section 5.14.1.2.

Table 1: Summary of AGI and BMCD Stakeholder Engagement

Date	Committee / Working Group	Topic
August 23, 2019	ICAPWG	Introduction to team and DCR
October 11, 2019	ICAPWG	DCR timeline Initial key DCR considerations
November 6, 2019	ICAPWG	Introduction to peaking plant technology evaluation Review of net Energy and Ancillary Services (EAS) revenue model for fossil generating resources (CT and CC) Process for selecting gas hubs for pricing
December 11, 2019	ICAPWG	Technology screening overview (CT, CC and battery storage) Proposed Net EAS revenues model modifications for CT and CC Potential approaches to model net EAS revenue for battery storage
January 30, 2020	ICAPWG	Technology screening and environmental review Preliminary unit performance, capital costs, and O&M estimates Level of excess adjustment factors Continued analysis of peaking pant amortization period and natural gas hubs Additional discussion of net EAS revenues battery storage modeling
February 25, 2020	ICAPWG	ICAP Demand Curve shape and slope Initial discussion of financial parameters Additional discussion of net EAS revenues battery storage modeling
March 26, 2020	ICAPWG	Technology selection review Updates to unit performance, capital costs, and O&M estimates Preliminary recommendations of financial parameters and gas hubs for pricing Overview of winter-summer ratio methodology Additional discussion of net EAS revenues battery storage modeling
April 22, 2020	ICAPWG	Capital cost and O&M updates Updates to recommendations for gas hubs for pricing and amortization period Preliminary recommendations regarding consideration of SCR emissions control and dual-fuel capability Discussion of COVID-19 related considerations on financial parameter recommendations Further enhancements to the net EAS revenues battery storage modeling

May 19, 2020	ICAPWG	Updates to financial parameter considerations Preliminary Level of Excess Adjustment Factor results PILOT payments and property taxes Preliminary reference point prices Additional details on net EAS model logic for fossil resources
June 10, 2020	ICAPWG	Overview of Draft Report Updated preliminary reference point prices Additional details on recommended gas hubs Additional details on PILOT payment rates
July 22, 2020	ICAPWG	Review of stakeholder feedback by topic: Peaking plant technology Selective Catalytic Reduction (SCR) emissions control technology Capital costs Financial parameters Amortization period Gas hub selection Net energy and ancillary services (EAS) revenue model Level of excess adjustment factors
August 10, 2020	ICAPWG	Updates to costs Updates to net EAS revenues model

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.[5] 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.[6] 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 a model constructed by AGI for this purpose. The model includes a mechanism to adjust the location based marginal prices (LBMPs) and reserve prices used in the net EAS revenues model to reflect market conditions at the Services Tariff-prescribed level of excess (LOE).[7]
- ***Determination of reference point price and ICAP Demand Curve in NYCA and each Locality (Section V).*** In this step, gross CONE estimates (from Section III) with expected net EAS revenues (from Section IV) are combined to calculate the reference point price (RP) values for the ICAP Demand Curves

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[5] Services Tariff, Section 5.14.1.2.

[6] 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.

[7] 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 AGI 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.

for NYCA and each Locality. Other parameters that govern the shape and slope of the ICAP Demand Curves, including the ZCP and the winter-to-summer ratio (WSR), are also considered.

- ***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 WSR.[8]

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.

AGI and BMCD developed their recommendations for this DCR through the continuous interaction with stakeholders over a nearly year-long period. AGI and BMCD received feedback on proposals and analyses from NYISO and stakeholders in written and verbal form across numerous meetings of the 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, at the outset of the process AGI 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, AGI 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 electricity 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.

[8] 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 WSR is used to account for the differences in capacity available. The WSR is discussed in greater detail in Section IV.

- *Feasibility* – The DCR design and implementation should be practical and feasible from regulatory and administrative perspectives.
- *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 also promotes market stability, which in turn reduces financial risk and developers' cost of entry.

E. Summary of Recommendations and Overview of RP Results

AGI has applied the methods, models and equations described in this Final Report to identify RP values and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2021/2022. These values are presented in Table 2, below.

To arrive at these results, AGI and BMCD considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of the RP values provided herein. Specifically, AGI and BMCD conclude the following:

- The GE 7HA.02 (H Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a dual fuel H Class Frame machine would be built with SCR emission control technology in Load Zone J, Load Zone K, Load Zone G (Rockland County), and Load Zone G (Dutchess County), and a gas only H Class Frame machine would be constructed without SCR emissions control technology in Load Zone C and Load Zone F.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures, consideration of applicable reliability and LDC tariff requirements, and developer expectations, the H Class Frame machine should include dual fuel capability in Load Zone G (Rockland County), Load Zone G (Dutchess County), Load Zone J, and Load Zone K. AGI and BMCD recommend a gas-only (without dual fuel capability) design in Load Zone C and Load Zone F.
- The state of New York has begun a process to decarbonize the power sector over the next couple decades, including passage of the Climate Leadership and Community Protection Act (CLCPA). This does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology. It does, however, suggest review of the ways in which these efforts affect the development and operation of such facilities, which could in turn affect the present-day financial analysis parameters (e.g., the appropriate amortization). For this DCR, we recommend a 17-year amortization period for fossil-fueled plants in consideration of the CLCPA's restrictions on fossil fuel operations for electric generation past 2039.
- Based on our review, battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time. We come to this conclusion based primarily on our estimates of the net CONE for a sample battery storage facility with 4-, 6-, and 8-hour duration of storage and the availability of lower cost viable technology options.
- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a 13.0% return on equity, for a WACC of 9.54%. Based on current tax rates in NY State and

New York City, this translates to a nominal after tax WACC (ATWACC) of 8.52% and 8.20%, respectively.

- Net EAS revenues are estimated for the peaking plant technologies using gas hubs that reflect consideration of a number of factors, including consistency of gas prices with LBMPs within each Load Zone, liquidity of trading, geographic consistency with the locations evaluated, and precedence of use in other studies/analysis. To that end, net EAS revenues are estimated using the following gas hubs, which remain fixed for the four year duration of the reset period:
  - Load Zone C: TGP Zone 4 (200L)
  - Load Zone F: Iroquois Zone 2
  - Load Zone G (Dutchess County): Iroquois Zone 2
  - Load Zone G (Rockland County): TETCO M3
  - Load Zone J: Transco Zone 6 New York
  - Load Zone K: Iroquois Zone 2
- 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 2021/2022 Capability Year ICAP Demand Curves for each location assessed consistent with the conclusions and technology findings described above. Table 3 through Table 5 provides additional information for the other technologies evaluated. For ICAP Demand Curves where more than one location is evaluated (i.e., NYCA and the G-J Locality), the appropriate locations and peaking plant technology and design selected as the basis for the 2021/2022 Capability Year ICAP Demand Curves remain fixed for the four year duration of the reset period.

Table 2: ICAP Demand Curve Parameters ($2021)

GE 7HA.02

Parameter	Source	Current Year (2021-2022) C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
Gross Cost of New Entry ($/kW-Year)	[1]	$114.75	$115.79	$145.32	$149.78	$196.41	$159.77
Net EAS Revenue ($/kW-Year)	[2]	$36.67	$24.56	$27.96	$35.15	$33.42	$54.15
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$78.08	$91.23	$117.35	$114.63	$162.99	$105.62
ICAP DMNC (MW)	[4]	326.7	328.5	347.0	347.0	348.8	348.8
Total Annual Reference Value	[5] = [3] * [4]	**$25,509,781**	**$29,967,642**	**$40,721,005**	**$39,776,090**	**$56,852,412**	**$36,841,547**
Level of Excess (%)	[6]	100.9%	100.9%	102.5%	102.5%	103.5%	106.5%
Ratio of Summer to Winter DMNCs	[7]	1.038	1.038	1.059	1.059	1.076	1.073
Summer DMNC (MW)	[8]	329.3	334.0	348.3	348.2	348.5	351.1
Winter DMNC (MW)	[9]	344.7	350.5	369.9	369.9	374.1	373.0
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.64	$8.84	$12.47	$12.18	$18.00	$12.58
Winter ($/kW-Month)	[11]	$5.04	$5.83	$6.61	$6.45	$8.56	$4.62
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,515,753	$2,952,627	$4,343,614	$4,242,399	$6,273,209	$4,415,188
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,735,875	$2,041,978	$2,443,190	$2,386,965	$3,202,184	$1,725,050
Seasonal Revenue (Summer)	[14] = 6 * [12]	$15,094,519	$17,715,761	$26,061,687	$25,454,395	$37,639,255	$26,491,127
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,415,248	$12,251,868	$14,659,137	$14,321,788	$19,213,103	$10,350,302
Total Annual Reference Value	[16] = [14]+[15]	**$25,509,768**	**$29,967,629**	**$40,720,824**	**$39,776,183**	**$56,852,357**	**$36,841,429**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$8.22	**$9.52**	**$14.91**	**$14.57**	**$22.36**	**$19.60**
ICAP Max Clearing Price ($/kW-Month)		$14.34	$14.47	$18.16	$18.72	$24.55	$19.97
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes:
[1] The peaking plant technology choice in Load Zones C and F is a 1x0 GE 7HA.02 operating in gas only mode without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[2] The peaking plant technology choice in Load Zones G (Rockland County), Load Zone G (Dutchess County), NYC, and LI is a 1x0 GE 7HA.02 (tuned to emit 25ppm NOx) that includes dual fuel capability and SCR emissions controls.
[3] The net EAS revenues are estimated using data for the three-year period September 1, 2017 through August 31, 2020 and the WSR values are based on data for the same period.

Table 3: Comparison of Reference Point Prices by Technology ($2021/kW-mo.)

Monthly Reference Point Price ($/kW-Month)							
Technology	Fuel Type/ Emission Control	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$27.16	$27.59	$39.64	$30.41
	Gas Only, with SCR	$21.23	$22.51	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$17.76	$17.96	$28.13	$20.94
	Gas Only, without SCR	$10.88	$12.47	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$14.91	$14.57	$22.36	$19.60
	Gas Only, tuned to 15 ppm, without SCR	$8.22	$9.52	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$24.71	$23.35	$52.28	$43.06
	Gas Only, with SCR	$15.42	$16.98	-	-	-	-
4-hr BESS	Battery Storage	$17.83	$17.83	$20.10	$21.06	$28.78	$23.85
6-hr BESS	Battery Storage	$24.23	$24.36	$27.37	$28.70	$37.32	$33.26
8-hr BESS	Battery Storage	$32.46	$32.64	$36.80	$38.48	$48.84	$45.39

Table 4: Comparison of Gross CONE by Technology ($2021/kW-year)

Gross CONE ($/kW-Year)							
Technology	Fuel Type/ Emission Control	C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$285.71	$293.62	$389.96	$302.26
	Gas Only, with SCR	$261.26	$264.07	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$184.57	$192.44	$267.28	$204.82
	Gas Only, without SCR	$148.09	$149.86	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$145.32	$149.78	$196.41	$159.77
	Gas Only, tuned to 15 ppm, without SCR	$114.75	$115.79	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$218.22	$231.74	$388.14	$257.42
	Gas Only, with SCR	$196.59	$199.81	-	-	-	-
4-hr BESS	Battery Storage	$200.79	$202.46	$204.04	$210.82	$261.74	$214.86
6-hr BESS	Battery Storage	$279.86	$282.27	$284.49	$294.28	$355.52	$302.63
8-hr BESS	Battery Storage	$358.90	$362.07	$364.93	$377.72	$449.29	$390.39

Table 5: Comparison of Net EAS by Technology ($2021/kW-year)

Net EAS ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$30.74	$34.68	$35.15	$54.22
	Gas Only, with SCR	$38.40	$27.52	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$29.10	$35.21	$33.65	$53.77
	Gas Only, without SCR	$39.85	$25.69	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$27.96	$35.15	$33.42	$54.15
	Gas Only, tuned to 15 ppm, without SCR	$36.67	$24.56	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$49.36	$72.17	$69.24	$111.00
	Gas Only, with SCR	$58.53	$48.22	-	-	-	-
4-hr BESS	Battery Storage	$47.04	$48.71	$50.17	$49.56	$51.25	$62.47
6-hr BESS	Battery Storage	$47.80	$48.95	$51.68	$50.08	$52.25	$66.52
8-hr BESS	Battery Storage	$47.91	$49.43	$51.86	$50.40	$52.48	$68.11

Note:
[1] Net EAS revenues are estimated using data for the three-year period September 1, 2017 through August 31, 2020.

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"[9]

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."[10] 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."[11] In this section, we consider the following:

1. Simple Cycle Plant – Simple cycle plants consist of one or more combustion turbines fueled by natural gas and/or liquid fossil fuels. This study analyzes multiple types and generations of simple cycle technologies.

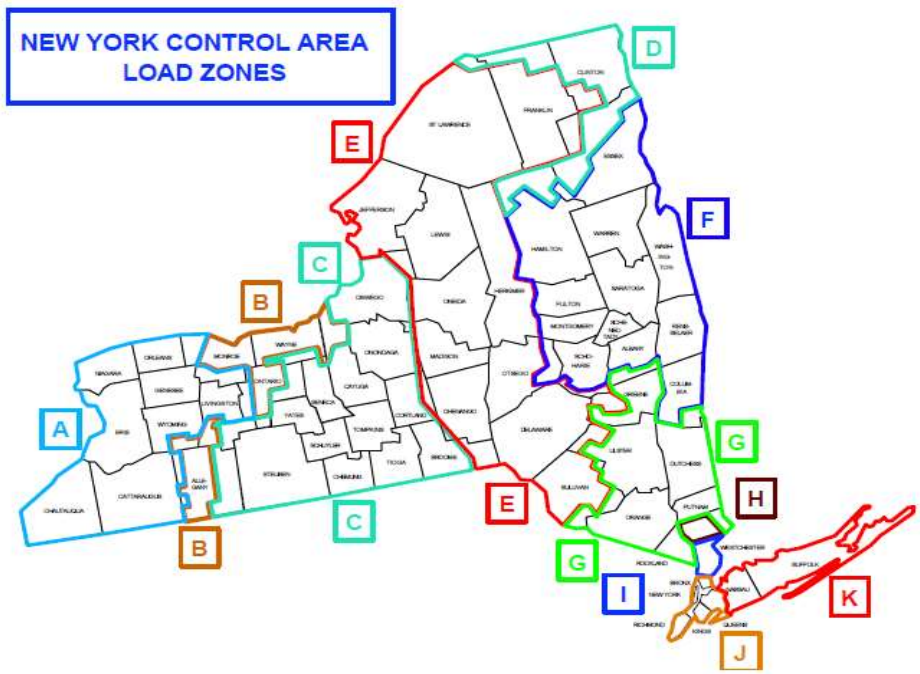
2. Energy Storage Plant - A battery storage plant is also included in the analysis. Battery storage options with duration capabilities of 4-hours, 6-hours, and 8-hours have been evaluated.

3. Combined Cycle Plant – A combined cycle plant is included in the analysis for informational purposes only. A combined cycle plant consists of a combination of simple cycle turbine(s) and steam turbine(s), which serve to recover waste heat to improve combined efficiency.

In Section II.B, we apply screening criteria to identify alternative simple cycle technologies 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, 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.

[9] Services Tariff, Section 5.14.1.2.
[10] Services Tariff, Section 5.14.1.2.
[11] 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

BMCD was engaged to select simple cycle and energy storage technology option(s) to evaluate as the potential peaking plant for each ICAP Demand Curve. BMCD evaluated peaking plant technology options for Load Zones C, F, G (Dutchess County), G (Rockland County), J, and K (see Figure 1). In addition, a combined cycle option was evaluated for each location for informational purposes only.

To comply with the Service Tariff requirements, BMCD 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 technologies and energy storage technology as technical candidates for peaking operation. Simple cycle 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 technologies with reliable fuel supply. Energy storage technologies were included alongside simple cycle technologies for economic evaluation. Selected representative battery technologies are described in Section

II.B.6. While lithium ion battery energy storage systems (BESS) were evaluated, the results of the economic evaluation indicate that BESS is not the lowest cost technology option to be selected to serve as a peaking plant in any location for this reset.

1. *Simple Cycle 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 (~10 minutes) and ramp rates
- Highest performing units generally require water injection for NO_x control in addition to a selective catalytic reduction (SCR) emissions control system
- 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 400 MW.
- 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 – 400 MW range.
- New frame peaking units in the United States will likely be F-class or advanced class.
- 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.
- 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. Conventional start is approximately 30 minutes
- 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, if there are more than 44.4 operating hours per start for the GE 7HA.02 unit or 27 operating hours per start for the GE 7F.05 unit, the major maintenance cost will be hours based. If there are generally less than 44.4 hours per start (GE 7HA.02) or 27 hours per start (GE 7F.05), the major maintenance cost will be start-based.
- Depending on the application, frame turbine models may be available with different NO_x emissions rates. Performance impacts may apply for lower 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 part load performance
- With site conditions below 3,000 feet and 95°F, 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. The GE LM9000 unit was not included because of lack of experience in North America in comparison to other GE aeroderivative models.

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-A65 (former Rolls Royce Trent 60)	First introduced in 1996. Mature technology with multiple model variants.	60 - 71 depending on model	8,800 - 9,200 depending on model
Siemens	SGT-A45	Core technology based on Rolls Royce Trent turbines, similar to SCG-A65.	44	9,400
Mitsubishi Hitachi Power Systems	FT4000 (former Pratt & Whitney FT4000)	First introduced in 2012. Single and twin pack designs available.	71 single GT	9,200

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 GE LMS100 and Siemens SGT-A65 units were the best representative candidates because of their higher capacity and efficiencies. Further refinement of the screening level analysis was performed to account for multiple units to achieve output in the 200 MW range. BMCD compared a 2x LMS100 plant (i.e. two LMS100 units in a single plant) to a 3x SGT-A65 plant with and without SCR emissions control technology for NO_x control. Screening costs normalized with and without SCR emissions controls favor the 3x Siemens SGT-A65 facility. It was noted that LMS100 units have a 25ppm NO_x emissions rate, so they are more likely to require SCR emissions controls because the heat input is above the 850 MMBtu/hr threshold in NSPS subpart KKKK, which requires them to meet a NO_x limit of 15ppm. Heat input for the Siemens SGT-A65 units is below the 850 MMBtu/hr threshold in Subpart KKKK, so they must meet a less restrictive NO_x limit of 25ppm. In addition, Siemens was recently awarded a project in New York City using the Siemens SGT-A65, so recent experience favors this unit as well. For these reasons, the 3x Siemens SGT-A65 option was selected as the representative aeroderivative technology.

3. Frame Combustion Turbine Peaking Option

The candidate peaking technologies included available advanced frame combustion turbines as 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.02	First introduced in 2017, fleet operating hours of 205,000 EOH	384	8,890
Siemens	SGT6-9000HL	No units in commercial operation in North America (First delivery accepted in Nov 2019)	405	8,891
Mitsubishi Hitachi Power Systems	501JAC	No units in commercial operation in North America	425	9,082
Siemens	SGT6-8000H	Installed fleet has accumulated >1MM EOH	310	9,468
Mitsubishi Hitachi Power Systems	MHPS 501GAC	First commercial operation in 2014, mature technology	283	9,469
General Electric	GE 7FA.05	First FA.05 in operation in 2014 - F-Class is GE fleet leader	243	9,513
Siemens	Siemens SGT6-5000F	Installed fleet has accumulated >15MM EOH	260	9,588

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 output and performance.
- Three OEMs have G/H class turbines. The Siemens SGT6-8000H, Mitsubishi Hitachi Power Systems (MHPS) 501G, and GE 7HA.01; machines are similar in output and performance; the MHPS 501G and Siemens SGT6-8000H both have operational experience in combined cycle but no simple cycle experience.
- F-class technology has proven simple cycle peaking application experience and hot SCR emissions controls operating experience.

- There is commercial operating experience with the GE 7HA.02 unit in the United States. It has been installed for simple cycle operation with hot SCR emissions controls, so it is considered a viable option for peaking technology.

Two peaking options for the DCR study were chosen from among the frame combustion turbines: the first was the GE 7F.05, an F class unit, a mature technology which has widespread operation experience across multiple markets in North America. An F class unit, the Siemens SGT6-5000F5, currently serves as the peaking plant technology underlying each of the ICAP Demand Curves. The second was the GE 7HA.02, an advanced class unit with commercial installations in North America, but fewer accumulated operating hours. The GE 7HA.02 has the most operating experience and best efficiency among similar advanced class units. The GE and Siemens F-class machines are similar in performance capabilities, but screening level cost analyses slightly favored the GE unit, so it was selected for this study.

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. Removing the RICE option also facilitated the assessment of more than one frame combustion turbine options and alternative storage durations of energy storage options. Therefore, RICE units were not considered for further study in the DCR.

5. Selected Simple Cycle Technology for Review

Based on the screening criteria and considerations presented above, costs were developed for the following peaking plants. Options were selected for the 200 MW size range for the aeroderivative and F class units, consistent with previous DCR studies. Given the larger capacity of advanced class units currently offered by manufacturers, the H class unit studied was sized around 350 MW.

- Three Siemens SGT-A65 units
- One GE 7F.05 unit
- One GE 7HA.02 unit

6. Energy Storage Power Plant

The lithium-ion battery storage market is growing, largely due to state level targets for storage and renewable energy, as well as declining costs for lithium-ion battery technology. In December 2018, the New York Public Service Commission issued an order establishing a target of 3,000 MW of energy storage by 2030.

The most likely candidates for new energy storage plants are battery energy storage systems (BESS) based on lithium-ion battery technology. Pumped hydro is the most mature storage technology, accounting for approximately 98% of worldwide electric power storage capacity, but this technology is limited in siting potential and requires longer permitting and implementation timelines than battery technologies. Flow battery 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 nascent for the technology at utility scale.

The DCR study includes the following systems for comparison to traditional simple cycle technologies:[12]

- 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 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 a different energy density and unique design considerations, and each may be more desirable for a specific site or application, but all three technologies may be suitable for the deep discharge peaking type application included in this DCR study. Since manufacturers 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.

A known limitation of lithium-ion technology is performance degradation. Over time, the energy capacity degrades due to age and cycling behavior. Therefore, a 200 MW battery with a 4-hour discharge duration today may have less than 4-hour discharge duration in the future after multiple years of operations (the power output remains constant). Longer project lifetimes will likely require capacity augmentation due to performance degradation throughout the life of the project, which means that additional batteries would be installed, or augmented to the existing batteries, during the operating life of the BESS. The original installation would typically be designed to account for future capacity augmentation, and the actual augmentation costs would be part of a long-term agreement that may also account for routine maintenance. The fixed O&M costs in this study are intended to account for routine system maintenance. The variable O&M costs in this study are intended to represent the costs for capacity augmentation, levelized annually over the life of the project. This is consistent with the current market as many lithium-ion manufacturers and/or integrators currently offer warranties or performance guarantees over extended timeframes.

BESS facility roundtrip efficiencies (the fraction of energy put into a battery that can be retrieved) 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%.

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

7. *Combined Cycle Power Plant for Informational Purposes*

A 1x1 combined cycle option was included in the study for informational purposes. The most likely candidates for new combined cycle plants are based on the F-class and advanced frame combustion turbines as shown in Table 8.

Table 8: Latest Advanced Combined Cycle Plant Options

GT Manufacturer	GT Base Model	1x1 Combined Cycle Nominal Capacity (MW)[1]	1x1 Combined Cycle HHV Heat Rate (Btu/kWh)[2]
General Electric	7HA.02	573	5,970
Siemens	SGT6-9000HL	595	6,010
Mitsubishi Hitachi Power Systems	501J	484	6,110
Siemens	SGT6-8000H	460	6,230
Mitsubishi Hitachi Power Systems	MHPS 501GAC	427	6,310
General Electric	GE 7FA.05	376	6,270
Siemens	Siemens SGT6-5000F	387	6,355

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 2x1 combined cycle power plant configuration is the most common design in the industry. However, since it is twice the capacity of the 1x1 combined cycle power plant configuration, it could require expensive system deliverability upgrades. To more closely provide peaker-type flexibility, the combined cycle plant would have to cycle frequently and start as quickly as possible. Fast start 1x1 combined cycle power plant configuration designs can hot start in about 35 minutes, per OEM data sheets. Therefore, without additional information to justify the additional capacity of a 2x1 combined cycle power plant, the 1x1 combined cycle configuration was selected for evaluation, with data presented for informational purposes only.

The combined cycle technology included for evaluation is the 1x1 GE 7HA.02. Advanced class machines exhibit better efficiencies than F-class units, and initial screening indicated that this unit may be the lowest cost alternative on a $/kW basis among 1x1 combined cycle options.

C. Plant Environmental and Siting Requirements

Environmental considerations, which can have significant impact on the design and permitting of simple cycle technology options and combined cycle power plant options, include air emissions, heat rejection, and water use. 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 and each of the combined cycle options would be required to obtain an air permit from the New York State Department of Environmental Conservation (NYSDEC). The air permit will require the new source 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 and combined cycle plants 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 and combined cycle options 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 TTTT – Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units (simple cycle and combined cycle plants)

These two 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).[13] These standards apply to all the combustion turbine options with heat inputs greater than 850 MMBtu/hr, including the GE 7F.05 and GE 7HA.02 units. Based on the typical vendor data, the F-class machine used in this DCR has a NO_x emissions rate of 9 ppm, so it would not require a 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).

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

Similarly, for turbines with heat inputs between 50 and up to and including 850 MMBtu/hour, Subpart KKKK limits NO_x emissions to 25 ppm when operating on natural gas and 74 ppm when firing fuels besides natural gas (e.g., ULSD). The NO_x emissions rate for the Siemens SGT-A65 is 25 ppm, but since its heat input is less than 850 MMBtu/hour, it does not require SCR emissions controls to satisfy Subpart KKKK.

Subpart TTTT establishes CO_2 limits for "base-load" combustion turbines. Base-load combustion turbines must meet an emission limit of 1,000 lb CO_2/MWh or 1,030 lb CO_2/MWh and the limit applies to all sizes of affected base-load units. The base-load unit requirements are applicable to the informational combined cycle plants evaluated. Non-base load units must meet an emission limit based on clean fuels and is an input based standard (e.g., lb CO_2/MMBtu basis). Non-base load status is based on a sliding scale for capacity factor based on a unit's net efficiency at International Organization for Standardization (ISO) conditions. BMCD estimated the net efficiency at 35% for simple cycle technologies. In order to avoid being subject to the "baseload" 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 the net LHV efficiency at International Organization for Standardization (ISO) conditions. This limits each of the fossil peaking plant technology options to 3,066 hours of operation based on a 12-month rolling average.[14]

New York State also has performance standards for CO_2 emissions in the NYCRR. Table 9 compares Subpart TTTT requirement to the requirements of NYCRR Part 251 - CO_2 Performance Standards for Major Electric Generating Facilities. Each of the peaking plant technology options and combined cycle options must comply with both Subpart TTTT and NYCRR Part 251 requirements.

Table 9: Comparison of 40 CRF Part 60 Subpart TTTT to NYCRR Part 251 Requirements

Generating Facility Type	Subpart TTTT	NYCRR Part 251
Simple Cycle Combustion Turbine Gas-Fired	120 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g or 160 lb CO_2/MMBtu
Simple Cycle Combustion Turbine Multi-Fuel Fired[1]	120 to 160 lb CO_2/MMBtu	1,450 lb CO_2/MWh-g or 160 lb CO_2/MMBtu
Combined Cycle Combustion Turbines (Informational)	1,000 lb CO_2/MWh-g or 1,030 lb CO_2/MWh-n	925 lb CO_2/MWh-g or 120 lb/MMBtu

Notes:
[1] For units determined to be non-base load units.
[2] MWH-g refers to gross generation output. MWH-n refers to net generation output, the energy generated minus the electricity used to operate the power plant.

b. New Source Review

The NSPS requirements discussed above are technology specific, not location specific. In addition to NSPS, new units will be subject to the EPA's New Source Review (NSR) program, which considers the impacts to the air

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

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 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 10. 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 10.

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.

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".[15] 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 10, the PSD major source thresholds are 100 tons/year for combined cycle facilities and 250 tons/year for the fossil peaking plant technologies.

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

Table 10: PSD Major Facility Thresholds and Significant Emission Rates

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

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 10) is required to perform a BACT analysis. Absent application of a synthetic operating limit, it is expected that in order for a new unit 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 2. 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 2: Current Nonattainment Areas in New York

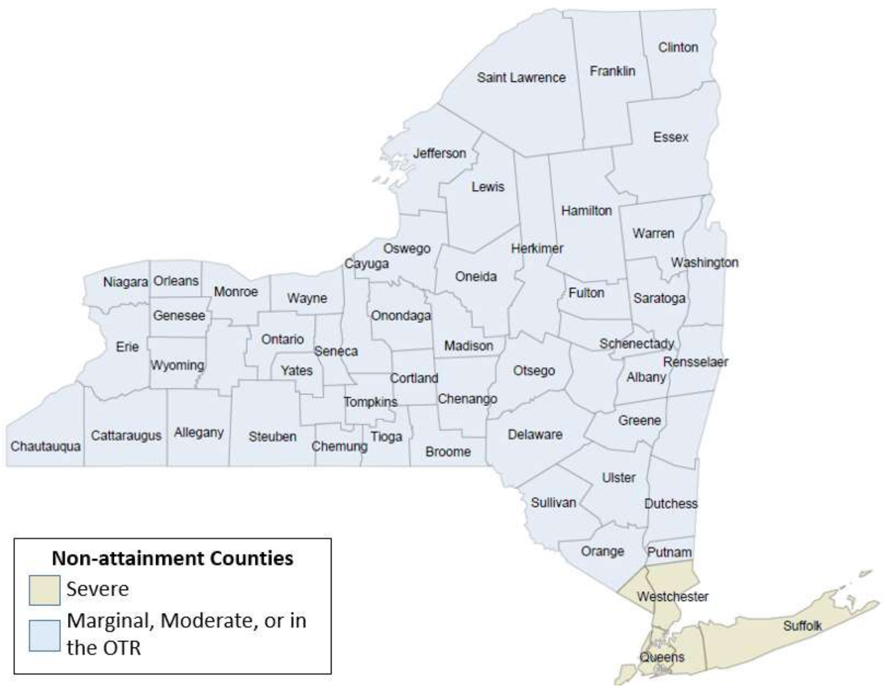


Table 11 presents the nonattainment major facility thresholds and emission offset ratios for each ozone nonattainment classification. Nonattainment areas classified as Severe include the New York City Metropolitan Area and the Lower Orange County Metropolitan Area. The New York City Metropolitan Area 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.[16] Table 12 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.

[16] Notably, Orange County includes areas that are both Severe and Marginal/Moderate nonattainment areas. Orange County is located within the G-J Locality, west of the Hudson River. Consistent with the past two DCRs, AGI and BMCD considered peaking plant technologies located in either Rockland County (west) or Dutchess County (east) in Load Zone G. The use of these two locations provides for a consideration of differences in attainment areas on peaking plant siting and permitting costs. AGI and BMCD did not consider specific locations within a county, which would be required to develop an accurate estimate for Orange County, given the differences in nonattainment designations throughout the region.

Table 11: 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 12: 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 11 and Table 12. Since the facility would no longer be subject to NNSR, the LAER analysis would no longer be required.

The GE 7HA.02 peaking plant technology option with a 25 ppm NO_x emissions rate and the 1x1 GE 7HA.02 informational combined cycle plant would already require the installation of SCR emissions controls per the NSPS Subpart KKKK limits discussed in the prior section. When using the *maximum* annual run hours limitation for simple cycle units for compliance with the NSPS TTTT regulation, the other technologies considered in this DCR would require SCR emissions controls as a part of NNSR analyses requiring LAER in all locations evaluated, regardless of nonattainment status of areas of each location. Based on the maximum hours per NSPS TTTT, the

CO catalyst would be required for the Siemens SGT-A65 and the 1x1 GE 7HA.02 in all locations evaluated. 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 13 below.

Table 13: 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
3x0 Siemens SGT-A65	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
1x0 GE 7F.05	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x0 GE 7HA.02, 15 ppm NO_x	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x0 GE 7HA.02, 25 ppm NO_x	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
1x1 GE 7HA.02 (Informational)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Notes:
[1] Values shown are for maximum annual hours of operation (3,066 hours for SCGT technologies and 8,760 for CCGT technology).
[2] For dual fuel SCGT, the evaluation considers 720 hours operating on ultra-low sulfur fuel oil and the remaining 2,346 hours on gas.
[3] For dual fuel CCGT (informational), evaluation considers 720 hours operating on ultra-low sulfur fuel oil and the remaining 8,040 hours on gas.
[4] For gas only operation, the SCR emissions controls and oxidation catalyst results above do not change.

In addition to the “maximum-hour” compliance analysis performed above, BMCD 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 14 and Table 15 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 14: 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
3x0 Siemens SGT-A65[1]	1,195	1,195	1,195	295	295	295
1x0 GE 7F.05	2,500	2,500	2,500	620	620	620
1x0 GE 7HA.02, 15 ppm NOx	1,060	1,060	1,060	260	260	260
1x0 GE 7HA.02, 25 ppm NOx	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]
1x1 GE 7HA.02 (Informational)	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]

Notes:
[1] These values are for the analyzed project (i.e., the Siemens SGT-A65 limit is for all three engines combined, per year).
[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).

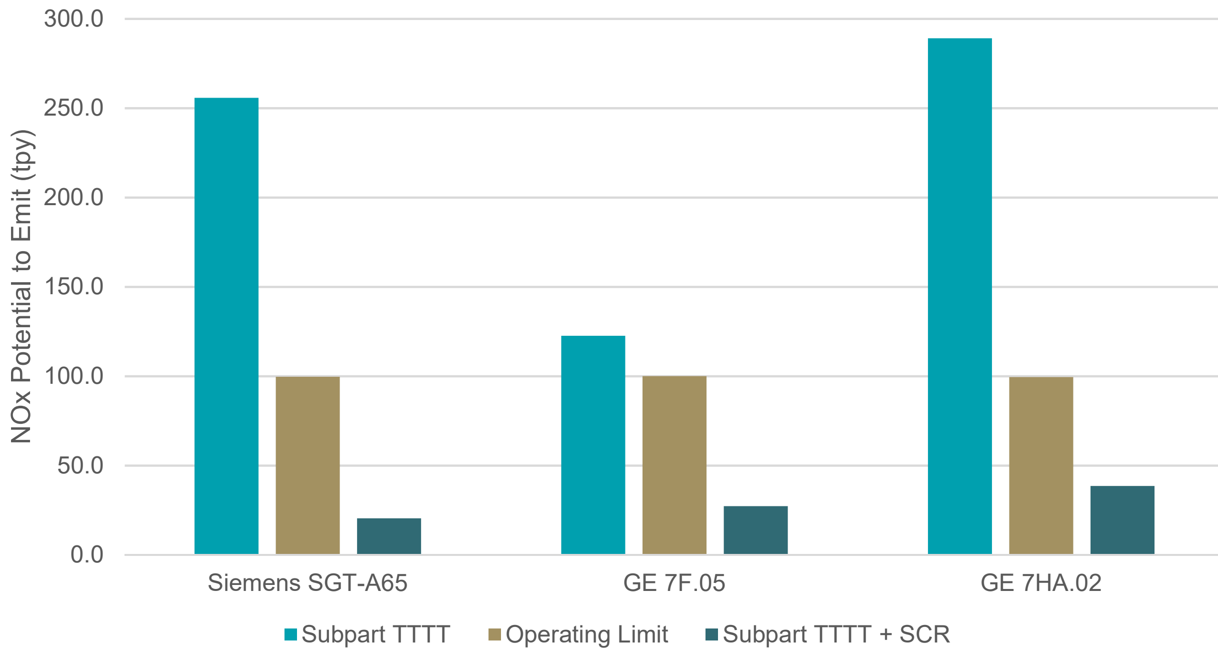
Table 15: Approximate Annual Operating Limits Needed to Not Require SCR Emissions Controls Using ULSD Only at a Greenfield Site

Technology	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
	Moderate	Moderate	Moderate	Severe	Severe	Severe
3x0 Siemens SGT-A65[1]	717	717	717	177	177	177
1x0 GE 7F.05	465	465	465	115	115	115
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[2]	N/A[2]	N/A[2]
1x1 GE 7HA.02 (Informational)	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]	N/A[2]

Notes:
[1] These values are for the analyzed project (i.e., the Siemens SGT-A65 limit is for all three engines combined, per year).
[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).

Figure 3 shows the estimated NO_x emissions for the Siemens SGT-A65 unit, the GE 7F.05 unit, and the GE 7HA.02 15 ppm unit using the Subpart TTTT limit, the annual operating limits to become a synthetic minor source, and the Subpart TTTT hourly limits with SCR emissions controls. The GE 7HA.02 25 ppm unit (either in simple or combined configuration) will require SCR emissions controls in order to comply with NSPS KKKK, and thus are not included in this depiction. The emissions estimates shown are for natural gas operation only. The approximate hourly operating limit is used as the threshold to trigger NNSR permitting in a moderate county (limited to 100 tpy NO_x).

Figure 3: NOx Emissions Comparison



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. As discussed below, 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 the facility will minimize or avoid adverse environmental impacts to the maximum extent practicable.[17] Based on the emissions estimates performed for the DCR, a dual fuel GE 7HA.02 simple cycle plant with SCR emissions controls would have a lower PTE than a gas only plant with annual operating limits to bring it below the NNSR thresholds.

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 AGI's and BMCD's opinion that the developer of a new plant in Load Zones C and F would not seek to include SCR emissions control technology for a gas only plant at the time of construction due to economic considerations. Instead, for these locations, it is assumed that the developer of a gas only peaking plant would accept and adhere to the applicable

[17] 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…"

annual operating hours limit necessary to become a synthetic minor source.[18] For Load Zone G (Dutchess County), AGI and BMCD determined that the balance of considerations supported the inclusion of SCR emissions control technology during construction for a dual fuel plant design. Based on prices from a three-year historical period (2016/17 to 2018/19), the GE 7HA.02 unit without SCR emissions control could emit less than its annual NO_x emissions limit by implementing an operating hours limit that curtailed relatively few hours of operation. However, we assume that a developer would choose to build a dual fuel unit with SCR emissions controls, reflecting several considerations. *First*, SCR emission controls provides optionality to operate above the synthetic minor operating limit, which could be financially valuable in the future. Our three-year analysis does not fully capture value of this optionality. 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. Within this context, a potentially relevant consideration is that the lower Hudson Valley also contains severe non-attainment areas and that selecting a plant without SCR emissions controls would not accommodate potential new plants throughout the region.

In addition to installing technologies to address LAER analysis, 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 11. 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 ERCs were calculated with SCR emissions controls for Load Zone G (Rockland County), NYC, and LI. The annual hours were restricted to those needed to comply with NSPS Subpart TTTT. The annual emissions used in the ERC cost calculations were based on the controlled emission rate assumptions that are shown in Table 16.

[18] As described in Section IV.B.2.a, the operating hours 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. Units without SCR emissions controls in moderate nonattainment zones are limited to a total of 100 tons/year of NO_x emissions.

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 7F.05	9	9	1.3	1,230
1x0 GE 7HA.02, 15 ppm NO_x	15	9	2	1,120
Natural Gas Firing with SCR				
3x0 Siemens SGT-A65	2	2	5	1,130
1x0 GE 7F.05	2	2	1	1,230
1x0 GE 7HA.02, 25 ppm NO_x	2	2	1	1,130
1x1 GE 7HA.02 (Informational)	2	2	1	760
Ultra-Low Sulfur Diesel Firing without SCR				
1x0 GE 7F.05	42	14	2.4	1,650
1x0 GE 7HA.02, 15 ppm NO_x	42	12	2.4	1,490
Ultra-Low Sulfur Diesel Firing with SCR				
3x0 Siemens SGT-A65	5	2	2	1,510
1x0 GE 7F.05	5	2	2	1,650
1x0 GE 7HA.02, 25 ppm NO_x	5	2	2	1,510
1x1 GE 7HA.02 (Informational)	5	2	2	1,050

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*

New stationary combustion sources 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)

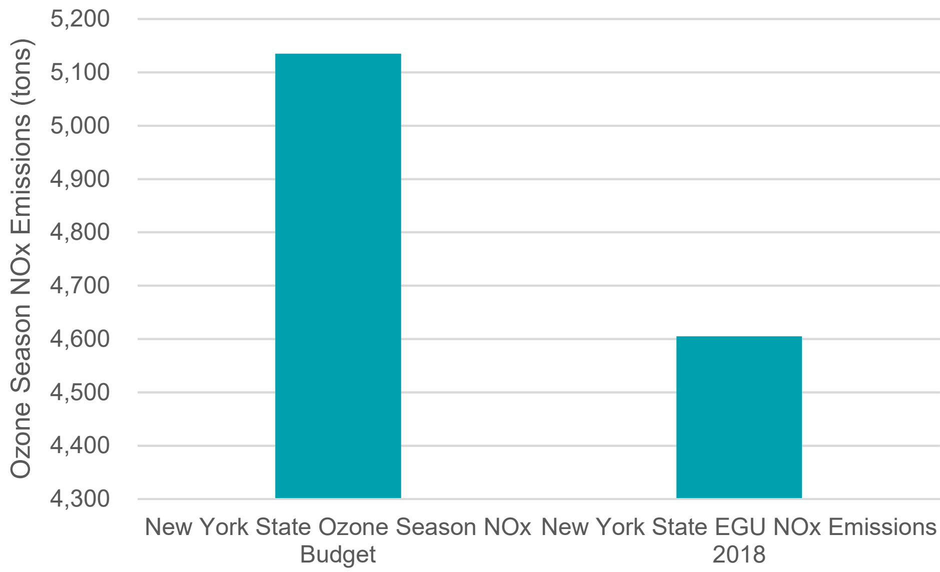
The CO_2 Budget Trading Program regulations would apply to all fossil peaking plant technologies assessed, as well as the informational combined cycle plants. Part 242 establishes the cap-and-trade provisions pursuant to the Regional Greenhouse Gas Initiative (RGGI), a nine-state cooperative effort to 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 the 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 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.

Starting in 2017, the CSAPR Update required New York electric generating units (EGUs) to participate in the new CSAPR NO_x Ozone Season Group 2 Trading Program instead of the original program (now named Group 1). The CSAPR update also lowered the ozone season budget for the State of New York by approximately 58% in order to address the revised and more stringent ozone NAAQS. Figure 4 demonstrates the new Group 2 ozone emissions budgeted for New York State, as well as the amount of NOx emissions emitted by EGUs in 2018 (the most recent year with data readily available).

Figure 4: New York State CSAPR Ozone Season NO_x Budgets and Electric Generating Units (EGUs) NO_x Emissions



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.

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 13 above, the new fossil peaking plant technologies assessed comply with these thresholds. Therefore, this rule will not directly impact the fossil peaking plants evaluated in this study.

4. Plant Cooling Requirements

The major source of heat rejection for combined cycle power plants is the steam turbine condenser. New combined cycle power plants typically use mechanical draft cooling towers or air-cooled condensers (ACCs). Both cooling methods can meet Clean Water Act Section 316(b) Rule requirements for new facilities. At some locations new combined cycle power plants are moving towards the use of ACCs driven by environmental and/or water scarcity concerns. The New York Department of Environmental Conservation issued NYSDEC Policy CP-#52, which seeks a performance goal of dry cooling for industrial facilities sited in coastal zones and the Hudson River up to Troy. For this study, it has been assumed that the informational combined cycle options would be designed with ACCs in all locations evaluated.

5. 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 recommended technology choice also requires determining for each location whether the peaking plant 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 Load Zone. 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 shown in the capital cost estimates in Appendix A, and highlighted in Table 17 below. The capital costs include gas turbine combustion system modifications provided by the OEM and field installed, 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.

Table 17: Incremental Dual Fuel Costs for Fossil Plants

	C - Central	F - Capital	G - Dutchess	G - Rockland
3x0 Siemens SGT-A65				
Capital Costs, 2020 MM$	$11.3	$11.3	$11.3	$11.3
Owner's Costs, 2020 MM$	$7.0	$7.0	$7.0	$7.0
1x0 GE 7F.05				
Capital Costs, 2020 MM$	$16.9	$16.9	$16.9	$16.9
Owner's Costs, 2020 MM$	$8.4	$8.4	$8.4	$8.4
1x0 GE 7HA.02				
Capital Costs, 2020 MM$	$25.4	$25.4	$25.4	$25.4
Owner's Costs, 2020 MM$	$12.5	$12.5	$12.5	$12.5
1x1 GE 7HA.02 (Informational)				
Capital Costs, 2020 MM$	$25.4	$25.4	$25.4	$25.4
Owner's Costs, 2020 MM$	$13.5	$13.5	$13.5	$13.5

Based on our evaluation, AGI recommends that the peaking plant technology design should continue to include dual fuel capability in Load Zones G, J, and K. Consistent with the current design for the NYCA ICAP Demand Curve, AGI recommends continued use of a gas-only design for Load Zones C and F. 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 that the answer to this question is yes in Load Zones G, J, and K, and no in Load Zones C and F:

- There are local electric reliability rules applicable to NYC and LI that require dual fuel capability. 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). Moreover, 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. These factors are particularly true in Load Zones G, J, and K, where there are potentially more meaningful constraints on natural gas availability in winter months than in the rest of the state.

- Potential peaking plant developers would also consider various risks and benefits associated with project development and siting. Specifically, on the one hand adding dual fuel capability would expand the geographical flexibility for power plant siting, by supporting the siting of plants on (and obtaining gas supply from) the distribution systems of local gas distribution companies. Expanding such geographic flexibility increases the potential of finding sites that coincidentally minimize the costs to obtain both natural gas and electrical interconnections. On the other hand, the addition of oil-fired capability can complicate the process of successfully siting and permitting the facility.
- Finally, in the downstate regions a developer would likely view the addition of dual fuel capability favorably in light of New York State's reliance on natural gas for power generation which is expected to continue in the coming years, as well as in recognition of constraints on the use of natural gas that arise, particularly during winter months.

FERC's acceptance of the current peaking plant designs recognized that dual fuel capability is mandatory in NYC and LI, and, although not mandatory in Load Zone G, FERC agreed that "dual fuel capability comes with increased revenue potential, siting benefits, and reliability benefits, plus it can serve as a hedge to mitigate electricity price spikes during times of high natural gas prices." FERC also agreed that "the G-J Locality is a relatively geographically constrained region; therefore, the inclusion of dual fuel capability is important for providing increased siting flexibility," and that "current concerns regarding the ability to expand natural gas pipeline infrastructure and capacity in New York underscore the reliability benefits gained from dual fuel capability in the G-J Locality." FERC's acceptance of dual fuel capability for NYC, LI, and the G-J Locality as part of the 2013 DCR was based on similar reasons.[19]

In accepting a gas-only design for the NYCA ICAP Demand Curve as part of the 2016 DCR, FERC agreed that Load Zones C and F are "far less geographically constrained than the G-J Locality" and that "natural gas supply conditions in load zones C and F are more favorable than in the G-J Locality because this region is generally located upstream of interstate natural gas pipeline constraints and has connections to natural gas supplies from the nearby shale gas producing regions." As a result, the "potential incremental revenues associated with having dual fuel capability are not outweighed by the potentially significant capital investment."[20]

E. Capital Investment Costs

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

- Three Siemens SGT-A65 units
- One GE 7F.05 unit
- One GE 7HA.02 unit

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

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

[19] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028, Docket No. ER17-386-000 (January 17, 2017) at P 48-49.
[20] *New York Independent System Operator, Inc.*, 158 FERC ¶ 61,028, Docket No. ER17-386-000 (January 17, 2017) at P 50-51.

- 200 MW, 8-hour (1,600 MWh stored energy) lithium-ion

In addition, for informational purposes, capital cost estimates were prepared for the construction of a 1x1 GE 7HA.02 combined cycle facility Load Zones, C, F, G, J, and K.

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 an additional 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	Gas Only	Gas Only	Dual Fuel	Dual Fuel	Dual Fuel	Dual Fuel
Siemens SGT-A65 Combustion System NO_x Control	Water Injection	Water Injection	Water Injection	Water Injection	Water Injection	Water Injection
Post Combustion Controls for: 3 x Siemens SGT-A65	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst
GE 7HA.02 base model NO_x emissions tuning	15 ppm	15 ppm	25 ppm	25 ppm	25 ppm	25 ppm
GE 7F.05 and GE 7HA.02 Combustion System NO_x Control	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry	Gas: Dry
	Fuel Oil: N/A	Fuel Oil: N/A	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection	Fuel Oil: Water Injection
Post Combustion Controls for GE 7F.05 and GE 7HA.02 simple cycle	None	None	SCR	SCR	SCR	SCR
Informational Combined Cycle Plant Cooling	Dry	Dry	Dry	Dry	Dry	Dry
Post Combustion Controls for Informational Combined Cycle	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst	SCR/CO Catalyst

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. BMCD considered that 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. 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 peaking plant assumes 50 hours of full load oil use for guarantee and emissions performance testing.

4. Cooling Design – As summarized in Table 18, it was concluded that for the informational combined cycle plants, cooling for all locations would include air cooled condenser (ACC) technology.

5. Inlet Cooling – Inlet air evaporative coolers were included for the aeroderivative and frame combustion turbines (for simple cycle plant options and the informational combined cycle plant). 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.

6. Gas Pressure – 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.

7. Emission Control Equipment – In Load Zones C, F, and G (Dutchess County), the NO_x limit to trigger PSD is 100 tons per year (tpy). Frame combustion turbines with NOx emissions rates equal to or less than 15 ppm (such as the GE 7F.05 unit and 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 AGI suggest that in Load Zones C and F, developers of a gas only peaking plant design may pursue this approach as a more profitable option from a financial perspective given that it is permissible under the currently applicable emission requirements. Therefore, BMCD recommends considering the GE 7F.05 and 15ppm version of the GE 7HA.02 without SCR emissions controls in Load Zones C and F. BMCD based its cost estimates for the GE 7F.05 and 25ppm version of the GE 7HA.02 on a dual fuel design that includes SCR emissions

controls in Load Zones G (Rockland County), G (Dutchess County), J, and K. The aeroderivative option and informational combined cycle plants in all locations are assumed to include SCR emissions controls.

8. 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 2016 DCR.

9. 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. New York State Department of Environmental Conservation 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 BCMD'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 BMCD permitting experience, the design basis assumes that all simple cycle gas turbine options would be installed indoors, and that the informational combined cycle plant would include a power island building that houses the gas turbine, steam turbine, and heat recovery steam generator (HRSG). For all fossil plant options, the buildings also include administrative facilities, control room, and warehouse space. The informational combined cycle plant also assumes the use of low noise fans on the ACC. All simple cycle, combined cycle, and BESS technologies include an additional 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 a host of 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.

10. Water Supply and Wastewater – For all Load Zones 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 Load Zones include a tank for process/fire water. Wastewater and facility drains are collected in onsite tanks and pumped out via trucks for disposal.

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[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

11. Energy Storage Sizing – It is important to note that costs and designs for lithium-ion battery projects are changing rapidly in the market. BMCD's recent project experience suggests that NMC, LFP, and NCA technologies are competing directly and often with different form factors. Batteries may be installed in large buildings, modified containers, or purpose-built enclosures.

    a. Building designs: For building designs, the batteries are field installed in large pre-engineered building(s).

    b. Container designs: Containers may be modified shipping containers or custom designed enclosures, but they are generally pre-engineered with lighting, communications/controls, fire suppression systems, and auxiliaries located inside. HVAC units are commonly mounted on the sides or tops of the containers. The batteries typically ship separately for field installation in containers.

    c. Purpose built enclosures: this is a recent trend in which OEMs or integrators ship a pre-engineered enclosure where the batteries and inverters may ship already installed at the factory. This is intended to reduce field installation costs.

There are site specific, application specific, and market specific cost drivers that may impact the form factor for a particular project. BMCD is not selecting a unique design basis, but the sizing process and criteria would be similar among all three technologies and all three form factors. 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 system components. The gross power output is sized to accommodate for the system losses, to achieve an output capability of 200 MW at the POI.

Table 19: BESS System Losses and Assumptions

BESS System Losses and Assumptions	
POI Rating (MW)	200
Duration (Hours)	4
Line Loss GSU to POI (%)	0.05%
GSU Loss (%)	0.50%
Auxiliary Load (%)	3.0%
Line Loss PCS Transformer to GSU (%)	0.3%
PCS Transformer Loss (%)	0.73%
Total Losses for Sizing PCS Inverters	4.58%
Gross MW Required	209

The power requirements detailed above are used to determine the inverter sizing and quantities. Table 20 shows the assumptions for power output based on an assumed inverter size.

Table 20: BESS Inverter Sizing

BESS Sizing for Power	
Inverter Power (MW)	2.65
Inverter Quantity	79
Gross MW	209

The battery capacity is sized to provide the gross MW for the design discharge duration. In addition to accounting for the system losses above, additional capacity is added for the inverter losses and battery specific losses. Because energy capacity degrades due to time and cycling behavior, projects with performance guarantees must be designed to account for the degradation. This is done through overbuild and/or augmentation strategies. Overbuild means additional capacity is included in the initial installation and capital cost. Augmentation means that additional batteries are added at intervals during the project life. The initial installation would be designed to accommodate future augmentation.

Overbuild and augmentation strategies are project specific decisions based on a multitude of design and risk factors that essentially assign the costs of performance degradation between capital and operating cost categories. For this study, the initial system was sized for minimal overbuild. While this may not be typical for an actual project, it is done to simplify the variables for capital cost and O&M costs. BESS augmentation is modeled as a combination of variable and fixed cost as a proxy for the structure of OEM service contracts, which depend in part on the expected average number of battery cycles per year of operation. Table 21 shows how the BESS 4-hour option was sized for initial energy capacity. The longer duration options have proportionally larger battery quantities. Augmentation costs are discussed further in the O&M section.

Table 21: BESS Energy Sizing

BESS Sizing for Energy	
Gross Power (MW)	209
Duration (hours)	4
Gross Energy to Cover Power Needs (MWh)	836
Inverter Loss (%)	1.60%
Minimum State of Charge (%)	5.0%
Battery Discharge Loss (%)	4.0%
Gross Energy Initial Installation (MWh)	932
Gross MWh Overbuild Percentage (%)	16.5%

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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 purposes of this study and is not intended for project budgeting, design, or construction purposes. The capital cost estimates are based on BMCD's experience as an EPC contractor, engineering design firm, and consultant in the power generation and energy storage industries. BMCD has recent project execution experience, consulting experience, and/or proposal experience on simple cycle, combined cycle, and energy storage projects in New York, including New York City. For example, BMCD was part of a joint venture that built a combined cycle plant in Orange County and an Owner's Engineer for a recent combined cycle facility installed in Dutchess County.

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 5% EPC contractor fee is also applied to all estimated EPC costs.

- Equipment and Material Costs - Gas turbine costs are based on budgetary estimates from the respective OEMs. Other equipment and material quantities and costs are based on recent BMCD project costs, designs, and proposals for simple cycle, combined cycle, and energy storage projects. For all technologies, the EPC electrical scope ends at the high side of the generator step up transformer (GSU). GSU cost and installation are included in the EPC cost. For BESS options, the battery pricing was based on recent BMCD EPC proposals for storage projects and Owner's Engineering experience on large utility scale storage projects.
- 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 the nearest municipality to 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 BMCD 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. Due to an increasingly dynamic storage market, BMCD intends for the BESS sizing, capital costs, and O&M costs to be indicative of the competitive market, not a specific technology or form factor.

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, BMCD 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 Owner and project opportunity. Key assumptions for Owner's costs are included below:

- 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.
- 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 22.
- The Startup and Testing Consumables allowance accounts for fuel and consumables during startup. Initial fuel inventory accounts for 96 hours of fuel oil storage for fossil unit options that include dual fuel capability. The tank and related infrastructure for fossil unit options that include dual fuel capability are included in the EPC cost.
- It is assumed that the project owner would receive a tax exemption certificate for capital purchases. Construction supplies and consumables would 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 22: 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 6.7% 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 24 months for the BESS units to 48 months for the informational combined cycle units. As a result, construction financing costs are estimated at 6.80% of overnight capital costs for simple cycle units, 5.64% for BESS units, and 10.55% for the informational combined cycle 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 conducted 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 analysis determined that all peaking plant options in all locations (simple cycle fossil units and BESS options) could be developed without a requirement to incur any SDU costs. Therefore, no SDU costs are included for any of the simple cycle or BESS options evaluated in this study.

Given that the combined cycle plant options are presented for informational purposes only, no deliverability assessment was conducted for these plants. As a result, no SDU costs have been included in the estimates developed for this study for the informational combined cycle options.

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 is included in the EPC estimate. BMCD included separate estimates for the plant switchyard and the interconnecting transmission line in the Owner's costs.

The interconnecting transmission line between the plant switchyard 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 interconnection in Load Zone J is assumed to be installed underground,[22] while interconnecting transmission lines in all other locations are assumed to be installed overhead.

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

- Air insulated switchgear (AIS) for all Load Zones except Load Zone J, which would include gas insulated switchgear (GIS) technology.[23]
- 345 kV high side voltage for all Load Zones except Load Zone K, which is assumed at 138 kV
- 5-position ring bus for 3x Siemens SGT-A65 option
- 3-position ring bus for 1x GE 7F.05, 1x GE 7HA.02, and BESS options
- 4-position breaker and a half configuration for the informational combined cycle plants

The costs for the switchyard, interconnecting transmission line to POI and SUFs at POI were estimated by BMCD. Budget pricing was obtained for the major electrical components. Bulk materials costs, installation labor costs,

[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, BMCD assumed an underground interconnection for the plants evaluated in this study.

[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 BMCD'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.

construction indirect and other indirect costs such as design, engineering and procurement were factored into the estimates developed for this study.

5. Gas Interconnection Cost

Gas interconnection cost estimates are based on BMCD'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.[24] BMCD developed costs reflecting an average gas lateral length of one mile in Load Zone J and five miles in all other Load Zones, with a 12-inch diameter pipeline for the 3x Siemens SGT-A65 and GE 7F.05 options and 16-inch diameter pipeline for the GE 7HA.02 options (both for the simple cycle options and informational combined cycle plants). In all Load Zones except Load Zone J, estimates are based on $250,000 per inch diameter per mile to represent total installed cost. The average cost for a metering and regulation station was estimated at $3.5 million in all Load Zones except Load Zone J.

These costs represent a generalized estimate to interconnect with either an interstate natural gas pipeline or a gas local distribution company (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.

It is reasonable to expect that the interconnection for Load Zone J would be shorter than the five mile length estimated for all other locations, but the difficulty of installing a pipeline in New York City would likely offset any savings from a shorter distance. This would result in an installed pipeline cost greater than the unit costs considered for all other locations. BMCD believes that a non-site-specific allowance for Load Zone J of $20 million for a one mile 12-inch or 16-inch diameter interconnect to an LDC pipeline plus a metering station is reasonable to account for the increased costs expected for gas interconnection within New York City.

6. Water Supply Costs

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 BMcD's experience and review of publicly available information for water main installation and/or restoration in NYC. For all other Load Zones, the water supply 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. Fossil simple cycle options for Load Zones C and F assume natural gas only projects, while dual fuel projects are assumed in all other locations. SCR emissions control technology is included for all informational combined cycle plants and Siemens SGT-A65 options in all locations. For the GE 7F.05 and GE 7HA.02 simple cycle units, SCR emissions controls are included for Load Zones G (Rockland County), G (Dutchess County), J, and K. The gas

[24] For example, CPV Valley in Middletown, NY included a gas interconnect that was 7.8 miles long. The length of the gas interconnect for the proposed Killingly Energy Center in CT is anticipated to be 2.8 miles long.

only GE 7F.05 and GE 7HA.02 simple cycle units for Load Zones C and F assume that the units would elect to be subject to an annual operating hours limitation to allow for avoidance of the need to install SCR emissions controls. Add/deduct costs for these options are included in the cost buildups 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 23: Capital Cost Estimates ($2020 million)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	$305	$307	$332	$342	$424	$350
1x0 GE 7F.05 (with Dual Fuel and SCR)	$271	$275	$280	$292	$381	$312
1x0 GE 7F.05 (Gas Only, without SCR)	$221	$224	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$360	$363	$368	$380	$470	$407
1x0 GE 7HA.02 (Gas Only, without SCR)	$270	$274	-	-	-	-
Informational Combined Cycle Plants						
1x1 GE 7HA.02 (with SCR)	$690	$704	$770	$821	$979	$915
Energy Storage						
BESS 4-hour	$307	$309	$312	$323	$381	$329
BESS 6-hour	$428	$432	$435	$451	$517	$464
BESS 8-hour	$549	$554	$559	$579	$652	$599

Note:
[1] Estimates for the Siemens SGT-A65 and informational 1x1 GE 7HA.02 combined cycle units are specified with dual fuel in Load Zone G (Dutchess County), Load Zone G (Rockland County), NYC, and LI, and are specified as gas-only designs in Load Zone C and Load Zone F.
[2] All estimates include construction financing costs.

Table 24: Capital Cost Estimates ($2020/kW)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	$1,920	$1,937	$2,091	$2,152	$2,670	$2,203
1x0 GE 7F.05 (with Dual Fuel and SCR)	$1,310	$1,319	$1,337	$1,398	$1,810	$1,482
1x0 GE 7F.05 (Gas Only, without SCR)	$1,068	$1,078	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$1,046	$1,050	$1,061	$1,095	$1,347	$1,166
1x0 GE 7HA.02 (Gas Only, without SCR)	$828	$834	-	-	-	-
Informational Combined Cycle Plants						
1x1 GE 7HA.02 (with SCR)	$1,393	$1,413	$1,538	$1,639	$1,949	$1,821
Energy Storage						
BESS 4-hour	$1,534	$1,547	$1,560	$1,615	$1,904	$1,644
BESS 6-hour	$2,139	$2,159	$2,177	$2,256	$2,584	$2,319
BESS 8-hour	$2,744	$2,770	$2,793	$2,896	$3,262	$2,994

Note:
[1] Estimates for the Siemens SGT-A65 and informational 1x1 GE 7HA.02 combined cycle units are specified with dual fuel in Load Zone G (Dutchess County), Load Zone G (Rockland County), NYC, and LI, and are specified as a gas-only design in Load Zone C and Load Zone F.
[2] All estimates include construction financing costs.

F. Fixed & Variable Operating and Maintenance Costs

In addition to the initial capital investment, there are other costs associated with the simple cycle, informational combined 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 were developed using BMCD 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 25. 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 25: Staffing Levels and Salaries Used for O&M Estimates

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	7	7	7	7	7	7
1x0 GE 7F.05	7	7	7	7	7	7
1x0 GE 7HA.02	7	7	7	7	7	7
Informational Combined Cycle Plants						
1x1 GE 7HA.02	22	22	22	22	22	22
Annual Salary (Wage plus Benefits)						
Full-Time Equivalent Personnel	$126,000	$136,000	$179,000	$188,000	$241,000	$209,000

BMCD escalated the labor rates from the 2016 DCR 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 since 2016. 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. In assessing the plant staff average labor rate and benefits, BMCD examined the 2019 – 2020 prevailing wage rate information for Operating Engineer codes for representative labor districts in each Load Zone. For the labor districts in Load Zones C, F, G, and K, the Operating Engineer Class A categories tracked within 0.5% - 8.5% of the escalated DCR assumptions when considering 2,000 hours at the prevailing wage plus supplemental benefits. For Load Zone J, the Operating Engineer Group 28 was used for a proxy for power plant operator. The annual salary using the prevailing wage was 15% lower than the escalated DCR value. Because the prevailing wage labor categories were broad and not necessarily specific to power generation equipment, BMCD used this information as proxies to evaluate the reasonableness of using escalated wage rates from the 2016 DCR. This evaluation indicated that the use of escalated wage rates from the 2016 DCR is a reasonable assumption for this study.

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. BMCD reviewed market transactions, property tax values and stakeholder-provided feedback in assessing the leasing cost assumptions. In addition to this review, BMCD considered quoted values obtained through discussions with various property owners in the potential acquisition of land for similar use. Particularly in Load Zone J, this resulted in a wide range of observed values. Using values from the 2016 DCR study, escalated to $2020 using the cumulative change in the Gross Domestic Product (GDP) implicit price deflator (Q1 2015-Q1 2020) arrived at values that were within the observed range of leasing costs identified by BMCD's review, indicating that the use of an escalation approach resulted in reasonable values for purposes of this study.

Table 26: Site Leasing Cost Assumptions ($2020)

	Load Zone J	Load Zone K	Load Zones C, F, and G
Land Requirement - Simple Cycle Options (acres)	12	15	15
Land Requirement – Informational Combined Cycle (acres)	27	30	30
Land Requirement - BESS 4-hour (acres)	9	12	12
Land Requirement - BESS 6-hour (acres)	12	15	15
Land Requirement - BESS 8-hour (acres)	15	18	18
Lease Rate ($/acre-year)	$270,000	$26,000	$22,000

c. Total Fixed Operations and Maintenance

The total fixed O&M expenses including the fixed plant expenses, site leasing costs, and property insurance are shown in Table 27. As described below, property taxes and insurance are estimated separately as a percentage of total installed costs. Property taxes are not included in Table 27.

Table 27: Fixed O&M Estimates ($2020/kW-year)

	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies[1,2]						
3x0 Siemens SGT-A65	$22.76	$23.48	$25.95	$26.27	$47.95	$28.61
1x0 GE 7F.05 (with Dual Fuel and SCR)	$16.49	$16.97	$18.45	$18.78	$35.24	$20.64
1x0 GE 7F.05 (Gas Only, without SCR)	$15.41	$15.89	-	-	-	-
1x0 GE 7HA.02 (with Dual Fuel and SCR)	$12.30	$12.57	$13.47	$13.64	$23.67	$14.87
1x0 GE 7HA.02 (Gas Only, without SCR)	$11.68	$11.97	-	-	-	-
Informational Combined Cycle Plant[2,3]						
1x1 GE 7HA.02 (with SCR)	$17.57	$18.23	$20.57	$21.08	$37.74	$23.44
Energy Storage[4]						
BESS 4-hour	$19.53	$19.60	$19.67	$19.96	$31.29	$20.63
BESS 6-hour	$27.17	$27.27	$27.37	$27.79	$43.02	$28.70
BESS 8-hour	$34.85	$34.99	$35.12	$35.68	$54.81	$36.82

Notes:
[1] Based on degraded performance at ICAP conditions
[2] Estimates for the Siemens SGT-A65 and informational 1x1 GE 7HA.02 combined cycle units are specified with dual fuel in Load Zone G (Dutchess County), Load Zone G (Rockland County), NYC, and LI, and are specified as a gas-only design in Load Zone C and Load Zone F.
[3] Based on degraded, unfired performance at ICAP conditions
[4] Based on 200,000 kW net output at point of interconnection.

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 plant, reflecting the installed capital cost exclusive of any SDU costs.

Outside of New York City, the effective property tax rate is assumed to be 0.5% 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 0.5% is a reasonable assumption for this study that is consistent with current PILOTs agreements for natural gas plants in New York.[25]

In New York City, the property tax rate equals 4.7%, which is equal to the product of (1) the Class 4 Property rate (10.5%) and (2) the 45% assessment ratio.[26]

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.[27] Accordingly, it is assumed that each simple cycle fossil peaking plant option receives this exemption and incurs taxes only for years 16 and beyond.[28]

Energy storage plants are provided a 15-year tax abatement statewide pursuant to New York Real Property Tax Law Section 487.[29] A 15 year property tax exemption is assumed for all battery storage plants in all locations for this study.[30]

The informational combined cycle plant is assumed to pay the same 0.8% effective property tax rate as simple cycle peaking plants for locations outside New York City. This plant is not assumed to be eligible for the New York City tax abatement applicable to the simple cycle plant options. As a result, the informational combined cycle plant is assumed to be subject to the 4.7% property tax rate in all years.

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 BMCD consulting experience in New York.

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[25] 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. AGI identified PILOT agreements for 8 natural gas plants, with effective PILOT tax rates ranging from 0.25% to 2.14%, and the median value of these rates was 0.81%, 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. Based on our review of these past changes, we assume 2% annual inflation in PILOT payments historically and estimate PILOT payments at the time the project became operational. Across the sample, the adjusted PILOT tax rate ranges from 0.14% to 1.53%, with a median value of 0.52%. 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. AGI did not review recent PILOT payments for nuclear units, which may have a different long-term outlook for energy revenues than gas plants. Analysis of these PILOT payments found that year-to-year adjustments to payments varied across plants, with some decreasing, some increasing and some remaining constant over time.

[26] *See* New York City Department of Finance, "Property Tax Rates," http://www1.nyc.gov/site/finance/taxes/property-tax-rates.page and New York City Department of Finance, "Determining Your Assessed Value," https://www1.nyc.gov/site/finance/taxes/property-determining-your-assessed-value.page.

[27] *See* New York Real Property Tax Law, Section 489-aaaaaa et seq.

[28] Any underlying level of real property tax on the land leased for the peaking plant that is not covered by the abatement is assumed to be accounted for within the land lease rate.

[29] *See* New York State Department of Taxation and Finance, Exemption Administration Manual, Section 4.01, RPTL Section 487.

[30] Any underlying level of real property tax on the land leased for the battery storage plant that is not covered by the abatement are assumed to be accounted for within the land lease rate.

2. *Variable O&M Costs*

For fossil plants, 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.

Simple cycle plants 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 turbines options if dual fuel capability is included in the design and for gas operation on the Siemens SGT-A65 option. This is reflected in the higher cost for water related O&M for those cases. The GE 7F.05 and GE 7HA.02 units have dry combustion on gas operation. Water consumed for inlet evaporative cooling is not demineralized. The informational combined cycle option includes an onsite demineralized water treatment system. Raw water source is assumed to be well water for all Load Zones except Load Zone J. In Load Zone J, use of municipal water is assumed at $5 per 1,000 gallons.

Wastewater and plant drains are collected in permanent onsite tanks for periodic removal using pump trucks. The variable O&M 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 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 BMCD's experience.

Major maintenance costs for the Siemens SGT-A65 unit are estimated on dollar per gas turbine hourly operation ($/GT-hr) basis and are not affected by number of starts. Estimates are shown for one turbine and should be multiplied by three when all three turbines are in operation.

Major maintenance costs for the frame engine options (GE 7F.05 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 44.4 operating hours per start for the GE 7HA.02 unit or 27 operating hours per start for the GE 7F.05 unit, the major maintenance cost will be hours based. If there are less than 44.4 hours per start (GE 7HA.02) or 27 hours per start (GE 7F.05), 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.[31]

[31] Table 45 shows that none of the single-cycle combustion turbine frame units operate for more than 27 hours per start (GE 7F.05) or 44.4 hours per start (GE 7HA.02) in any location considered for this study; as such, these units incur major maintenance costs on a $/start basis in all locations. For the informational 1x1 GE 7HA.02 combined cycle plants, maintenance costs are assumed on a $/start basis but incur costs on a $/hr basis. This approach ensures the expected operating profile of a combined cycle plant (long runtimes and low start-counts) while also incurring maintenance costs consistent with the standards applied to other modeled units.

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.

Table 28: Major Maintenance ($2020 USD)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies							
3x0 Siemens SGT-A65	$/GT-hour	$190	$190	$190	$190	$190	$190
	$/start	-	-	-	-	-	-
1x0 GE 7F.05	$/GT-hour	$350	$350	$350	$350	$350	$350
	$/start	$9,500	$9,500	$9,500	$9,500	$9,500	$9,500
1x0 GE 7HA.02 (25 ppm, with SCR)	$/GT-hour	$600	$600	$600	$600	$600	$600
	$/start	$26,600	$26,600	$26,600	$26,600	$26,600	$26,600
1x0 GE 7HA.02 (15 ppm, No SCR)	$/GT-hour	$600	$600	-	-	-	-
	$/start	$26,600	$26,600	-	-	-	-
Informational Combined Cycle Plant							
1x1 GE 7HA.02 (25 ppm, with SCR)	$/GT-hour	$600	$600	$600	$600	$600	$600
	$/start	$26,600	$26,600	$26,600	$26,600	$26,600	$26,600

Table 29: Natural Gas Variable O&M Costs ($2020/MWh)

		C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies							
3x0 Siemens SGT-A65	With SCR	$10.09	$9.97	$9.87	$9.87	$10.19	$9.74
1x0 GE 7F.05	With SCR	$1.52	$1.52	$1.52	$1.52	$1.54	$1.52
	No SCR	$0.94	$0.94	-	-	-	-
1x0 GE 7HA.02 (25 ppm)	With SCR	$1.40	$1.39	$1.39	$1.39	$1.43	$1.39
1x0 GE 7HA.02 (15 ppm)	No SCR	$0.93	$0.93	-	-	-	-
Informational Combined Cycle Plant							
1x1 GE 7HA.02 (25 ppm)	With SCR	$1.59	$1.59	$1.59	$1.59	$1.61	$1.58

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

3. *Battery Augmentation Costs*

O&M for BESS options is included to account for capacity augmentation over time. Per Section II.B.6, all lithium-ion batteries experience performance degradation based on age and cycling behavior. Capacity augmentation means that batteries are added to the system over its life to maintain the full discharge duration at rated capacity. Recent market trends indicate that battery integrators and OEMs are commonly offering fixed or annual pricing for performance and/or capacity guarantees rather than an explicit variable pricing model that would be more comparable to fossil technologies. While variable pricing structures may not represent the recent trend, BMCD has reviewed proposals and/or contracts with variable pricing structures on past projects. For modeling comparisons with fossil technologies, it was desirable to model the augmentation as both a fixed and a variable cost for the purposes of this study.

Battery performance degradation differs depending on the battery chemistry, discharge duration, and cycling behavior. However, based on curves received from multiple vendors for recent projects with similar use cases (approximately 100-365 deep discharge cycles per year), it is reasonable to assume a 2% annual degradation rate for modeling purposes. BMCD modeled capacity augmentation in part as a levelized variable cost over the project life, shown in terms of dollars per MWh discharged, and in part as a fixed cost per battery-year. This cost structure is not meant to exactly represent the setup of service contracts as written in the current market, but instead is meant to serve as a proxy for the total cost of battery augmentation over the course of a battery's economic life, taking into account annual expected run hours.

When calculating the estimates for augmentation, BMCD considered two key pricing factors:

- It is widely assumed in the industry that lithium-ion battery pricing will continue to decline over the upcoming decade. Due to confidentiality, battery pricing for augmentation is not based on forward pricing information provided by battery OEMs. Instead, future battery pricing for the augmentation events considered publicly available battery pricing projections (developed by others).
- BMCD also considered a modest learning rate for battery installers.

The variable O&M cost estimate result is $8.12/MWh for all BESS options and the fixed augmentation O&M cost estimate is $1.14M/yr for the 4-hour BESS option, $1.71M/yr for 6-hour BESS option, and $2.28M/yr for 8-hour BESS option. The combined fixed plus variable O&M results in this DCR are consistent with recent proposals and estimates reviewed by BMCD for similar systems and use cases.

G. Operating Characteristics

The plant operating characteristics used to evaluate the fossil technology options in each Load Zone 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 demand forced outage rate (EFORd); and
- Plant startup time and fuel required for startup.

The net output and net heat rate for all the combustion turbine and combined cycle technology options are impacted by ambient conditions (temperature and relative humidity) and site elevations. The site elevations in each Load Zone are defined in Table 30.

Table 30 also provides the ambient temperatures and relative humidity for the summer, winter, summer DMNC, winter DMNC and ICAP. The summer and winter ambient conditions in each Load Zone are determined at the average winter and summer conditions. The summer and winter DMNC ambient conditions in each Load Zone 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 approved 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. Ambient conditions for summer average, winter average, summer DMNC, and winter DMNC are based on data from 17 New York airports provided by the NYISO. The temperature inputs from applicable airports were used to determine the ambient conditions based on the weighted inputs and methodology set forth in the NYISO Installed Capacity Manual. 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.

Table 30: Ambient Conditions for Current DCR

Load Zone	Elevation (ft)	Season	Ambient Temperature (°F)	Relative Humidity (%)
C - Central	421	Summer	64.4	76.0
		Winter	32.0	74.4
		Spring-Fall	59.0	60.0
		Summer DMNC	88.9	57.7
		Winter DMNC	10.8	55.7
		ICAP	90.0	70.0
F - Capital	275	Summer	65.5	69.1
		Winter	33.1	65.6
		Spring-Fall	59.0	60.0
		Summer DMNC	89.4	54.7
		Winter DMNC	13.2	59.1
		ICAP	90.0	70.0
G - Dutchess County	165	Summer	67.1	77.2
		Winter	36.0	75.5
		Spring-Fall	59.0	60.0
		Summer DMNC	92.9	51.5
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
G - Rockland County	165	Summer	67.1	77.2
		Winter	36.0	75.5
		Spring-Fall	59.0	60.0
		Summer DMNC	92.9	51.5
		Winter DMNC	12.5	57.6
		ICAP	90.0	70.0
J - New York City	20	Summer	70.7	66.4
		Winter	41.2	60.9
		Spring-Fall	59.0	60.0
		Summer DMNC	93.3	58.8
		Winter DMNC	21.1	46.4
		ICAP	90.0	70.0
K - Long Island	16	Summer	67.8	77.3
		Winter	39.5	69.2
		Spring-Fall	59.0	60.0
		Summer DMNC	88.8	59.0
		Winter DMNC	16.5	50.2
		ICAP	90.0	70.0

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

Gross performance results for Siemens SGT-A65 option are based on Siemens Performance Estimating Program (SiPEP). Gross performance ratings for GE 7F.05 and GE 7HA.02 options are based on data requested from GE at performance points across a range of ambient conditions and adjusted for differences between these conditions. All performance ratings shown 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 30 above.

BMCD 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 are shown in Table 31. These degradation adjustments are indicative of average degradation between overhauls, based on BMCD experience on past projects. The same adjustment values were also assumed for the 2016 DCR.

The degraded net plant capacity and degraded net plant heat rates at the ICAP ambient conditions (90°F and 70% relative humidity) for each Load Zone are shown in Table 32 and Table 33, 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: Average Plant Performance Degradation over Economic Life

Plant	Average Degradation of Net Output	Average Degradation of Net Heat Rate
3x0 Siemens SGT-A65	2.5%	0.8%
1x0 GE 7F.05	3%	1.8%
1x0 GE 7HA.02	3%	1.8%
1x1 GE 7HA.02 Combined Cycle (Informational)	1.8%	1.1%

Table 32: Average Degraded Net Plant Capacity ICAP (MW)

Natural Gas (MW)	C - Central	F - Capital	G - Dutchess	G - Rockland	J - NYC	K - Long Island
Simple Cycle Peaking Plant Technologies						
3x0 Siemens SGT-A65	159	159	159	159	159	159
1x0 GE 7F.05	207	208	209	209	210	210
1x0 GE 7HA.02 (with SCR)	344	346	347	347	349	349
1x0 GE 7HA.02 (without SCR)	327	329	330	-	-	-
Informational Combined Cycle Plant						
1x1 GE 7HA.02 (with SCR)	495	499	501	501	502	503

Note:
[1] Based on degraded ICAP performance. Informational combined cycle option is base load, unfired performance.

Table 33: Average Degraded 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						
3x0 Siemens SGT-A65	9,730	9,730	9,730	9,730	9,720	9,720
1x0 GE 7F.05	10,360	10,360	10,360	10,360	10,360	10,360
1x0 GE 7HA.02 (with SCR)	9,460	9,460	9,460	9,460	9,460	9,460
1x0 GE 7HA.02 (without SCR)	9,490	9,500	9,490	-	-	-
Informational Combined Cycle Plant						
1x1 GE 7HA.02 (with SCR)	6,410	6,400	6,400	6,400	6,410	6,410

Note:
[1] Based on degraded ICAP performance. Informational combined cycle option is base load, unfired performance.

Table 34: BESS Net Power at POI

Net Power (MW)	C - Central	F - Capital	G - (Dutchess)	G - (Rockland)	J - NYC	K - Long Island
Energy Storage						
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 capacity is maintained through capacity augmentation throughout the project life.
[2] Heat rate is not applicable to BESS units because fuel is not directly consumed.

For the fossil fuel units, 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."[32] The North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS) continuously collects availability/reliability data from more than 7,700 power plants in the US and Canada. The data is organized by plant type, size ranges and plant age ranges. BMCD included EFORd data extracted from NERC GADS based on the performance since 2012 for units that are no more than 10 years old.

Based on capacity market rules for energy storage resources, capacity derating factors for battery units will be calculated based on the Upper Operating Limit (UOL) metric, which depends on both forced outages and average state of charge.[33] The study assumes that the BESS units are NYISO-managed, which means that the unit is considered to have its full UOL even when drained of energy. Based on OEM data on the expected forced outage rates for new battery installations, a 3% outage rate is assumed for all of the BESS units.

The original equipment manufacturers provided start-up times and start up curves that were used to calculate the start-up fuel consumption. The start-up data is included in Appendix A. For the simple cycle frame combustion turbines, both conventional start- up and fast start- up information is provided. The GE 7HA.02 unit can achieve full output in 10 minutes. The GE 7F.05 unit can achieve approximately 200 MW in 10 minutes, but full load takes another 1-4 minutes. For the informational combined cycle plants the start-up data is for hot, cold, and warm starts.

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 the 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

[32] *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.
[33] NYISO, "Capacity Market Rules for Energy Storage Resources," presentation to the Installed Capacity Working Group, August 23, 2018.

levelized fixed charge (e.g., an annual carrying charge) that allows full recovery of the plant's capital costs over the course of the plant's assumed 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 values 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 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 return on equity (ROE), 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 of 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 and variability in 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. AGI'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 developers and people in the finance community; and AGI'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.

AGI also presents its thoughts on some of the key perspectives with respect to development approaches, key existing and emerging development, market, and regulatory risks that are needed to interpret available data and information. Finally, AGI 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 on investment. In the context of the DCR model, 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. In this sense, what is often referred to as the "economic life" of the asset can, in principle, differ materially from the potential physical or operational life of the plant; 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 reflects 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-fueled peaking plant.[34] 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.

In light of these factors, the 2016 DCR recommended an AP of 20 years for a fossil peaking plant, reflecting the balance of risks and uncertainty faced by project developers.[35] However, we modify this recommendation for fossil peaking plants in light of recent policy development in the State of New York. Specifically, in 2019 the New York enacted the Climate Leadership and Community Protection Act (CLCPA), which requires that all load in New York be supplied by zero-emissions resources as of 2040.[36] In effect, the CLCPA prohibits the operation of a peaking plant in New York burning fossil fuels after 2039. In principle, the owner of a fossil generating facility constructed now could implement plant modifications that would allow the plant to continue to operate, for example, by using a zero-carbon fuel (e.g., hydrogen) or the acquisition of zero-carbon "drop in" fuels that could be used in place of the current fossil fuels. While we recognize this may be possible, the technology and/or markets to accomplish this

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[34] 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.
[35] Analysis Group Inc. & Lummus Consultants International, Inc., "Study to Establish New York Electricity Market ICAP Demand Curve Parameters," September 13, 2016.
[36] 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.

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 fossil peaking plants under the CLCPA, we estimate the number of years over which lenders and investors would seek to recover their investment given the economically viable fossil peaking technologies considered. We do not assume upgrades, modifications or other future design changes that could potentially facilitate continued operation as a zero-emission resource beginning in 2040. This time period will vary depending on when the 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, 2021) should not expect an operating life exceeding approximately 18.7 years (i.e., the time between May 1, 2021 and December 31, 2039) without plant retrofits to remain compliant with the CLCPA's zero-emission requirement beginning in 2040. Similarly, a new plant commencing operations at a later point in time would expect to operate for a shorter economic life. Table 35 shows the economic life a fossil peaking could reasonably assume depending on the Capability Year encompassed by this DCR in which the plant commences operations.

Given these factors, AGI recommends an AP of 17 years for fossil-fueled peaking plant options in all locations evaluated. This is an appropriate assumption given the balance of risks and uncertainty faced by project developers in New York markets. As shown in Table 35, 17 years represents the average economic operating life of a fossil peaking plant over the upcoming four-year period covered by this DCR.

An amortization period of 17 years 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.

Table 35: Potential Economic Operating Life of Fossil Plants

Capability Year	Potential Operating Life of Fossil Plant	Average Operating Life of Fossil Plant over 4 Capability Years
2021-2022	18.7 Years	17 Years
2022-2023	17.7 Years	
2023-2024	16.7 Years	
2024-2025	15.7 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 battery storage plants face a different set of considerations than fossil peaking plants. Unlike fossil plants, battery storage plants do not face the same regulatory constraint on future operations. On the other hand, there is simply no current experience with battery storage operating for more than 10 years. Thus, battery storage operation generally, and specifically in the New York context, faces a wide range of uncertainties related to the expected economic and physical lifetime of new battery units. These uncertainties include 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. Further, because battery storage is still an early-stage technology likely to experience further improvements in operational performance, particularly cycling energy losses, 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 technologies. This reduced competitiveness may translate into lower net revenues, particularly toward the end of the amortization period. These technology effects are more significant for battery technologies, given their early state of technological development, compared to fossil peaking technologies.

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 battery variable O&M costs, rather than 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, we assume an AP for battery storage technologies of 15 years, slightly shorter than that assumed for fossil peaking plant technology options.

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 to equity – and the “cost” of different sources of capital – that is, the required return on equity and the cost of debt. These costs, in turn, reflect the project’s capital structure, because this structure affects the likelihood that debt will be paid and equity will receive returns (in excess of project costs). 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., 2021-2025) 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. As a result, AGI developed its recommended WACC based on data from a number of different sources.

- **Metrics from publicly traded companies.** AGI considered financial metrics from publicly traded companies with largely (if not exclusively) unregulated power generation assets – that is, independent power producers (IPPs). Many IPPs are no longer publicly traded after a series of purchases by private firms.[37] Data on these companies before their purchase include various data or analytic measures of COD, ROE and D/E ratios based on publicly available report data. While such data is not current, it provides insight into the cost of capital in recent years. AGI'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.[38]

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

AGI's recommendations are based on its professional judgment, reflecting the information and data identified below; past professional experience, including conversations with developers and people in 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, AGI views the appropriate WACC for a new peaking plant as being informed by both the WACCs typical of established IPPs and the WACCs that are more representative of stand-alone project-financed developments. 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.[39] The WACC for a new merchant project may exceed that of publicly-traded IPP companies because these companies tend to 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. But, publicly available information on financing arrangements for a stand-alone project finance approach developed by a privately-held entity (or within a publicly-traded IPP) is limited. Moreover, irrespective of the approach actually pursued to develop the project, both sources of information on capital costs can inform choices about the appropriate WACC for a peaking plant, recognizing the differences in capital structure that may apply to the different financing approaches.[40]

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[37] Riverstone Holdings LLC acquired Talen Energy in December 2016. *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; 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.

[38] "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.

[39] 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.

[40] Different sources of information on the cost of capital may capture differences in risk posed by different financial instruments, particularly in light of the non-recourse nature of project finance debt structures, if that approach is pursued.

Below, AGI evaluates the individual financial parameters that bear on the recommended WACC, recognizing the interrelationships among these parameters in determining the WACC. Our recommendations reflect considerations of the impact of the COVID-19 pandemic on financial markets in the near term, while also recognizing the forward-looking four-year period covered by this DCR (i.e., 2021-2025). While COVID-19 initially caused substantial turmoil in capital markets, market conditions have stabilized sufficiently to develop reasonable estimates of the cost of debt and return on equity for this forward-looking period.

Cost of Debt

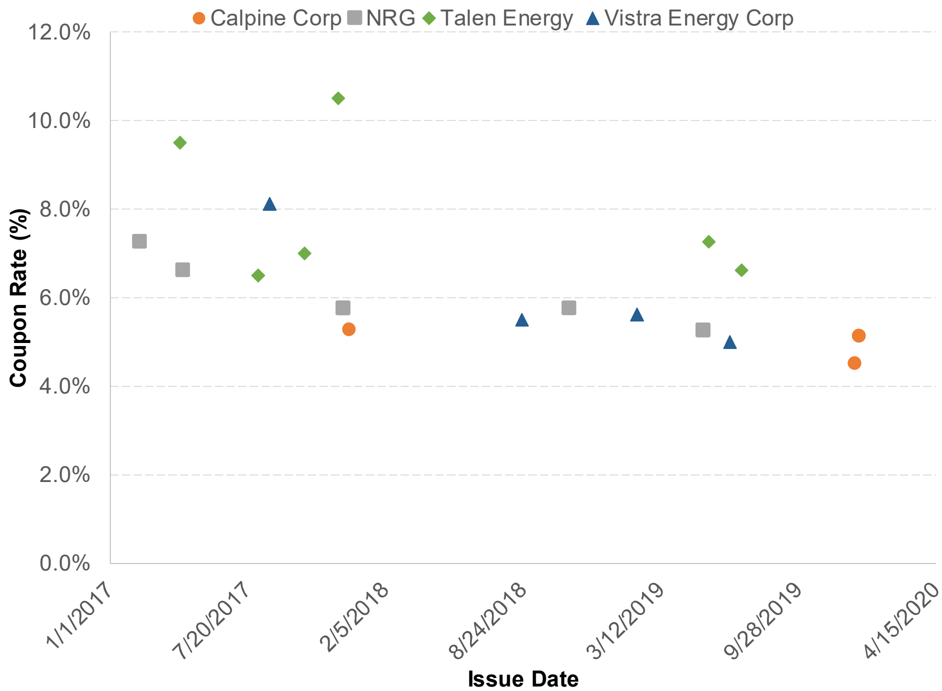
The cost of debt reflects a project developer's ability to raise funds on debt markets. Figure 5 reports the cost of debt issued from January 1, 2017 to present for four power companies with meaningful ownership of merchant units: Calpine Corporation, NRG Energy Inc., Talen Energy Supply LLC, and Vistra Energy Corp. Further detail on these debt issuances are provided in Appendix B.

Coupon rates since 2017 largely range from approximately 4% to 8%, although some issuances have required high rates, above 10% in one case. All four companies listed above have issued below-investment grade debt in 2019: Calpine issued debt rated B and BB, NRG and Vistra both issued debt rated BB and BBB-, and Talen's issuances are rated B+. In 2019, debt issues by IPPs has ranged from 4.5% to 7.3%.

AGI also considered data on the generic cost of corporate debt. Figure 6 provides the generic corporate COD for companies with BB and B credit ratings. The figure shows that COD for below-investment grade issues had generally decreased prior to the COVID-19 outbreak, with rates falling below 6%. At the beginning of the outbreak, the COD for BB and B generic debt rose significantly, as high as 12.39% for B-rated debt (on March 23, 2020). But, in the ensuing months, rates for below-investment grade debt have gradually declined, closer to levels observed prior to the COVID-19 pandemic. For example, for the four weeks of June 8, 2020 - July 3, 2020, the average rate for B-rated generic debt was 6.61%.

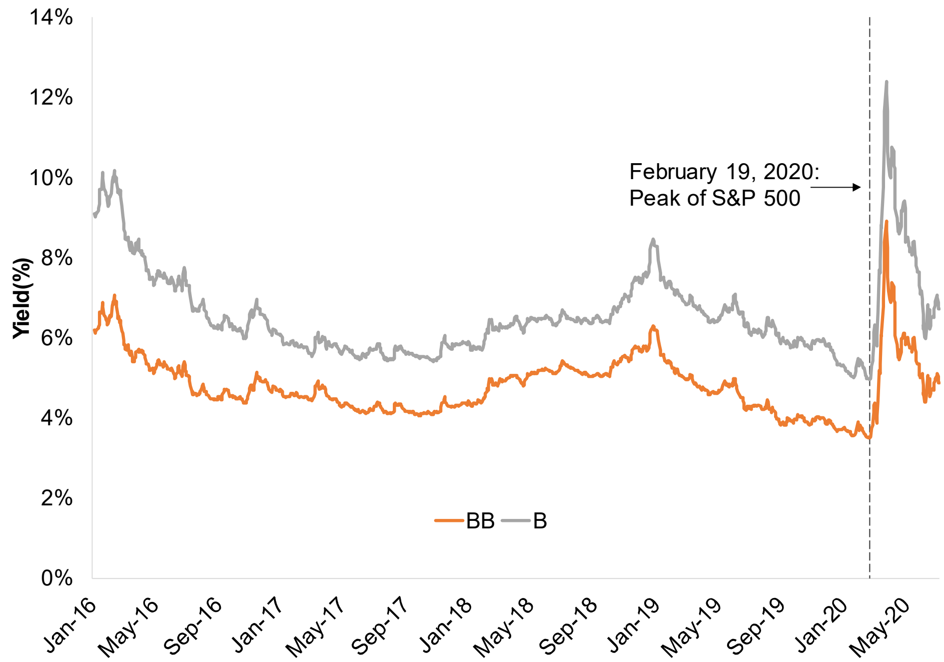
Based on these factors, AGI recommends a COD of 6.7%. This recommendation reflects a number of factors, including: B rated debt; current as well as pre-COVID-19 debt rates, in recognition of the need to capture immediate market conditions as well as longer-run market trends; differences between COD to IPPs relative to generic debt indices; and other market conditions.

Figure 5: Cost of B and BB Rated Debt for Independent Power Producers, by Issuance, 2017-2020



Note:
[1] Accessed on March 2020 from Bloomberg. Additional detail is provided in Appendix B.

Figure 6: Generic Corporate Bond Yields, by Credit Grade



Sources:
[1] St. Louis Federal Reserve Bank of St. Louis, FRED, ICE BofA BB US High Yield Effective Yield Index (BAMLH0A1HYBBEY); St. Louis Federal Reserve Bank of St. Louis, FRED, ICE BofA Single-B US High Yield Effective Yield Index (BAMLH0A2HYBEY).

<u>Return on Equity</u>

The recommended ROE is developed using data from several sources. One source of data is the estimated return on equity for publicly traded IPPs. In the 2016 DCR, AGI evaluated the cost of equity for four companies, Calpine, NRG Energy, Dynegy and Talen Energy, finding the average cost of equity to be 10.47% and 11.05% based on Bloomberg and Value Line data, respectively. Since that time, Calpine, Dynegy and Talen were acquired by private corporations[41], which do not publicly report their finances. Table 36 reports the estimated ROE for NRG Energy and Vistra Energy based on the capital asset pricing model (CAPM).[42,43] Appendix B provides further details on these calculations. Company betas are obtained from Value Line and Bloomberg. With Value Line betas, estimated ROEs are 7.75% for Vistra and 10.51% for NRG, with an average of 9.13%. With Bloomberg betas, estimated ROEs are 6.57% for Vistra to 9.01% for NRG, with an average of 7.79%. While both NRG and

[41] Vistra Energy, which acquired Dynegy in 2018, is publically traded. We reviewed Vistra's financial profile as part of our analysis.
[42] Other approaches not used include the Discounted Cash Flow (DCF) and historical risk premium. Similarly, AGI notes that utility regulators may consider a variety of information and models (including CAPM, DCF, or historical risk premiums) when setting the ROE for regulated utilities. Therefore, AGI did not consider a comparison of CAPM estimates of ROEs for regulated utilities when estimating the relevant ROE for a merchant power plant developer. This is consistent with the assumption that the rate of return for a safer project this regulated cost recovery is not the same as the return for a riskier project that does not benefit from guaranteed cost recovery.
[43] We evaluated publicly traded companies operating in electricity markets to identify companies with sufficient activity in merchant power supply to provide useful information on the return on equity for IPPs. Our assessment identified only two companies, NRG Energy and Vistra.

Vistra have substantial merchant generation holdings, they also have substantial holdings in other regulated and unregulated businesses in the electric power sector, including generation facilities operated under long-term contracts and competitive retail supply operations.[44] 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 return on equity are not necessarily comparable to the required return on equity for a new peaking plant project in New York.

A second source of data is independent estimates of the ROE 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 ROEs ranging from 12.8% to 13.8% in recent net CONE studies.[45] These values reflect different methodologies and data sources.

A third source of data considered is estimates of the ROE for stand-alone project finance developments. Based on several independent sources, ROEs for stand-alone project finance developments have ranged from approximately the low teens to as high as 20%.[46]

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 (which may increase or decrease over time) and the mix of resources given legislative changes and energy and environmental policies, such as the CLCPA, and regulations such as the NYDEC peaker rule. Market outcomes may also change due to modifications to NYISO 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.

Finally, we considered the consequences of the COVID-19 pandemic when developing a recommended ROE. Many factors were considered when accounting for COVID-19, including the reduction in risk-free return on equity due to stimulus from the U.S. Federal Reserve (and low risk-free rates, prior to the pandemic), increases in the risk-premium due to elevated market risks and uncertainties as a consequence of the pandemic, and the likely duration of these effects given the requirement to determine a forward-looking ROE for the timeframe of interest in this DCR (i.e., 2021-2025). In light of these factors, we make no explicit adjustment for the COVID-19 pandemic.

[44] *See*, Freitas Jr, Gerson, "Virus May Show How Wall Street Misjudged Two Power Companies," Bloomberg, May 4, 2020.
[45] See, The Brattle Group, PJM Cost of New Entry: Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, report prepared for PJM Interconnection, L.L.C., April 19, 2018; 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.
[46] *See*, for example, EPA, Integrated Planning Model v6, November 2018 Reference Case, Documentation for Chapter 10: Financial Assumptions, p. 10-7, which reports a 12.16% ROE at a 55% target debt ratio and 3.45% risk free rate for merchant projects (project finance and corporate finance alike); Energy Sector Planning and Analysis, *Update of Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects*, report prepared for Department of Energy National Energy Technology Laboratory, September 29, 2011, p. 2, which indicates that a 15% to 25% ROE is common for low and high risk power projects at debt ratios of 60% to 70% (); Esty, Benjamin and Kane, Michael, "Calpine Corporate: The Evolution from Project to Corporate Finance." Harvard Business School, Case Study 9-201-098, January 21, 2003, p. 4, which notes that Calpine typically sought an 18% to 22% as a project finance developer circa 2002, with a debt ratio of 65%; and Chadbourne, "Merchant Gas Projects: How Many More?" Project Finance NewsWire, August 2016, p. 40, which quoted a developer describing long-term equity investors as seeking "returns … in the low teens to low 20s."

Based on this information, AGI recommends a ROE of 13.0%, reflecting a balance between the lower IPP values (which range up to 10.51%) and higher project finance values. The recommended ROE is near the bottom of the range of WACC values from the previous net CONE studies in PJM and ISO-NE, largely reflecting the low value of the risk free rate at this time.

Table 36: Cost of Equity for Publicly Traded IPPs

Corporation	Ticker	Value Line Beta	Value Line Cost of Equity	Bloomberg Beta	Bloomberg Cost of Equity
NRG Energy Inc	NRG	1.25	10.51%	1.03	9.01%
Vistra Energy	VST	0.85	7.75%	0.68	6.57%
Group Average		1.05	9.13%	0.86	7.79%

Notes:
[1] CAPM estimates are based on a 6.9% market risk premium from Duff and Phelps, *2019 Cost of Capital: Annual U.S. Guidance and Examples*, Chapter 3: Basic Building Blocks of the Cost of Equity Capital: Risk-free Rate and Equity Risk Premium, p. 64, and a 1.88% risk free rate based on the Thirty-Year Treasury Constant Maturity Rate.
[2] Company beta values are from Value Line and Bloomberg.

Debt to Equity Ratio

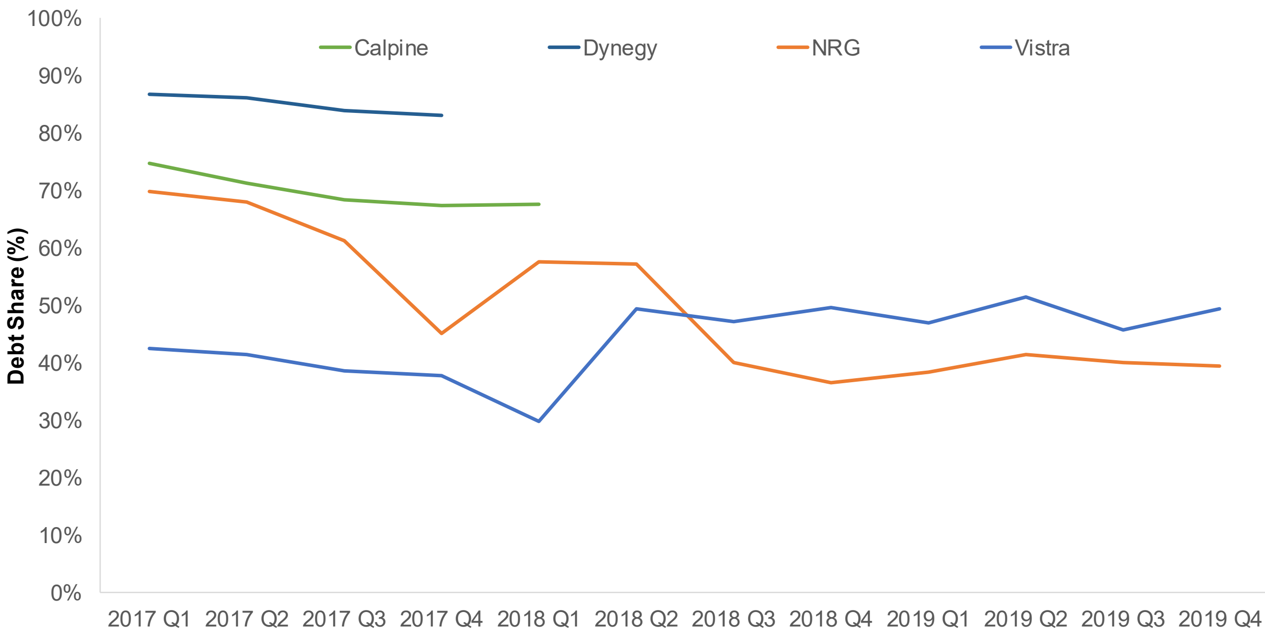
The choice of capital structure – that is, the ratio of debt to equity – can vary depending on many factors, particularly the nature of the revenue streams (with certain sure revenue streams supporting higher levels of debt), the structure of the project's management and financing, and the nature of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

AGI 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. On the one hand, the capital structure of IPP companies (at the corporate, not the project level) currently reflect lower levels of debt than have been historically carried. Figure 7, which shows the debt share of capital for Calpine, Dynegy, NRG, and Vistra over the past 3 years, illustrates this effect.[47] While corporate level capital structure may not be directly informative to an appropriate project-level capital structure, we consider the general trend toward lower leverage, given low debt costs (prior to the COVID-19 outbreak), in our assessment.[48] On the other hand, project financing capital structures can vary, with some projects involving higher levels of debt than assumed in our analysis. Our recommendation is more conservative than the capital structure adopted in recent similar studies for ISO-NE and PJM, which assume 60% and 65% debt, respectively.[49] Our recommendation also considers the range of values

[47] The market value of equity is calculated as enterprise value minus cash and near-cash items; data for the calculations is from Bloomberg.
[48] Note that deleveraging of these companies (i.e., lower debt share), which was previously expected by the companies themselves and analysts, may place pressure to lower debt levels of individual projects. *See*, e.g., UBS Securities, "How to Value Power?", December 8, 2015 ("We believe all IPPs will accelerate their debt paydown efforts…").
[49] *See*, 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.

developed in other contexts, including recommendations by the California Energy Commission and National Energy Technology Laboratory.[50]

Figure 7: Debt to Capital Share, Independent Power Producers, 2017-2019



Note:
[1] The market value of equity is calculated as the enterprise value minus cash and near cash items.
Source:
[1] Bloomberg, accessed March 2020.

<u>Calculation of the WACC</u>

AGI's assessment of factors related to the calculation of the WACC has considered the data on the following: ROE, 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:

[50] California Energy Commission, Estimated Cost of New Utility-Scale Generation in California: 2018 Update, May 2019, Table B-1; National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, September 24, 2019, p. 558.

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

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%),[51] and, for Load Zone J, the New York City business corporation tax rate (8.85%).[52] These result in composite income tax rates of 36.35% (NYC) and 27.5% (all other locations).[53]

Using these equations and the considerations presented above, AGI recommends a WACC of 9.54%, based on a debt ratio of 55%, a COD of 6.70%, and a ROE of 13.00%. This results in a nominal ATWACC of 8.52% in NYCA, LI, and the G-J Locality and 8.20% in NYC.

The recommended ATWACC is consistent with previous and currently approved capital cost values in NYISO and other neighboring market (e.g., ISO-NE and PJM) for net CONE evaluations utilized for capacity market purposes. The current ATWACCs in ISO-NE and PJM are 8.1% and 7.5% (respectively), while the current ATWACC for the NYISO as approved during the 2016 DCR is 8.46%. The ATWACC proposed for this DCR reflects a combination of factors. Relative to the other 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, expectations for relatively flat load growth over the time period encompassed by this DCR (i.e., 2021-2025), 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 2016 DCR, the slightly higher ATWACC reflects the slightly lower cost of debt, 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. AGI 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 fossil peaking plant technologies in NYC and for battery storage options in all locations).

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.[54] Second, the net present value

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[51] *See* New York State Department of Taxation and Finance, Form CT-3/4-I.
[52] *See* New York City Department of Finance, "Business Corporation Tax," http://www1.nyc.gov/site/finance/taxes/business-corporation-tax.page.
[53] State and local taxes are no longer deductible from federal corporate taxes, so the composite rate now sums the applicable federal, state, and local tax rates.
[54] Similarly, using the required cash flow to equity, income taxes can be calculated as:

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 ROE, are expressed in constant real 2021 dollars. Capital costs were estimated by BMCD as of Q1 2020, so were escalated to reflect costs as of Q2 2021, when the 2021-2022 Capability Year (which runs from May 1, 2021 - April 30, 2022) begins. The difference between Q2 2021 and Q1 2020 is 5 quarters, or 15 months, so the cost escalation factor applied to the Q1 2020 capital costs reflect cost escalation as of the last 15 months of available data. Table 37 shows the details of the escalation rates used for each capital cost component.

Table 37: Capital Cost Escalation Rates

Price Index	Data Release used as of September 8, 2020	Starting Time Period Used for Escalation Factors	Starting Index Value	Ending Time Period Used for Escalation Factors	Ending Index Value	Escalation Rate Formula to Convert $Q1 2020 to $Q2 2021	Escalation Rate to Convert $Q1 2020 to $Q2 2021
			[A]		[B]		[C]
GDP Price Index	Q2 2020 (prelim)	Q1 2019	111.424	Q2 2020	112.755	[B]/[A]-1	1.19%
PPI: Turbines and Generators	April 2020 (prelim)	Nov '18-Jan '19 Avg	228.0	Feb '20-Apr '20 Avg	238.8	[B]/[A]-1	4.71%
PPI: Storage Batteries	April 2020 (prelim)	Nov '18-Jan '19 Avg	205.8	Feb '20-Apr '20 Avg	205.0	[B]/[A]-1	-0.40%
PPI: Materials and Components for Construction	April 2020 (prelim)	Nov '18-Jan '19 Avg	249.8	Feb '20-Apr '20 Avg	253.4	[B]/[A]-1	1.43%
QCEW: Utility Construction Wages (New York)	2019 Annual	2017 Annual	$101,108	2019 Annual	$107,893	([B]/[A])^(5/8)-1	4.14%

Note:
[1] Indexes are subject to revision by the publishing agency.

The analysis assumes forward-looking inflation of 2.1% 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 2020,[55] as well as long-term inflation in electricity prices as reported by the EIA Annual Energy Outlook.[56]

Table 38 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 39. Depreciation schedules are based on the Federal Internal Revenue Service (IRS) Publication 946 and follow the half-year convention. Fossil peaking plant options are

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

[55] The Survey of Professional Forecasters forecast headline CPI of 2.20% between 2020-2029 and headline PCE of 2.00% between 2020-2029. *See* Federal Reserve Bank of Philadelphia, "First Quarter 2020 Survey of Professional Forecasters," February 14, 2020, https://www.phil.frb.org/research-and-data/real-time-center/survey-of-professional-forecasters/2020/survq120.

[56] *See* EIA Annual Energy Outlook (AEO) 2020, January 29, 2020, Table 3: Energy Prices by Sector and Source. The EIA forecasts real price growth for residential electricity of 0.0% for the period 2019 to 2050 and nominal price growth of 2.3% 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 0.6% and nominal growth of 3.0%.

depreciated with a 15-year schedule; the informational combined cycle plants are depreciated with a 20-year schedule; and battery storage plants are depreciated with a 7-year schedule.[57]

Table 38: Summary of Financial Parameters by Location

Finance Category	NYCA	G-J	NYC	LI
Inflation Factor (%)	2.10%	2.10%	2.10%	2.10%
Debt Fraction (%)	55.00%	55.00%	55.00%	55.00%
Debt Rate (%)				
Nominal	6.70%	6.70%	6.70%	6.70%
Real	4.51%	4.51%	4.51%	4.51%
Equity Rate (%)				
Nominal	13.00%	13.00%	13.00%	13.00%
Real	10.68%	10.68%	10.68%	10.68%
Composite Tax Rate (%)	27.50%	27.50%	36.35%	27.50%
Federal Tax Rate	21%	21%	21%	21%
State Tax Rate	6.50%	6.50%	6.50%	6.50%
City Tax Rate	0.00%	0.00%	8.85%	0.00%
WACC Nominal (%)	9.54%	9.54%	9.54%	9.54%
ATWACC Nominal (%)	8.52%	8.52%	8.20%	8.52%
ATWACC Real (%)	6.29%	6.29%	5.97%	6.29%
Amortization Period (Years)	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit	17-Year Fossil Unit; 15-Year Battery Unit
Tax Depreciation Schedule	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)	7-Year MACRS (Battery); 15-Year MACRS (Simple Cycle)
Fixed Property Tax Rate (%)	0.5% with 15-Year Abatement for Battery	0.5% with 15-Year Abatement for Battery	4.7% with 15-Year Abatement	0.5% with 15-Year Abatement for Battery
Insurance Rate (%)	0.60%	0.60%	0.60%	0.60%
Levelized Fixed Charge (%)	12.04% CT Unit; 12.47% CC Unit; 11.71% Battery Unit	12.04% CT Unit; 12.47% CC Unit; 11.71% Battery Unit	12.40% CT Unit; 17.44% CC Unit; 11.99% Battery Unit	12.04% CT Unit; 12.47% CC Unit; 11.71% Battery Unit

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, battery plants, and the informational combined cycle units 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.

[57] For discussion of the depreciation of battery units see, National Renewable Energy Laboratory, "Federal Tax Incentives for Energy Storage Systems," January 2018, https://www.nrel.gov/docs/fy18osti/70384.pdf.

Table 39: Modified Accelerated Cost Recovery Tax Depreciation Schedules

	Tax Depreciation		
Year	7 Year (Battery)	15 Year (Simple Cycle)	20 Year (Combined Cycle)
1	14.29%	5.00%	3.75%
2	24.49%	9.50%	7.22%
3	17.49%	8.55%	6.68%
4	12.49%	7.70%	6.18%
5	8.93%	6.93%	5.71%
6	8.92%	6.23%	5.29%
7	8.93%	5.90%	4.89%
8	4.46%	5.90%	4.52%
9	0.00%	5.91%	4.46%
10	0.00%	5.90%	4.46%
11	0.00%	5.91%	4.46%
12	0.00%	5.90%	4.46%
13	0.00%	5.91%	4.46%
14	0.00%	5.90%	4.46%
15	0.00%	5.91%	4.46%
16	0.00%	2.95%	4.46%
17	0.00%	0.00%	4.46%
18	0.00%	0.00%	4.46%
19	0.00%	0.00%	4.46%
20	0.00%	0.00%	4.46%
21	0.00%	0.00%	2.23%

Source:

[1] 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 40 and Table 41 provides annualized gross CONE values for each peaking plant within each location.

Table 40: Gross CONE by Peaking Plant Technology and Load Zone ($2021/kW-Year)

Peaking Plant Technology		C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
GE 7F.05	**Dual Fuel with SCR**						
	Fixed O&M	$11.58	$12.01	$13.43	$13.43	$29.57	$14.64
	Insurance	$5.39	$5.45	$5.56	$5.89	$6.70	$6.61
	Levelized Fixed Charge	$162.30	$163.41	$165.58	$173.12	$231.02	$183.58
	Gross CONE	$179.27	$180.87	$184.57	$192.44	$267.28	$204.82
	Gas only with SCR						
	Fixed O&M	$11.58	$12.01	$13.43	$13.43	-	-
	Insurance	$4.89	$4.95	$5.06	$5.39	-	-
	Levelized Fixed Charge	$146.12	$147.32	$149.55	$157.09	-	-
	Gross CONE	$162.58	$164.28	$168.04	$175.91	-	-
	Gas only without SCR						
	Fixed O&M	$11.58	$12.01	$13.43	-	-	-
	Insurance	$4.28	$4.34	$4.45	-	-	-
	Levelized Fixed Charge	$132.24	$133.51	$135.80	-	-	-
	Gross CONE	$148.09	$149.86	$153.69	-	-	-
1x0 GE 7HA.02 25ppm	**Dual Fuel with SCR**						
	Fixed O&M	$8.18	$8.43	$9.29	$9.29	$19.01	$10.01
	Insurance	$4.49	$4.52	$4.58	$4.76	$5.36	$5.30
	Levelized Fixed Charge	$129.64	$130.17	$131.45	$135.73	$172.05	$144.46
	Gross CONE	$142.31	$143.12	$145.32	$149.78	$196.41	$159.77
	Gas only with SCR						
	Fixed O&M	$8.18	$8.43	$9.29	$9.29	-	-
	Insurance	$4.03	$4.06	$4.13	$4.31	-	-
	Levelized Fixed Charge	$115.04	$115.65	$116.99	$121.27	-	-
	Gross CONE	$127.25	$128.14	$130.40	$134.87	-	-
1x0 GE 7HA.02 15ppm	**Dual Fuel without SCR**						
	Fixed O&M	$8.61	$8.88	$9.78	-	-	-
	Insurance	$3.90	$3.94	$4.01	-	-	-
	Levelized Fixed Charge	$118.09	$118.74	$120.15	-	-	-
	Gross CONE	$130.60	$131.56	$133.93	-	-	-
	Gas only without SCR						
	Fixed O&M	$8.61	$8.88	$9.78	-	-	-
	Insurance	$3.42	$3.46	$3.53	-	-	-
	Levelized Fixed Charge	$102.72	$103.45	$104.92	-	-	-
	Gross CONE	$114.75	$115.79	$118.23	-	-	-

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

Table 41: Gross CONE by Battery Storage Technology and Load Zone ($2021/kW-Year)

Peaking Plant Technology		C - Central	F - Capital	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	J - New York City	K - Long Island
4-Hr BESS	**Battery**						
	Fixed O&M	$12.10	$12.10	$12.10	$12.10	$23.04	$12.35
	Insurance	$7.59	$7.66	$7.73	$8.03	$8.51	$8.45
	Levelized Fixed Charge	$181.10	$182.70	$184.20	$190.69	$230.19	$194.06
	Gross CONE	$200.79	$202.46	$204.04	$210.82	$261.74	$214.86
6-Hr BESS	**Battery**						
	Fixed O&M	$16.53	$16.53	$16.53	$16.53	$31.20	$16.83
	Insurance	$10.85	$10.96	$11.06	$11.49	$12.17	$12.10
	Levelized Fixed Charge	$252.47	$254.78	$256.90	$266.26	$312.15	$273.70
	Gross CONE	$279.86	$282.27	$284.49	$294.28	$355.52	$302.63
8-Hr BESS	**Battery**						
	Fixed O&M	$21.01	$21.01	$21.01	$21.01	$39.41	$21.37
	Insurance	$14.11	$14.25	$14.38	$14.94	$15.83	$15.74
	Levelized Fixed Charge	$323.77	$326.80	$329.54	$341.77	$394.05	$353.29
	Gross CONE	$358.90	$362.07	$364.93	$377.72	$449.29	$390.39

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 over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services."[58]

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…"[59]

AGI 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 for NYCA and each Locality. 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.[60]

First, AGI summarizes its approach for estimating net EAS, including a description of the net EAS model, the data inputs, and the approach to adjusting prices to be consistent with LOE market conditions. Second, AGI summarizes the process for annually updating estimated net EAS revenues over the reset period. Finally, AGI presents results of applying the net EAS revenues model for the 2021/2022 Capability Year.

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. 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

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[58] Services Tariff, Section 5.14.1.2.
[59] Services Tariff, Section 5.14.1.2.
[60] 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, AGI uses both terms, when appropriate. For example, when describing system capacity need in MW, AGI uses ICR. When referencing the required level of reserves in percentage terms, AGI uses IRM.

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. AGI'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 (with a lag) consistent with actual EAS market outcomes (as adjusted for LOE conditions).

AGI's model estimates the net EAS revenues of the peaking plant on an hourly basis 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 same model, 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 Model Logic

The AGI simulated dispatch model uses a "dispatch logic" functionally consistent with NYISO energy and ancillary services markets.[61] Specifically, the AGI 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.[62] In the model, the peaking plant 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 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 8 and Figure 9 contain schematics of the commitment/dispatch logic for the DAM and RTM, respectively. 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 peaking plant's DAM commitment. Thus, the 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 Load Zone. 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

[61] 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.
[62] AGI assumes that LBMPs would not be affected by the incremental supply provided by the peaking plant.

on the part of either the buyer or seller.[63] This additional cost is incorporated into RTM buy out decisions for all plants. As illustrated in Figure 9, 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

In contrast, the net EAS revenues model for the informational combined cycle plants only consider the energy commitment and dispatch of the plant in both DAM and RTM, including the ability to buy out of a DAM energy commitment in the RTM. The informational combined cycle plants are assigned a flat annual adder of $3.90/kW-year as an estimate of net ancillary services revenues, based on settlement data provided by the NYISO for comparable plants.

When evaluating an energy commitment in either the DAM or RTM, the model ensures that all costs, including amortized start-up costs, can be recovered.[64] In the DAM, start-up costs for the Frame combustion turbine can be recovered over the full runtime block, which is determined dynamically based on profitable hours; within the RTM, Frame combustion turbine plants must recover their startup costs over two hours. In contrast, in both the DAM and RTM; aeroderivative plants recover start-up costs over the first hour of commitment.

Plants are also constrained by applicable runtime limitations as described in Section II.C. For peaking plants modeled with SCR emissions control technology, the NSPS limitation for CO_2 is a limiting constraint on hours of operation. BMCD estimated the maximum annual runtimes for all combustion turbines with SCR emissions control technology to be 3,066 hours. BMCD deemed that the informational combined cycle plants, which are assumed to install SCR emissions control technology, would not face runtime limitations. 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

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[63] These costs are based on estimates reported by the NYISO Market Monitoring Unit (MMU) in their State of the Market Report 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.

[64] 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.

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.[65]

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.[66] 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 (see Table 44).

If the generator 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, which is discussed in further detail below (see Table 44). 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).[67]

[65] 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, 2019 to August 31, 2020). 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.

[66] 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.

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

Figure 8: Net EAS Revenues Model Day-Ahead Commitment Logic

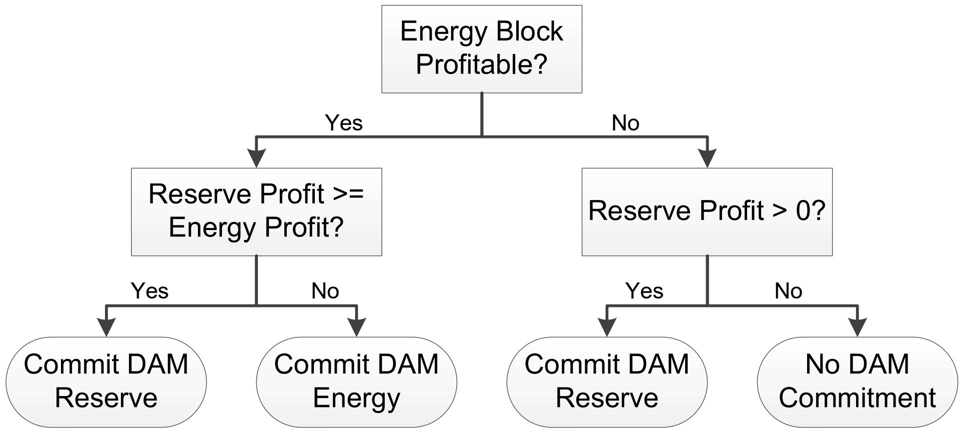
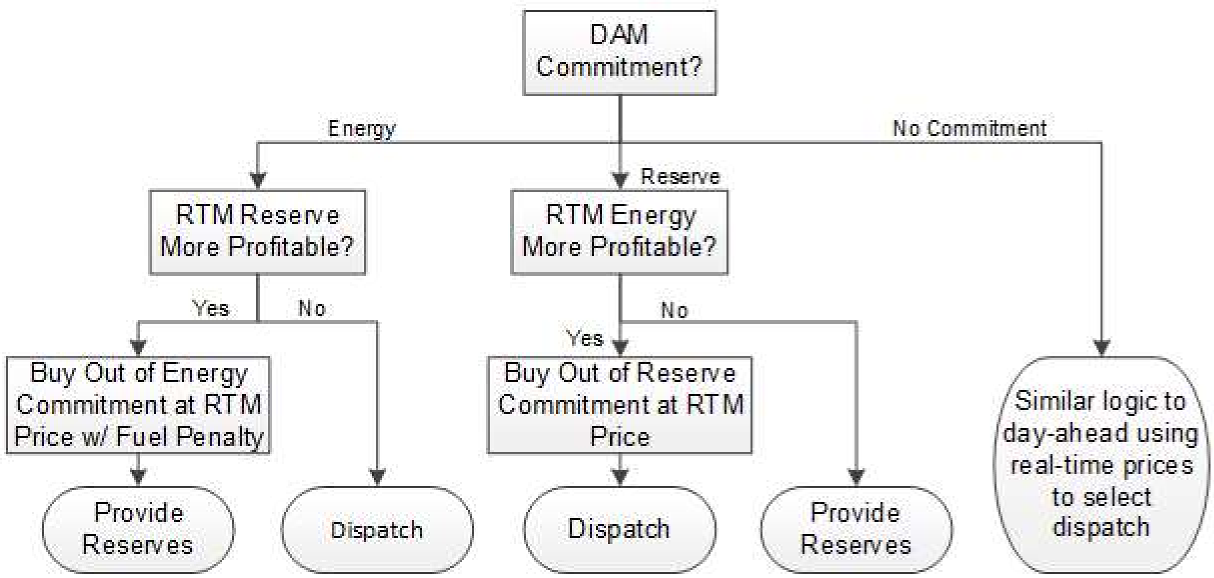


Figure 9: Net EAS Revenues Model Real-Time Supply Logic



The net EAS revenues model estimates hourly revenue streams for the peaking plants based on prices over the three-year historical period. Within this hourly model, peaking plants 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. In contrast, the net EAS revenues estimates for the informational combined cycle plants assume the plant may be committed at minimum load between energy commitments, to the extent that this would be more profitable than incurring an additional startup cost.

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 Load Zone and, when applicable, each peaking plant:[68]

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

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 = Amortized startup cost (dynamically determined)

$RS1$ = 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, the model separately considers relevant unit parameters for Summer and Winter Capability Period months, including each plant's seasonal capacity and heat rate. Total annual revenues are the sum of revenues earned during each hour of the year reflecting seasonal ratings, with energy and reserves revenues derated by the peaking plant's EFORd.

[68] 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 a flat adder for providing Voltage Support Service (VSS).[69]

An important component of the net EAS revenues model is the ability of the model to assess 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 peaking plant is assumed to operate on the most economic fuel for a full runtime block. Plants are not allowed to fuel switch within an individual block.

Notably, the current model does not consider potential limitations in gas only operations; all gas plants are assumed to be able to procure fuel as needed, at historical prices.[70] As described in Section II, AGI considered potential limitations in fuel availability as part of its qualitative review.

b. Battery Model Logic

Like the fossil model, the AGI simulated dispatch model for battery storage uses a “dispatch logic” that is functionally consistent with NYISO energy and ancillary services markets.[71] Net EAS revenues are earned by the battery on an hourly basis in the RTM and DAM energy and reserve markets. The model’s “dispatch logic” 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 markets, which follows three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch.

Due to the physical energy limitations of a battery, the model determines charge and discharge of the battery simultaneously in hour-pairs. 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 model accounts 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.

---

[69] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Historical average annual net EAS revenues are escalated from the three-year midpoint (here, $2017) into real dollars (here, $2019) for the ICAP Demand Curves using the GDP implicit price deflator.

[70] Similarly, the model does not account for Operational Flow Order (OFO) restrictions which may limit hourly or daily deviations in gas burn from nominations. AGI 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.

[71] 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.

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 or is charging. 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 model assumes 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.

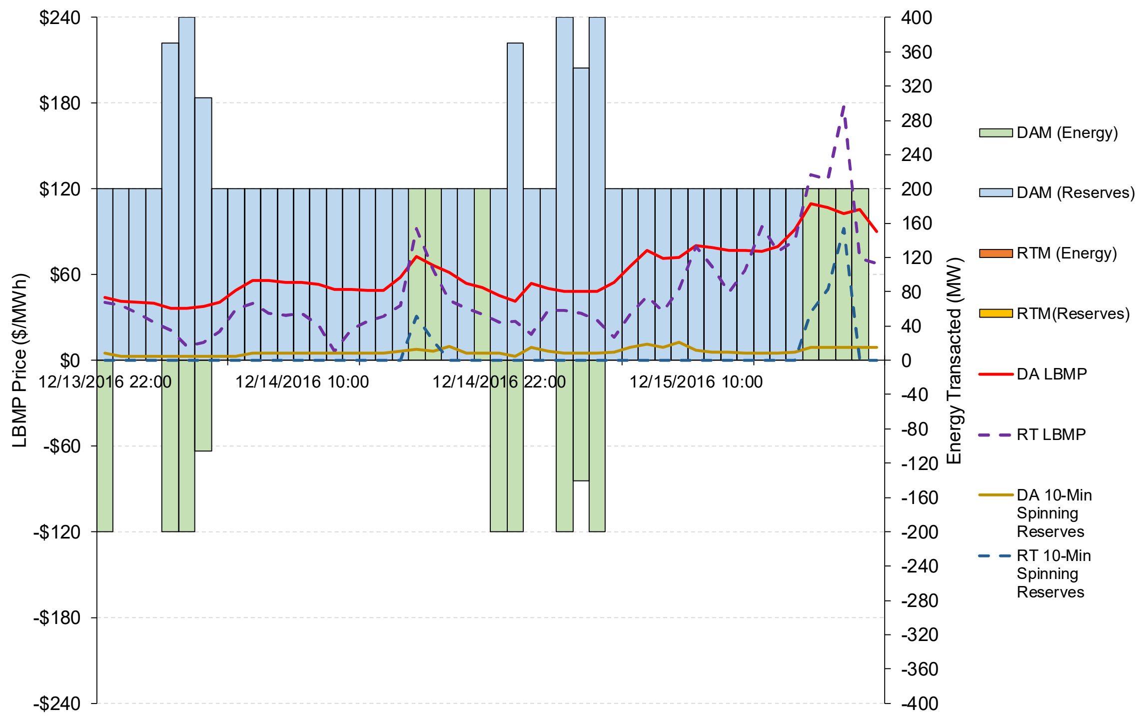
The dispatch logic for battery storage is split into three steps: (1) daily DAM commitments, (2) multi-day DAM revisions, and (3) daily RTM dispatch. Figure 10, Figure 11, and Figure 13 illustrate how the model is solved for two illustrative days in the three steps. The left axis (and lines) show the 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.[72] For each cycle-day, the model generates every feasible day-ahead position hour-pair given the current position of the battery storage resource. It 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 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 10. Three hour-pairs are committed on the first DAM day and four hour-pairs are committed on second DAM market day, as depicted by the green 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.

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

Figure 10: AGI Battery Model Step 1 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery

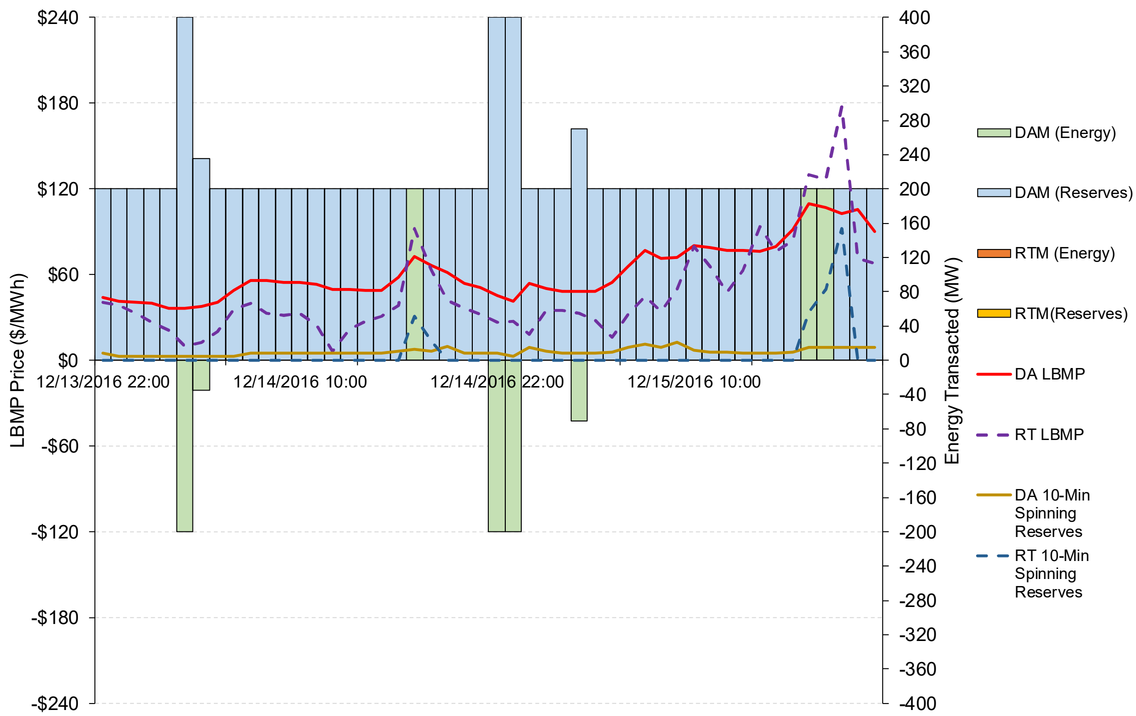


The **second step** considers whether net revenues are maximized by emptying the battery each day or maintaining stored energy between cycle-days. The model determines the multi-day behavior of the battery by comparing net EAS revenues of these two different options.[73]

The outcomes of this second step can be seen in Figure 11. Here, the model determined it was more profitable to enter the day of 12/15 with energy stored, and thus it eliminated two discharge hours on 12/14 and charging hours on 12/15. The model similarly compares 12/13 and 12/14 as well as 12/15 and 12/16.

[73] The model calculates net EAS revenues of maintain energy levels across days by adjoining adjacent cycle-days. For each pair of days, the model creates 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 model. Otherwise, the initial DAM commitments are left unchanged. The model pairs 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 model.

Figure 11: **AGI Battery Model Step 2 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery**



The **third step** determines any incremental RTM positions using logic similar to the daily DAM position process. 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 DAM energy position, the battery can buy out of DAM reserve position and take on a RTM energy position instead.

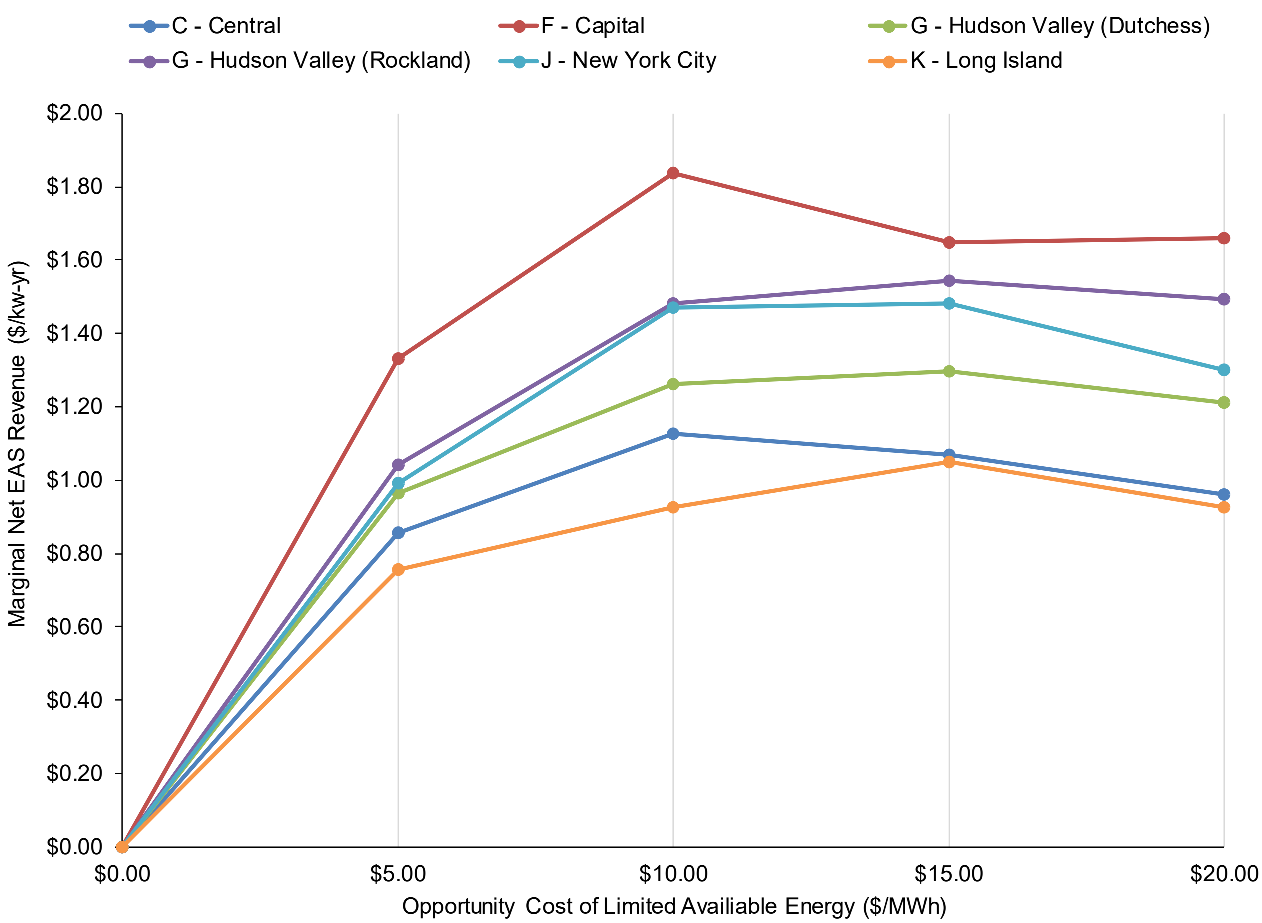
To evaluate such arbitrage opportunities, the model generates every feasible RTM hour-pair given the current hourly positions of the battery. When evaluating and ranking the profitability of adding hour-pairs in the RTM, the model calculates an 'estimated profit' using the RTM LBMP for the first hour and the DAM LBMP for the second hour. This reflects the fact that, in real-time, a resource operator would not know a future RTM LBMP and could use the DAM LBMP as an approximation. However, once these RTM positions are entered into, the model will use RTM LBMPs to calculate realized profits, which may be higher or lower than the estimated profits used to enter into the position.

Real-time dispatch (and charging) decisions also incorporate a hurdle rate that accounts for LBMP uncertainty in the real-time market. This hurdle rate reflects two components - an opportunity cost of limited available energy and a risk premium. The battery model must clear the hurdle rate (i.e., estimate its new position to be more profitable than the hurdle rate) in order to enter into a RTM position.

The opportunity cost of limited available energy reflects 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. The risk premium accounts for market participant's risk aversion when participating in the real-time market, given the potential for higher volatility of real-time prices and the potential for losses to result from deviations from its DAM positions. We assume the risk premium is $10/MWh, and calculate the opportunity cost of limited available energy empirically using the model, see Figure 12.

Figure 12 provides the marginal net EAS revenues evaluated for different assumed 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). To obtain the total hurdle rate, we add the $10/MWh risk premium to this opportunity cost value. This assessment resulted in a total hurdle rate assumption of $20 per MWh in Load Zone C and Load Zone F, and $25 per MWh in Load Zone G (Dutchess County), Load Zone G (Rockland County), Load Zone J, and Load Zone K.

Figure 12: Change in RTM Net EAS Revenues for Alternative Bid Offer Hurdle Costs, 4-Hour Battery

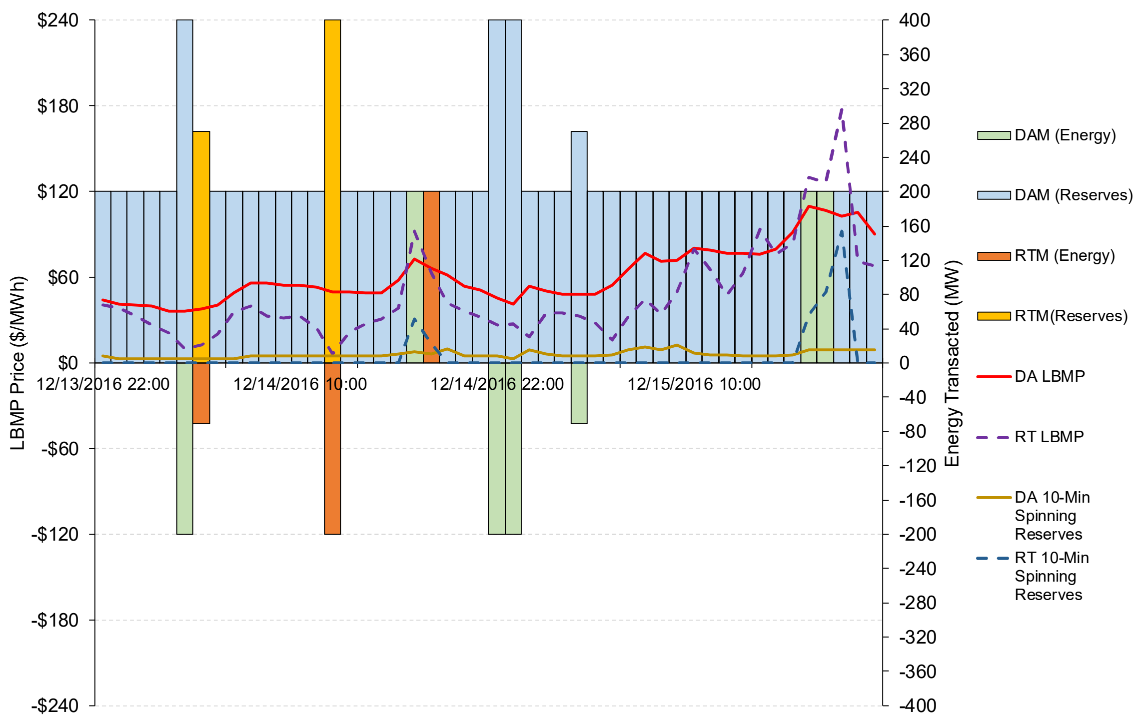


Note:
[1] Marginal Net EAS revenue is defined as the extra revenue gained compared to an evaluated $0/MWh opportunity cost value.

For each RTM hour-pair, partial charging is updated accordingly to reflect the additional power needed for the extra hour pair. The partial charging hour is assigned to the hour with the lowest RTM LBMP that is feasible. This process concludes the RTM positions determined by the model. Unlike the previous two DAM steps, the realized profits may not reflect the maximum RTM energy and reserve revenues because of imperfect knowledge and risk aversion.

In Figure 13, the model commits one RTM hour-pair on 12/14 and no RTM hour-pairs on 12/15. On 12/14, the battery capitalizes on low RTM LBMPs for charging and discharges based on higher expected real-time prices compared to DAM prices. This can be seen by the dark orange bars. The estimated profits for discharge in the second hour use a DAM LBMP that is higher than the RTM LBMP. As a result, the realized profits will be lower than the estimated profits.

Figure 13: AGI Battery Model Step 3 Example: Zone G (Rockland), December 14-15, 2016, 4 Hour Battery



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 net EAS revenues model estimates hourly revenues streams for the battery plants based on prices over the three-year historical period. Equation 4 and 5 provide a simplified representation of the net EAS revenues (NEAR) calculation used in each hour when considering charging and reserves and discharging dispatch, respectively. Profits are determined using parameters specific to each Load Zone and, when applicable, each battery duration:

Charging and reserves:

$$CHARGE\ COST = P_{charge} * 1\ hr * \left(LOEAF * LBMP_{Energy} + RS1 + TRANS\right)$$

$$RESERVE\ REV\ = P_{charge} * 1\ hr * (LOEAF * LBMP_{Reserve}) + \min(E_{stored},\ CAP * 1\ hr) * (LOEAF * LBMP_{Reserve})$$

$$NEAR = RESERVE\ REV - CHARGE\ COST \quad (4)$$

Discharging:

$$NEAR = P_{discharge} * 1\ hr * \left(LOEAF * LBMP_{Energy} - VOM\ - RS1\right) \quad (5)$$

Where:

$LOEAF$ = LOE adjustment factors for each Load Zone and time period (%)

$LBMP_{energy}$ = Hourly energy LBMPs (either DAM or RTM) for each Load Zone ($/MWh)

$LBMP_{reserve}$ = Hourly reserve prices (either DAM or RTM) for each Load Zone ($/MWh)

P_{charg} = Power withdrawn from grid (MW)

$P_{discharge}$ = Power injected into grid (MW)

CAP = Power capacity of battery (MW)

E_{stored} = Stored energy in battery (MWh)

VOM = Variable operations and maintenance costs ($/MWh)

RS1 = NYISO Rate Schedule 1 injection charge (varies over time, but is constant across Load Zones and technology) ($/MWh)

TRANS = Transmission Service Charge rates (varies over time and across Load Zones) ($/MWh)

Total annual revenues are the sum of revenues earned during each hour of the year with energy and reserves revenues derated by the plant's assumed UOL availability factor.[74] As a final step, the model calculates the annual

[74] As described in Section II.G, total annual battery revenues are derated by 3% to account for forced.

average net EAS revenues as the simple average of all revenues over the three-year period, plus a flat adder for providing VSS.[75] Unlike the fossil model, the batteries have no seasonal differences in unit parameters or ratings.

c. Model Data

The data used in the net EAS revenues model includes hourly 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.[76] 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. Reserve prices are based on prices for 10-minute non-spinning reserves for the GE 7HA.02 and Siemens SGT-A65 units, as BMCD, in discussion with NYISO, has determined that these unit types are capable of supplying 10-minute non-spinning reserves. Reserve prices are based on 30-minute operating reserves for the GE 7F.05 units.

In addition to energy and reserve revenues, the peaking plants can also supply VSS. VSS revenues are determined outside the dispatch model. VSS payments are added to the final estimate of annual net EAS revenues and are based on actual settlement data analyzed by the NYISO. The annual average VSS revenue was found to be \$2.04/kW-year for combustion turbines and battery storage options.[77] A VSS adder of \$1.63/kW-year is used for the informational combined cycle plants. (The fixed VSS adder is incremental to the \$3.90/kW-year net ancillary services revenue adder used for the informational combined cycle plants.) These revenues are included as fixed adders for all peaking plant (combustion turbines and battery storage) and informational combined cycle plants in all locations evaluated in this study.

ii. Oil and Natural Gas Prices

Natural gas prices are based on price indices for natural gas market hubs selected by AGI 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 for actual next-day transactions at various points along identified sections of pipelines, and represent volume-weighted average prices for next day delivery, excluding outliers that are greater than two standard deviations from the mean.[78] AGI's net EAS revenues model aligns gas day delivery and DAM LBMPs, and applies a fixed intraday premium or discount for real time gas purchases, as discussed below.

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[75] Within the demand curve model, net EAS revenues are expressed in constant real dollars, consistent with assumptions for forward looking costs and revenues. Historical average annual net EAS revenues are escalated from the three-year midpoint (here, \$2019) into real dollars (here, \$2021) for the ICAP Demand Curves using the GDP implicit price deflator.

[76] For the results presented in this Report for the 2021/2022 Capability Year ICAP Demand Curves, we use data for the three-year period September 1, 2017 through August 31, 2020.

[77] VSS adder values were calculated based on data over the time period of January 2016 through December 2019.

[78] *See,* S&P Global Market Intelligence Natural Gas and Power Index Methodology and Code of Conduct, 2018.

Despite the existence of numerous pricing hubs in and around New York, it is not necessarily a straightforward process to select the gas index most appropriate for a peaking plant in a given location. AGI considered numerous gas index options for the peaking plants in question, based on several 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 peaking plant net EAS revenues calculations would reflect a long-term equilibrium rather than short-run arbitrage opportunities created due to near-term or transitory natural gas system conditions.
- *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 potential peaking plant locations going forward, or otherwise have a logical nexus to prices at relevant delivery points. While recognizing the relevance of geographic proximity, AGI also considered whether gas indices fully captured variation in pricing within a given Load Zone, particularly to the extent that such pricing variation is relevant to delivery to a peaking plant in NYCA.
- *Precedent/Continuity.* The natural gas index selected 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.[79] While the appropriate choice of gas index can vary in accordance with the purpose and objectives of the study, consistency and continuity should be considered when other factors do not clearly indicate an alternative.

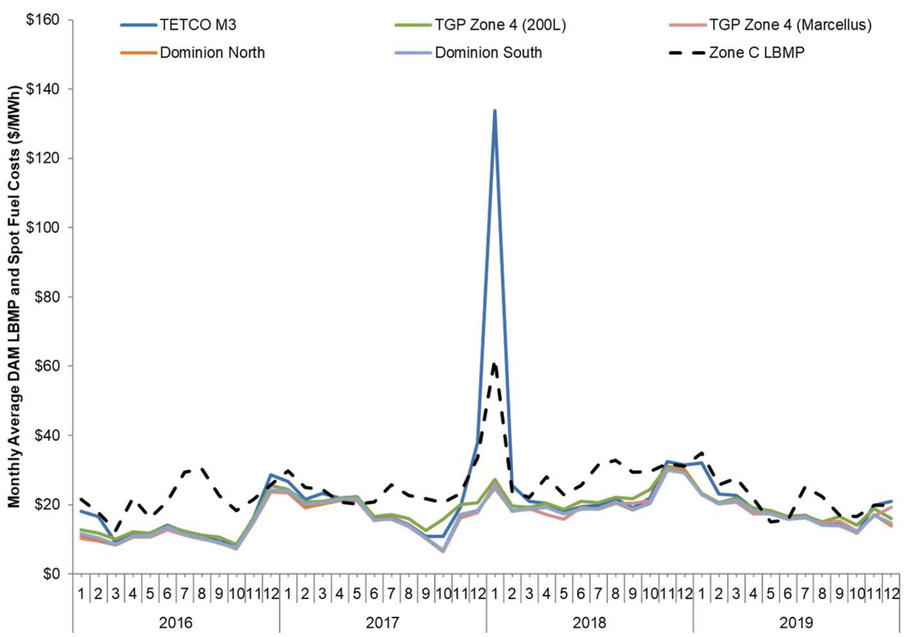
The recommended natural gas index for each Load Zone was selected based on balancing the considerations listed above, recognizing that the natural gas indices do not necessarily capture all factors affecting the market-based pricing for natural gas to a hypothetical peaking plant. In considering geography, a 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 (e.g., having sufficient liquidity) do not represent delivery points within the Load Zone of interest. In these cases, selection among available natural gas indices aim to identify the index that reasonably represents the natural gas prices that would be faced by a peaking plant within that Load Zone. Because the price for natural gas to the 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. 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 firm rights to transportation); reasonable estimates of transportation charges from a point of delivery (potentially outside a Load Zone) to the hypothetical peaking plant given factors such as tariff charges for delivery between points and market

[79] In particular, we reviewed gas hubs used in the 2016 DCR study, the 2019 CARIS Phase I study, and the 2019 NYISO State of the Market (SOM) Study.

prices 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 peaking plant 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 would expect as new (peaking plant) entry (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 through Figure 18 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 generation plant (with a heat rate of 8 MMBtu/MWh) and monthly average LBMPs for 2016 to 2019.

Figure 14: Natural Gas Price Indices and Load Zone C LBMPs



Note:
[1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources:
[1] S&P Global Market Intelligence.
[2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports.

Figure 15: Natural Gas Price Indices and Load Zone F LBMPs

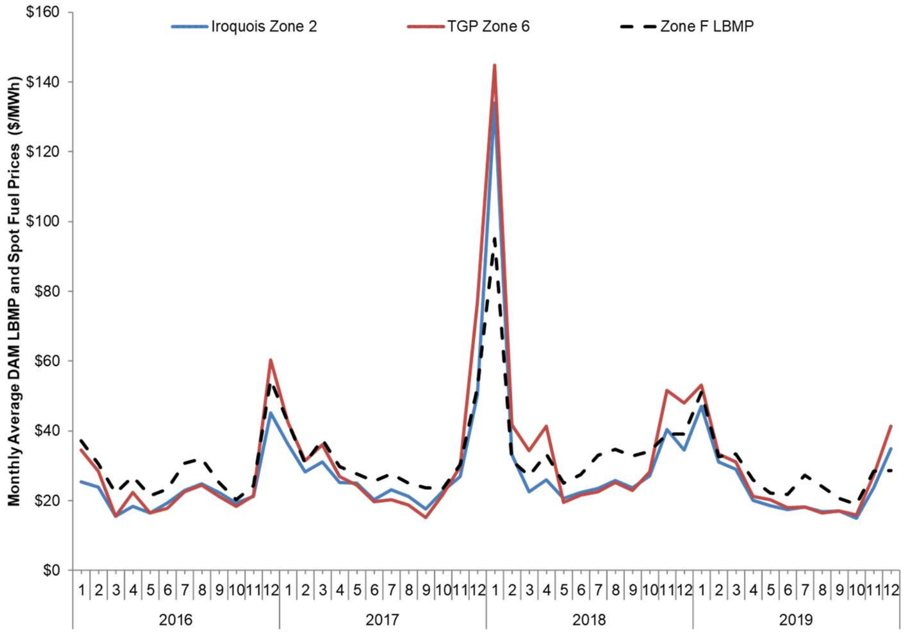
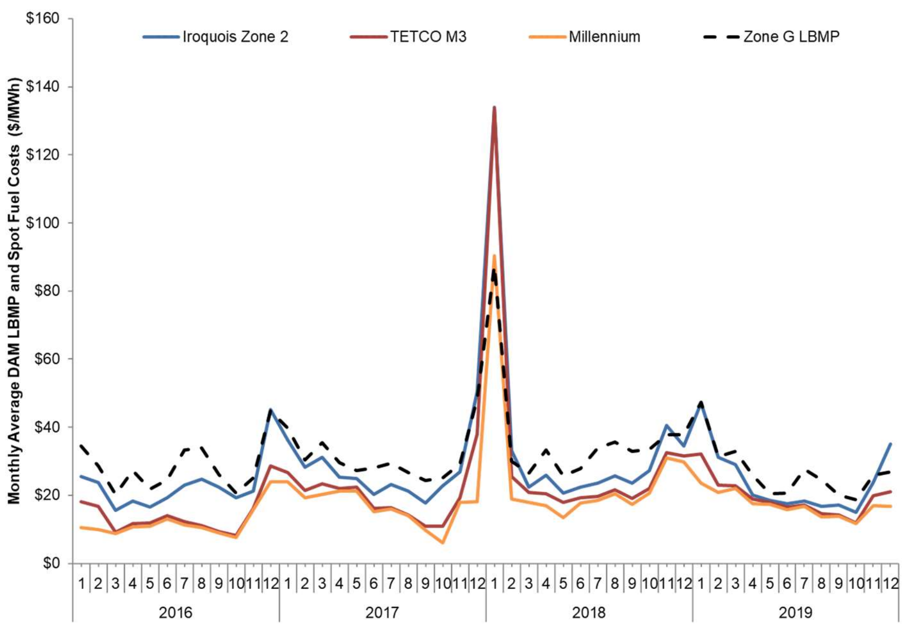


Figure 16: Natural Gas Price Indices and Load Zone G LBMPs



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Note:
[1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources:
[1] S&P Global Market Intelligence.
[2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports.

Figure 17: Natural Gas Price Indices and Load Zone J LBMPs

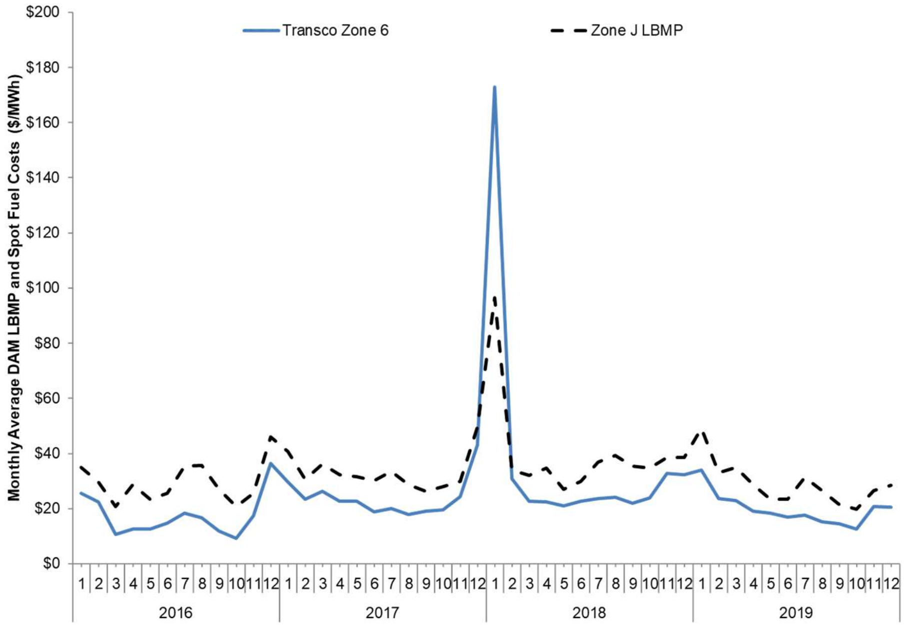
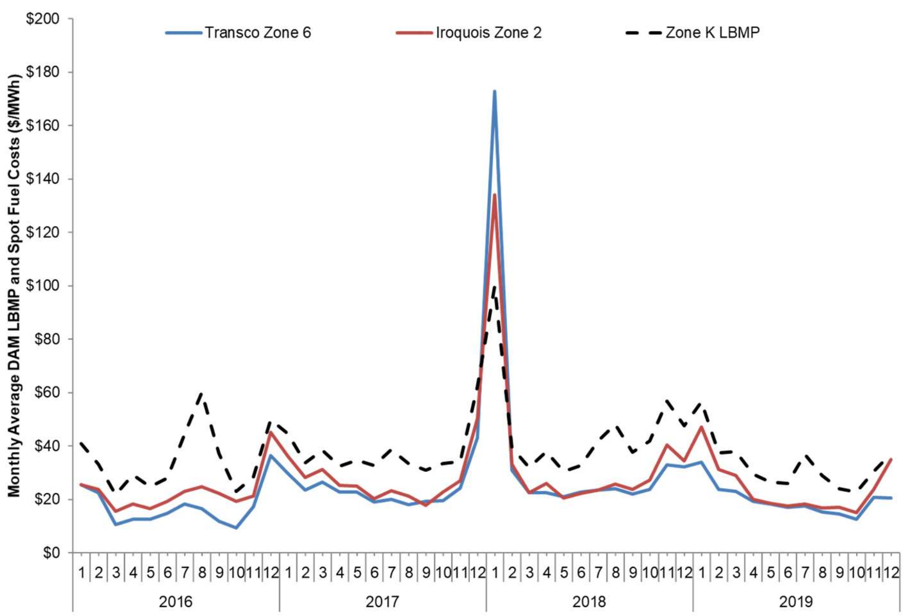


Figure 18: Natural Gas Price Indices and Load Zone K LBMPs



Note:
[1] Natural gas fuel costs are expressed in $/MWh assuming a heat rate of 8 MMBtu/MWh.
Sources:
[1] S&P Global Market Intelligence.
[2] NYISO, "Custom Reports," https://www.nyiso.com/custom-reports.

Table 42 identifies the gas hubs selected by AGI based on the considerations listed above, along with consideration of input and discussions with stakeholders and the Market Monitoring Unit. Table 43 summarizes AGI's assessment of potentially applicable natural gas indices for each location based on the criteria identified above.

For Load Zones 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.

For Load Zone F, Load Zone G (Dutchess County), and Load Zone K, AGI 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), AGI recommends the use of TETCO M3 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 pipeline crosses the zone through Rockland County, but it may not have the required flexibility of supply for a peaking generator 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, TETCO M3 is a liquid trading hub which reasonably reflects the fuel cost of a generator such as the peaking plant that is expected to operate intermittently throughout the year.[80] While TETCO M3 delivery points are outside Rockland County, TETCO M3 delivers to points proximate to Rockland County and the transportation costs (discussed below) provide a reasonable estimate of the incremental costs needed to obtain fuel in Rockland County relative to points in Northeast New Jersey.

In Load Zone C, a number of pipelines, including those owned by Tennessee Gas Pipeline (TGP), Dominion, and Millennium, cross the zone. The Market Monitoring Unit conducted certain analyses which found that historical energy price patterns best matched simulated operations based on the TGP Zone 4 (200L) gas hub. Based on a balance of considerations, particularly market dynamics, trading liquidity, and geography, AGI recommends the use of TGP Zone 4 (200L) as the natural gas index for Load Zone C.

[80] The determination of TETCO M3 as meeting the geographic criterion for gas hub selection as it relates to the Rockland County location within Load Zone G differs from the conclusion reached in the 2016 DCR study due to the updated methodology of assessing gas hubs for each location in Load Zone G separately. The 2016 DCR study assessed the selection of a single, representative gas hub for Load Zone G rather than evaluating the selection of representative gas hubs separately for the Dutchess County and Rockland County locations evaluated within Load Zone G. For this study, it was determined that TETCO M3 met the geographic criterion for the Rockland County location, but did not meet this criterion for the Dutchess County location.

Table 42: Recommended Gas Index by Load Zone

Load Zone	Natural Gas Index
Load Zone C	TGP Zone 4 (200L)
Load Zone F	Iroquois Zone 2
Load Zone G (Dutchess)	Iroquois Zone 2
Load Zone G (Rockland)	TETCO M3
Load Zone J	Transco Zn 6 NY
Load Zone K	Iroquois Zone 2

Table 43: Natural Gas Hub Selection Criteria, By Load Zone

<table>
<tr><th colspan="7">Load Zone C</th></tr>
<tr><th colspan="2">Decision Criteria</th><th>TETCO M3</th><th>TGP Zone 4 (200L)</th><th>TGP Zone 4 (Marcellus)</th><th>Dominion North</th><th>Dominion South</th></tr>
<tr><td colspan="2">Market Dynamics</td><td>High LBMP Correlation</td><td>Medium LBMP correlation</td><td>Medium LBMP correlation</td><td>Medium LBMP correlation</td><td>Medium LBMP correlation</td></tr>
<tr><td colspan="2">Liquidity</td><td>High</td><td>High</td><td>Medium</td><td>Medium</td><td>High</td></tr>
<tr><td colspan="2">Geography</td><td>No</td><td>Yes</td><td>Yes</td><td>Yes</td><td>No</td></tr>
<tr><td colspan="2">Recommendation</td><td></td><td>✔</td><td></td><td></td><td></td></tr>
<tr><td rowspan="3">Precedent</td><td>2016 DCR</td><td>Yes</td><td>No</td><td>No</td><td>No</td><td>No</td></tr>
<tr><td>CARIS (2019) Phase I</td><td>No</td><td>No</td><td>No</td><td>No</td><td>Part of Zones A-E Blend</td></tr>
<tr><td>SOM (2019)</td><td>No</td><td>Part of Zones B,C, and E Blend</td><td>No</td><td>No</td><td>No</td></tr>
</table>

Load Zone F			
Decision Criteria		**TGP Zone 6**	**Iroquois Zone 2**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation
	Liquidity	High	Medium
	Geography	No	Yes
	Recommendation		✔
Precedent	**2016 DCR**	No	Yes
	CARIS (2019) Phase I	Part of Zones F-I Blend	Part of Zones F-I Blend
	SOM (2019)	Part of Zone F Blend	Part of Zone F Blend

Load Zone G (Dutchess)			
Decision Criteria		**TETCO M3**	**Iroquois Zone 2**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation
	Liquidity	High	Medium
	Geography	No	Yes
	Recommendation		✔
Precedent	**2016 DCR**	No	Yes
	CARIS (2019) Phase I	No	Part of Zones F-I Blend
	SOM (2019)	Part of Zones G-I Blend	Part of Zones G-I Blend

Load Zone G (Rockland)				
Decision Criteria		**TETCO M3**	**Iroquois Zone 2**	**Millennium**
	Market Dynamics	High LBMP Correlation	High LBMP Correlation	Medium LBMP correlation
	Liquidity	High	Medium	Low
	Geography	Yes	No	Yes
	Recommendation	✔		
Precedent	**2016 DCR**	No	Yes	No
	CARIS (2019) Phase I	No	Part of Zones F-I Blend	No
	SOM (2019)	Part of Zones G-I Blend	Part of Zones G-I Blend	No

Load Zone J			
Decision Criteria			**Transco Zone 6 NY**
		Market Dynamics	High LBMP Correlation
		Liquidity	High
		Geography	Yes
		Recommendation	✔
Precedent	**2016 DCR**		Yes
	CARIS (2019) Phase I		Yes
	SOM (2019)		Yes

Load Zone K				
Decision Criteria			**Transco Zone 6 NY**	**Iroquois Zone 2**
		Market Dynamics	Medium LBMP correlation	Medium LBMP correlation
		Liquidity	High	Medium
		Geography	Yes	Yes
		Recommendation		✔
Precedent	**2016 DCR**		Yes	No
	CARIS (2019) Phase I		Part of Zone K Blend	Part of Zone K Blend
	SOM (2019)		No	Yes

For plants 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).[81]

Table 44 identifies assumptions for various additional costs associated with the use of natural gas or ULSD (for plants assumed to include dual fuel capability). 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.[82] Within the net EAS model, if the 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.

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[81] 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.

[82] As discussed in Section II, dual fuel plants 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, 2017 through August 31, 2020 associated with the results provided in this Report, AGI found that for dual fuel peaking plants in Load Zones G, J, and K – assuming the GE HA.02 25ppm with dual fuel and SCR emissions controls – no units burns more than 96 hours of fuel oil during a single model year except for the Load Zone K peaking unit (106 hours in September 2017 to August 2018). The minimum number of days for the peaking unit in this zone to burn 96 hours of fuel oil during that year was 6 days. See Appendix D for additional details regarding operations on oil projected by the net EAS revenues model for the results presented in this Report.

Table 44: 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, 2019 State of the Market Report for the New York ISO Markets, May 2020, Table A-16.
[2] New York State Department of Taxation and Finance, Publication 718-A: Enactment and Effective Dates of Sales and Use Tax Rates, effective August 1, 2019.

iii. Emission Allowance Prices:

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.[83] CO_2 allowance prices are obtained from the Regional Greenhouse Gas Initiative's (RGGI) auction results, representing RGGI-region clearing prices established on a quarterly basis.[84]

iv. Other Fossil 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 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. **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).
2. **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.
3. **Revenue and pricing data**: this data include voltage support services adders (for all plants) and ancillary service adders (for the informational combined-cycle plants). 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 44 and Appendix A.

[83] 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.
[84] 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/market/co2_auctions/results.

v. Battery Specific Data

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

1. **Battery 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 BMCD.
2. **Battery operating costs:** these data include variable O&M costs provided by BMCD.
3. **Revenue and pricing data:** these data include transmission service charge rates and prices for 10-minute 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 $2.04/kW-year adder as applicable to combustion turbines peaking plant options is applied to the battery storage options.

d. Level of Excess Adjustment Factors

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).[85] Consistent with the 2016 DCR, 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.[86]

AGI has developed 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 within the 2019 Congestion Assessment Resource Integration Study (CARIS) Phase 1 Base Case data, updated to include certain resource and load forecast updates.[87]

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[85] Services Tariff, Section 5.14.1.2.2
[86] 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.
[87] For additional details regarding the development of the LOE-AFs, *see* NYISO, "Appendix: DCR Level of Excess - Adjustment Factors: Results of Additional MAPS Runs," presentation to NYISO Installed Capacity Working Group, July 22, 2020.

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. LOE-AFs are developed as the ratio of average day-ahead LBMPs in the base case to average LBMPs in the LOE case for each Load Zone, where LBMPs are first averaged within each month and period across all of the modeled years 2021 to 2025. Three periods are evaluated: on-peak, peak load window, and off-peak, are defined as follows:

- *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: [88]
  - 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.

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 GE 7HA.02 turbine) for each capacity region.

Within GE-MAPS, LBMPs are modeled in every hour of each year of the DCR period (2021 – 2025). Each LOE-AF (by Load Zone, month and period) reflects the average over the four-year DCR period. A single set of LOE-AFs was developed. This set of LOE-AFs, calculated at the time of the DCR, will remain set for the duration of the reset period, and will be applied to historical LBMPs and reserve prices used in each subsequent Capability Year's net EAS revenues calculation during the reset period.

As described in Equation (1), LBMPs and reserve prices are 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.

Average LOE-AFs across all months and periods ranged from 1.02 in Load Zones F and J to 1.06 in Load Zone C. Appendix C contains the full set of LOE-AFs used in the net EAS revenues analysis by Load Zone, month and period based on the GE-MAPS analysis.

[88] 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. AGI reviewed average annual LBMPs by Load Zone and month and confirmed that peak periods are consistent with this definition.

C. Results

The values in this Report are for the 2021/2022 Capability Year. For subsequent Capability Years encompassed by this reset period, the net EAS revenues will be calculated using the same model, but with updated data as part of the annual update process described in Section VI below.

Net EAS results for the Capability Year 2021/2022, by location, are summarized in Table 45 through Table **47**. 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.

Table 45: Net EAS Model Results for Fossil Plants by Load Zone, Dual Fuel Capability

		Annual Average Net EAS Revenues ($/kW-year)						Annual Average Run Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	$37.52	$38.79	$37.53	$35.83	$38.94	$57.19	1,070	1,173	879	748	1,287	4,789
F	Capital	$25.94	$26.53	$28.56	$25.42	$26.81	$51.17	588	708	688	501	746	4,660
G	Hudson Valley (Dutchess)	$27.33	$28.43	$30.04	$27.15	$28.85	$48.23	480	576	516	462	607	4,503
G	Hudson Valley (Rockland)	$34.35	$34.40	$33.88	-	-	$70.52	1,355	1,397	847	-	-	6,513
J	New York City	$32.65	$32.89	$34.35	-	-	$67.65	1,134	1,181	742	-	-	6,674
K	Long Island	$52.91	$52.54	$52.98	-	-	$108.46	2,321	2,193	1,376	-	-	7,907

		Annual Average Unit Starts						Annual Average Hours per Start					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	73	118	281	48	124	44	14.7	10.0	3.1	15.5	10.4	108.8
F	Capital	64	108	295	55	110	55	9.1	6.5	2.3	9.1	6.8	85.2
G	Hudson Valley (Dutchess)	57	95	236	52	99	55	8.5	6.0	2.2	8.9	6.1	82.4
G	Hudson Valley (Rockland)	85	126	285	-	-	35	15.9	11.1	3.0	-	-	187.9
J	New York City	94	135	295	-	-	37	12.1	8.8	2.5	-	-	180.4
K	Long Island	162	205	378	-	-	27	14.3	10.7	3.6	-	-	296.5

		Annual Average Reserve Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	30	15	17	31	14	-
F	Capital	108	22	89	108	22	-
G	Hudson Valley (Dutchess)	105	21	93	102	23	-
G	Hudson Valley (Rockland)	101	20	86	-	-	-
J	New York City	92	10	102	-	-	-
K	Long Island	55	6	64	-	-	-

Notes:
[1] Results reflect data for the period September 1, 2017 through August 31, 2020.
[2] Assumes $2.04/kW-year VSS revenues for combustion turbine plants and $5.53/kW-year revenues for the informational combined cycle plants from VSS and other ancillary services, based on settlement data analyzed by NYISO.
[3] Runtime limits were applied based on NSPS and annual NO_x emissions limits for plants that do not include SCR emissions controls.
[4] Combined cycle plants are modeled for informational purposes only. Reserve dispatch is not modeled for the informational combined cycle plants; reserve revenues are incorporated through the $5.53/kW-year adder described in note [2] above.

Table 46: Net EAS Model Results for Fossil Plants by Load Zone, Natural Gas-Only

		Annual Average Net EAS Revenues ($/kW-year)						Annual Average Run Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65
C	Central	$37.52	$38.79	$37.53	$35.83	$38.94	$57.19	1,070	1,173	879	748	1,287	4,789
F	Capital	$24.35	$24.85	$26.89	$24.00	$25.10	$47.11	560	678	652	552	716	4,593
G	Hudson Valley (Dutchess)	$26.14	$27.40	$28.82	$25.97	$27.83	$45.03	456	551	488	456	582	4,437
G	Hudson Valley (Rockland)	$33.42	$33.66	$32.75	-	-	$67.75	1,337	1,377	825	-	-	6,462

		Annual Average Unit Starts						Annual Average Hours per Start					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR	Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65
C	Central	73	118	281	48	124	44	14.7	10.0	3.1	15.5	10.4	108.8
F	Capital	64	106	293	60	108	56	8.8	6.4	2.2	9.2	6.6	82.0
G	Hudson Valley (Dutchess)	56	93	234	53	97	56	8.2	5.9	2.1	8.6	6.0	79.7
G	Hudson Valley (Rockland)	84	124	283	-	-	36	15.9	11.1	2.9	-	-	179.5

		Annual Average Reserve Hours					
		Combustion Turbine With SCR			Combustion Turbine Without SCR		Combined Cycle With SCR
Load Zone		1x0 GE 7HA.02	1x0 GE 7F.05	3x0 Siemens SGT-A65	1x0 GE 7HA.02	1x0 GE 7F.05	1x1 GE 7HA.02
C	Central	30	15	17	31	14	-
F	Capital	109	22	90	110	22	-
G	Hudson Valley (Dutchess)	109	22	96	106	24	-
G	Hudson Valley (Rockland)	103	20	88	-	-	-

Notes:
[1] Results reflect data for the period September 1, 2017 through August 31, 2020.
[2] Assumes $2.04/kW-year VSS revenues for combustion turbine plants and $5.53/kW-year revenues for the informational combined cycle plants from VSS and other ancillary services, based on settlement data analyzed by NYISO.
[3] Runtime limits were applied based on NSPS and annual NO_x emissions limits for plants that do not include SCR emissions controls.
[4] Combined cycle plants are modeled for informational purposes only. Reserve dispatch is not modeled for the informational combined cycle plants; reserve revenues are incorporated through the $5.53/kW-year adder described in note [2] above.

Table 47: Net EAS Model Results for BESS by Load Zone

		Annual Average Net EAS Revenues ($/kW-year)			Annual Average Run Hours		
		Battery Duration			Battery Duration		
Load Zone		4-Hour	6-Hour	8-Hour	4-Hour	6-Hour	8-Hour
C	Central	$45.96	$46.71	$46.81	248	265	285
F	Capital	$47.59	$47.83	$48.30	153	169	186
G	Hudson Valley (Dutchess)	$49.03	$50.50	$50.67	291	325	341
G	Hudson Valley (Rockland)	$48.43	$48.94	$49.24	199	211	225
J	New York City	$50.08	$51.06	$51.28	224	255	278
K	Long Island	$61.04	$65.00	$66.55	592	726	838

		Annual Average Unit Cycles			Average Daily Hours		
		Battery Duration			Battery Duration		
Load Zone		4-Hour	6-Hour	8-Hour	4-Hour	6-Hour	8-Hour
C	Central	62	44	36	0.7	0.7	0.8
F	Capital	38	28	23	0.4	0.5	0.5
G	Hudson Valley (Dutchess)	73	54	43	0.8	0.9	0.9
G	Hudson Valley (Rockland)	50	35	28	0.5	0.6	0.6
J	New York City	56	42	35	0.6	0.7	0.8
K	Long Island	148	121	105	1.6	2.0	2.3

Notes:
[1] Results reflect data for the period September 1, 2017 through August 31, 2020.
[2] Assumes $2.04/kW-year VSS revenues for all plants, based on settlement data analyzed by NYISO.

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 new peaking plant resources to maintain resource adequacy. In Sections III and IV, AGI established the values for gross CONE and net EAS revenues for the peaking plant technologies 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 technologies. 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, AGI presents the resulting ICAP Demand Curve parameters for each capacity region for Capability Year 2021/2022. Section VI summarizes the procedures for annual updating of ICAP Demand Curve parameters through the formulaic approach established at the time of this DCR.

B. 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 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 provides 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, and reduces incentives for the exercise of market power.

The ICAP Demand Curves are constructed such that the peaking plant would recover its ARV when the system is at the LOE – that is, the applicable ICR/LCR plus the capacity of the peaking plant. Given differences in costs between Load Zones 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:

1) Maximum allowable price: A horizontal line with the price equal to 1.5 times the 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.[89]

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. The following sections provide additional detail on the ZCPR, winter-to-summer ratio (WSR), 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 2013 DCR, the ZCPs for NYCA and the Localities 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.[90] While FTI had recommended revising the ZCPs based on the results of its analysis, the independent consultant during the 2013 DCR ultimately recommended adjusting ZCPs to a point midway between then-current values and the values recommended by FTI. After the completion of the consultant's study report for the 2013 DCR, an analysis was performed by the Market Monitor Unit (Potomac Economics) that was also based on GE-MARS modeling completed by NYISO Planning staff.[91]

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 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 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.

Since the 2013 DCR, no additional studies have been conducted to specifically inform the determination of ZCPs for the ICAP Demand Curves. However, in the *Reliability and Market Considerations for a Grid in Transition* report, the NYISO recommended consideration of a separate initiative to assess the shape and slope of the ICAP Demand Curves.[92] Considering these factors, AGI recommends that the current ZCPs remain unchanged for this DCR.

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[89] When referencing the ZCP in percentage terms relative to applicable IRM or LCR, AGI uses the term zero crossing point ratio (ZCPR).
[90] 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.
[91] 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.
[92] NYISO, 2019 Reliability and Market Considerations for a Grid in Transition, December 20, 2019, p. 54.

2. *Winter-to-Summer Ratio*

The WSR captures differences in the 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. Figure 19 illustrates the differences in price during the winter season when there is a higher quantity of system capacity.

The WSR is calculated as the ratio of total winter ICAP to total summer 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 using a locational EFORd. These totals are adjusted for certain resource entry and exit circumstances.[93] 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.

[93] 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.

Figure 19: Illustration of the Reference Point Price, Level of Excess, and Seasonal Capacity

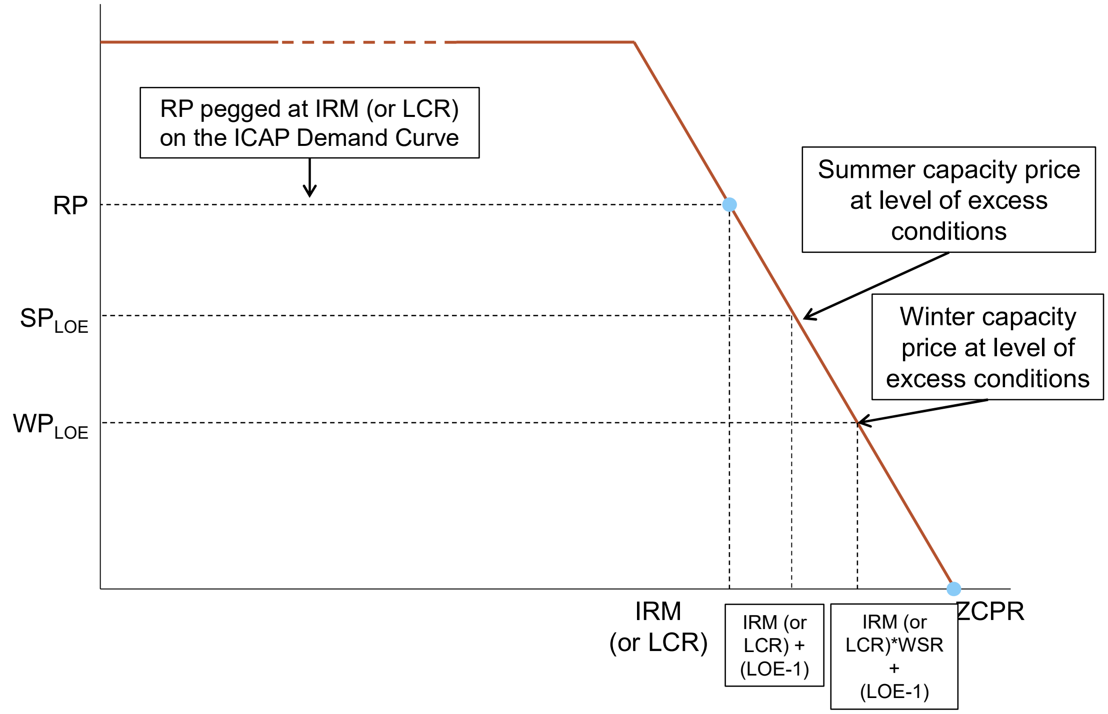


Table 48 provides the WSR values used in this Report and reflect data for the period September 1, 2017 through August 31, 2020.

Table 48: Winter-to-Summer Ratio by Location

Capacity Region	Capability Year	Winter-Summer Ratio
NYCA	2021-2022	1.038
G-J	2021-2022	1.059
New York City	2021-2022	1.076
Long Island	2021-2022	1.073

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

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

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 2020/2021 Capability Year. Table 49 and Table 50 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 49: Fossil Plant Level of Excess by Technology and Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2020)	2020-2021 IRM/LCR	LOE (%) by Technology				
			3x0 Siemens SGT-A65	1x0 GE 7F.05	1x0 GE 7HA.02 25ppm	1x0 GE 7HA.02 15ppm	1x1 GE 7HA.02 CC
NYCA	32,296	118.9%	100.41%	100.54%	100.90%	100.85%	101.29%
G-J	15,695	90.0%	101.12%	101.48%	102.46%	-	103.54%
NYC	11,477	86.6%	101.60%	102.11%	103.51%	-	105.05%
LI	5,227	103.4%	102.94%	103.89%	106.45%	-	109.30%

Note:
[1] Average degraded net capacity by technology is provided in Table 32.

Table 50: BESS Level of Excess by Location, Expressed in Percentage Terms

Capacity Zone	Peak Load in MW (2020)	2020-2021 IRM/LCR	LOE (%) by Battery Duration		
			4-hr BESS	6-hr BESS	8-hr BESS
NYCA	32,296	118.9%	100.52%	100.52%	100.52%
G-J	15,695	90.0%	101.42%	101.42%	101.42%
NYC	11,477	86.6%	102.01%	102.01%	102.01%
LI	5,227	103.4%	103.70%	103.70%	103.70%

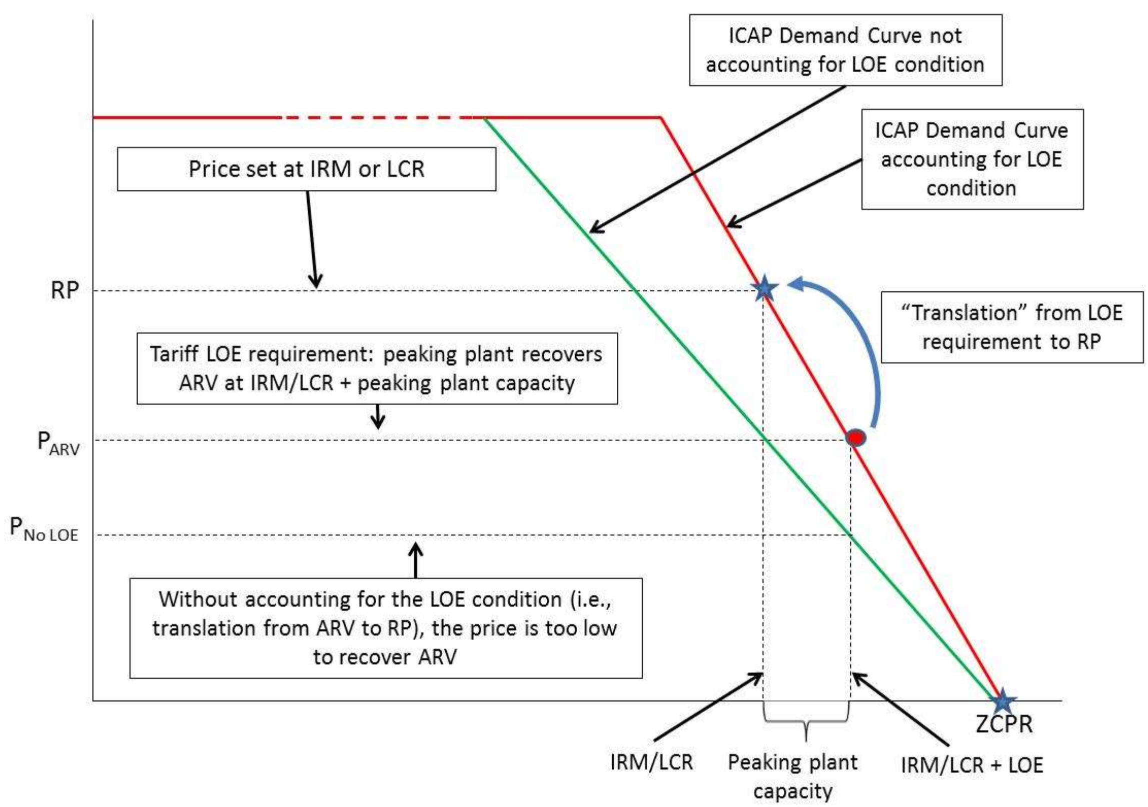
Note:
[1] Average degraded net capacity by technology is provided in Table 32.

C. Reference Point Price Calculations

Figure 20 illustrates the "geometry" of the 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 "IRM/LCR + LOE"; 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 RP can be calculated at the appropriate quantity for each capacity region – that is, the IRM for NYCA and the LCR for each Locality. This calculation requires a translation that is defined below.

Figure 20 also 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 LOE condition, 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



Equation (7) defines the RP as a function of both the seasonal capacity adjustment (the WSR) and the LOE requirement:

$$RP = \frac{ARV * AssmdCap}{6 * \left[SDMNC * \left(1 - \frac{LOE}{ZCPR - 1}\right) + WDMNC * \left(1 - \frac{(LOE - 1) + (WSR - 1)}{ZCPR - 1}\right)\right]} * \frac{1}{DAF} \quad (7)$$

Where:

ARV is the annual reference value for the relevant peaking plant ($/kW-year)

SDMNC is the summer dependable maximum net capability for the relevant peaking plant (MW)

WDMNC 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

LOE is the ratio of IRM/LCR plus the assumed capacity of the relevant peaking plant to IRM/LCR (%)

WSR is the ratio of total winter ICAP to total summer ICAP, as calculated by the NYISO for the relevant capacity region

ZCPR is the ZCP ratio of the ICAP Demand Curve for the relevant capacity region

RP is the reference point price ($/kW-month) of the ICAP Demand Curve for the relevant capacity region

DAF is the Duration Adjustment Factor applied for the BESS units due to their assumed status as a Resource with an Energy Duration Limitation. DAF is assumed at 90% for 4-hour BESS units and at 100% for 6-hour and 8-hour BESS units.[94]

Along with accounting for the LOE requirement, Equation (7) also accounts for differences in the capacity market revenue and peaking plant capacity between Summer and Winter Capability Periods. These differences in seasonal prices were illustrated in Figure 19. Thus, the plant's ARV (defined in $/kW-year) is met through different revenue streams in each season – that is:

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

Where:

SP and *WP* represent the assumed summer and winter capacity prices at the tariff prescribed LOE conditions as illustrated in Figure 19 and Figure 20.

Equation 7 reflects the solution to the revenue adequacy requirement in Equation 8, given the following equations for *SP* and *WP*:

[94] Applicable Duration Adjustment Factor depends on the level of battery resources on the NYISO system. *See* NYISO, "DER Energy & Capacity Market Design," presentation to the NYISO Business Issues Committee, April 17, 2019.

$$SP = RP \times \left(1 - \frac{LOE - 1}{ZCPR - 1}\right)$$

$$WP = RP \times \left(1 - \frac{(LOE - 1) + (WSR - 1)}{ZCPR - 1}\right)$$

D. ICAP Demand Curve Parameters

AGI has applied the methods, models and equations described in this Report to identify RPs and other ICAP Demand Curve parameters for NYCA and Localities for the Capability Year 2021/2022. These values are presented in Table 51 through Table 54, below. Figure 21 through Figure 24 provides a comparison of these ICAP Demand Curve parameters relative to ICAP Demand Curve parameters for the first Capability Year encompassed by prior DCRs.[95]

To arrive at these results, AGI and BMCD considered relevant market and technology issues, and came to a number of conclusions key to the final calculation of RP values. Specifically, AGI and BMCD conclude the following:

- The GE 7HA.02 (H Class Frame) represents the highest variable cost, lowest fixed cost peaking plant that is economically viable. To be economically viable and practically constructible, a dual fuel H Class Frame machine would be built with SCR emissions control technology in Load Zone J, Load Zone K, Load Zone G (Rockland County), and Load Zone G (Dutchess County), and a gas only H Class Frame machine would be constructed without SCR emissions control technology in Load Zone C and Load Zone F.
- Based on market expectations for fuel availability and fuel assurance, changes in market structures, consideration of applicable reliability and LDC tariff requirements, and developer expectations, the H Class Frame machine should be built with dual fuel capability in Load Zone G (Dutchess County), Load Zone G (Rockland County), Load Zone J, and Load Zone K. AGI and BMCD recommend a gas-only (without dual fuel capability) design in Load Zone C and Load Zone F.
- The state of New York has begun a process to decarbonize the power sector over the next couple decades. This does not eliminate consideration of a fossil-fueled plant as the potential peaking plant technology. It does, however, suggest review of the ways in which these efforts affect the development and operation of such facilities, which could in turn affect the present-day financial analysis parameters (e.g., the appropriate amortization). For this DCR, we recommend a 17-year amortization period for fossil-fueled plants in consideration of restrictions on fossil fuel operations past 2039 pursuant to the CLCPA.
- Based on our review, battery energy storage should not be selected to serve as the peaking plant underlying any of the ICAP Demand Curves at this time. We come to this conclusion based primarily on our estimates of the net CONE for a sample battery storage facility with 4-, 6-, and 8-hour duration of storage and the availability of lower cost viable technology options.
- The weighted average cost of capital (WACC) used to develop the localized levelized embedded gross CONE should reflect a capital structure of 55% debt and 45% equity; a 6.7% cost of debt; and a

[95] All values are expressed in nominal dollars.

13.0% return on equity, for a WACC of 9.54%. Based on current tax rates in NY State and New York City, this translates to a nominal after tax WACC (ATWACC) of 8.52% and 8.20%, respectively.

- Net EAS revenues are estimated for the peaking plant technologies using gas hubs that reflect consideration of a number of factors, including consistency of gas prices with LBMPs within each Load Zone, liquidity of trading, geographic consistency with the locations evaluated, and precedence of use in other studies/analysis. To that end, net EAS revenues are estimated using the following gas hubs, which are fixed for the four-year duration of the reset period:
  - Load Zone C: TGP Zone 4 (200L)
  - Load Zone F: Iroquois Zone 2
  - Load Zone G (Dutchess County): Iroquois Zone 2
  - Load Zone G (Rockland County): TETCO M3
  - Load Zone J: Transco Zone 6 New York
  - Load Zone K: Iroquois Zone 2
- 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 51 provides the parameters of the ICAP Demand Curves for the 2021/2022 Capability Year consistent with the conclusions and technology findings described above. Table 52 through Table 54 provides additional information for the other technologies evaluated. For ICAP Demand Curves where more than one location is evaluated (i.e., NYCA and the G-J Locality), the appropriate location and peaking plant technology selected as the basis for the 2021/2022 Capability Year ICAP Demand Curves remain fixed for the four year duration of the reset period.

Table 51: ICAP Demand Curve Parameters ($2021)

GE 7HA.02

		Current Year (2021-2022)					
Parameter	**Source**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
Gross Cost of New Entry ($/kW-Year)	[1]	$114.75	$115.79	$145.32	$149.78	$196.41	$159.77
Net EAS Revenue ($/kW-Year)	[2]	$36.67	$24.56	$27.96	$35.15	$33.42	$54.15
Annual ICAP Reference Value ($/kW-Year)	[3] = [1] - [2]	$78.08	$91.23	$117.35	$114.63	$162.99	$105.62
ICAP DMNC (MW)	[4]	326.7	328.5	347.0	347.0	348.8	348.8
Total Annual Reference Value	[5] = [3] * [4]	**$25,509,781**	**$29,967,642**	**$40,721,005**	**$39,776,090**	**$56,852,412**	**$36,841,547**
Level of Excess (%)	[6]	100.9%	100.9%	102.5%	102.5%	103.5%	106.5%
Ratio of Summer to Winter DMNCs	[7]	1.038	1.038	1.059	1.059	1.076	1.073
Summer DMNC (MW)	[8]	329.3	334.0	348.3	348.2	348.5	351.1
Winter DMNC (MW)	[9]	344.7	350.5	369.9	369.9	374.1	373.0
Assumed Capacity Prices at Tariff Prescribed Level of Excess Conditions							
Summer ($/kW-Month)	[10]	$7.64	$8.84	$12.47	$12.18	$18.00	$12.58
Winter ($/kW-Month)	[11]	$5.04	$5.83	$6.61	$6.45	$8.56	$4.62
Monthly Revenue (Summer)	[12] = [10]*[8]	$2,515,753	$2,952,627	$4,343,614	$4,242,399	$6,273,209	$4,415,188
Monthly Revenue (Winter)	[13] = [11]*[9]	$1,735,875	$2,041,978	$2,443,190	$2,386,965	$3,202,184	$1,725,050
Seasonal Revenue (Summer)	[14] = 6 * [12]	$15,094,519	$17,715,761	$26,061,687	$25,454,395	$37,639,255	$26,491,127
Seasonal Revenue (Winter)	[15] = 6 * [13]	$10,415,248	$12,251,868	$14,659,137	$14,321,788	$19,213,103	$10,350,302
Total Annual Reference Value	[16] = [14]+[15]	**$25,509,768**	**$29,967,629**	**$40,720,824**	**$39,776,183**	**$56,852,357**	**$36,841,429**
ICAP Demand Curve Parameters							
		ICAP Monthly Reference Point Price ($/kW-Month)					
		$8.22	**$9.52**	**$14.91**	**$14.57**	**$22.36**	**$19.60**
ICAP Max Clearing Price ($/kW-Month)		$14.34	$14.47	$18.16	$18.72	$24.55	$19.97
Demand Curve Length		12.0%	12.0%	15.0%	15.0%	18.0%	18.0%

Notes:
[1] The peaking plant technology choice in Load Zones C and F is a 1x0 GE 7HA.02 operating in gas only mode without SCR emissions controls which is tuned to emit 15ppm NOx by limiting combustion temperature.
[2] The peaking plant technology choice in Load Zones G (Rockland County), Load Zone G (Dutchess County), NYC, and LI is a 1x0 GE 7HA.02 (tuned to emit 25ppm NOx) that includes dual fuel capability and SCR emissions controls.
[3] The net EAS revenues are estimated using data for the three-year period September 1, 2017 through August 31, 2020 and the WSR values are based on data for the same period.

Table 52: Comparison of Reference Point Prices by Technology ($2021/kW-mo.)

Monthly Reference Point Price ($/kW-Month)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$27.16	$27.59	$39.64	$30.41
	Gas Only, with SCR	$21.23	$22.51	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$17.76	$17.96	$28.13	$20.94
	Gas Only, without SCR	$10.88	$12.47	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$14.91	$14.57	$22.36	$19.60
	Gas Only, tuned to 15 ppm, without SCR	$8.22	$9.52	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$24.71	$23.35	$52.28	$43.06
	Gas Only, with SCR	$15.42	$16.98	-	-	-	-
4-hr BESS	Battery Storage	$17.83	$17.83	$20.10	$21.06	$28.78	$23.85
6-hr BESS	Battery Storage	$24.23	$24.36	$27.37	$28.70	$37.32	$33.26
8-hr BESS	Battery Storage	$32.46	$32.64	$36.80	$38.48	$48.84	$45.39

Table 53: Comparison of Gross CONE by Technology ($2021/kW-year)

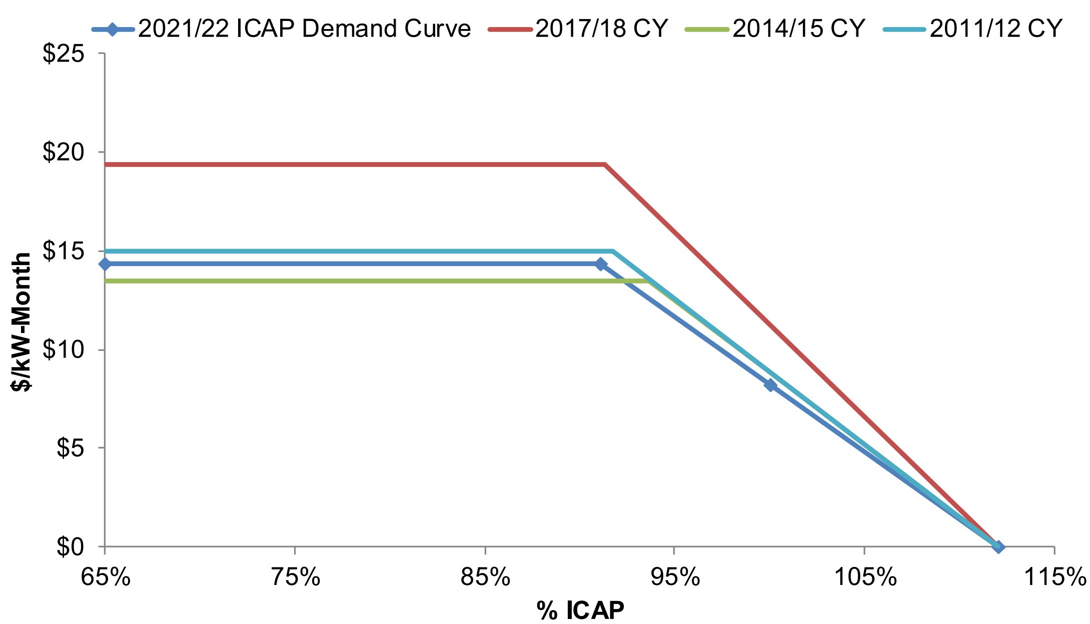
Gross CONE ($/kW-Year)							
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$285.71	$293.62	$389.96	$302.26
	Gas Only, with SCR	$261.26	$264.07	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$184.57	$192.44	$267.28	$204.82
	Gas Only, without SCR	$148.09	$149.86	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$145.32	$149.78	$196.41	$159.77
	Gas Only, tuned to 15 ppm, without SCR	$114.75	$115.79	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$218.22	$231.74	$388.14	$257.42
	Gas Only, with SCR	$196.59	$199.81	-	-	-	-
4-hr BESS	Battery Storage	$200.79	$202.46	$204.04	$210.82	$261.74	$214.86
6-hr BESS	Battery Storage	$279.86	$282.27	$284.49	$294.28	$355.52	$302.63
8-hr BESS	Battery Storage	$358.90	$362.07	$364.93	$377.72	$449.29	$390.39

Table 54: Comparison of Net EAS Revenues by Technology ($2021/kW-year)

		Net EAS ($/kW-Year)					
Technology	**Fuel Type/ Emission Control**	**C - Central**	**F - Capital**	**G - Hudson Valley (Dutchess)**	**G - Hudson Valley (Rockland)**	**J - New York City**	**K - Long Island**
3x0 Siemens SGT-A65	Dual Fuel, with SCR	-	-	$30.74	$34.68	$35.15	$54.22
	Gas Only, with SCR	$38.40	$27.52	-	-	-	-
1x0 GE 7F.05	Dual Fuel, with SCR	-	-	$29.10	$35.21	$33.65	$53.77
	Gas Only, without SCR	$39.85	$25.69	-	-	-	-
1x0 GE 7HA.02	Dual Fuel, tuned to 25 ppm, with SCR	-	-	$27.96	$35.15	$33.42	$54.15
	Gas Only, tuned to 15 ppm, without SCR	$36.67	$24.56	-	-	-	-
Informational 1x1 GE 7HA.02 CC	Dual Fuel, with SCR	-	-	$49.36	$72.17	$69.24	$111.00
	Gas Only, with SCR	$58.53	$48.22	-	-	-	-
4-hr BESS	Battery Storage	$47.04	$48.71	$50.17	$49.56	$51.25	$62.47
6-hr BESS	Battery Storage	$47.80	$48.95	$51.68	$50.08	$52.25	$66.52
8-hr BESS	Battery Storage	$47.91	$49.43	$51.86	$50.40	$52.48	$68.11

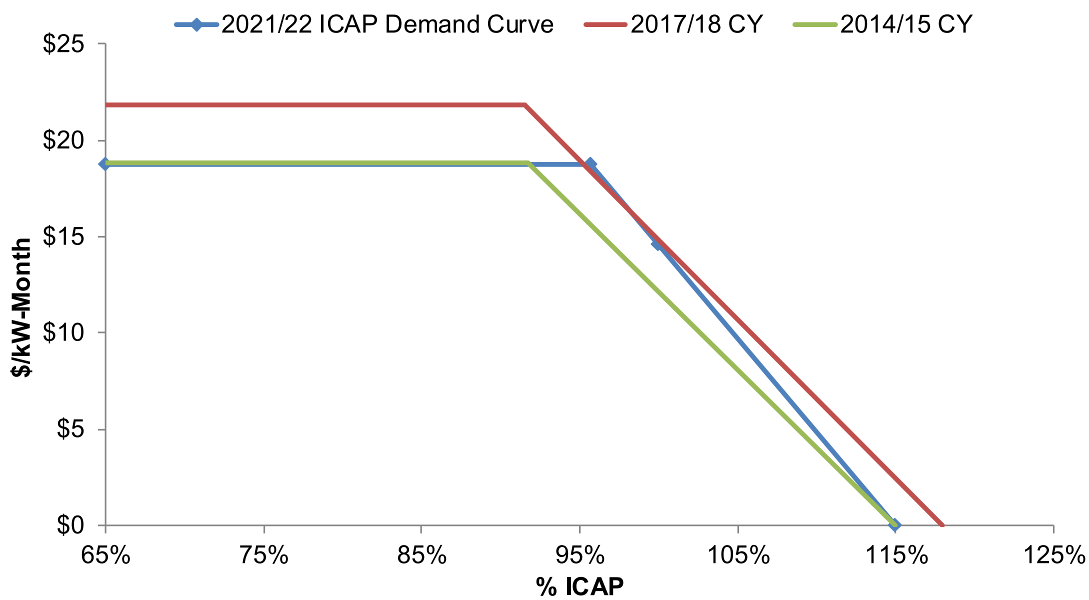
Note:
[1] The net EAS revenues are estimated using data for the three-year period September 1, 2017 through August 31, 2020.

Figure 21: Comparison of NYCA 2021/2022 ICAP Demand Curves to Prior ICAP Demand Curves



Note:
[1] 2021/2022 NYCA ICAP Demand Curve is based on peaking plant located in Load Zone C.

Figure 22: Comparison of G-J Locality 2021/2022 ICAP Demand Curve to Prior ICAP Demand Curves



Note:
[1] 2021/2022 ICAP Demand Curves for the G-J Locality is based on a peaking plant located in Rockland County location within Load Zone G.

Figure 23: Comparison of NYC 2021/22 ICAP Demand Curve to Prior ICAP Demand Curves

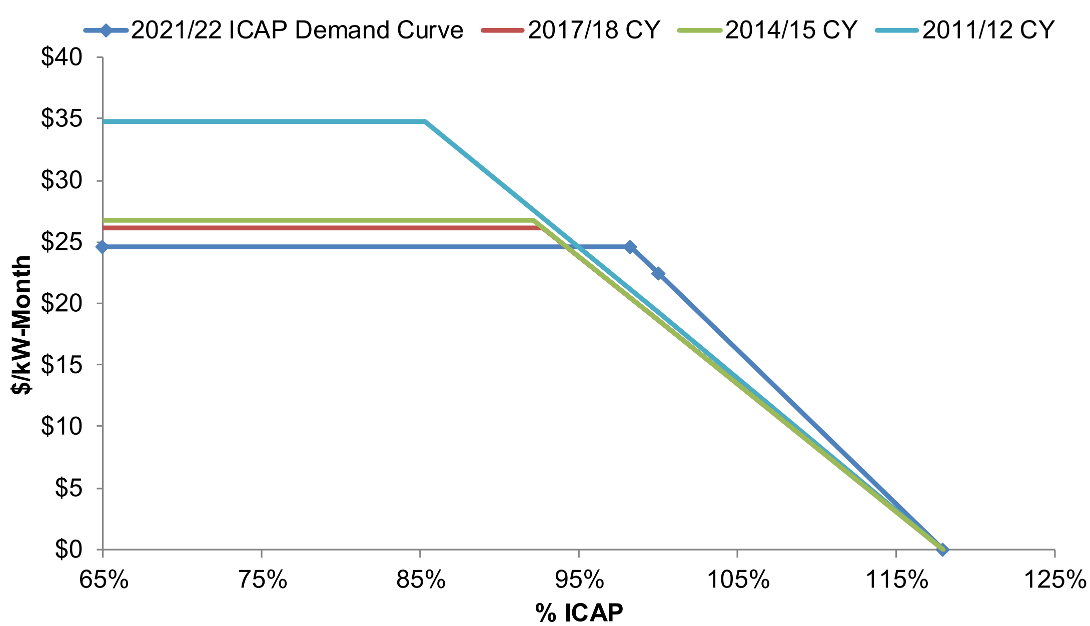
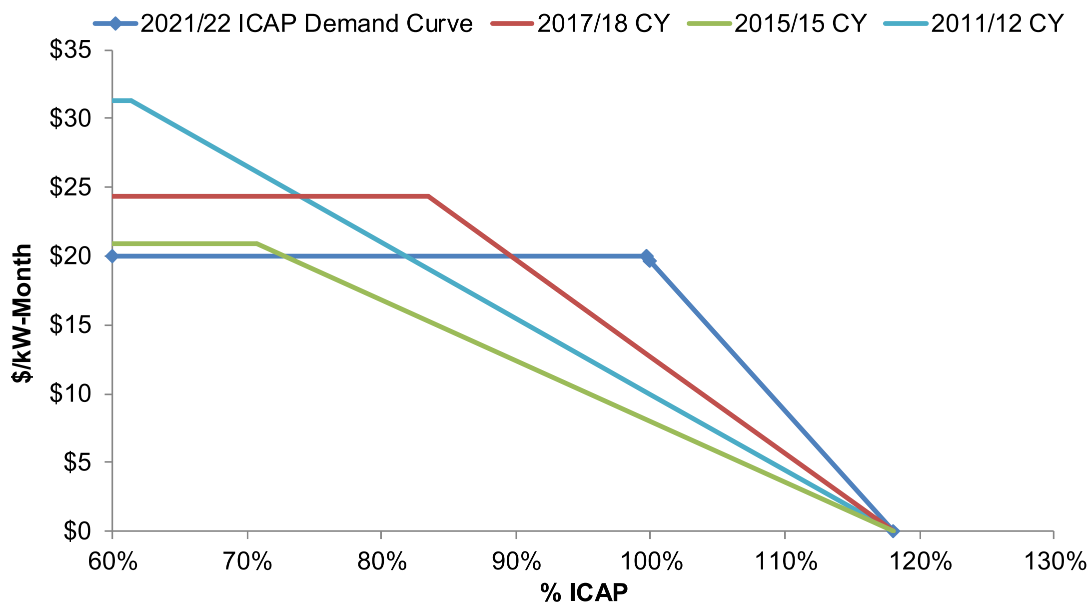


Figure 24: Comparison of LI 2021/2022 ICAP Demand Curve to Prior ICAP Demand Curves



VI. Annual Updating of ICAP Demand Curve Parameters

As described above, AGI's demand curve model calculates the RPs for each Locality and NYCA based input values for revenue requirements (i.e., ARV), financial parameters, "shape" parameters and other parameters (WSR, 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 $/year), ICAP monthly RP ($/kW-Month), ICAP Demand Curve maximum clearing price ($/kW-Month), and ICAP Demand Curve length (%).

ICAP Demand Curves will be updated annually based the updating of (1) gross CONE, (2) net EAS revenues, and (3) the WSR. 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 55 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 55: 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 WSR	**NYISO Published Values**

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, 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, 2020 in the case of this DCR), minus one.[96]

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 share of total peaking plant installed capital costs. Table 56 provides the (publicly available) index to be used for measuring changes over time for each cost component, and each component's relative weight for each peaking plant technology. The same weighting factors and indices will be used over the reset period, but the values resulting from the indices will be updated annually based on the indices and component weights described in Table 56.

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 2021/2022 Capability Year (i.e., the first Capability Year covered by the four year duration of this reset period).

[96] Services Tariff, Section 5.14.1.2.2.1. This methodology represents a change since the 2016 DCR. *See, New York Independent System Operator, Inc.*, Proposed Enhancements to the ICAP Demand Curve Annual Update Procedures, FERC Docket No. ER20-1049-000 (February 21, 2020); and *New York Independent System Operator, Inc.*, Letter Order, FERC Docket No. ER20-1049-000 (April 3, 2020).

Table 56: Composite Escalation Rate Indices and Component Weights, by Technology (2021-22 Capability Year)

Cost Component	Index	Interval	Calculation of Index Value	Growth Rate	Component Weight, by Technology							
					SGT-A65 WLE	GE 7F.05	1x0 GE 7HA.02 25ppm	1x0 GE 7HA.02 15ppm	8000J CC	BESS 4h	BESS 6h	BESS 8h
Construction Labor Cost	BLS Quarterly Census of Employment and Wages, New York - Statewide, NAICS 2371 Utility System Construction, Private, All Establishment Sizes, Average Annual Pay	Annually	Most recent annual value	4.14%	22%	33%	27%	24%	37%	16%	16%	16%
Materials Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Intermediate Demand by Commodity Type (ID6), Materials and Components for Construction (12)	Monthly	Average of finalized February, March, April values	1.43%	28%	21%	23%	19%	28%	16%	14%	13%
Gas and Steam Turbine Cost	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Turbines and Turbine Generator Sets (97)	Monthly	Average of finalized February, March, April values	4.71%	28%	20%	26%	32%	11%			
Storage Battery Costs	BLS Producer Price Index for Commodities, Not Seasonally Adjusted, Machinery and Equipment (11), Storage Batteries (7901)	Monthly	Average of finalized February, March, April values	-0.40%						53%	55%	57%
GDP Deflator	Bureau of Economic Analysis: Gross Domestic Product Implicit Price Deflator, Index 2009 = 100, Seasonally Adjusted	Quarterly	Most recent Q2 value	1.19%	22%	27%	24%	25%	24%	16%	15%	15%
Composite Escalation Rate					**2.89%**	**2.90%**	**2.95%**	**3.06%**	**2.75%**	**0.85%**	**0.80%**	**0.78%**

Note:
[1] Escalation rates in this Report reflect the most current data available for each index.[97]

[97] The recommended index for the "turbine component" of the composite escalation factor is different for battery storage plants than fossil peaking plant options. For fossil peaking plant options, the "turbine component" is labeled as "Gas and Steam Turbine Costs" in the table. For battery storage options, the "turbine component" is labeled as "Storage Battery Costs" in the table.

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 2021/2022 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 to run the model and the LOE-AFs would not be updated for the purposes of annual recalculation of net EAS revenues.

Table 57 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 57: 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
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	Fixed for Quadrennial Reset Period
Fuel tax and transportation cost adders	Fixed Value (Fixed for Quadrennial Reset Period)
Real-time intraday gas acquisition premium/purchase discount	Fixed Value (Fixed for Quadrennial Reset Period)
Fuel Pricing Points (*e.g.*, natural gas trading hub)	Fixed for Quadrennial Reset Period
Fuel Price	**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	Fixed Value (Fixed for Quadrennial Reset Period)
CO_2 Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
Peaking plant NO_x Emissions Rate	Fixed Value (Fixed for Quadrennial Reset Period)
NO_x Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
Peaking plant SO_2 Emissions Rate	Fixed Value (Fixed for Quadrennial Reset Period)
SO_2 Emission Allowance Cost	**Subscription Service Data Source or Publicly Available Data Source**
NYISO Rate Schedule 1 Charges	**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, public 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 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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Addendum: Gas Price Index

This addendum describes a change in how gas prices are incorporated in the fossil net EAS revenues model. It outlines the previous method, the change in the model, and the impact on results.

The net EAS revenues model imports daily natural gas spot price index data from S&P Global Market Intelligence and applies the natural gas spot prices to hourly decision-making logic. The previous version of the model accompanying the Interim Final Report released on August 10, 2020, incorporated S&P's daily natural gas prices as prices on the "trading dates," when delivery contracts were agreed upon, and considered the subsequent date as the "flow date" upon which gas would be delivered. For this reason, in assessing potential dispatch decisions for a given operating day, we shifted S&P reported gas prices one day forward to ensure that the dates of the gas prices used in the model corresponded to the historical operating day LBMPs and reserve prices. The gas price assigned to weekends and holidays was the Friday reported price, or the last day before a weekend/holiday. Table 1 shows this method for a set of example dates.

Table 1: Interim Final Report Model Assumption (Example Dates)

Reporting Date in S&P Data	Trading Date	Flow Date	Date S&P Gas Prices applied in Model
Monday 2/1	Monday 2/1	Tuesday 2/2	Tuesday 2/2
…	…	…	…
Thursday 2/4	Thursday 2/4	Friday 2/5	Friday 2/5
Friday 2/5	Friday 2/5	Sat. 2/6 - Mon. 2/8	Sat. 2/6 - Mon. 2/8
Monday 2/8	Monday 2/8	Tuesday 2/9	Tuesday 2/9

Based on stakeholder input and follow-up conversations with S&P Global Market Intelligence, Analysis Group confirmed that the natural gas spot price index actually reflects the flow date. This required a change in the fossil logic of the net EAS revenues model to remove the one day forward shift. In addition, the gas price assigned to weekends and holidays was changed to the Monday price or the first day after the holiday. Table 2 shows this method for a set of example dates. This change has been made to the model and is reflected in the updated values set forth in the updated version of the Final Report published on September 9, 2020.

Table 2: Final Report Model Revised Assumption (Example Dates)

Reporting Date in S&P Data	Trading Date	Flow Date	Date S&P Gas Prices applied in Model
Monday 2/1	Friday 1/29	Monday 2/1	Monday 2/1
…	…	…	…
Thursday 2/4	Wednesday 2/3	Thursday 2/4	Thursday 2/4
Friday 2/5	Thursday 2/4	Friday 2/5	Friday 2/5
Monday 2/8	Friday 2/5	Sat. 2/6 - Mon. 2/8	Sat. 2/6 - Mon. 2/8

Holding all else the same, this change increases the ICAP monthly reference point prices by approximately: (i) 0.2 percent in Load Zone C; (ii) 3.0 percent in Load Zones F, K, and G (Rockland County); (iii) 2.5 percent in Load Zone G (Dutchess County); and (iv) 2.0 percent in Load Zone J.

Appendices

A. Additional Detail on Unit Specifications

This appendix provides additional detail on the units selected for modeling in this report. It includes basic plant descriptions as well as details on unit performance, operating emissions, and capital and O&M costs.

3x0 Siemens SGT-A65 Dual Fuel with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	3	3	3	3	3	3
Representative Class Gas Turbine	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE
Startup Time to Base Load, min	5	5	5	5	5	5
Startup Time to MECL, min	4	4	4	4	4	4
Cold Startup Time to SCR Compliance, min	45	45	45	45	45	45
Equivalent Forced Outage Rate Demand, %	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Assumed Land Use During Operation, Acres	15	15	15	15	12	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NOx Control	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3	3	3
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	166,700	166,700	166,500	166,500	166,500	166,600
Net Plant Output - Winter Performance	188,200	188,200	188,200	188,200	188,200	188,200
DMNC Summer	160,900	161,200	160,200	160,200	158,800	160,800
DMNC Winter	188,200	188,200	188,200	188,200	188,200	188,200
DMNC ICAP	158,600	158,600	158,700	158,700	158,700	158,700
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,670	9,660	9,670	9,670	9,670	9,670
Net Plant Heat Rate - Winter	9,440	9,440	9,440	9,440	9,460	9,450
Net Plant Heat Rate - DMNC Summer	9,730	9,720	9,730	9,730	9,730	9,720
Net Plant Heat Rate - DMNC Winter	9,380	9,390	9,380	9,380	9,400	9,390
Net Plant Heat Rate - DMNC ICAP	9,730	9,730	9,730	9,730	9,720	9,720
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	100	100	100	100	100	100

3x0 Siemens SGT-A65 Dual Fuel with SCR, Emissions						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	167	167	167	167	167	167
SO_2	3.5	3.5	3.5	3.5	3.5	3.5
CO	302	302	302	302	302	302
CO_2	208,800	208,800	208,800	208,800	208,800	208,800
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	13	13	13	13	13	13
SO_2	3.5	3.5	3.5	3.5	3.5	3.5
CO	7	7	7	7	7	7
CO_2	208,800	208,800	208,800	208,800	208,800	208,800
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	278	278	278	278	278	278
SO_2	2.6	2.6	2.6	2.6	2.6	2.6
CO	81	81	81	81	81	81
CO_2	278,400	278,400	278,400	278,400	278,400	278,400
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	42	42	42	42	42	42
SO_2	2.6	2.6	2.6	2.6	2.6	2.6
CO	12	12	12	12	12	12
CO_2	278,400	278,400	278,400	278,400	278,400	278,400

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For Siemens A65, 2.5% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

3x0 Siemens SGT-A65 Dual Fuel with SCR, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$39,780,000	$41,450,000	$45,620,000	$53,790,000	$72,370,000	$69,920,000
Materials	$67,070,000	$67,210,000	$66,610,000	$66,770,000	$66,890,000	$66,950,000
Turbines or Batteries	$66,000,000	$66,000,000	$66,000,000	$66,000,000	$66,000,000	$66,000,000
Other	$51,770,000	$52,310,000	$53,240,000	$53,240,000	$56,220,000	$55,550,000
EPC Project Capital Cost Subtotal, 2020$	**$224,620,000**	**$226,970,000**	**$231,470,000**	**$239,800,000**	**$261,480,000**	**$258,420,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000	$480,000	$410,000
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000	$570,000	$480,000
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000	$1,330,000	$1,120,000
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000	$1,470,000	$1,240,000
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000	$350,000	$300,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$510,000	$510,000	$510,000	$510,000	$660,000	$560,000
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Switchyard	$17,080,000	$17,080,000	$17,080,000	$17,080,000	$52,030,000	$9,320,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000	$18,500,000	$20,000,000	$18,500,000
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$10,900,000	$0
Emission Reduction Credits	$100,000	$100,000	$100,000	$400,000	$400,000	$400,000
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Startup/Testing (Fuel & Consumables)	$2,640,000	$2,640,000	$2,640,000	$2,640,000	$2,640,000	$2,640,000
Initial Fuel Inventory	$4,180,000	$4,180,000	$4,180,000	$4,180,000	$4,180,000	$4,180,000
Site Security	$580,000	$580,000	$580,000	$580,000	$750,000	$640,000
Operating Spare Parts	$3,110,000	$3,110,000	$3,110,000	$3,110,000	$3,110,000	$3,110,000
Builders Risk Insurance (0.45% of Construction Costs)	$1,010,790	$1,021,365	$1,041,615	$1,079,100	$1,176,660	$1,162,890
Owner's Contingency (5% for Screening Purposes)	$14,453,040	$14,571,068	$14,797,081	$15,230,455	$18,889,333	$15,586,645
Owner's Cost Allowance Subtotal, 2020$	**$78,893,830**	**$79,022,433**	**$79,268,696**	**$80,039,555**	**$135,195,993**	**$68,899,535**
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
AFUDC, 2020$						
EPC Portion	$15,274,160	$15,433,960	$15,739,960	$16,306,400	$17,780,640	$17,572,560
Non-EPC Portion	$5,364,780	$5,373,525	$5,390,271	$5,442,690	$9,193,328	$4,685,168
AFUDC Subtotal, 2020$	**$20,638,940**	**$20,807,485**	**$21,130,231**	**$21,749,090**	**$26,973,968**	**$22,257,728**
Total Project Costs, 2020$	**$324,152,770**	**$326,799,919**	**$331,868,927**	**$341,588,645**	**$423,649,961**	**$349,577,263**

Notes:

[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

3x0 Siemens SGT-A65 Dual Fuel with SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000	$1,700,000	$1,500,000
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000
Property Insurance Allowance	$1,347,720	$1,361,820	$1,388,820	$1,438,800	$1,568,880	$1,550,520
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000	$3,240,000	$390,000
Total Fixed O&M Cost 2020$/Yr	**$3,677,720**	**$3,791,820**	**$4,118,820**	**$4,168,800**	**$7,608,880**	**$4,540,520**
Total Fixed O&M Cost 2020$/kW - Yr	**$23.19**	**$23.91**	**$25.95**	**$26.27**	**$47.95**	**$28.61**
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$190	$190	$190	$190	$190	$190
Major Maintenance Cost, 2020$/GT-start	N/A	N/A	N/A	N/A	N/A	N/A
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$8.37	$8.24	$8.14	$8.14	$8.46	$8.01
SCR Related Costs	$0.82	$0.83	$0.83	$0.83	$0.83	$0.83
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
Total Variable O&M - Gas Operation, 2020$/MWh	**$10.09**	**$9.97**	**$9.87**	**$9.87**	**$10.19**	**$9.74**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$8.22	$8.12	$8.02	$8.02	$8.30	$7.88
SCR Related Costs	$1.00	$1.00	$1.00	$1.00	$1.03	$1.03
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
Total Variable O&M - Fuel Oil Operation, 2020$/MWh	**$10.12**	**$10.02**	**$9.92**	**$9.92**	**$10.23**	**$9.81**

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

3x0 Siemens SGT-A65 Gas Only with SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Number of Gas Turbines	3	3	3	3		
Representative Class Gas Turbine	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE	Siemens SGT-A65 WLE		
Startup Time to Base Load, min	5	5	5	5		
Startup Time to MECL, min	4	4	4	4		
Cold Startup Time to SCR Compliance, min	45	45	45	45		
Equivalent Forced Outage Rate Demand, %	10.0%	10.0%	10.0%	10.0%		
Assumed Land Use During Operation, Acres	15	15	15	15		
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only		
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler		
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger		
NOx Control	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR	Water Injection and SCR		
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst		
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice		
Interconnection Voltage, kV	345	345	345	345		
Technology Rating	Mature	Mature	Mature	Mature		
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3		
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	166,700	166,700	166,500	166,500		
Net Plant Output - Winter Performance	188,200	188,200	188,200	188,200		
DMNC Summer	160,900	161,200	160,200	160,200		
DMNC Winter	188,200	188,200	188,200	188,200		
DMNC ICAP	158,600	158,600	158,700	158,700		
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,670	9,660	9,670	9,670		
Net Plant Heat Rate - Winter	9,440	9,440	9,440	9,440		
Net Plant Heat Rate - DMNC Summer	9,730	9,720	9,730	9,730		
Net Plant Heat Rate - DMNC Winter	9,380	9,390	9,380	9,380		
Net Plant Heat Rate - DMNC ICAP	9,730	9,730	9,730	9,730		
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	100	100	100	100		

3x0 Siemens SGT-A65 Gas Only with SCR, Emissions						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	167	167	167	167		
SO_2	3.5	3.5	3.5	3.5		
CO	302	302	302	302		
CO_2	208,800	208,800	208,800	208,800		
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	13	13	13	13		
SO_2	3.5	3.5	3.5	3.5		
CO	7	7	7	7		
CO_2	208,800	208,800	208,800	208,800		

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.

[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.

[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.

[4] Degraded performance assumed for all scenarios. For Siemens A65, 2.5% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.

[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US

[6] Emissions estimates are shown for steady state operation at ISO conditions.

3x0 Siemens SGT-A65 Gas Only with SCR, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$37,690,000	$39,310,000	$43,330,000	$51,220,000		
Materials	$63,550,000	$63,740,000	$63,260,000	$63,580,000		
Turbines or Batteries	$63,000,000	$63,000,000	$63,000,000	$63,000,000		
Other	$49,060,000	$49,600,000	$50,570,000	$50,690,000		
EPC Project Capital Cost Subtotal, 2020$	**$213,300,000**	**$215,650,000**	**$220,160,000**	**$228,490,000**		
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000		
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000		
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000		
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000		
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000		
Sales Tax	$0	$0	$0	$0		
Construction Power and Water	$510,000	$510,000	$510,000	$510,000		
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Switchyard	$17,080,000	$17,080,000	$17,080,000	$17,080,000		
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000		
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000	$18,500,000		
System Deliverability Upgrade Costs	$0	$0	$0	$0		
Water Supply Infrastructure	$0	$0	$0	$0		
Emission Reduction Credits	$100,000	$100,000	$100,000	$400,000		
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000		
Startup/Testing (Fuel & Consumables)	$720,000	$720,000	$720,000	$720,000		
Initial Fuel Inventory	$0	$0	$0	$0		
Site Security	$580,000	$580,000	$580,000	$580,000		
Operating Spare Parts	$3,110,000	$3,110,000	$3,110,000	$3,110,000		
Builders Risk Insurance (0.45% of Construction Costs)	$959,850	$970,425	$990,720	$1,028,205		
Owner's Contingency (5% for Screening Purposes)	$13,579,493	$13,697,521	$13,924,036	$14,357,410		
Owner's Cost Allowance Subtotal, 2020$	**$71,869,343**	**$71,997,946**	**$72,244,756**	**$73,015,615**		
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%		
AFUDC, 2020$						
EPC Portion	$14,504,400	$14,664,200	$14,970,880	$15,537,320		
Non-EPC Portion	$4,887,115	$4,895,860	$4,912,643	$4,965,062		
AFUDC Subtotal, 2020$	**$19,391,515**	**$19,560,060**	**$19,883,523**	**$20,502,382**		
Total Project Costs, 2020$	**$304,560,858**	**$307,208,007**	**$312,288,279**	**$322,007,997**		

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

3x0 Siemens SGT-A65 Gas Only with SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000		
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000	$1,100,000		
Property Insurance Allowance	$1,279,800	$1,293,900	$1,320,960	$1,370,940		
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000		
Total Fixed O&M Cost 2020$/Yr	**$3,609,800**	**$3,723,900**	**$4,050,960**	**$4,100,940**		
Total Fixed O&M Cost 2020$/kW - Yr	**$22.76**	**$23.48**	**$25.53**	**$25.84**		
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$190	$190	$190	$190		
Major Maintenance Cost, 2020$/GT-start	N/A	N/A	N/A	N/A		
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$8.37	$8.24	$8.14	$8.14		
SCR Related Costs	$0.82	$0.83	$0.83	$0.83		
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90		
Total Variable O&M - Gas Operation, 2020$/MWh	**$10.09**	**$9.97**	**$9.87**	**$9.87**		

Notes:
[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7F.05 Dual Fuel with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05
Startup Time to Base Load, min	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional
Cold Startup Time to SCR Compliance, min	45	45	45	45	45	45
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
Assumed Land Use During Operation, Acres	15	15	15	15	12	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NOx Control	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3	3	3
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	215,800	217,000	217,000	217,000	217,800	218,000
Net Plant Output - Winter Performance	224,900	225,900	226,500	226,500	226,900	227,200
DMNC Summer	208,700	210,000	210,000	210,000	210,100	211,700
DMNC Winter	225,900	227,100	228,000	228,000	229,200	229,200
DMNC ICAP	207,100	208,200	209,100	209,100	210,200	210,200
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	10,180	10,180	10,200	10,200	10,210	10,200
Net Plant Heat Rate - Winter	9,880	9,880	9,890	9,890	9,900	9,890
Net Plant Heat Rate - DMNC Summer	10,360	10,350	10,370	10,350	10,370	10,360
Net Plant Heat Rate - DMNC Winter	9,830	9,830	9,830	9,830	9,850	9,840
Net Plant Heat Rate - DMNC ICAP	10,360	10,360	10,360	10,360	10,360	10,360
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)

1x0 GE 7F.05 Dual Fuel with SCR, Emissions						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	80	80	80	80	80	80
SO_2	4.5	4.5	4.6	4.6	4.6	4.6
CO	49	49	49	49	49	49
CO_2	271,200	272,400	273,600	273,600	276,000	276,000
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	18	18	18	18	18	18
SO_2	4.5	4.5	4.6	4.6	4.6	4.6
CO	11	11	11	11	11	11
CO_2	271,200	272,400	273,600	273,600	276,000	276,000
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	430	430	430	430	430	430
SO_2	3.4	3.5	3.5	3.5	3.5	3.5
CO	84	84	84	84	84	84
CO_2	361,600	363,200	364,800	364,800	368,000	368,000
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	65	65	65	65	65	65
SO_2	3.4	3.5	3.5	3.5	3.5	3.5
CO	14	14	14	14	14	14
CO_2	361,600	363,200	364,800	364,800	368,000	368,000

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7F.05 Dual Fuel with SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$53,360,000	$55,770,000	$58,150,000	$64,960,000	$86,490,000	$84,230,000
Materials	$36,100,000	$35,940,000	$37,980,000	$41,070,000	$44,970,000	$44,950,000
Turbines or Batteries	$39,500,000	$39,500,000	$39,500,000	$39,500,000	$39,500,000	$39,500,000
Other	$51,950,000	$52,640,000	$52,520,000	$53,820,000	$56,990,000	$56,230,000
EPC Project Capital Cost Subtotal, 2020$	**$180,910,000**	**$183,850,000**	**$188,150,000**	**$199,350,000**	**$227,950,000**	**$224,910,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000	$480,000	$410,000
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000	$570,000	$480,000
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000	$1,330,000	$1,120,000
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000	$1,470,000	$1,240,000
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000	$350,000	$300,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$510,000	$510,000	$510,000	$510,000	$660,000	$560,000
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000	$43,800,000	$5,590,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000	$18,500,000	$20,000,000	$18,500,000
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$10,900,000	$0
Emission Reduction Credits	$200,000	$200,000	$200,000	$300,000	$300,000	$300,000
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Startup/Testing (Fuel & Consumables)	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000
Initial Fuel Inventory	$4,880,000	$4,880,000	$4,880,000	$4,880,000	$4,880,000	$4,880,000
Site Security	$580,000	$580,000	$580,000	$580,000	$750,000	$640,000
Operating Spare Parts	$5,500,000	$5,500,000	$5,500,000	$5,500,000	$5,500,000	$5,500,000
Builders Risk Insurance (0.45% of Construction Costs)	$814,095	$827,325	$846,675	$897,075	$1,025,775	$1,012,095
Owner's Contingency (5% for Screening Purposes)	$12,098,705	$12,246,366	$12,462,334	$13,029,854	$16,966,289	$13,889,605
Owner's Cost Allowance Subtotal, 2020$	**$73,162,800**	**$73,323,691**	**$73,559,009**	**$74,276,929**	**$128,342,064**	**$66,771,700**
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
AFUDC, 2020$						
EPC Portion	$12,301,880	$12,501,800	$12,794,200	$13,555,800	$15,500,600	$15,293,880
Non-EPC Portion	$4,975,070	$4,986,011	$5,002,013	$5,050,831	$8,727,260	$4,540,476
AFUDC Subtotal, 2020$	**$17,276,950**	**$17,487,811**	**$17,796,213**	**$18,606,631**	**$24,227,860**	**$19,834,356**
Total Project Costs, 2020$	**$271,349,750**	**$274,661,502**	**$279,505,221**	**$292,233,560**	**$380,519,924**	**$311,516,055**

Notes:

[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7F.05 Dual Fuel with SCR, O&M Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000	$1,700,000	$1,500,000
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,100,000
Property Insurance Allowance	$1,085,460	$1,103,100	$1,128,900	$1,196,100	$1,367,700	$1,349,460
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000	$3,240,000	$390,000
Total Fixed O&M Cost 2020$/Yr	**$3,415,460**	**$3,533,100**	**$3,858,900**	**$3,926,100**	**$7,407,700**	**$4,339,460**
Total Fixed O&M Cost 2020$/kW - Yr	**$16.49**	**$16.97**	**$18.45**	**$18.78**	**$35.24**	**$20.64**
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$350	$350	$350	$350	$350	$350
Major Maintenance Cost, 2020$/GT-start	$9,500	$9,500	$9,500	$9,500	$9,500	$9,500
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.04	$0.04	$0.04	$0.04	$0.06	$0.04
SCR Related Costs	$0.58	$0.58	$0.58	$0.58	$0.57	$0.57
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.91	$0.91
Total Variable O&M - Gas Operation, 2020$/MWh	**$1.52**	**$1.52**	**$1.52**	**$1.52**	**$1.54**	**$1.52**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$7.14	$7.14	$7.14	$7.14	$7.52	$7.15
SCR Related Costs	$0.80	$0.80	$0.80	$0.80	$0.79	$0.79
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.90	$0.89
Total Variable O&M - Fuel Oil Operation, 2020$/MWh	**$8.84**	**$8.84**	**$8.84**	**$8.84**	**$9.21**	**$8.83**

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7F.05 Dual Fuel without SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7F.05			
Startup Time to Base Load, min	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional			
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional			
Cold Startup Time to SCR Compliance, min	45	45	45			
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%			
Assumed Land Use During Operation, Acres	15	15	15			
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)			
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler			
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			
NOx Control	DLN (Gas), Water Injection (Fuel Oil)	DLN (Gas), Water Injection (Fuel Oil)	DLN (Gas), Water Injection (Fuel Oil)			
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Interconnection Voltage, kV	345	345	345			
Technology Rating	Mature	Mature	Mature			
Permitting & Construction Schedule (Years from FNTP)	3	3	3			
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	215,800	217,000	217,000			
Net Plant Output - Winter Performance	224,900	225,900	226,500			
DMNC Summer	208,700	210,000	210,000			
DMNC Winter	225,900	227,100	228,000			
DMNC ICAP	207,100	208,200	209,100			
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	10,180	10,180	10,200			
Net Plant Heat Rate - Winter	9,880	9,880	9,890			
Net Plant Heat Rate - DMNC Summer	10,360	10,350	10,370			
Net Plant Heat Rate - DMNC Winter	9,830	9,830	9,830			
Net Plant Heat Rate - DMNC ICAP	10,360	10,360	10,360			
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)			

1x0 GE 7F.05 Dual Fuel without SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	80	80	80			
SO_2	4.5	4.5	4.6			
CO	49	49	49			
CO_2	271,200	272,400	273,600			
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	430	430	430			
SO_2	3.4	3.5	3.5			
CO	84	84	84			
CO_2	361,600	363,200	364,800			

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7F.05 Dual Fuel without SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$45,590,000	$47,810,000	$50,100,000			
Materials	$30,840,000	$30,810,000	$32,710,000			
Turbines or Batteries	$39,500,000	$39,500,000	$39,500,000			
Other	$44,380,000	$45,130,000	$45,240,000			
EPC Project Capital Cost Subtotal, 2020$	**$160,310,000**	**$163,250,000**	**$167,550,000**			
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000			
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000			
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000			
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000			
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000			
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000			
Sales Tax	$0	$0	$0			
Construction Power and Water	$510,000	$510,000	$510,000			
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000			
Switchyard	$10,250,000	$10,250,000	$10,250,000			
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000			
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000			
System Deliverability Upgrade Costs	$0	$0	$0			
Water Supply Infrastructure	$0	$0	$0			
Emission Reduction Credits	$200,000	$200,000	$200,000			
Political Concessions & Area Development	$500,000	$500,000	$500,000			
Startup/Testing (Fuel & Consumables)	$3,100,000	$3,100,000	$3,100,000			
Initial Fuel Inventory	$4,880,000	$4,880,000	$4,880,000			
Site Security	$580,000	$580,000	$580,000			
Operating Spare Parts	$5,500,000	$5,500,000	$5,500,000			
Builders Risk Insurance (0.45% of Construction Costs)	$721,395	$734,625	$753,975			
Owner's Contingency (5% for Screening Purposes)	$11,064,070	$11,211,731	$11,427,699			
Owner's Cost Allowance Subtotal, 2020$	**$72,035,465**	**$72,196,356**	**$72,431,674**			
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%			
AFUDC, 2020$						
EPC Portion	$10,901,080	$11,101,000	$11,393,400			
Non-EPC Portion	$4,898,412	$4,909,352	$4,925,354			
AFUDC Subtotal, 2020$	**$15,799,492**	**$16,010,352**	**$16,318,754**			
Total Project Costs, 2020$	**$248,144,956**	**$251,456,708**	**$256,300,428**			

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7F.05 Dual Fuel without SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000			
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000			
Property Insurance Allowance	$961,860	$979,500	$1,005,300			
Site Leasing Allowance	$330,000	$330,000	$330,000			
Total Fixed O&M Cost 2020$/Yr	**$3,291,860**	**$3,409,500**	**$3,735,300**			
Total Fixed O&M Cost 2020$/kW - Yr	**$15.90**	**$16.38**	**$17.86**			
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$350	$350	$350			
Major Maintenance Cost, 2020$/GT-start	$9,500	$9,500	$9,500			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.04	$0.04	$0.04			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Gas Operation, 2020$/MWh	**$0.94**	**$0.94**	**$0.94**			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$7.14	$7.14	$7.14			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Fuel Oil Operation, 2020$/MWh	**$8.04**	**$8.04**	**$8.04**			

Notes:
[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7F.05 Gas Only with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1		
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7F.05	GE 7F.05		
Startup Time to Base Load, min	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional		
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional		
Cold Startup Time to SCR Compliance, min	45	45	45	45		
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%	4.3%		
Assumed Land Use During Operation, Acres	15	15	15	15		
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only		
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler		
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger		
NOx Control	DLN (Gas), SCR	DLN (Gas), SCR	DLN (Gas), SCR	DLN (Gas), SCR		
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst		
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice		
Interconnection Voltage, kV	345	345	345	345		
Technology Rating	Mature	Mature	Mature	Mature		
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3		
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	215,800	217,000	217,000	217,000		
Net Plant Output - Winter Performance	224,900	225,900	226,500	226,500		
DMNC Summer	208,700	210,000	210,000	210,000		
DMNC Winter	225,900	227,100	228,000	228,000		
DMNC ICAP	207,100	208,200	209,100	209,100		
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	10,180	10,180	10,200	10,200		
Net Plant Heat Rate - Winter	9,880	9,880	9,890	9,890		
Net Plant Heat Rate - DMNC Summer	10,360	10,350	10,370	10,350		
Net Plant Heat Rate - DMNC Winter	9,830	9,830	9,830	9,830		
Net Plant Heat Rate - DMNC ICAP	10,360	10,360	10,360	10,360		
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)		

1x0 GE 7F.05 Gas Only with SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	80	80	80	80		
SO_2	4.5	4.5	4.6	4.6		
CO	49	49	49	49		
CO_2	271,200	272,400	273,600	273,600		
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	18	18	18	18		
SO_2	4.5	4.5	4.6	4.6		
CO	11	11	11	11		
CO_2	271,200	272,400	273,600	273,600		

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.

[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.

[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.

[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.

[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7F.05 Gas Only with SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$47,550,000	$49,820,000	$52,130,000	$58,700,000		
Materials	$32,170,000	$32,110,000	$34,040,000	$37,110,000		
Turbines or Batteries	$38,000,000	$38,000,000	$38,000,000	$38,000,000		
Other	$46,290,000	$47,020,000	$47,080,000	$48,640,000		
EPC Project Capital Cost Subtotal, 2020$	**$164,010,000**	**$166,950,000**	**$171,250,000**	**$182,450,000**		
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000		
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000		
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000		
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000		
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000		
Sales Tax	$0	$0	$0	$0		
Construction Power and Water	$510,000	$510,000	$510,000	$510,000		
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000		
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000		
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000	$18,500,000		
System Deliverability Upgrade Costs	$0	$0	$0	$0		
Water Supply Infrastructure	$0	$0	$0	$0		
Emission Reduction Credits	$200,000	$200,000	$200,000	$300,000		
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000		
Startup/Testing (Fuel & Consumables)	$830,000	$830,000	$830,000	$830,000		
Initial Fuel Inventory	$0	$0	$0	$0		
Site Security	$580,000	$580,000	$580,000	$580,000		
Operating Spare Parts	$5,500,000	$5,500,000	$5,500,000	$5,500,000		
Builders Risk Insurance (0.45% of Construction Costs)	$738,045	$751,275	$770,625	$821,025		
Owner's Contingency (5% for Screening Purposes)	$10,892,402	$11,040,064	$11,256,031	$11,823,551		
Owner's Cost Allowance Subtotal, 2020$	**$64,730,447**	**$64,891,339**	**$65,126,656**	**$65,844,576**		
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%		
AFUDC, 2020$						
EPC Portion	$11,152,680	$11,352,600	$11,645,000	$12,406,600		
Non-EPC Portion	$4,401,670	$4,412,611	$4,428,613	$4,477,431		
AFUDC Subtotal, 2020$	**$15,554,350**	**$15,765,211**	**$16,073,613**	**$16,884,031**		
Total Project Costs, 2020$	**$244,294,798**	**$247,606,550**	**$252,450,269**	**$265,178,607**		

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7F.05 Gas Only with SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000		
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000	$1,100,000		
Property Insurance Allowance	$984,060	$1,001,700	$1,027,500	$1,094,700		
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000		
Total Fixed O&M Cost 2020$/Yr	**$3,314,060**	**$3,431,700**	**$3,757,500**	**$3,824,700**		
Total Fixed O&M Cost 2020$/kW - Yr	**$16.00**	**$16.48**	**$17.97**	**$18.29**		
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$350	$350	$350	$350		
Major Maintenance Cost, 2020$/GT-start	$9,500	$9,500	$9,500	$9,500		
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.04	$0.04	$0.04	$0.04		
SCR Related Costs	$0.58	$0.58	$0.58	$0.58		
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90		
Total Variable O&M - Gas Operation, 2020$/MWh	**$1.52**	**$1.52**	**$1.52**	**$1.52**		

Notes:
[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7F.05 Gas Only without SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7F.05			
Startup Time to Base Load, min	11 fast / 30 conventional	11 fast / 30 conventional	11 fast / 30 conventional			
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional			
Cold Startup Time to SCR Compliance, min	45	45	45			
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%			
Assumed Land Use During Operation, Acres	15	15	15			
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only			
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler			
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			
NOx Control	DLN (Gas)	DLN (Gas)	DLN (Gas)			
CO Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Interconnection Voltage, kV	345	345	345			
Technology Rating	Mature	Mature	Mature			
Permitting & Construction Schedule (Years from FNTP)	3	3	3			
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	215,800	217,000	217,000			
Net Plant Output - Winter Performance	224,900	225,900	226,500			
DMNC Summer	208,700	210,000	210,000			
DMNC Winter	225,900	227,100	228,000			
DMNC ICAP	207,100	208,200	209,100			
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	10,180	10,180	10,200			
Net Plant Heat Rate - Winter	9,880	9,880	9,890			
Net Plant Heat Rate - DMNC Summer	10,360	10,350	10,370			
Net Plant Heat Rate - DMNC Winter	9,830	9,830	9,830			
Net Plant Heat Rate - DMNC ICAP	10,360	10,360	10,360			
Estimated Startup Fuel Usage						
Start to Base Load, MMBtu	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)	140 (fast) / 325 (typ)			

1x0 GE 7F.05 Gas Only without SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	80	80	80			
SO_2	4.5	4.5	4.6			
CO	49	49	49			
CO_2	271,200	272,400	273,600			

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.

[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.

[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.

[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.

[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7F.05 Gas Only without SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$39,780,000	$41,860,000	$44,070,000			
Materials	$26,910,000	$26,980,000	$28,780,000			
Turbines or Batteries	$38,000,000	$38,000,000	$38,000,000			
Other	$38,720,000	$39,510,000	$39,800,000			
EPC Project Capital Cost Subtotal, 2020$	**$143,410,000**	**$146,350,000**	**$150,650,000**			
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000			
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000			
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000			
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000			
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000			
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000			
Sales Tax	$0	$0	$0			
Construction Power and Water	$510,000	$510,000	$510,000			
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000			
Switchyard	$10,250,000	$10,250,000	$10,250,000			
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000			
Gas Interconnection and Reinforcement	$18,500,000	$18,500,000	$18,500,000			
System Deliverability Upgrade Costs	$0	$0	$0			
Water Supply Infrastructure	$0	$0	$0			
Emission Reduction Credits	$200,000	$200,000	$200,000			
Political Concessions & Area Development	$500,000	$500,000	$500,000			
Startup/Testing (Fuel & Consumables)	$830,000	$830,000	$830,000			
Initial Fuel Inventory	$0	$0	$0			
Site Security	$580,000	$580,000	$580,000			
Operating Spare Parts	$5,500,000	$5,500,000	$5,500,000			
Builders Risk Insurance (0.45% of Construction Costs)	$645,345	$658,575	$677,925			
Owner's Contingency (5% for Screening Purposes)	$9,857,767	$10,005,429	$10,221,396			
Owner's Cost Allowance Subtotal, 2020$	**$63,603,112**	**$63,764,004**	**$63,999,321**			
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%			
AFUDC, 2020$						
EPC Portion	$9,751,880	$9,951,800	$10,244,200			
Non-EPC Portion	$4,325,012	$4,335,952	$4,351,954			
AFUDC Subtotal, 2020$	**$14,076,892**	**$14,287,752**	**$14,596,154**			
Total Project Costs, 2020$	**$221,090,004**	**$224,401,756**	**$229,245,475**			

Notes:

[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7F.05 Gas Only without SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000			
Fixed O&M Cost - Other	$1,100,000	$1,100,000	$1,100,000			
Property Insurance Allowance	$860,460	$878,100	$903,900			
Site Leasing Allowance	$330,000	$330,000	$330,000			
Total Fixed O&M Cost 2020$/Yr	**$3,190,460**	**$3,308,100**	**$3,633,900**			
Total Fixed O&M Cost 2020$/kW - Yr	**$15.41**	**$15.89**	**$17.38**			
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$350	$350	$350			
Major Maintenance Cost, 2020$/GT-start	$9,500	$9,500	$9,500			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.04	$0.04	$0.04			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Gas Operation, 2020$/MWh	**$0.94**	**$0.94**	**$0.94**			

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.

[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.

[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).

[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7HA.02 tuned to emit 25ppm Dual Fuel with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02
Startup Time to Base Load, min	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional
Cold Startup Time to SCR Compliance, min	45	45	45	45	45	45
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
Assumed Land Use During Operation, Acres	15	15	15	15	12	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger
NOx Control	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR	DLN (Gas), Water Injection (Fuel Oil), SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3	3	3
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	355,600	357,700	357,400	357,400	358,700	359,000
Net Plant Output - Winter Performance	367,400	369,200	370,200	370,200	370,200	371,100
DMNC Summer	346,100	348,200	348,300	348,200	348,500	351,100
DMNC Winter	366,000	368,600	369,900	369,900	374,100	373,000
DMNC ICAP	343,700	345,600	347,000	347,000	348,800	348,800
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,350	9,350	9,360	9,360	9,370	9,370
Net Plant Heat Rate - Winter	9,280	9,290	9,300	9,300	9,300	9,300
Net Plant Heat Rate - DMNC Summer	9,460	9,450	9,460	9,450	9,470	9,460
Net Plant Heat Rate - DMNC Winter	9,210	9,210	9,210	9,210	9,250	9,230
Net Plant Heat Rate - DMNC ICAP	9,460	9,460	9,460	9,460	9,460	9,460
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)

1x0 GE 7HA.02 tuned to emit 25ppm Dual Fuel with SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	331	331	331	331	331	331
SO_2	6.8	6.8	6.9	6.9	6.9	6.9
CO	72	72	72	72	72	72
CO_2	408,000	410,400	411,600	411,600	414,000	414,000
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	26	26	26	26	26	26
SO_2	6.8	6.8	6.9	6.9	6.9	6.9
CO	16	16	16	16	16	16
CO_2	408,000	410,400	411,600	411,600	414,000	414,000
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	640	640	640	640	640	640
SO_2	5.2	5.2	5.2	5.2	5.3	5.3
CO	109	109	109	109	109	109
CO_2	544,000	547,200	548,800	548,800	552,000	552,000
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	96	96	96	96	96	96
SO_2	5.2	5.2	5.2	5.2	5.3	5.3
CO	19	19	19	19	19	19
CO_2	544,000	547,200	548,800	548,800	552,000	552,000

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7HA.02 tuned to emit 25ppm Dual Fuel with SCR, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$59,800,000	$62,960,000	$63,180,000	$72,900,000	$99,220,000	$96,770,000
Materials	$56,700,000	$55,890,000	$61,160,000	$61,860,000	$65,190,000	$65,300,000
Turbines or Batteries	$68,500,000	$68,500,000	$68,500,000	$68,500,000	$68,500,000	$68,500,000
Other	$64,570,000	$65,290,000	$64,290,000	$64,180,000	$69,580,000	$68,860,000
EPC Project Capital Cost Subtotal, 2020$	**$249,570,000**	**$252,640,000**	**$257,130,000**	**$267,440,000**	**$302,490,000**	**$299,430,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000	$480,000	$410,000
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000	$570,000	$480,000
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000	$1,330,000	$1,120,000
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000	$1,470,000	$1,240,000
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000	$350,000	$300,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$550,000	$550,000	$550,000	$550,000	$720,000	$610,000
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000	$43,800,000	$5,590,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000	$23,500,000	$20,000,000	$23,500,000
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$10,900,000	$0
Emission Reduction Credits	$70,000	$70,000	$70,000	$400,000	$400,000	$400,000
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Startup/Testing (Fuel & Consumables)	$4,500,000	$4,500,000	$4,500,000	$4,500,000	$4,500,000	$4,500,000
Initial Fuel Inventory	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000
Site Security	$580,000	$580,000	$580,000	$580,000	$750,000	$640,000
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000	$6,500,000	$6,500,000	$6,500,000
Builders Risk Insurance (0.45% of Construction Costs)	$1,123,065	$1,136,880	$1,157,085	$1,203,480	$1,361,205	$1,347,435
Owner's Contingency (5% for Screening Purposes)	$16,030,653	$16,184,844	$16,410,354	$16,944,674	$20,956,060	$18,127,872
Owner's Cost Allowance Subtotal, 2020$	**$87,073,718**	**$87,241,724**	**$87,487,439**	**$88,398,154**	**$137,587,265**	**$81,255,307**
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
AFUDC, 2020$						
EPC Portion	$16,970,760	$17,179,520	$17,484,840	$18,185,920	$20,569,320	$20,361,240
Non-EPC Portion	$5,921,013	$5,932,437	$5,949,146	$6,011,074	$9,355,934	$5,525,361
AFUDC Subtotal, 2020$	**$22,891,773**	**$23,111,957**	**$23,433,986**	**$24,196,994**	**$29,925,254**	**$25,886,601**
Total Project Costs, 2020$	**$359,535,491**	**$362,993,681**	**$368,051,425**	**$380,035,148**	**$470,002,519**	**$406,571,908**

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7HA.02 tuned to emit 25ppm Dual Fuel with SCR, O&M Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000	$1,700,000	$1,500,000
Fixed O&M Cost - Other	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000	$1,500,000
Property Insurance Allowance	$1,497,420	$1,515,840	$1,542,780	$1,604,640	$1,814,940	$1,796,580
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000	$3,240,000	$390,000
Total Fixed O&M Cost 2020$/Yr	**$4,227,420**	**$4,345,840**	**$4,672,780**	**$4,734,640**	**$8,254,940**	**$5,186,580**
Total Fixed O&M Cost 2020$/kW - Yr	**$12.30**	**$12.57**	**$13.47**	**$13.64**	**$23.67**	**$14.87**
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600	$600	$600	$600
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600	$26,600	$26,600	$26,600
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.03	$0.03	$0.03	$0.03	$0.05	$0.03
SCR Related Costs	$0.47	$0.46	$0.46	$0.46	$0.48	$0.46
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
Total Variable Variable O&M - Gas Operation, 2020$/MWh	**$1.40**	**$1.39**	**$1.39**	**$1.39**	**$1.43**	**$1.39**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$9.31	$9.31	$9.33	$9.33	$9.86	$9.33
SCR Related Costs	$0.70	$0.70	$0.70	$0.70	$0.70	$0.70
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
Total Variable Variable O&M - Fuel Oil Operation, 2020$/MWh	**$10.91**	**$10.91**	**$10.93**	**$10.93**	**$11.46**	**$10.93**

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.

[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.

[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).

[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7HA.02 tuned to emit 15ppm Dual Fuel without SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02			
Startup Time to Base Load, min	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional			
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional			
Cold Startup Time to SCR Compliance, min	45	45	45			
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%			
Assumed Land Use During Operation, Acres	15	15	15			
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)			
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler			
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			
NOx Control	DLN (Gas), Water Injection (Fuel Oil)	DLN (Gas), Water Injection (Fuel Oil)	DLN (Gas), Water Injection (Fuel Oil)			
CO Control	CO Catalyst	CO Catalyst	CO Catalyst			
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Interconnection Voltage, kV	345	345	345			
Technology Rating	Mature	Mature	Mature			
Permitting & Construction Schedule (Years from FNTP)	3	3	3			
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	338,000	341,200	340,900			
Net Plant Output - Winter Performance	346,100	351,000	350,500			
DMNC Summer	329,300	334,000	331,600			
DMNC Winter	344,700	350,500	350,200			
DMNC ICAP	326,700	328,500	329,900			
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,370	9,390	9,390			
Net Plant Heat Rate - Winter	9,320	9,320	9,340			
Net Plant Heat Rate - DMNC Summer	9,470	9,470	9,480			
Net Plant Heat Rate - DMNC Winter	9,250	9,250	9,250			
Net Plant Heat Rate - DMNC ICAP	9,490	9,500	9,490			
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)			

1x0 GE 7HA.02 tuned to emit 15ppm Dual Fuel without SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	189	189	189			
SO_2	6.4	6.4	6.4			
CO	69	69	69			
CO_2	381,600	384,000	385,200			
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	640	640	640			
SO_2	4.8	4.9	4.9			
CO	109	109	109			
CO_2	508,800	512,000	513,600			

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7HA.02 tuned to emit 15ppm Dual Fuel without SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$47,220,000	$50,460,000	$50,280,000			
Materials	$35,740,000	$34,870,000	$41,480,000			
Turbines or Batteries	$68,500,000	$68,500,000	$68,500,000			
Other	$54,670,000	$55,350,000	$53,430,000			
EPC Project Capital Cost Subtotal, 2020$	**$206,130,000**	**$209,180,000**	**$213,690,000**			
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000			
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000			
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000			
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000			
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000			
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000			
Sales Tax	$0	$0	$0			
Construction Power and Water	$550,000	$550,000	$550,000			
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000			
Switchyard	$10,250,000	$10,250,000	$10,250,000			
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000			
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000			
System Deliverability Upgrade Costs	$0	$0	$0			
Water Supply Infrastructure	$0	$0	$0			
Emission Reduction Credits	$400,000	$400,000	$400,000			
Political Concessions & Area Development	$500,000	$500,000	$500,000			
Startup/Testing (Fuel & Consumables)	$4,500,000	$4,500,000	$4,500,000			
Initial Fuel Inventory	$7,240,000	$7,240,000	$7,240,000			
Site Security	$580,000	$580,000	$580,000			
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000			
Builders Risk Insurance (0.45% of Construction Costs)	$927,585	$941,310	$961,605			
Owner's Contingency (5% for Screening Purposes)	$13,865,379	$14,018,566	$14,245,080			
Owner's Cost Allowance Subtotal, 2020$	**$85,042,964**	**$85,209,876**	**$85,456,685**			
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%			
AFUDC, 2020$						
EPC Portion	$14,016,840	$14,224,240	$14,530,920			
Non-EPC Portion	$5,782,922	$5,794,272	$5,811,055			
AFUDC Subtotal, 2020$	**$19,799,762**	**$20,018,512**	**$20,341,975**			
Total Project Costs, 2020$	**$310,972,726**	**$314,408,387**	**$319,488,660**			

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7HA.02 tuned to emit 15ppm Dual Fuel without SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000			
Fixed O&M Cost - Other	$1,500,000	$1,500,000	$1,500,000			
Property Insurance Allowance	$1,236,780	$1,255,080	$1,282,140			
Site Leasing Allowance	$330,000	$330,000	$330,000			
Total Fixed O&M Cost 2020$/Yr	**$3,966,780**	**$4,085,080**	**$4,412,140**			
Total Fixed O&M Cost 2020$/kW - Yr	**$12.14**	**$12.44**	**$13.37**			
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600			
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.03	$0.03	$0.03			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Gas Operation, 2020$/MWh	**$0.93**	**$0.93**	**$0.93**			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$9.31	$9.31	$9.31			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Fuel Oil Operation, 2020$/MWh	**$10.21**	**$10.21**	**$10.21**			

Notes:
[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7HA.02 tuned to emit 25ppm Gas Only with SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1		
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02		
Startup Time to Base Load, min	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional		
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional		
Cold Startup Time to SCR Compliance, min	45	45	45	45		
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%	4.3%		
Assumed Land Use During Operation, Acres	15	15	15	15		
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only		
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler		
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger		
NOx Control	DLN (Gas), SCR	DLN (Gas), SCR	DLN (Gas), SCR	DLN (Gas), SCR		
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst		
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice		
Interconnection Voltage, kV	345	345	345	345		
Technology Rating	Mature	Mature	Mature	Mature		
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3		
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	355,600	357,700	357,400	357,400		
Net Plant Output - Winter Performance	367,400	369,200	370,200	370,200		
DMNC Summer	346,100	348,200	348,300	348,200		
DMNC Winter	366,000	368,600	369,900	369,900		
DMNC ICAP	343,700	345,600	347,000	347,000		
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,350	9,350	9,360	9,360		
Net Plant Heat Rate - Winter	9,280	9,290	9,300	9,300		
Net Plant Heat Rate - DMNC Summer	9,460	9,450	9,460	9,450		
Net Plant Heat Rate - DMNC Winter	9,210	9,210	9,210	9,210		
Net Plant Heat Rate - DMNC ICAP	9,460	9,460	9,460	9,460		
Estimated Startup Fuel Usage, MMBtu						
Start to Base Load	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)		

1x0 GE 7HA.02 tuned to emit 25ppm Gas Only with SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	331	331	331	331		
SO_2	6.8	6.8	6.9	6.9		
CO	72	72	72	72		
CO_2	408,000	410,400	411,600	411,600		
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	26	26	26	26		
SO_2	6.8	6.8	6.9	6.9		
CO	16	16	16	16		
CO_2	408,000	410,400	411,600	411,600		

Notes:

[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.

[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.

[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.

[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.

[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.

[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7HA.02 tuned to emit 25ppm Gas Only with SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$51,910,000	$54,790,000	$55,180,000	$64,140,000		
Materials	$49,220,000	$48,640,000	$53,420,000	$54,430,000		
Turbines or Batteries	$67,000,000	$67,000,000	$67,000,000	$67,000,000		
Other	$56,040,000	$56,810,000	$56,130,000	$56,470,000		
EPC Project Capital Cost Subtotal, 2020$	**$224,170,000**	**$227,240,000**	**$231,730,000**	**$242,040,000**		
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000	$370,000		
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000	$440,000		
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000	$1,020,000		
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000	$1,130,000		
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000	$270,000		
Sales Tax	$0	$0	$0	$0		
Construction Power and Water	$550,000	$550,000	$550,000	$550,000		
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000		
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000		
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000	$23,500,000		
System Deliverability Upgrade Costs	$0	$0	$0	$0		
Water Supply Infrastructure	$0	$0	$0	$0		
Emission Reduction Credits	$70,000	$70,000	$70,000	$400,000		
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000		
Startup/Testing (Fuel & Consumables)	$1,150,000	$1,150,000	$1,150,000	$1,150,000		
Initial Fuel Inventory	$0	$0	$0	$0		
Site Security	$580,000	$580,000	$580,000	$580,000		
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000	$6,500,000		
Builders Risk Insurance (0.45% of Construction Costs)	$1,008,765	$1,022,580	$1,042,785	$1,089,180		
Owner's Contingency (5% for Screening Purposes)	$14,225,438	$14,379,629	$14,605,139	$15,139,459		
Owner's Cost Allowance Subtotal, 2020$	**$74,564,203**	**$74,732,209**	**$74,977,924**	**$75,888,639**		
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%	6.80%		
AFUDC, 2020$						
EPC Portion	$15,243,560	$15,452,320	$15,757,640	$16,458,720		
Non-EPC Portion	$5,070,366	$5,081,790	$5,098,499	$5,160,427		
AFUDC Subtotal, 2020$	**$20,313,926**	**$20,534,110**	**$20,856,139**	**$21,619,147**		
Total Project Costs, 2020$	**$319,048,129**	**$322,506,319**	**$327,564,063**	**$339,547,786**		

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7HA.02 tuned to emit 25ppm Dual Fuel with SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000	$1,300,000		
Fixed O&M Cost - Other	$1,500,000	$1,500,000	$1,500,000	$1,500,000		
Property Insurance Allowance	$1,345,020	$1,363,440	$1,390,380	$1,452,240		
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000		
Total Fixed O&M Cost 2020$/Yr	**$4,075,020**	**$4,193,440**	**$4,520,380**	**$4,582,240**		
Total Fixed O&M Cost 2020$/kW - Yr	**$11.86**	**$12.13**	**$13.03**	**$13.21**		
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600	$600		
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600	$26,600		
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.03	$0.03	$0.03	$0.03		
SCR Related Costs	$0.47	$0.46	$0.46	$0.46		
Other Consumables and Variable O&M	$0.90	$0.90	$0.90	$0.90		
Total Variable O&M - Gas Operation, 2020$/MWh	**$1.40**	**$1.39**	**$1.39**	**$1.39**		

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.
[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.
[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).
[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x0 GE 7HA.02 tuned to emit 15ppm Gas Only without SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1			
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02			
Startup Time to Base Load, min	10 fast / 30 conventional	10 fast / 30 conventional	10 fast / 30 conventional			
Startup Time to MECL, min	8 fast / 24 conventional	8 fast / 24 conventional	8 fast / 24 conventional			
Cold Startup Time to SCR Compliance, min	45	45	45			
Equivalent Forced Outage Rate Demand, %	4.3%	4.3%	4.3%			
Assumed Land Use During Operation, Acres	15	15	15			
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only			
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler			
Heat Rejection	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger	Fin Fan Heat Exchanger			
NOx Control	DLN (Gas)	DLN (Gas)	DLN (Gas)			
CO Control	CO Catalyst	CO Catalyst	CO Catalyst			
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice			
Interconnection Voltage, kV	345	345	345			
Technology Rating	Mature	Mature	Mature			
Permitting & Construction Schedule (Years from FNTP)	3	3	3			
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	338,000	341,200	340,900			
Net Plant Output - Winter Performance	346,100	351,000	350,500			
DMNC Summer	329,300	334,000	331,600			
DMNC Winter	344,700	350,500	350,200			
DMNC ICAP	326,700	328,500	329,900			
Net Plant Heat Rate (HHV Basis), Btu/kWh						
Net Plant Heat Rate - Summer	9,370	9,390	9,390			
Net Plant Heat Rate - Winter	9,320	9,320	9,340			
Net Plant Heat Rate - DMNC Summer	9,470	9,470	9,480			
Net Plant Heat Rate - DMNC Winter	9,250	9,250	9,250			
Net Plant Heat Rate - DMNC ICAP	9,490	9,500	9,490			
Estimated Startup Fuel Usage						
Start to Base Load, MMBtu	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)	240 (fast) / 490 (typ)			

1x0 GE 7HA.02 tuned to emit 15ppm Gas Only without SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs Operating, NO SCR / CO Catalyst (lb/hr, HHV)						
NO_X	189	189	189			
SO_2	6.4	6.4	6.4			
CO	69	69	69			
CO_2	381,600	384,000	385,200			

Notes:
[1] Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
[2] MECL start time assumes the min load at which the GT achieves the steady state NOx emissions ppm rate. The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired SCR emissions.
[3] Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[4] Degraded performance assumed for all scenarios. For frame units, 3% average degradation is assumed. All performance ratings based on natural gas operation. Minimum loads are based on OEM information at requested ambient conditions.
[5] Fuel Oil emissions based on ultra low sulfur diesel. Per the US EPA, this fuel must meet 15 ppm sulfur.
[6] Emissions estimates are shown for steady state operation at ISO conditions.

1x0 GE 7HA.02 tuned to emit 15ppm Gas Only without SCR, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$39,020,000	$41,890,000	$42,010,000			
Materials	$29,530,000	$28,950,000	$34,650,000			
Turbines or Batteries	$67,000,000	$67,000,000	$67,000,000			
Other	$45,180,000	$45,940,000	$44,630,000			
EPC Project Capital Cost Subtotal, 2020$	**$180,730,000**	**$183,780,000**	**$188,290,000**			
Owner's Cost Allowances, 2020$						
Owner's Project Development	$370,000	$370,000	$370,000			
Owner's Operational Personnel Prior to COD	$440,000	$440,000	$440,000			
Owner's Engineer	$1,020,000	$1,020,000	$1,020,000			
Owner's Project Management	$1,130,000	$1,130,000	$1,130,000			
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000			
Owner's Start-up Engineering and Commissioning	$270,000	$270,000	$270,000			
Sales Tax	$0	$0	$0			
Construction Power and Water	$550,000	$550,000	$550,000			
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000			
Switchyard	$10,250,000	$10,250,000	$10,250,000			
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000			
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000			
System Deliverability Upgrade Costs	$0	$0	$0			
Water Supply Infrastructure	$0	$0	$0			
Emission Reduction Credits	$400,000	$400,000	$400,000			
Political Concessions & Area Development	$500,000	$500,000	$500,000			
Startup/Testing (Fuel & Consumables)	$1,150,000	$1,150,000	$1,150,000			
Initial Fuel Inventory	$0	$0	$0			
Site Security	$580,000	$580,000	$580,000			
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000			
Builders Risk Insurance (0.45% of Construction Costs)	$813,285	$827,010	$847,305			
Owner's Contingency (5% for Screening Purposes)	$12,060,164	$12,213,351	$12,439,865			
Owner's Cost Allowance Subtotal, 2020$	**$72,533,449**	**$72,700,361**	**$72,947,170**			
AFUDC as a Percentage of Capital Costs (%)	6.80%	6.80%	6.80%			
AFUDC, 2020$						
EPC Portion	$12,289,640	$12,497,040	$12,803,720			
Non-EPC Portion	$4,932,275	$4,943,625	$4,960,408			
AFUDC Subtotal, 2020$	**$17,221,915**	**$17,440,665**	**$17,764,128**			
Total Project Costs, 2020$	**$270,485,364**	**$273,921,025**	**$279,001,298**			

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated Costs exclude decommissioning costs and salvage values.
[4] Assumes incoming gas pressure of 250 psig. Compression included in EPC scope. Owner's costs include 5 miles pipeline for all zones except Zone J, which assumes 1 mile. 12" pipeline for aero and F class. 16" pipeline for J class.

1x0 GE 7HA.02 tuned to emit 15ppm Gas Only without SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$900,000	$1,000,000	$1,300,000			
Fixed O&M Cost - Other	$1,500,000	$1,500,000	$1,500,000			
Property Insurance Allowance	$1,084,380	$1,102,680	$1,129,740			
Site Leasing Allowance	$330,000	$330,000	$330,000			
Total Fixed O&M Cost 2020$/Yr	**$3,814,380**	**$3,932,680**	**$4,259,740**			
Total Fixed O&M Cost 2020$/kW - Yr	**$11.68**	**$11.97**	**$12.91**			
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600			
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600			
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.03	$0.03	$0.03			
Other Consumables and Variable O&M	$0.90	$0.90	$0.90			
Total Variable O&M - Gas Operation, 2020$/MWh	**$0.93**	**$0.93**	**$0.93**			

Notes:

[1] Fixed O&M costs are presented in 2020 USD $.

[2] FOM costs assume 7 full time personnel. FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM.

[3] Major maintenance $/hr holds for all aero gas turbines. Major maintenance $/hr holds for frame gas turbines where hours per start is >27 (7F.05) or >44.4 (7HA.02).

[4] VOM assumes the use of temporarily trailers for demineralized water treatment.

1x1 GE 7HA.02 Dual Fuel with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1	1	1
Number of Steam Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02
Steam Conditions (Main Steam / Reheat)	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F
Main Steam Pressure	2330	2330	2330	2330	2330	2330
Steam Cycle Type	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Startup Time, Minutes (Cold Start to Unfired Base Load)	180	180	180	180	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load)	120	120	120	120	120	120
Startup Time, Minutes (Hot Start to Unfired Base Load)	80	80	80	80	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance)	60	60	60	60	60	60
Equivalent Forced Outage Rate Demand, %	2.9%	2.9%	2.9%	2.9%	2.9%	2.9%
Assumed Land Use During Operation, Acres	30	30	30	30	27	30
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)	Dual Fuel (Natural Gas and Fuel Oil)
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler
Heat Rejection	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)
NOx Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Interconnection Voltage, kV	345	345	345	345	345	345
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	4	4	4	4	4	4

1x1 GE 7HA.02 Dual Fuel with SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED PERFORMANCE						
Net Plant Capacity - Base Load, kW						
Net Plant Output - Summer Performance	509,900	513,300	514,700	514,700	512,300	517,900
Net Plant Output - Winter Performance	539,200	542,100	544,800	544,800	546,700	547,800
DMNC Summer	486,000	488,300	486,500	486,500	484,700	501,600
DMNC Winter	530,000	532,500	536,300	536,300	544,900	542,600
DMNC ICAP	495,100	498,500	500,600	500,600	502,200	502,500
Net Plant Heat Rate (HHV Basis) - Base Load, Btu/kWh						
Net Plant Heat Rate - Summer	6,370	6,360	6,360	6,360	6,370	6,370
Net Plant Heat Rate - Winter	6,360	6,360	6,350	6,350	6,350	6,340
Net Plant Heat Rate - DMNC Summer	6,410	6,410	6,410	6,410	6,440	6,400
Net Plant Heat Rate - DMNC Winter	6,390	6,390	6,390	6,390	6,380	6,380
Net Plant Heat Rate - DMNC ICAP	6,410	6,400	6,400	6,400	6,410	6,410
Net Plant Capacity - Single Turbine at MECL, kW						
Net Plant Output - Summer Performance	232,100	233,400	234,000	234,000	232,300	235,700
Net Plant Output - Winter Performance	197,000	198,000	198,700	198,700	199,300	199,500
DMNC Summer	216,900	218,300	217,400	217,400	216,500	224,300
DMNC Winter	196,100	197,100	198,400	198,400	200,400	200,000
DMNC ICAP	221,500	223,400	224,400	224,400	225,300	224,900
Net Plant Heat Rate (HHV Basis) - Single Turbine at MECL, Btu/kWh						
Net Plant Heat Rate - Summer	7,130	7,130	7,130	7,130	7,180	7,130
Net Plant Heat Rate - Winter	7,570	7,560	7,550	7,550	7,530	7,540
Net Plant Heat Rate - DMNC Summer	7,370	7,350	7,370	7,370	7,400	7,330
Net Plant Heat Rate - DMNC Winter	7,650	7,650	7,630	7,630	7,590	7,620
Net Plant Heat Rate - DMNC ICAP	7,340	7,320	7,320	7,320	7,320	7,340
Estimated Startup Fuel Usage, MMBtu						
Start to Unfired Base Load (Warm Start)	3,940	3,940	3,940	3,940	3,940	3,940

1x1 GE 7HA.02 Dual Fuel with SCR, Emissions						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	26	26	26	26	26	26
SO_2	6.6	6.7	6.7	6.7	6.8	6.8
CO	16	16	16	16	16	16
CO_2	393,600	403,200	404,400	404,400	406,800	406,800
ESTIMATED BASE LOAD OPERATING EMISSIONS: ULTRA-LOW SULFUR FUEL OIL						
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	96	96	96	96	96	96
SO_2	5.2	5.2	5.2	5.2	5.3	5.3
CO	19	19	19	19	19	19
CO_2	544,000	547,200	548,800	548,800	552,000	552,000

Notes:
[1] Performance ratings were determined using heat balance modeling software. Performance is based on 1.8% average degradation for capacity and 1.1% average degradation for heat rate. All performance is based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions.
[2] The duct firing incremental values note incremental performance output. The incremental heat rate reflects the effective heat rate of the additional output due to the duct burners.
[3] Startup time to stack emissions compliance is not the same as the start time for gas turbine MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.
[4] Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.
[5] Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown.
[6] Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. Fast start packages are not included in CCGT plants.
[7] Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts.

1x1 GE 7HA.02 Dual Fuel with SCR, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$163,310,000	$175,100,000	$189,840,000	$228,420,000	$295,850,000	$291,030,000
Materials	$170,420,000	$170,820,000	$168,290,000	$169,240,000	$171,930,000	$170,670,000
Turbines or Batteries	$68,500,000	$68,500,000	$68,500,000	$68,500,000	$68,500,000	$68,500,000
Other	$134,770,000	$135,130,000	$142,200,000	$145,200,000	$160,190,000	$160,170,000
EPC Project Capital Cost Subtotal, 2020$	**$537,000,000**	**$549,550,000**	**$568,830,000**	**$611,360,000**	**$696,470,000**	**$690,370,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$3,500,000	$3,500,000	$3,500,000	$3,500,000	$4,550,000	$3,850,000
Owner's Operational Personnel Prior to COD	$2,400,000	$2,400,000	$2,400,000	$2,400,000	$3,120,000	$2,640,000
Owner's Engineer	$2,600,000	$2,600,000	$2,600,000	$2,600,000	$3,380,000	$2,860,000
Owner's Project Management	$4,800,000	$4,800,000	$4,800,000	$4,800,000	$6,240,000	$5,280,000
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Owner's Start-up Engineering and Commissioning	$540,000	$540,000	$540,000	$540,000	$700,000	$590,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$1,540,000	$1,540,000	$1,540,000	$1,540,000	$2,000,000	$1,690,000
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,300,000	$1,100,000
Switchyard	$18,940,000	$18,940,000	$18,940,000	$18,940,000	$54,630,000	$18,940,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$11,000,000
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000	$23,500,000	$20,000,000	$23,500,000
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$10,900,000	$0
Emission Reduction Credits	$200,000	$200,000	$200,000	$1,200,000	$1,200,000	$1,200,000
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Startup/Testing (Fuel & Consumables)	$5,450,000	$5,450,000	$5,450,000	$5,450,000	$5,450,000	$5,450,000
Initial Fuel Inventory	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000	$7,240,000
Site Security	$1,100,000	$1,100,000	$1,100,000	$1,100,000	$1,430,000	$1,210,000
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000	$6,500,000	$6,500,000	$6,500,000
Builders Risk Insurance (0.45% of Construction Costs)	$2,416,500	$2,472,975	$2,559,735	$2,751,120	$3,134,115	$3,106,665
Owner's Contingency (5% for Screening Purposes)	$31,561,325	$32,191,649	$33,159,987	$35,346,056	$42,160,206	$39,408,833
Owner's Cost Allowance Subtotal, 2020$	**$125,787,825**	**$126,474,624**	**$127,529,722**	**$130,907,176**	**$188,894,321**	**$137,215,498**
AFUDC as a Percentage of Capital Costs (%)	10.55%	10.55%	10.55%	10.55%	10.55%	10.55%
AFUDC, 2020$						
EPC Portion	$56,653,500	$57,977,525	$60,011,565	$64,498,480	$73,477,585	$72,834,035
Non-EPC Portion	$13,270,616	$13,343,073	$13,454,386	$13,810,707	$19,928,351	$14,476,235
AFUDC Subtotal, 2020$	**$69,924,116**	**$71,320,598**	**$73,465,951**	**$78,309,187**	**$93,405,936**	**$87,310,270**
Total Project Costs, 2020$	**$732,711,941**	**$747,345,222**	**$769,825,672**	**$820,576,363**	**$978,770,257**	**$914,895,768**

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. CCGT unit includes duct firing capability.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated costs exclude decommissioning costs and salvage values.

1x1 GE 7HA.02 Dual Fuel with SCR, O&M Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$2,828,571	$3,142,857	$4,085,714	$4,085,714	$5,342,857	$4,714,286
Fixed O&M Cost - Other	$2,140,000	$2,140,000	$2,140,000	$2,140,000	$2,140,000	$2,140,000
Property Insurance Allowance	$3,222,000	$3,297,300	$3,412,980	$3,668,160	$4,178,820	$4,142,220
Site Leasing Allowance	$660,000	$660,000	$660,000	$660,000	$7,290,000	$780,000
Total Fixed O&M Cost 2020$/Yr	**$8,850,571**	**$9,240,157**	**$10,298,694**	**$10,553,874**	**$18,951,677**	**$11,776,506**
Total Fixed O&M Cost 2020$/kW - Yr	**$17.88**	**$18.54**	**$20.57**	**$21.08**	**$37.74**	**$23.44**
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600	$600	$600	$600
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600	$26,600	$26,600	$26,600
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.05	$0.05	$0.05	$0.05	$0.07	$0.05
SCR Related Costs	$0.32	$0.32	$0.32	$0.32	$0.32	$0.32
Other Consumables and Variable O&M	$1.22	$1.22	$1.22	$1.22	$1.22	$1.21
Total Variable O&M - Gas Operation, 2020$/MWh	**$1.59**	**$1.59**	**$1.59**	**$1.59**	**$1.61**	**$1.58**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - FUEL OIL OPERATION, 2020$/MWh						
Water Related O&M	$0.75	$0.75	$0.75	$0.75	$1.15	$0.78
SCR Related Costs	$0.50	$0.50	$0.50	$0.50	$0.46	$0.48
Other Consumables and Variable O&M	$1.20	$1.20	$1.20	$1.20	$1.23	$1.22
Total Variable O&M - Fuel Oil Operation, 2020$/MWh	**$2.45**	**$2.45**	**$2.45**	**$2.45**	**$2.84**	**$2.48**

Notes:
[1] Variable O&M costs are based on performance at annual average conditions.
[2] Fixed O&M costs are presented in 2020 USD $.
[3] Fixed O&M assumes 22 FTE for a 1x1 configuration.
[4] Variable O&M costs assume onsite demineralized water treatment system (included in EPC cost).

1x1 GE 7HA.02 Gas Only with SCR, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Number of Gas Turbines	1	1	1	1		
Number of Steam Turbines	1	1	1	1		
Representative Class Gas Turbine	GE 7HA.02	GE 7HA.02	GE 7HA.02	GE 7HA.02		
Steam Conditions (Main Steam / Reheat)	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F	1,085°F / 1,085°F		
Main Steam Pressure	2,330	2,330	2,330	2,330		
Steam Cycle Type	Subcritical	Subcritical	Subcritical	Subcritical		
Startup Time, Minutes (Cold Start to Unfired Base Load)	180	180	180	180		
Startup Time, Minutes (Warm Start to Unfired Base Load)	120	120	120	120		
Startup Time, Minutes (Hot Start to Unfired Base Load)	80	80	80	80		
Startup Time, Minutes (Cold Start to Stack Emissions Compliance)	60	60	60	60		
Equivalent Forced Outage Rate Demand, %	3%	3%	3%	3%		
Assumed Land Use During Operation, Acres	30	30	30	30		
Fuel Design	Natural Gas Only	Natural Gas Only	Natural Gas Only	Natural Gas Only		
Inlet Conditioning	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler	Evaporative Cooler		
Heat Rejection	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)	Air Cooled Condenser (ACC)		
NO_x Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR		
CO Control	CO Catalyst	CO Catalyst	CO Catalyst	CO Catalyst		
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice		
Interconnection Voltage, kV	345	345	345	345		
Technology Rating	Mature	Mature	Mature	Mature		
Permitting & Construction Schedule (Years from FNTP)	4	4	4	4		

1x1 GE 7HA.02 Gas Only with SCR, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED PERFORMANCE						
Net Plant Capacity - Base Load, kW						
Net Plant Output - Summer Performance	509,900	513,300	514,700	514,700		
Net Plant Output - Winter Performance	539,200	542,100	544,800	544,800		
DMNC Summer	486,000	488,300	486,500	486,500		
DMNC Winter	530,000	532,500	536,300	536,300		
DMNC ICAP	495,100	498,500	500,600	500,600		
Net Plant Heat Rate (HHV Basis) - Base Load, Btu/kWh						
Net Plant Heat Rate - Summer	6,370	6,360	6,360	6,360		
Net Plant Heat Rate - Winter	6,360	6,360	6,350	6,350		
Net Plant Heat Rate - DMNC Summer	6,410	6,410	6,410	6,410		
Net Plant Heat Rate - DMNC Winter	6,390	6,390	6,390	6,390		
Net Plant Heat Rate - DMNC ICAP	6,410	6,400	6,400	6,400		
Net Plant Capacity - Single Turbine at MECL, kW						
Net Plant Output - Summer Performance	232,100	233,400	234,000	234,000		
Net Plant Output - Winter Performance	197,000	198,000	198,700	198,700		
DMNC Summer	216,900	218,300	217,400	217,400		
DMNC Winter	196,100	197,100	198,400	198,400		
DMNC ICAP	221,500	223,400	224,400	224,400		
Net Plant Heat Rate (HHV Basis) - Single Turbine at MECL, Btu/kWh						
Net Plant Heat Rate - Summer	7,130	7,130	7,130	7,130		
Net Plant Heat Rate - Winter	7,570	7,560	7,550	7,550		
Net Plant Heat Rate - DMNC Summer	7,370	7,350	7,370	7,370		
Net Plant Heat Rate - DMNC Winter	7,650	7,650	7,630	7,630		
Net Plant Heat Rate - DMNC ICAP	7,340	7,320	7,320	7,320		
Estimated Startup Fuel Usage, MMBtu						
Start to Unfired Base Load (Warm Start)	3,940	3,940	3,940	3,940		

1x1 GE 7HA.02 Gas Only with SCR, Emissions						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS						
All GTs with SCR and CO Catalyst (lb/hr, HHV)						
NO_X	26	26	26	26		
SO_2	6.6	6.7	6.7	6.7		
CO	16	16	16	16		
CO_2	393,600	403,200	404,400	404,400		

Notes:

[1] Performance ratings were determined using heat balance modeling software. Performance is based on 1.8% average degradation for capacity and 1.1% average degradation for heat rate. All performance is based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions.

[2] The duct firing incremental values note incremental performance output. The incremental heat rate reflects the effective heat rate of the additional output due to the duct burners.

[3] Startup time to stack emissions compliance is not the same as the start time for gas turbine MECL. Stack emissions compliance is expected to be limited by the temperature of the CO catalyst, which impacts VOC emissions.

[4] Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2010 or later. Reporting period is 2012-2019.

[5] Cold start is >72 hours after shutdown. Hot start is <8 hours after shutdown.

[6] Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. Fast start packages are not included in CCGT plants.

[7] Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of SCR and CO catalysts.

1x1 GE 7HA.02 Gas Only with SCR, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$154,980,000	$166,400,000	$180,770,000	$218,360,000		
Materials	$161,720,000	$162,330,000	$160,250,000	$161,790,000		
Turbines or Batteries	$67,000,000	$67,000,000	$67,000,000	$67,000,000		
Other	$127,900,000	$128,420,000	$135,410,000	$138,810,000		
EPC Project Capital Cost Subtotal, 2020$	**$511,600,000**	**$524,150,000**	**$543,430,000**	**$585,960,000**		
Owner's Cost Allowances, 2020$						
Owner's Project Development	$3,500,000	$3,500,000	$3,500,000	$3,500,000		
Owner's Operational Personnel Prior to COD	$2,400,000	$2,400,000	$2,400,000	$2,400,000		
Owner's Engineer	$2,600,000	$2,600,000	$2,600,000	$2,600,000		
Owner's Project Management	$4,800,000	$4,800,000	$4,800,000	$4,800,000		
Owner's Legal Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Owner's Start-up Engineering and Commissioning	$540,000	$540,000	$540,000	$540,000		
Sales Tax	$0	$0	$0	$0		
Construction Power and Water	$1,540,000	$1,540,000	$1,540,000	$1,540,000		
Permitting and Licensing Fees	$1,000,000	$1,000,000	$1,000,000	$1,000,000		
Switchyard	$18,940,000	$18,940,000	$18,940,000	$18,940,000		
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000		
Gas Interconnection and Reinforcement	$23,500,000	$23,500,000	$23,500,000	$23,500,000		
System Deliverability Upgrade Costs	$0	$0	$0	$0		
Water Supply Infrastructure	$0	$0	$0	$0		
Emission Reduction Credits	$200,000	$200,000	$200,000	$1,200,000		
Political Concessions & Area Development	$500,000	$500,000	$500,000	$500,000		
Startup/Testing (Fuel & Consumables)	$1,150,000	$1,150,000	$1,150,000	$1,150,000		
Initial Fuel Inventory	$0	$0	$0	$0		
Site Security	$1,100,000	$1,100,000	$1,100,000	$1,100,000		
Operating Spare Parts	$6,500,000	$6,500,000	$6,500,000	$6,500,000		
Builders Risk Insurance (0.45% of Construction Costs)	$2,302,200	$2,358,675	$2,445,435	$2,636,820		
Owner's Contingency (5% for Screening Purposes)	$29,708,610	$30,338,934	$31,307,272	$33,493,341		
Owner's Cost Allowance Subtotal, 2020$	**$112,280,810**	**$112,967,609**	**$114,022,707**	**$117,400,161**		
AFUDC as a Percentage of Capital Costs (%)	10.55%	10.55%	10.55%	10.55%		
AFUDC, 2020$						
EPC Portion	$53,973,800	$55,297,825	$57,331,865	$61,818,780		
Non-EPC Portion	$11,845,625	$11,918,083	$12,029,396	$12,385,717		
AFUDC Subtotal, 2020$	**$65,819,425**	**$67,215,908**	**$69,361,261**	**$74,204,497**		
Total Project Costs, 2020$	**$689,700,235**	**$704,333,516**	**$726,813,967**	**$777,564,658**		

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes gas, water, sewer, communications are available at plant fenceline. CCGT unit includes duct firing capability.
[2] Capital costs are presented in 2020 USD $.
[3] Estimated costs exclude decommissioning costs and salvage values.

1x1 GE 7HA.02 Gas Only with SCR, O&M Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Labor	$2,828,571	$3,142,857	$4,085,714	$4,085,714		
Fixed O&M Cost - Other	$2,140,000	$2,140,000	$2,140,000	$2,140,000		
Property Insurance Allowance	$3,069,600	$3,144,900	$3,260,580	$3,515,760		
Site Leasing Allowance	$660,000	$660,000	$660,000	$660,000		
Total Fixed O&M Cost 2020$/Yr	**$8,698,171**	**$9,087,757**	**$10,146,294**	**$10,401,474**		
Total Fixed O&M Cost 2020$/kW - Yr	**$17.57**	**$18.23**	**$20.27**	**$20.78**		
LEVELIZED MAJOR MAINTENANCE COSTS						
Major Maintenance Cost, 2020$/GT-hr or $/engine-hr	$600	$600	$600	$600		
Major Maintenance Cost, 2020$/GT-start	$26,600	$26,600	$26,600	$26,600		
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - GAS OPERATION, 2020$/MWh						
Water Related O&M	$0.05	$0.05	$0.05	$0.05		
SCR Related Costs	$0.32	$0.32	$0.32	$0.32		
Other Consumables and Variable O&M	$1.22	$1.22	$1.22	$1.22		
Total Variable O&M - Gas Operation, 2020$/MWh	**$1.59**	**$1.59**	**$1.59**	**$1.59**		

Notes:
[1] Variable O&M costs are based on performance at annual average conditions.
[2] Fixed O&M costs are presented in 2020 USD $.
[3] Fixed O&M assumes 22 FTE for a 1x1 configuration.
[4] Variable O&M costs assume onsite demineralized water treatment system (included in EPC cost).

BESS 4h Battery, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	4	4	4	4	4	4
Assumed Useful Life (years)	20	20	20	20	20	20
Equivalent Planned Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Forced Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Availability Factor (%)	97%	97%	97%	97%	97%	97%
Assumed Land Use During Operation, Acres	12	12	12	12	9	12
Heat Rejection	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC
Annual System Cycles	350	350	350	350	350	350
Storage System Initial Overbuild (%)	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%
Storage System Degradation (%/yr)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2	2	2	2	2	2
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	200,000	200,000	200,000	200,000	200,000	200,000
Net Plant Output - Winter Performance	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Summer	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Winter	200,000	200,000	200,000	200,000	200,000	200,000
DMNC ICAP	200,000	200,000	200,000	200,000	200,000	200,000
Output Duration, hrs						
Output Duration - Summer	4	4	4	4	4	4
Output Duration - Winter	4	4	4	4	4	4
Output Duration - DMNC Summer	4	4	4	4	4	4
Output Duration - DMNC Winter	4	4	4	4	4	4
Output Duration - DMNC ICAP	4	4	4	4	4	4
Net Plant Energy Capacity, kWh						
Net Plant Energy Capacity - Summer	800,000	800,000	800,000	800,000	800,000	800,000
Net Plant Energy Capacity - Winter	800,000	800,000	800,000	800,000	800,000	800,000
Net Plant Energy Capacity - DMNC Summer	800,000	800,000	800,000	800,000	800,000	800,000
Net Plant Energy Capacity - DMNC Winter	800,000	800,000	800,000	800,000	800,000	800,000
Net Plant Energy Capacity - DMNC ICAP	800,000	800,000	800,000	800,000	800,000	800,000

Notes:

[1] NERC GADS performance statistics are not available for battery storage technologies. Availability and outage rate assumptions are based on vendor correspondence and industry publications.

BESS 4h Battery, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$28,380,000	$30,470,000	$32,280,000	$41,220,000	$53,470,000	$52,570,000
Materials	$42,530,000	$42,730,000	$42,600,000	$43,260,000	$44,330,000	$43,710,000
Turbines or Batteries	$139,800,000	$139,800,000	$139,800,000	$139,800,000	$139,800,000	$139,800,000
Other	$40,130,000	$40,270,000	$40,880,000	$41,140,000	$43,580,000	$43,300,000
EPC Project Capital Cost Subtotal, 2020$	**$250,840,000**	**$253,270,000**	**$255,560,000**	**$265,420,000**	**$281,180,000**	**$279,380,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$170,000	$170,000	$170,000	$170,000	$220,000	$190,000
Owner's Operational Personnel Prior to COD	$110,000	$110,000	$110,000	$110,000	$140,000	$120,000
Owner's Engineer	$190,000	$190,000	$190,000	$190,000	$250,000	$210,000
Owner's Project Management	$350,000	$350,000	$350,000	$350,000	$460,000	$390,000
Owner's Legal Costs	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Owner's Start-up Engineering and Commissioning	$70,000	$70,000	$70,000	$70,000	$90,000	$80,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$450,000	$450,000	$450,000	$450,000	$590,000	$500,000
Permitting and Licensing Fees	$250,000	$250,000	$250,000	$250,000	$330,000	$280,000
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000	$43,800,000	$5,590,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$0	$0	$0	$0	$0	$0
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$0	$0
Emission Reduction Credits	$0	$0	$0	$0	$0	$0
Political Concessions & Area Development	$100,000	$100,000	$100,000	$100,000	$130,000	$110,000
Startup/Testing (Fuel & Consumables)	$0	$0	$0	$0	$0	$0
Initial Fuel Inventory	$0	$0	$0	$0	$0	$0
Site Security	$370,000	$370,000	$370,000	$370,000	$480,000	$410,000
Operating Spare Parts	$770,000	$770,000	$770,000	$770,000	$770,000	$770,000
Builders Risk Insurance (0.45% of Construction Costs)	$1,128,780	$1,139,715	$1,150,020	$1,194,390	$1,265,310	$1,257,210
Owner's Contingency (5% for Screening Purposes)	$13,827,439	$13,949,486	$14,064,501	$14,559,720	$17,168,266	$14,816,861
Owner's Cost Allowance Subtotal, 2020$	**$39,536,219**	**$39,669,201**	**$39,794,521**	**$40,334,110**	**$79,353,576**	**$31,774,071**
AFUDC as a Percentage of Capital Costs (%)	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
AFUDC, 2020$						
EPC Portion	$14,147,376	$14,284,428	$14,413,584	$14,969,688	$15,858,552	$15,757,032
Non-EPC Portion	$2,229,843	$2,776,900	$2,785,300	$2,823,100	$5,555,200	$2,224,600
AFUDC Subtotal, 2020$	**$16,377,219**	**$17,061,328**	**$17,198,884**	**$17,792,788**	**$21,413,752**	**$17,981,632**
Total Project Costs, 2020$	**$306,753,438**	**$310,000,529**	**$312,553,405**	**$323,546,898**	**$381,947,328**	**$329,135,703**

Notes:
[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes utilities are available at plant fenceline.
[2] EPC cost includes initial overbuild to account for stystem losses, minimum state of charge, auxiliaries, and first year of assumed degradation.
[3] Estimated Costs exclude decommisioning costs and salvage values.

BESS 4h Battery, O&M Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Augmentation (via LTSA)	$1,140,000	$1,140,000	$1,140,000	$1,140,000	$1,140,000	$1,140,000
Property Insurance Allowance	$1,505,040	$1,519,620	$1,533,360	$1,592,520	$1,687,080	$1,676,280
Site Leasing Allowance	$260,000	$260,000	$260,000	$260,000	$2,430,000	$310,000
Total Fixed O&M Cost 2020$/Yr	**$3,905,040**	**$3,919,620**	**$3,933,360**	**$3,992,520**	**$6,257,080**	**$4,126,280**
Total Fixed O&M Cost 2020$/kW - Yr	**$19.53**	**$19.60**	**$19.67**	**$19.96**	**$31.29**	**$20.63**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - BATTERY OPERATION, 2020$/MWh						
Capacity Augmentation (via LTSA) Levelized	$8.12	$8.12	$8.12	$8.12	$8.12	$8.12
Total Variable Variable O&M - Battery Operation, 2020$/MWh	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**

Notes:
[1] Battery FOM accounts for routine system maintenance and assumes the site is remotely controlled.
[2] Variable O&M is modeled to account for augmentation for assumed capacity requirement (costs are levelized).

BESS 6h Battery, Performance						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	6	6	6	6	6	6
Assumed Useful Life (years)	20	20	20	20	20	20
Equivalent Planned Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Forced Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Availability Factor (%)	97%	97%	97%	97%	97%	97%
Assumed Land Use During Operation, Acres	15	15	15	15	12	15
Heat Rejection	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC
Annual System Cycles	350	350	350	350	350	350
Storage System Initial Overbuild (%)	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%
Storage System Degradation (%/yr)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2	2	2	2	2	2
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	200,000	200,000	200,000	200,000	200,000	200,000
Net Plant Output - Winter Performance	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Summer	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Winter	200,000	200,000	200,000	200,000	200,000	200,000
DMNC ICAP	200,000	200,000	200,000	200,000	200,000	200,000
Output Duration, hrs						
Output Duration - Summer	6	6	6	6	6	6
Output Duration - Winter	6	6	6	6	6	6
Output Duration - DMNC Summer	6	6	6	6	6	6
Output Duration - DMNC Winter	6	6	6	6	6	6
Output Duration - DMNC ICAP	6	6	6	6	6	6
Net Plant Energy Capacity, kWh						
Net Plant Energy Capacity - Summer	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Net Plant Energy Capacity - Winter	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Net Plant Energy Capacity - DMNC Summer	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Net Plant Energy Capacity - DMNC Winter	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Net Plant Energy Capacity - DMNC ICAP	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000

Notes:

[1] NERC GADS performance statistics are not available for battery storage technologies. Availability and outage rate assumptions are based on vendor correspondence and industry publications.

BESS 6h Battery, Capital Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$40,830,000	$43,410,000	$45,950,000	$59,310,000	$76,840,000	$75,640,000
Materials	$52,700,000	$53,100,000	$53,290,000	$53,850,000	$55,480,000	$54,640,000
Turbines or Batteries	$209,700,000	$209,700,000	$209,700,000	$209,700,000	$209,700,000	$209,700,000
Other	$55,630,000	$56,160,000	$56,660,000	$56,970,000	$60,360,000	$60,000,000
EPC Project Capital Cost Subtotal, 2020$	**$358,860,000**	**$362,370,000**	**$365,600,000**	**$379,830,000**	**$402,380,000**	**$399,980,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$170,000	$170,000	$170,000	$170,000	$220,000	$190,000
Owner's Operational Personnel Prior to COD	$110,000	$110,000	$110,000	$110,000	$140,000	$120,000
Owner's Engineer	$230,000	$230,000	$230,000	$230,000	$300,000	$250,000
Owner's Project Management	$410,000	$410,000	$410,000	$410,000	$530,000	$450,000
Owner's Legal Costs	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Owner's Start-up Engineering and Commissioning	$140,000	$140,000	$140,000	$140,000	$180,000	$150,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$510,000	$510,000	$510,000	$510,000	$660,000	$560,000
Permitting and Licensing Fees	$250,000	$250,000	$250,000	$250,000	$330,000	$280,000
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000	$43,800,000	$5,590,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$0	$0	$0	$0	$0	$0
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$0	$0
Emission Reduction Credits	$0	$0	$0	$0	$0	$0
Political Concessions & Area Development	$100,000	$100,000	$100,000	$100,000	$130,000	$110,000
Startup/Testing (Fuel & Consumables)	$0	$0	$0	$0	$0	$0
Initial Fuel Inventory	$0	$0	$0	$0	$0	$0
Site Security	$440,000	$440,000	$440,000	$440,000	$570,000	$480,000
Operating Spare Parts	$1,120,000	$1,120,000	$1,120,000	$1,120,000	$1,120,000	$1,120,000
Builders Risk Insurance (0.45% of Construction Costs)	$1,614,870	$1,630,665	$1,645,200	$1,709,235	$1,810,710	$1,799,910
Owner's Contingency (5% for Screening Purposes)	$19,285,244	$19,461,533	$19,623,760	$20,338,462	$23,291,536	$20,906,496
Owner's Cost Allowance Subtotal, 2020$	**$46,130,114**	**$46,322,198**	**$46,498,960**	**$47,277,697**	**$86,742,246**	**$39,056,406**
AFUDC as a Percentage of Capital Costs (%)	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
AFUDC, 2020$						
EPC Portion	$20,239,704	$20,437,668	$20,619,840	$21,422,412	$22,694,232	$22,558,872
Non-EPC Portion	$2,601,738	$3,242,400	$3,255,000	$3,309,600	$6,071,800	$2,734,200
AFUDC Subtotal, 2020$	**$22,841,442**	**$23,680,068**	**$23,874,840**	**$24,732,012**	**$28,766,032**	**$25,293,072**
Total Project Costs, 2020$	**$427,831,556**	**$432,372,266**	**$435,973,800**	**$451,839,709**	**$517,888,278**	**$464,329,478**

Notes:

[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes utilities are available at plant fenceline.

[2] EPC cost includes initial overbuild to account for stystem losses, minimum state of charge, auxiliaries, and first year of assumed degradation.

[3] Estimated Costs exclude decommisioning costs and salvage values.

BESS 6h Battery, O&M Costs						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM	$1,240,000	$1,240,000	$1,240,000	$1,240,000	$1,240,000	$1,240,000
Augmentation (via LTSA)	$1,710,000	$1,710,000	$1,710,000	$1,710,000	$1,710,000	$1,710,000
Property Insurance Allowance	$2,153,160	$2,174,220	$2,193,600	$2,278,980	$2,414,280	$2,399,880
Site Leasing Allowance	$330,000	$330,000	$330,000	$330,000	$3,240,000	$390,000
Total Fixed O&M Cost 2020$/Yr	**$5,433,160**	**$5,454,220**	**$5,473,600**	**$5,558,980**	**$8,604,280**	**$5,739,880**
Total Fixed O&M Cost 2020$/kW - Yr	**$27.17**	**$27.27**	**$27.37**	**$27.79**	**$43.02**	**$28.70**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - BATTERY OPERATION, 2020$/MWh						
Capacity Augmentation (via LTSA) Levelized	$8.12	$8.12	$8.12	$8.12	$8.12	$8.12
Total Variable Variable O&M - Battery Operation, 2020$/MWh	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**

Notes:
[1] Battery FOM accounts for routine system maintenance and assumes the site is remotely controlled.
[2] Variable O&M is modeled to account for augmentation for assumed capacity requirement (costs are levelized).

BESS 8h Battery, Performance						
	ZONE C - Central	**ZONE F - Capital**	**ZONE G - Dutchess**	**ZONE G - Rockland**	**ZONE J - NYC**	**ZONE K - Long Island**
BASE PLANT DESCRIPTION						
Nominal Output, MW	200	200	200	200	200	200
Nominal Duration, hr	8	8	8	8	8	8
Assumed Useful Life (years)	20	20	20	20	20	20
Equivalent Planned Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Forced Outage Rate (%)	< 3%	< 3%	< 3%	< 3%	< 3%	< 3%
Equivalent Availability Factor (%)	97%	97%	97%	97%	97%	97%
Assumed Land Use During Operation, Acres	18	18	18	18	15	18
Heat Rejection	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC	Air-cooled HVAC
Annual System Cycles	350	350	350	350	350	350
Storage System Initial Overbuild (%)	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%
Storage System Degradation (%/yr)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	85%	85%	85%
Interconnection Voltage, kV	345	345	345	345	345	138
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2	2	2	2	2	2
ESTIMATED PERFORMANCE						
Net Plant Capacity, kW						
Net Plant Output - Summer Performance	200,000	200,000	200,000	200,000	200,000	200,000
Net Plant Output - Winter Performance	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Summer	200,000	200,000	200,000	200,000	200,000	200,000
DMNC Winter	200,000	200,000	200,000	200,000	200,000	200,000
DMNC ICAP	200,000	200,000	200,000	200,000	200,000	200,000
Output Duration, hrs						
Output Duration - Summer	8	8	8	8	8	8
Output Duration - Winter	8	8	8	8	8	8
Output Duration - DMNC Summer	8	8	8	8	8	8
Output Duration - DMNC Winter	8	8	8	8	8	8
Output Duration - DMNC ICAP	8	8	8	8	8	8
Net Plant Energy Capacity, kWh						
Net Plant Energy Capacity - Summer	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Net Plant Energy Capacity - Winter	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Net Plant Energy Capacity - DMNC Summer	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Net Plant Energy Capacity - DMNC Winter	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000
Net Plant Energy Capacity - DMNC ICAP	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000

Notes:

[1] NERC GADS performance statistics are not available for battery storage technologies. Availability and outage rate assumptions are based on vendor correspondence and industry publications.

BESS 8h Battery, Capital Costs						
	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2020$ (w/o Owner's Costs)						
Labor	$53,290,000	$56,640,000	$59,960,000	$77,390,000	$100,210,000	$98,710,000
Materials	$62,500,000	$63,050,000	$63,260,000	$64,300,000	$67,800,000	$66,730,000
Turbines or Batteries	$279,600,000	$279,600,000	$279,600,000	$279,600,000	$279,600,000	$279,600,000
Other	$71,420,000	$72,130,000	$72,770,000	$72,900,000	$75,900,000	$75,470,000
EPC Project Capital Cost Subtotal, 2020$	**$466,810,000**	**$471,420,000**	**$475,590,000**	**$494,190,000**	**$523,510,000**	**$520,510,000**
Owner's Cost Allowances, 2020$						
Owner's Project Development	$170,000	$170,000	$170,000	$170,000	$220,000	$190,000
Owner's Operational Personnel Prior to COD	$110,000	$110,000	$110,000	$110,000	$140,000	$120,000
Owner's Engineer	$260,000	$260,000	$260,000	$260,000	$340,000	$290,000
Owner's Project Management	$480,000	$480,000	$480,000	$480,000	$620,000	$530,000
Owner's Legal Costs	$500,000	$500,000	$500,000	$500,000	$650,000	$550,000
Owner's Start-up Engineering and Commissioning	$180,000	$180,000	$180,000	$180,000	$230,000	$200,000
Sales Tax	$0	$0	$0	$0	$0	$0
Construction Power and Water	$550,000	$550,000	$550,000	$550,000	$720,000	$610,000
Permitting and Licensing Fees	$250,000	$250,000	$250,000	$250,000	$330,000	$280,000
Switchyard	$10,250,000	$10,250,000	$10,250,000	$10,250,000	$43,800,000	$5,590,000
Electrical Interconnection and Deliverability	$11,000,000	$11,000,000	$11,000,000	$11,000,000	$13,010,000	$6,500,000
Gas Interconnection and Reinforcement	$0	$0	$0	$0	$0	$0
System Deliverability Upgrade Costs	$0	$0	$0	$0	$0	$0
Water Supply Infrastructure	$0	$0	$0	$0	$0	$0
Emission Reduction Credits	$0	$0	$0	$0	$0	$0
Political Concessions & Area Development	$100,000	$100,000	$100,000	$100,000	$130,000	$110,000
Startup/Testing (Fuel & Consumables)	$0	$0	$0	$0	$0	$0
Initial Fuel Inventory	$0	$0	$0	$0	$0	$0
Site Security	$510,000	$510,000	$510,000	$510,000	$660,000	$560,000
Operating Spare Parts	$1,470,000	$1,470,000	$1,470,000	$1,470,000	$1,470,000	$1,470,000
Builders Risk Insurance (0.45% of Construction Costs)	$2,100,645	$2,121,390	$2,140,155	$2,223,855	$2,355,795	$2,342,295
Owner's Contingency (5% for Screening Purposes)	$24,737,032	$24,968,570	$25,178,008	$26,112,193	$29,409,290	$26,992,615
Owner's Cost Allowance Subtotal, 2020$	**$52,667,677**	**$52,919,960**	**$53,148,163**	**$54,166,048**	**$94,085,085**	**$46,334,910**
AFUDC as a Percentage of Capital Costs (%)	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
AFUDC, 2020$						
EPC Portion	$26,328,084	$26,588,088	$26,823,276	$27,872,316	$29,525,964	$29,356,764
Non-EPC Portion	$2,970,457	$3,704,400	$3,720,500	$3,791,200	$6,586,300	$3,243,100
AFUDC Subtotal, 2020$	**$29,298,541**	**$30,292,488**	**$30,543,776**	**$31,663,516**	**$36,112,264**	**$32,599,864**
Total Project Costs, 2020$	**$548,776,218**	**$554,632,448**	**$559,281,939**	**$580,019,564**	**$653,707,349**	**$599,444,774**

Notes:

[1] Capital cost assumes EPC full wrap methodology. EPC electrical scope ends at the high side of the GSU. Assumes utilities are available at plant fenceline.

[2] EPC cost includes initial overbuild to account for stystem losses, minimum state of charge, auxiliaries, and first year of assumed degradation.

[3] Estimated Costs exclude decommisioning costs and salvage values.

BESS 8h Battery, O&M Costs	ZONE C - Central	ZONE F - Capital	ZONE G - Dutchess	ZONE G - Rockland	ZONE J - NYC	ZONE K - Long Island
FIXED O&M COSTS, 2020$/Yr						
Fixed O&M Cost - Assumes LTSA with Integrator/OEM	$1,490,000	$1,490,000	$1,490,000	$1,490,000	$1,490,000	$1,490,000
Augmentation (via LTSA)	$2,280,000	$2,280,000	$2,280,000	$2,280,000	$2,280,000	$2,280,000
Property Insurance Allowance	$2,800,860	$2,828,520	$2,853,540	$2,965,140	$3,141,060	$3,123,060
Site Leasing Allowance	$400,000	$400,000	$400,000	$400,000	$4,050,000	$470,000
Total Fixed O&M Cost 2020$/Yr	**$6,970,860**	**$6,998,520**	**$7,023,540**	**$7,135,140**	**$10,961,060**	**$7,363,060**
Total Fixed O&M Cost 2020$/kW - Yr	**$34.85**	**$34.99**	**$35.12**	**$35.68**	**$54.81**	**$36.82**
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE) - BATTERY OPERATION, 2020$/MWh						
Capacity Augmentation (via LTSA) Levelized	$8.12	$8.12	$8.12	$8.12	$8.12	$8.12
Total Variable Variable O&M - Battery Operation, 2020$/MWh	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**	**$8.12**

Notes:
[1] Battery FOM accounts for routine system maintenance and assumes the site is remotely controlled.
[2] Variable O&M is modeled to account for augmentation for assumed capacity requirement (costs are levelized).

B. Additional Detail on Financing Parameters

This appendix provides additional detail on the data presented in Section III.

The first table provides detail on each debt issuance shown in Figure 5. The second figure includes additional detail on the data used to estimate the risk free rate within the CAPM model and Table 36.

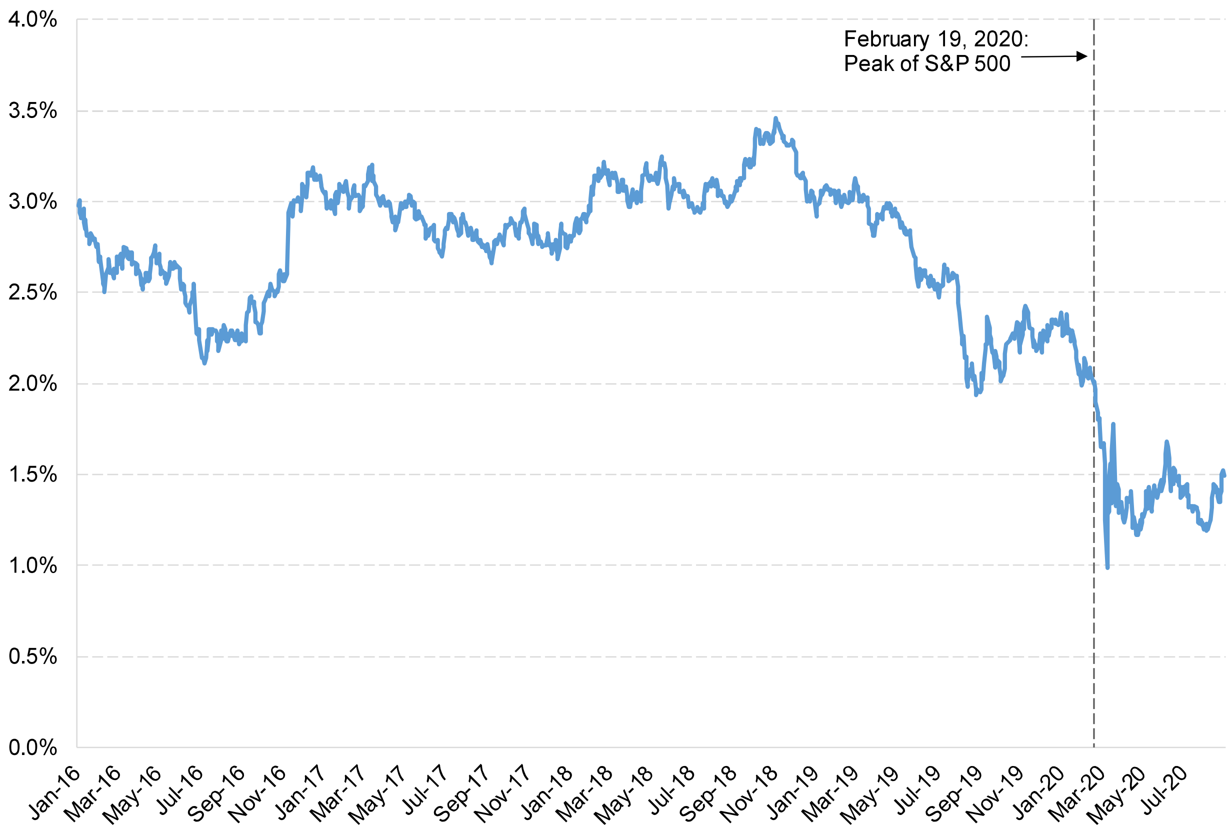
Appendix B Table 1: Additional Detail on Cost of Debt for Independent Power Producers by Issuance, 2017 – 2019

Company	Ticker	Maturity Type	Currency	Bloomberg Composite Rating	Coupon	Issue Date	Maturity	Years to Maturity
Calpine Corp	CPN	CALLABLE	USD	BB	5.3%	12/15/2017	6/1/2026	8.5
Calpine Corp	CPN	CALLABLE	USD	BB	4.5%	12/20/2019	2/15/2028	8.2
Calpine Corp	CPN	CALLABLE	USD	BB	4.5%	12/20/2019	2/15/2028	8.2
Calpine Corp	CPN	CALLABLE	USD	B	5.1%	12/27/2019	3/15/2028	8.2
Calpine Corp	CPN	CALLABLE	USD	B	5.1%	12/27/2019	3/15/2028	8.2
NRG Energy	NRG	CALLABLE	USD	BB	7.3%	2/14/2017	5/15/2026	9.3
NRG Energy	NRG	CALLABLE	USD	BB	6.6%	4/18/2017	1/15/2027	9.8
NRG Energy	NRG	CALLABLE	USD	BB	5.8%	12/7/2017	1/15/2028	10.1
NRG Energy	NRG	CALLABLE	USD	BB	5.8%	12/7/2017	1/15/2028	10.1
NRG Energy	NRG	CALLABLE	USD	BB	5.8%	10/30/2018	1/15/2028	9.2
NRG Energy	NRG	CALLABLE	USD	BB	5.3%	5/14/2019	6/15/2029	10.1
NRG Energy	NRG	CALLABLE	USD	BB	5.3%	5/14/2019	6/15/2029	10.1
NRG Energy	NRG	CALLABLE	USD	BB	5.3%	5/14/2019	6/15/2029	10.1
Talen Energy	TLN	CALLABLE	USD	B-	9.5%	4/13/2017	7/15/2022	5.3
Talen Energy	TLN	CALLABLE	USD	B-	9.5%	4/13/2017	7/15/2022	5.3
Talen Energy	TLN	CALLABLE	USD	B-	6.5%	8/4/2017	9/15/2024	7.1
Talen Energy	TLN	CALLABLE	USD	B-	6.5%	8/4/2017	9/15/2024	7.1
Talen Energy	TLN	CALLABLE	USD	B-	7.0%	10/11/2017	10/15/2027	10.0
Talen Energy	TLN	CALLABLE	USD	B-	10.5%	11/29/2017	1/15/2026	8.1
Talen Energy	TLN	CALLABLE	USD	B-	10.5%	11/29/2017	1/15/2026	8.1
Talen Energy	TLN	CALLABLE	USD	B+	7.3%	5/21/2019	5/15/2027	8.0
Talen Energy	TLN	CALLABLE	USD	B+	7.3%	5/21/2019	5/15/2027	8.0
Talen Energy	TLN	CALLABLE	USD	B+	6.6%	7/8/2019	1/15/2028	8.5
Talen Energy	TLN	CALLABLE	USD	B+	6.6%	7/8/2019	1/15/2028	8.5
Vistra Energy Corp	VST	CALLABLE	USD	BB	8.1%	8/21/2017	1/30/2026	8.4
Vistra Energy Corp	VST	CALLABLE	USD	BB	8.1%	8/21/2017	1/30/2026	8.4
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.5%	8/22/2018	9/1/2026	8.0
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.5%	8/22/2018	9/1/2026	8.0
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.6%	2/6/2019	2/15/2027	8.0
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.6%	2/6/2019	2/15/2027	8.0
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.0%	6/21/2019	7/31/2027	8.1
Vistra Energy Corp	VST	CALLABLE	USD	BB	5.0%	6/21/2019	7/31/2027	8.1

Source:
[1] Bloomberg, L.P.

Appendix B Figure 1 provides additional detail on the risk free rate used in the CAPM model. AGI used a 1.88% risk free rate based on the 30-year Treasury Constant Maturity Rate. This rate reflects the average 30-year treasury yields over the period from January 2016-January 2020, the impact on the COVID-19 pandemic on risk-free rates, and the expectation of some recovery in financial markets after 2020. Over the three-year period from January 2016 to January 2020, the average 30-year treasury constant maturity rate was 2.78%. Over the seven-month period from February 2020 to August 2020, the average 30-year treasury constant maturity rate was 1.45%.

Appendix B Figure 1: Historical 30 Year Treasury Constant Maturity Rate
January 2016 - August 2020



Source:
[1] St. Louis Federal Reserve Bank of St. Louis, FRED.

C. Additional Detail on Level of Excess Adjustment Factors

This appendix provides additional detail on the data presented in Section IV. The table below shows the level of excess adjustment factors used in the net EAS revenues model.

Load Zone	Peak Period	January	February	March	April	May	June	July	August	September	October	November	December
Central (Zone C)	Off-Peak	1.088	1.114	1.085	1.025	1.037	1.050	1.037	1.044	1.033	1.035	1.030	1.050
	On-Peak	1.113	1.122	1.105	1.032	1.047	1.051	1.058	1.061	1.046	1.046	1.043	1.061
	High On-Peak	1.199	1.184	-	-	-	1.064	1.098	1.146	-	-	-	1.111
Capital (Zone F)	Off-Peak	1.015	1.011	1.005	1.016	1.014	1.024	1.027	1.033	1.025	1.027	1.014	1.025
	On-Peak	1.020	1.017	1.001	1.027	1.036	1.030	1.042	1.047	1.036	1.036	1.021	1.035
	High On-Peak	0.991	1.005	-	-	-	1.036	1.068	1.107	-	-	-	1.016
Hudson Valley (Zone G)	Off-Peak	1.029	1.026	1.018	1.017	1.016	1.026	1.026	1.034	1.024	1.029	1.017	1.026
	On-Peak	1.041	1.038	1.019	1.025	1.025	1.030	1.043	1.045	1.034	1.036	1.033	1.041
	High On-Peak	1.027	1.032	-	-	-	1.049	1.085	1.142	-	-	-	1.039
NYC (Zone J)	Off-Peak	1.027	1.023	1.016	1.016	1.015	1.022	1.022	1.028	1.020	1.026	1.014	1.024
	On-Peak	1.025	1.033	1.015	1.021	1.020	1.019	1.027	1.031	1.021	1.028	1.024	1.031
	High On-Peak	1.021	1.025	-	-	-	1.031	1.059	1.118	-	-	-	1.028
Long Island (Zone K)	Off-Peak	1.053	1.057	1.035	1.022	1.032	1.037	1.043	1.039	1.035	1.042	1.038	1.053
	On-Peak	1.083	1.073	1.033	1.025	1.021	1.035	1.070	1.073	1.038	1.045	1.048	1.065
	High On-Peak	1.071	1.066	-	-	-	1.049	1.164	1.268	-	-	-	1.063

D. Additional Detail on Net EAS Revenues

This appendix provides additional detail on the data presented in Section IV. The tables included cover yearly revenues and runtimes during the three-year review period broken down by fuel type, as well as revenues and hours by day-ahead commitment and real-time dispatch behavior.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 3x0 Siemens SGT-A65 WLE with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,561	0	1,561	$42.64	$0.00	$42.64
F	Capital	962	129	1,091	$20.46	$6.32	$26.78
G	Hudson Valley (Dutchess)	777	104	881	$16.88	$5.21	$22.08
G	Hudson Valley (Rockland)	1,405	114	1,519	$21.74	$5.39	$27.13
J	New York City	958	91	1,049	$21.73	$4.12	$25.85
K	Long Island	1,714	135	1,849	$43.32	$6.60	$49.92

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	695	0	695	$14.59	$0.00	$14.59
F	Capital	572	9	581	$10.27	$0.27	$10.54
G	Hudson Valley (Dutchess)	411	7	418	$8.20	$0.31	$8.51
G	Hudson Valley (Rockland)	622	0	622	$11.06	$0.00	$11.06
J	New York City	654	6	660	$13.78	$0.26	$14.04
K	Long Island	1,242	12	1,254	$28.28	$0.47	$28.75

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	382	0	382	$5.60	$0.00	$5.60
F	Capital	392	0	392	$5.79	$0.00	$5.79
G	Hudson Valley (Dutchess)	250	0	250	$3.69	$0.00	$3.69
G	Hudson Valley (Rockland)	401	0	401	$5.68	$0.00	$5.68
J	New York City	516	0	516	$8.84	$0.00	$8.84
K	Long Island	1,026	0	1,026	$22.48	$0.00	$22.48

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 3x0 Siemens SGT-A65 WLE with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,561	0	1,561	$42.64	$0.00	$42.64
F	Capital	991	0	991	$22.95	$0.00	$22.95
G	Hudson Valley (Dutchess)	803	0	803	$18.29	$0.00	$18.29
G	Hudson Valley (Rockland)	1,452	0	1,452	$23.40	$0.00	$23.40

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	695	0	695	$14.59	$0.00	$14.59
F	Capital	573	0	573	$10.28	$0.00	$10.28
G	Hudson Valley (Dutchess)	412	0	412	$8.22	$0.00	$8.22
G	Hudson Valley (Rockland)	622	0	622	$11.06	$0.00	$11.06

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	382	0	382	$5.60	$0.00	$5.60
F	Capital	392	0	392	$5.79	$0.00	$5.79
G	Hudson Valley (Dutchess)	250	0	250	$3.69	$0.00	$3.69
G	Hudson Valley (Rockland)	401	0	401	$5.68	$0.00	$5.68

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 1x0 GE 7F.05 with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,124	0	2,124	$49.63	$0.00	$49.63
F	Capital	1,058	103	1,161	$19.49	$5.67	$25.15
G	Hudson Valley (Dutchess)	916	89	1,005	$16.48	$4.83	$21.31
G	Hudson Valley (Rockland)	2,459	98	2,557	$28.93	$5.03	$33.96
J	New York City	1,530	76	1,606	$24.64	$3.32	$27.97
K	Long Island	2,822	112	2,934	$50.35	$5.31	$55.66

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	883	0	883	$17.23	$0.00	$17.23
F	Capital	568	5	573	$13.25	$0.14	$13.39
G	Hudson Valley (Dutchess)	458	5	463	$9.94	$0.19	$10.13
G	Hudson Valley (Rockland)	1,070	0	1,070	$14.18	$0.00	$14.18
J	New York City	1,114	0	1,114	$16.19	$0.00	$16.19
K	Long Island	2,154	6	2,160	$30.83	$0.25	$31.07

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	511	0	511	$5.14	$0.00	$5.14
F	Capital	391	0	391	$4.15	$0.00	$4.15
G	Hudson Valley (Dutchess)	259	0	259	$2.75	$0.00	$2.75
G	Hudson Valley (Rockland)	563	0	563	$5.34	$0.00	$5.34
J	New York City	824	0	824	$8.81	$0.00	$8.81
K	Long Island	1,485	0	1,485	$24.46	$0.00	$24.46

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 1x0 GE 7F.05 without SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,277	0	2,277	$50.28	$0.00	$50.28
F	Capital	1,104	104	1,208	$19.71	$5.75	$25.46
G	Hudson Valley (Dutchess)	954	87	1,041	$16.97	$4.73	$21.69

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	965	0	965	$17.10	$0.00	$17.10
F	Capital	608	5	613	$13.53	$0.14	$13.67
G	Hudson Valley (Dutchess)	480	5	485	$10.22	$0.20	$10.42

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	620	0	620	$5.80	$0.00	$5.80
F	Capital	418	0	418	$4.32	$0.00	$4.32
G	Hudson Valley (Dutchess)	294	0	294	$2.98	$0.00	$2.98

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 1x0 GE 7F.05 with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,124	0	2,124	$49.63	$0.00	$49.63
F	Capital	1,076	0	1,076	$21.47	$0.00	$21.47
G	Hudson Valley (Dutchess)	935	0	935	$18.26	$0.00	$18.26
G	Hudson Valley (Rockland)	2,498	0	2,498	$31.61	$0.00	$31.61

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	883	0	883	$17.23	$0.00	$17.23
F	Capital	568	0	568	$13.25	$0.00	$13.25
G	Hudson Valley (Dutchess)	458	0	458	$9.94	$0.00	$9.94
G	Hudson Valley (Rockland)	1,070	0	1,070	$14.18	$0.00	$14.18

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	511	0	511	$5.14	$0.00	$5.14
F	Capital	391	0	391	$4.15	$0.00	$4.15
G	Hudson Valley (Dutchess)	259	0	259	$2.75	$0.00	$2.75
G	Hudson Valley (Rockland)	563	0	563	$5.34	$0.00	$5.34

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 1x0 GE 7F.05 without SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,277	0	2,277	$50.28	$0.00	$50.28
F	Capital	1,122	0	1,122	$21.71	$0.00	$21.71
G	Hudson Valley (Dutchess)	973	0	973	$18.75	$0.00	$18.75

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	965	0	965	$17.10	$0.00	$17.10
F	Capital	608	0	608	$13.53	$0.00	$13.53
G	Hudson Valley (Dutchess)	480	0	480	$10.22	$0.00	$10.22

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	620	0	620	$5.80	$0.00	$5.80
F	Capital	418	0	418	$4.32	$0.00	$4.32
G	Hudson Valley (Dutchess)	294	0	294	$2.98	$0.00	$2.98

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 1x0 GE 7HA.02 25ppm with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,026	0	2,026	$46.71	$0.00	$46.71
F	Capital	976	102	1,078	$16.83	$5.96	$22.79
G	Hudson Valley (Dutchess)	846	86	932	$13.67	$4.76	$18.42
G	Hudson Valley (Rockland)	2,510	91	2,601	$28.43	$4.86	$33.29
J	New York City	1,574	78	1,652	$24.48	$3.74	$28.23
K	Long Island	2,960	106	3,066	$50.77	$5.42	$56.19

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	823	0	823	$14.06	$0.00	$14.06
F	Capital	364	5	369	$5.96	$0.15	$6.11
G	Hudson Valley (Dutchess)	331	5	336	$5.16	$0.20	$5.36
G	Hudson Valley (Rockland)	1,022	0	1,022	$11.31	$0.00	$11.31
J	New York City	1,013	0	1,013	$13.27	$0.00	$13.27
K	Long Island	2,382	5	2,387	$30.60	$0.24	$30.84

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	360	0	360	$3.17	$0.00	$3.17
F	Capital	318	0	318	$2.95	$0.00	$2.95
G	Hudson Valley (Dutchess)	173	0	173	$1.40	$0.00	$1.40
G	Hudson Valley (Rockland)	443	0	443	$3.92	$0.00	$3.92
J	New York City	738	0	738	$6.98	$0.00	$6.98
K	Long Island	1,509	0	1,509	$22.96	$0.00	$22.96

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 1x0 GE 7HA.02 15ppm without SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,059	0	1,059	$39.91	$0.00	$39.91
F	Capital	713	102	815	$14.92	$5.95	$20.87
G	Hudson Valley (Dutchess)	786	80	866	$13.16	$4.63	$17.79

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	819	0	819	$13.41	$0.00	$13.41
F	Capital	373	5	378	$5.96	$0.15	$6.10
G	Hudson Valley (Dutchess)	343	5	348	$5.14	$0.20	$5.34

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	366	0	366	$3.12	$0.00	$3.12
F	Capital	311	0	311	$2.80	$0.00	$2.80
G	Hudson Valley (Dutchess)	171	0	171	$1.36	$0.00	$1.36

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 1x0 GE 7HA.02 25ppm with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	2,026	0	2,026	$46.71	$0.00	$46.71
F	Capital	997	0	997	$18.68	$0.00	$18.68
G	Hudson Valley (Dutchess)	863	0	863	$14.66	$0.00	$14.66
G	Hudson Valley (Rockland)	2,546	0	2,546	$30.30	$0.00	$30.30

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	823	0	823	$14.06	$0.00	$14.06
F	Capital	364	0	364	$5.96	$0.00	$5.96
G	Hudson Valley (Dutchess)	331	0	331	$5.16	$0.00	$5.16
G	Hudson Valley (Rockland)	1,022	0	1,022	$11.31	$0.00	$11.31

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	360	0	360	$3.17	$0.00	$3.17
F	Capital	318	0	318	$2.95	$0.00	$2.95
G	Hudson Valley (Dutchess)	173	0	173	$1.40	$0.00	$1.40
G	Hudson Valley (Rockland)	443	0	443	$3.92	$0.00	$3.92

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 1x0 GE 7HA.02 15ppm without SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	1,059	0	1,059	$39.91	$0.00	$39.91
F	Capital	971	0	971	$17.96	$0.00	$17.96
G	Hudson Valley (Dutchess)	855	0	855	$14.33	$0.00	$14.33

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	819	0	819	$13.41	$0.00	$13.41
F	Capital	373	0	373	$5.96	$0.00	$5.96
G	Hudson Valley (Dutchess)	343	0	343	$5.14	$0.00	$5.14

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	366	0	366	$3.12	$0.00	$3.12
F	Capital	311	0	311	$2.80	$0.00	$2.80
G	Hudson Valley (Dutchess)	171	0	171	$1.36	$0.00	$1.36

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.

Runtime and Energy Revenues by Fuel Type and Year
Dual Fuel: 1x1 GE 7HA.02 with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,283	0	6,283	$82.83	$0.00	$82.83
F	Capital	5,261	264	5,525	$52.80	$12.78	$65.58
G	Hudson Valley (Dutchess)	5,593	241	5,834	$49.77	$12.09	$61.86
G	Hudson Valley (Rockland)	7,358	264	7,622	$82.57	$13.36	$95.93
J	New York City	7,057	261	7,318	$75.34	$11.41	$86.75
K	Long Island	7,799	264	8,063	$122.77	$14.80	$137.57

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	4,965	0	4,965	$43.50	$0.00	$43.50
F	Capital	5,274	31	5,305	$35.61	$0.91	$36.52
G	Hudson Valley (Dutchess)	4,909	31	4,940	$34.96	$0.87	$35.83
G	Hudson Valley (Rockland)	6,795	0	6,795	$63.15	$0.00	$63.15
J	New York City	7,123	0	7,123	$61.85	$0.00	$61.85
K	Long Island	8,063	64	8,127	$100.47	$1.81	$102.29

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	3,120	0	3,120	$16.54	$0.00	$16.54
F	Capital	3,149	0	3,149	$16.35	$0.00	$16.35
G	Hudson Valley (Dutchess)	2,734	0	2,734	$12.94	$0.00	$12.94
G	Hudson Valley (Rockland)	5,121	0	5,121	$26.44	$0.00	$26.44
J	New York City	5,581	0	5,581	$30.79	$0.00	$30.79
K	Long Island	7,530	0	7,530	$61.66	$0.00	$61.66

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.

Runtime and Energy Revenues by Fuel Type and Year
Gas-Only: 1x1 GE 7HA.02 with SCR

September 2017 - August 2018							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	6,283	0	6,283	$82.83	$0.00	$82.83
F	Capital	5,356	0	5,356	$54.81	$0.00	$54.81
G	Hudson Valley (Dutchess)	5,669	0	5,669	$53.11	$0.00	$53.11
G	Hudson Valley (Rockland)	7,469	0	7,469	$87.65	$0.00	$87.65

September 2018 - August 2019							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	4,965	0	4,965	$43.50	$0.00	$43.50
F	Capital	5,274	0	5,274	$35.61	$0.00	$35.61
G	Hudson Valley (Dutchess)	4,909	0	4,909	$34.96	$0.00	$34.96
G	Hudson Valley (Rockland)	6,795	0	6,795	$63.15	$0.00	$63.15

September 2019 - August 2020							
		Runtime Hours			Net Energy Revenues ($/kW-year)		
Load Zone		Gas	Oil	Total	Gas	Oil	Total
C	Central	3,120	0	3,120	$16.54	$0.00	$16.54
F	Capital	3,149	0	3,149	$16.35	$0.00	$16.35
G	Hudson Valley (Dutchess)	2,734	0	2,734	$12.94	$0.00	$12.94
G	Hudson Valley (Rockland)	5,121	0	5,121	$26.44	$0.00	$26.44

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 3x0 Siemens SGT-A65 WLE with SCR

Run Hours: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	787	0	162	0	762	6	6,646	0	12	0	385	0	8,760
F	Capital	341	36	66	0	717	62	6,022	0	33	0	1,483	0	8,760
G	Hudson Valley (Dutchess)	367	10	96	0	514	77	7,670	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	898	30	255	0	621	46	6,884	0	0	0	26	0	8,760
J	NYC	556	0	195	0	493	85	7,403	0	0	0	28	0	8,760
K	Long Island	1,330	9	272	0	519	52	6,552	0	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	228	2	151	0	452	26	7,178	0	15	0	708	0	8,760
F	Capital	73	8	61	0	466	115	6,049	0	42	4	1,942	0	8,760
G	Hudson Valley (Dutchess)	89	1	72	0	329	141	8,118	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	213	39	179	0	409	103	7,807	0	0	0	10	0	8,760
J	NYC	263	10	96	0	397	128	7,855	0	0	0	11	0	8,760
K	Long Island	779	15	247	0	475	95	7,141	0	0	0	8	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	60	0	46	0	322	16	8,291	0	0	0	49	0	8,784
F	Capital	36	2	23	0	323	40	7,621	0	33	1	705	0	8,784
G	Hudson Valley (Dutchess)	26	4	14	0	224	46	8,221	0	0	0	249	0	8,784
G	Hudson Valley (Rockland)	96	4	29	0	305	36	8,065	0	0	0	249	0	8,784
J	NYC	126	0	19	0	389	83	7,913	0	1	0	253	0	8,784
K	Long Island	527	0	129	0	496	20	7,364	0	3	0	245	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 3x0 Siemens SGT-A65 WLE with SCR

Net EAS Revenues: September 2017 - August 2018																
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$26.11	$0.00	$2.80	$0.00	$16.03	$0.01	$11.40	$0.00	$0.50	$0.00	$0.00	$0.00	$56.86	$58.90
F	Capital	$8.95	$1.22	$1.32	$0.00	$17.17	$0.15	$10.65	$0.00	$0.65	$0.00	$0.00	$0.00	$40.11	$42.15
G	Hudson Valley (Dutchess)	$8.26	$0.17	$1.97	$0.00	$13.83	$0.24	$17.70	$0.00	$0.00	$0.00	$0.00	$0.00	$42.16	$44.20
G	Hudson Valley (Rockland)	$13.50	$0.63	$3.95	$0.00	$13.64	$0.12	$15.29	$0.00	$0.00	$0.00	$0.00	$0.00	$47.12	$49.16
J	NYC	$12.46	$0.00	$2.75	$0.00	$13.39	$0.26	$16.60	$0.00	$0.00	$0.00	$0.00	$0.00	$45.45	$47.49
K	Long Island	$31.39	$0.33	$5.14	$0.00	$18.53	$0.16	$14.30	$0.00	$0.00	$0.00	$0.00	$0.00	$69.86	$71.90

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$4.03	$0.03	$3.16	$0.00	$9.99	$0.07	$11.39	$0.00	$0.57	$0.00	$0.00	$0.00	$29.24	$31.28
F	Capital	$0.97	$0.12	$1.35	$0.00	$8.39	$0.42	$9.96	$0.00	$1.18	$0.17	$0.00	$0.00	$22.55	$24.59
G	Hudson Valley (Dutchess)	$0.89	$0.03	$1.41	$0.00	$7.62	$0.61	$16.58	$0.00	$0.00	$0.00	$0.00	$0.00	$27.15	$29.19
G	Hudson Valley (Rockland)	$2.35	$1.22	$3.90	$0.00	$8.70	$0.41	$15.43	$0.00	$0.00	$0.00	$0.00	$0.00	$32.02	$34.06
J	NYC	$4.57	$0.00	$1.67	$0.00	$9.47	$0.51	$15.92	$0.00	$0.00	$0.00	$0.00	$0.00	$32.14	$34.18
K	Long Island	$13.31	$0.19	$4.96	$0.00	$15.44	$0.34	$14.14	$0.00	$0.00	$0.00	$0.00	$0.00	$48.38	$50.42

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$0.47	$0.00	$0.70	$0.00	$5.13	$0.05	$14.01	$0.00	$0.00	$0.00	$0.00	$0.00	$20.36	$22.40
F	Capital	$0.18	$0.04	$0.28	$0.00	$4.90	$0.09	$10.71	$0.00	$0.71	$0.01	$0.00	$0.00	$16.91	$18.95
G	Hudson Valley (Dutchess)	$0.13	$0.04	$0.15	$0.00	$3.55	$0.10	$10.71	$0.00	$0.00	$0.00	$0.00	$0.00	$14.69	$16.73
G	Hudson Valley (Rockland)	$0.82	$0.04	$0.30	$0.00	$4.86	$0.06	$10.30	$0.00	$0.00	$0.00	$0.00	$0.00	$16.39	$18.43
J	NYC	$1.69	$0.00	$0.22	$0.00	$7.14	$0.24	$10.03	$0.00	$0.01	$0.00	$0.00	$0.00	$19.33	$21.37
K	Long Island	$10.76	$0.00	$2.71	$0.00	$11.67	$0.02	$9.36	$0.00	$0.04	$0.00	$0.00	$0.00	$34.57	$36.61

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 3x0 Siemens SGT-A65 WLE with SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	787	0	162	0	762	6	6,646	0	12	0	385	0	8,760
F	Capital	258	36	66	0	679	63	5,890	0	54	2	1,712	0	8,760
G	Hudson Valley (Dutchess)	298	10	93	0	505	87	7,741	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	849	30	252	0	603	53	6,947	0	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	228	2	151	0	452	26	7,178	0	15	0	708	0	8,760
F	Capital	73	8	61	0	457	115	5,962	0	43	4	2,037	0	8,760
G	Hudson Valley (Dutchess)	89	1	72	0	323	141	8,124	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	213	39	179	0	409	103	7,807	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	60	0	46	0	322	16	8,291	0	0	0	49	0	8,784
F	Capital	36	2	23	0	323	40	7,621	0	33	1	705	0	8,784
G	Hudson Valley (Dutchess)	26	4	14	0	224	46	8,221	0	0	0	249	0	8,784
G	Hudson Valley (Rockland)	96	4	29	0	305	36	8,065	0	0	0	249	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 3x0 Siemens SGT-A65 WLE with SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$26.11	$0.00	$2.80	$0.00	$16.03	$0.01	$11.40	$0.00	$0.50	$0.00	$0.00	$0.00	$56.86	$58.90
F	Capital	$5.30	$1.22	$1.32	$0.00	$15.06	$0.15	$9.76	$0.00	$2.59	$0.33	$0.00	$0.00	$35.73	$37.77
G	Hudson Valley (Dutchess)	$5.07	$0.17	$1.92	$0.00	$13.21	$0.44	$18.15	$0.00	$0.00	$0.00	$0.00	$0.00	$38.95	$40.99
G	Hudson Valley (Rockland)	$10.93	$0.63	$3.89	$0.00	$12.47	$0.24	$15.57	$0.00	$0.00	$0.00	$0.00	$0.00	$43.73	$45.77

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$4.03	$0.03	$3.16	$0.00	$9.99	$0.07	$11.39	$0.00	$0.57	$0.00	$0.00	$0.00	$29.24	$31.28
F	Capital	$0.97	$0.12	$1.35	$0.00	$8.13	$0.42	$9.57	$0.00	$1.19	$0.17	$0.00	$0.00	$21.91	$23.95
G	Hudson Valley (Dutchess)	$0.89	$0.03	$1.41	$0.00	$7.33	$0.61	$16.42	$0.00	$0.00	$0.00	$0.00	$0.00	$26.70	$28.74
G	Hudson Valley (Rockland)	$2.35	$1.22	$3.90	$0.00	$8.70	$0.41	$15.43	$0.00	$0.00	$0.00	$0.00	$0.00	$32.02	$34.06

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$0.47	$0.00	$0.70	$0.00	$5.13	$0.05	$14.01	$0.00	$0.00	$0.00	$0.00	$0.00	$20.36	$22.40
F	Capital	$0.18	$0.04	$0.28	$0.00	$4.90	$0.09	$10.71	$0.00	$0.71	$0.01	$0.00	$0.00	$16.91	$18.95
G	Hudson Valley (Dutchess)	$0.13	$0.04	$0.15	$0.00	$3.55	$0.10	$10.71	$0.00	$0.00	$0.00	$0.00	$0.00	$14.69	$16.73
G	Hudson Valley (Rockland)	$0.82	$0.04	$0.30	$0.00	$4.86	$0.06	$10.30	$0.00	$0.00	$0.00	$0.00	$0.00	$16.39	$18.43

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 1x0 GE 7F.05 with SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,394	0	238	0	713	7	5,976	0	17	0	415	0	8,760
F	Capital	629	22	223	0	489	6	5,149	0	43	0	2,199	0	8,760
G	Hudson Valley (Dutchess)	623	7	213	0	382	8	7,501	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	2,172	23	363	0	380	0	5,796	0	5	0	21	0	8,760
J	NYC	1,309	0	159	0	297	10	6,957	0	0	0	28	0	8,760
K	Long Island	2,615	0	324	0	317	6	5,473	0	2	0	23	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	440	0	166	0	420	12	6,707	0	23	0	992	0	8,760
F	Capital	179	0	130	0	352	14	5,656	0	42	0	2,387	0	8,760
G	Hudson Valley (Dutchess)	228	0	123	0	235	19	8,145	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	804	0	334	0	266	4	7,342	0	0	0	10	0	8,760
J	NYC	902	0	153	0	212	7	7,475	0	0	0	11	0	8,760
K	Long Island	1,896	0	270	0	263	7	6,316	0	1	0	7	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	238	11	94	0	273	14	8,073	0	0	0	81	0	8,784
F	Capital	155	0	42	0	206	25	7,436	0	30	0	890	0	8,784
G	Hudson Valley (Dutchess)	125	0	18	0	133	29	8,229	0	1	0	249	0	8,784
G	Hudson Valley (Rockland)	373	12	61	0	185	21	7,883	0	5	0	244	0	8,784
J	NYC	604	0	69	0	219	13	7,624	0	1	0	254	0	8,784
K	Long Island	1,204	0	188	0	278	6	6,902	0	3	0	203	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 1x0 GE 7F.05 with SCR

Net EAS Revenues: September 2017 - August 2018

Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$36.21	$0.00	$3.03	$0.00	$13.25	$0.02	$9.43	$0.00	$0.17	$0.00	$0.00	$0.00	$62.10	$64.14
F	Capital	$10.88	$0.70	$2.84	$0.00	$13.28	$0.01	$7.23	$0.00	$0.99	$0.00	$0.00	$0.00	$35.95	$37.99
G	Hudson Valley (Dutchess)	$10.01	$0.11	$2.41	$0.00	$11.30	$0.02	$14.78	$0.00	$0.00	$0.00	$0.00	$0.00	$38.64	$40.68
G	Hudson Valley (Rockland)	$25.57	$0.51	$4.30	$0.00	$8.38	$0.00	$11.17	$0.00	$0.01	$0.00	$0.00	$0.00	$49.94	$51.98
J	NYC	$19.35	$0.00	$1.67	$0.00	$8.62	$0.03	$13.09	$0.00	$0.00	$0.00	$0.00	$0.00	$42.76	$44.80
K	Long Island	$44.13	$0.00	$4.59	$0.00	$11.52	$0.02	$9.94	$0.00	$0.01	$0.00	$0.00	$0.00	$70.19	$72.23

Net EAS Revenues: September 2018 - August 2019

Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.27	$0.00	$1.94	$0.00	$9.41	$0.04	$10.04	$0.00	$0.55	$0.00	$0.00	$0.00	$29.25	$31.29
F	Capital	$1.79	$0.00	$1.83	$0.00	$10.62	$0.04	$7.80	$0.00	$0.98	$0.00	$0.00	$0.00	$23.06	$25.10
G	Hudson Valley (Dutchess)	$1.86	$0.00	$1.64	$0.00	$8.27	$0.07	$15.15	$0.00	$0.00	$0.00	$0.00	$0.00	$26.99	$29.03
G	Hudson Valley (Rockland)	$7.47	$0.00	$4.44	$0.00	$6.71	$0.01	$12.83	$0.00	$0.00	$0.00	$0.00	$0.00	$31.46	$33.50
J	NYC	$9.48	$0.00	$2.17	$0.00	$6.71	$0.03	$12.97	$0.00	$0.00	$0.00	$0.00	$0.00	$31.35	$33.39
K	Long Island	$21.73	$0.00	$3.38	$0.00	$9.34	$0.03	$11.09	$0.00	$0.00	$0.00	$0.00	$0.00	$45.58	$47.62

Net EAS Revenues: September 2019 - August 2020

Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.69	$0.05	$0.73	$0.00	$3.45	$0.04	$12.93	$0.00	$0.00	$0.00	$0.00	$0.00	$18.89	$20.93
F	Capital	$0.70	$0.00	$0.31	$0.00	$2.84	$0.07	$9.92	$0.00	$0.61	$0.00	$0.00	$0.00	$14.46	$16.50
G	Hudson Valley (Dutchess)	$0.60	$0.00	$0.14	$0.00	$2.14	$0.08	$10.60	$0.00	$0.00	$0.00	$0.00	$0.00	$13.56	$15.60
G	Hudson Valley (Rockland)	$2.34	$0.06	$0.44	$0.00	$2.99	$0.05	$9.78	$0.00	$0.01	$0.00	$0.00	$0.00	$15.68	$17.72
J	NYC	$4.72	$0.00	$0.46	$0.00	$4.07	$0.03	$9.11	$0.00	$0.02	$0.00	$0.00	$0.00	$18.42	$20.46
K	Long Island	$16.75	$0.00	$2.63	$0.00	$7.67	$0.01	$8.63	$0.00	$0.03	$0.00	$0.00	$0.00	$35.72	$37.76

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 1x0 GE 7F.05 without SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,535	0	236	0	725	6	5,829	0	17	0	412	0	8,760
F	Capital	679	22	242	0	488	6	5,086	0	41	0	2,196	0	8,760
G	Hudson Valley (Dutchess)	660	7	229	0	381	8	7,449	0	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	517	0	190	0	426	12	6,601	0	22	0	992	0	8,760
F	Capital	210	0	145	0	360	14	5,612	0	43	0	2,376	0	8,760
G	Hudson Valley (Dutchess)	247	0	144	0	238	19	8,102	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	329	11	82	0	291	14	7,976	0	0	0	81	0	8,784
F	Capital	172	0	46	0	216	25	7,406	0	30	0	889	0	8,784
G	Hudson Valley (Dutchess)	150	11	19	0	143	24	8,187	0	1	0	249	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 1x0 GE 7F.05 without SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$37.49	$0.00	$3.12	$0.00	$12.63	$0.01	$9.06	$0.00	$0.17	$0.00	$0.00	$0.00	$62.47	$64.51
F	Capital	$11.43	$0.70	$3.03	$0.00	$13.09	$0.01	$7.12	$0.00	$0.95	$0.00	$0.00	$0.00	$36.33	$38.37
G	Hudson Valley (Dutchess)	$10.58	$0.11	$2.87	$0.00	$11.12	$0.02	$14.57	$0.00	$0.00	$0.00	$0.00	$0.00	$39.26	$41.30

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.73	$0.00	$2.14	$0.00	$8.82	$0.04	$9.83	$0.00	$0.55	$0.00	$0.00	$0.00	$29.10	$31.14
F	Capital	$1.93	$0.00	$1.96	$0.00	$10.74	$0.04	$7.72	$0.00	$1.00	$0.00	$0.00	$0.00	$23.39	$25.43
G	Hudson Valley (Dutchess)	$2.02	$0.00	$1.91	$0.00	$8.40	$0.07	$15.03	$0.00	$0.00	$0.00	$0.00	$0.00	$27.43	$29.47

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$2.22	$0.05	$0.57	$0.00	$3.58	$0.04	$12.67	$0.00	$0.00	$0.00	$0.00	$0.00	$19.13	$21.17
F	Capital	$0.82	$0.00	$0.32	$0.00	$2.88	$0.07	$9.88	$0.00	$0.62	$0.00	$0.00	$0.00	$14.59	$16.63
G	Hudson Valley (Dutchess)	$0.74	$0.06	$0.14	$0.00	$2.24	$0.06	$10.50	$0.00	$0.00	$0.00	$0.00	$0.00	$13.74	$15.78

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 1x0 GE 7F.05 with SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,394	0	238	0	713	7	5,976	0	17	0	415	0	8,760
F	Capital	561	22	223	0	454	6	5,012	0	61	0	2,421	0	8,760
G	Hudson Valley (Dutchess)	569	7	213	0	366	11	7,568	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	2,135	23	363	0	358	0	5,855	0	5	0	21	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	440	0	166	0	420	12	6,707	0	23	0	992	0	8,760
F	Capital	179	0	130	0	347	14	5,565	0	42	0	2,483	0	8,760
G	Hudson Valley (Dutchess)	228	0	123	0	230	19	8,150	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	804	0	334	0	266	4	7,342	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	238	11	94	0	273	14	8,073	0	0	0	81	0	8,784
F	Capital	155	0	42	0	206	25	7,436	0	30	0	890	0	8,784
G	Hudson Valley (Dutchess)	125	0	18	0	133	29	8,229	0	1	0	249	0	8,784
G	Hudson Valley (Rockland)	373	12	61	0	185	21	7,883	0	5	0	244	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 1x0 GE 7F.05 with SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$36.21	$0.00	$3.03	$0.00	$13.25	$0.02	$9.43	$0.00	$0.17	$0.00	$0.00	$0.00	$62.10	$64.14
F	Capital	$7.72	$0.70	$2.84	$0.00	$10.78	$0.01	$6.41	$0.00	$2.98	$0.00	$0.00	$0.00	$31.44	$33.48
G	Hudson Valley (Dutchess)	$7.38	$0.11	$2.41	$0.00	$10.88	$0.08	$15.05	$0.00	$0.00	$0.00	$0.00	$0.00	$35.91	$37.95
G	Hudson Valley (Rockland)	$23.60	$0.51	$4.30	$0.00	$7.99	$0.00	$11.31	$0.00	$0.01	$0.00	$0.00	$0.00	$47.73	$49.77

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.27	$0.00	$1.94	$0.00	$9.41	$0.04	$10.04	$0.00	$0.55	$0.00	$0.00	$0.00	$29.25	$31.29
F	Capital	$1.79	$0.00	$1.83	$0.00	$10.48	$0.04	$7.40	$0.00	$0.98	$0.00	$0.00	$0.00	$22.52	$24.56
G	Hudson Valley (Dutchess)	$1.86	$0.00	$1.64	$0.00	$8.08	$0.07	$14.99	$0.00	$0.00	$0.00	$0.00	$0.00	$26.62	$28.66
G	Hudson Valley (Rockland)	$7.47	$0.00	$4.44	$0.00	$6.71	$0.01	$12.83	$0.00	$0.00	$0.00	$0.00	$0.00	$31.46	$33.50

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.69	$0.05	$0.73	$0.00	$3.45	$0.04	$12.93	$0.00	$0.00	$0.00	$0.00	$0.00	$18.89	$20.93
F	Capital	$0.70	$0.00	$0.31	$0.00	$2.84	$0.07	$9.92	$0.00	$0.61	$0.00	$0.00	$0.00	$14.46	$16.50
G	Hudson Valley (Dutchess)	$0.60	$0.00	$0.14	$0.00	$2.14	$0.08	$10.60	$0.00	$0.00	$0.00	$0.00	$0.00	$13.56	$15.60
G	Hudson Valley (Rockland)	$2.34	$0.06	$0.44	$0.00	$2.99	$0.05	$9.78	$0.00	$0.01	$0.00	$0.00	$0.00	$15.68	$17.72

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 1x0 GE 7F.05 without SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,535	0	236	0	725	6	5,829	0	17	0	412	0	8,760
F	Capital	610	22	242	0	453	6	4,950	0	59	0	2,418	0	8,760
G	Hudson Valley (Dutchess)	605	7	224	0	368	11	7,519	0	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	517	0	190	0	426	12	6,601	0	22	0	992	0	8,760
F	Capital	210	0	145	0	355	14	5,521	0	43	0	2,472	0	8,760
G	Hudson Valley (Dutchess)	247	0	144	0	233	19	8,107	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	329	11	82	0	291	14	7,976	0	0	0	81	0	8,784
F	Capital	172	0	46	0	216	25	7,406	0	30	0	889	0	8,784
G	Hudson Valley (Dutchess)	150	11	19	0	143	24	8,187	0	1	0	249	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 1x0 GE 7F.05 without SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$37.49	$0.00	$3.12	$0.00	$12.63	$0.01	$9.06	$0.00	$0.17	$0.00	$0.00	$0.00	$62.47	$64.51
F	Capital	$8.21	$0.70	$3.03	$0.00	$10.56	$0.01	$6.30	$0.00	$2.94	$0.00	$0.00	$0.00	$31.77	$33.81
G	Hudson Valley (Dutchess)	$7.90	$0.11	$2.74	$0.00	$10.85	$0.08	$14.89	$0.00	$0.00	$0.00	$0.00	$0.00	$36.57	$38.61

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.73	$0.00	$2.14	$0.00	$8.82	$0.04	$9.83	$0.00	$0.55	$0.00	$0.00	$0.00	$29.10	$31.14
F	Capital	$1.93	$0.00	$1.96	$0.00	$10.59	$0.04	$7.32	$0.00	$1.00	$0.00	$0.00	$0.00	$22.84	$24.88
G	Hudson Valley (Dutchess)	$2.02	$0.00	$1.91	$0.00	$8.20	$0.07	$14.87	$0.00	$0.00	$0.00	$0.00	$0.00	$27.06	$29.10

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$2.22	$0.05	$0.57	$0.00	$3.58	$0.04	$12.67	$0.00	$0.00	$0.00	$0.00	$0.00	$19.13	$21.17
F	Capital	$0.82	$0.00	$0.32	$0.00	$2.88	$0.07	$9.88	$0.00	$0.62	$0.00	$0.00	$0.00	$14.59	$16.63
G	Hudson Valley (Dutchess)	$0.74	$0.06	$0.14	$0.00	$2.24	$0.06	$10.50	$0.00	$0.00	$0.00	$0.00	$0.00	$13.74	$15.78

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 1x0 GE 7HA.02 25ppm with SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,580	0	263	0	425	11	6,143	0	21	0	317	0	8,760
F	Capital	632	51	202	0	428	58	6,053	0	18	0	1,318	0	8,760
G	Hudson Valley (Dutchess)	670	21	193	0	262	77	7,511	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	2,300	42	356	0	294	38	5,704	0	7	0	19	0	8,760
J	NYC	1,441	0	98	0	210	73	6,910	0	1	0	27	0	8,760
K	Long Island	2,867	18	331	18	197	40	5,263	4	2	0	20	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	506	11	148	0	305	33	7,127	0	12	0	618	0	8,760
F	Capital	160	0	143	0	184	140	6,247	0	25	4	1,857	0	8,760
G	Hudson Valley (Dutchess)	189	0	134	0	147	159	8,121	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	861	89	291	0	161	75	7,273	0	0	0	10	0	8,760
J	NYC	851	15	142	0	162	107	7,472	0	0	0	11	0	8,760
K	Long Island	2,183	14	246	0	202	71	6,037	0	2	0	5	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	219	0	71	0	141	35	8,280	0	0	0	38	0	8,784
F	Capital	160	0	27	0	138	69	7,771	0	20	1	598	0	8,784
G	Hudson Valley (Dutchess)	101	0	28	0	70	59	8,277	0	2	0	247	0	8,784
G	Hudson Valley (Rockland)	313	14	39	0	119	46	8,006	0	11	0	236	0	8,784
J	NYC	614	0	53	0	121	81	7,663	0	3	0	249	0	8,784
K	Long Island	1,303	0	200	0	204	22	6,876	0	2	0	177	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 1x0 GE 7HA.02 25ppm with SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$38.26	$0.00	$3.16	$0.00	$8.24	$0.03	$10.76	$0.00	$0.20	$0.00	$0.00	$0.00	$60.66	$62.70
F	Capital	$12.01	$1.55	$2.43	$0.00	$10.36	$0.15	$10.84	$0.00	$0.43	$0.00	$0.00	$0.00	$37.77	$39.81
G	Hudson Valley (Dutchess)	$10.96	$0.33	$2.34	$0.00	$7.46	$0.25	$17.39	$0.00	$0.00	$0.00	$0.00	$0.00	$38.72	$40.76
G	Hudson Valley (Rockland)	$27.47	$0.71	$3.98	$0.00	$5.79	$0.13	$13.09	$0.00	$0.02	$0.00	$0.00	$0.00	$51.21	$53.25
J	NYC	$22.09	$0.00	$1.09	$0.00	$6.13	$0.22	$15.13	$0.00	$0.00	$0.00	$0.00	$0.00	$44.67	$46.71
K	Long Island	$48.31	$0.42	$4.50	$0.04	$7.87	$0.13	$11.28	$0.02	$0.01	$0.00	$0.00	$0.00	$72.58	$74.62

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.99	$0.04	$1.77	$0.00	$5.67	$0.10	$11.60	$0.00	$0.40	$0.00	$0.00	$0.00	$27.58	$29.62
F	Capital	$1.80	$0.00	$2.07	$0.00	$3.87	$0.53	$10.50	$0.00	$0.44	$0.18	$0.00	$0.00	$19.39	$21.43
G	Hudson Valley (Dutchess)	$1.74	$0.00	$1.88	$0.00	$3.62	$0.70	$16.62	$0.00	$0.00	$0.00	$0.00	$0.00	$24.56	$26.60
G	Hudson Valley (Rockland)	$8.23	$2.63	$3.25	$0.00	$3.08	$0.28	$13.75	$0.00	$0.00	$0.00	$0.00	$0.00	$31.21	$33.25
J	NYC	$9.56	$0.10	$1.79	$0.00	$3.71	$0.42	$14.56	$0.00	$0.00	$0.00	$0.00	$0.00	$30.14	$32.18
K	Long Island	$23.93	$0.13	$2.88	$0.00	$6.90	$0.27	$11.62	$0.00	$0.01	$0.00	$0.00	$0.00	$45.74	$47.78

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.45	$0.00	$0.53	$0.00	$1.72	$0.11	$14.38	$0.00	$0.00	$0.00	$0.00	$0.00	$18.20	$20.24
F	Capital	$0.81	$0.00	$0.23	$0.00	$1.75	$0.20	$11.15	$0.00	$0.39	$0.01	$0.00	$0.00	$14.54	$16.58
G	Hudson Valley (Dutchess)	$0.43	$0.00	$0.19	$0.00	$0.96	$0.15	$10.83	$0.00	$0.01	$0.00	$0.00	$0.00	$12.58	$14.62
G	Hudson Valley (Rockland)	$2.19	$0.07	$0.21	$0.00	$1.71	$0.10	$10.20	$0.00	$0.02	$0.00	$0.00	$0.00	$14.50	$16.54
J	NYC	$4.75	$0.00	$0.40	$0.00	$2.23	$0.22	$9.43	$0.00	$0.00	$0.00	$0.00	$0.00	$17.03	$19.07
K	Long Island	$17.41	$0.00	$2.54	$0.00	$5.54	$0.04	$8.76	$0.00	$0.01	$0.00	$0.00	$0.00	$34.29	$36.33

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 1x0 GE 7HA.02 15ppm without SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	833	0	259	811	209	11	6,077	224	17	0	314	5	8,760
F	Capital	452	53	203	198	349	58	6,057	35	14	0	1,337	4	8,760
G	Hudson Valley (Dutchess)	625	13	197	53	241	80	7,520	5	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	539	11	159	0	267	35	7,097	0	13	0	639	0	8,760
F	Capital	161	0	138	0	192	140	6,238	0	25	4	1,862	0	8,760
G	Hudson Valley (Dutchess)	204	0	136	0	144	155	8,111	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	220	0	84	0	146	35	8,261	0	0	0	38	0	8,784
F	Capital	169	0	28	0	127	69	7,767	0	15	1	608	0	8,784
G	Hudson Valley (Dutchess)	104	0	28	0	65	59	8,279	0	2	0	247	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 1x0 GE 7HA.02 15ppm without SCR

Net EAS Revenues: September 2017 - August 2018																
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$33.56	$0.00	$3.05	$2.34	$6.17	$0.03	$10.55	$0.38	$0.18	$0.00	$0.00	$0.00	$56.27	$58.31
F	Capital	$11.15	$1.57	$2.43	$0.64	$9.32	$0.15	$10.85	$0.05	$0.40	$0.00	$0.00	$0.00	$36.56	$38.60
G	Hudson Valley (Dutchess)	$10.65	$0.18	$2.35	$0.28	$7.13	$0.25	$17.42	$0.02	$0.00	$0.00	$0.00	$0.00	$38.28	$40.32

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$8.23	$0.04	$1.86	$0.00	$4.87	$0.11	$11.54	$0.00	$0.32	$0.00	$0.00	$0.00	$26.96	$29.00
F	Capital	$1.82	$0.00	$2.01	$0.00	$3.87	$0.53	$10.44	$0.00	$0.42	$0.18	$0.00	$0.00	$19.25	$21.29
G	Hudson Valley (Dutchess)	$1.80	$0.00	$1.90	$0.00	$3.54	$0.69	$16.58	$0.00	$0.00	$0.00	$0.00	$0.00	$24.51	$26.55

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.48	$0.00	$0.59	$0.00	$1.64	$0.11	$14.30	$0.00	$0.00	$0.00	$0.00	$0.00	$18.13	$20.17
F	Capital	$0.84	$0.00	$0.23	$0.00	$1.66	$0.20	$11.09	$0.00	$0.30	$0.01	$0.00	$0.00	$14.34	$16.38
G	Hudson Valley (Dutchess)	$0.45	$0.00	$0.19	$0.00	$0.91	$0.15	$10.84	$0.00	$0.01	$0.00	$0.00	$0.00	$12.54	$14.58

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 1x0 GE 7HA.02 25ppm with SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	1,580	0	263	0	425	11	6,143	0	21	0	317	0	8,760
F	Capital	563	51	202	0	405	59	5,918	0	29	3	1,530	0	8,760
G	Hudson Valley (Dutchess)	610	21	188	0	253	87	7,575	0	0	0	26	0	8,760
G	Hudson Valley (Rockland)	2,259	42	351	0	280	44	5,758	0	7	0	19	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	506	11	148	0	305	33	7,127	0	12	0	618	0	8,760
F	Capital	160	0	143	0	179	140	6,156	0	25	4	1,953	0	8,760
G	Hudson Valley (Dutchess)	189	0	134	0	142	159	8,126	0	0	0	10	0	8,760
G	Hudson Valley (Rockland)	861	89	291	0	161	75	7,273	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	219	0	71	0	141	35	8,280	0	0	0	38	0	8,784
F	Capital	160	0	27	0	138	69	7,771	0	20	1	598	0	8,784
G	Hudson Valley (Dutchess)	101	0	28	0	70	59	8,277	0	2	0	247	0	8,784
G	Hudson Valley (Rockland)	313	14	39	0	119	46	8,006	0	11	0	236	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 1x0 GE 7HA.02 25ppm with SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$38.26	$0.00	$3.16	$0.00	$8.24	$0.03	$10.76	$0.00	$0.20	$0.00	$0.00	$0.00	$60.66	$62.70
F	Capital	$8.34	$1.55	$2.43	$0.00	$8.41	$0.16	$9.89	$0.00	$1.93	$0.83	$0.00	$0.00	$33.54	$35.58
G	Hudson Valley (Dutchess)	$8.03	$0.33	$2.21	$0.00	$6.62	$0.45	$17.89	$0.00	$0.00	$0.00	$0.00	$0.00	$35.53	$37.57
G	Hudson Valley (Rockland)	$25.41	$0.71	$3.85	$0.00	$4.87	$0.25	$13.30	$0.00	$0.02	$0.00	$0.00	$0.00	$48.42	$50.46

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$7.99	$0.04	$1.77	$0.00	$5.67	$0.10	$11.60	$0.00	$0.40	$0.00	$0.00	$0.00	$27.58	$29.62
F	Capital	$1.80	$0.00	$2.07	$0.00	$3.72	$0.53	$10.10	$0.00	$0.44	$0.18	$0.00	$0.00	$18.84	$20.88
G	Hudson Valley (Dutchess)	$1.74	$0.00	$1.88	$0.00	$3.41	$0.70	$16.45	$0.00	$0.00	$0.00	$0.00	$0.00	$24.19	$26.23
G	Hudson Valley (Rockland)	$8.23	$2.63	$3.25	$0.00	$3.08	$0.28	$13.75	$0.00	$0.00	$0.00	$0.00	$0.00	$31.21	$33.25

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.45	$0.00	$0.53	$0.00	$1.72	$0.11	$14.38	$0.00	$0.00	$0.00	$0.00	$0.00	$18.20	$20.24
F	Capital	$0.81	$0.00	$0.23	$0.00	$1.75	$0.20	$11.15	$0.00	$0.39	$0.01	$0.00	$0.00	$14.54	$16.58
G	Hudson Valley (Dutchess)	$0.43	$0.00	$0.19	$0.00	$0.96	$0.15	$10.83	$0.00	$0.01	$0.00	$0.00	$0.00	$12.58	$14.62
G	Hudson Valley (Rockland)	$2.19	$0.07	$0.21	$0.00	$1.71	$0.10	$10.20	$0.00	$0.02	$0.00	$0.00	$0.00	$14.50	$16.54

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 1x0 GE 7HA.02 15ppm without SCR

Run Hours: September 2017 - August 2018														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	833	0	259	811	209	11	6,077	224	17	0	314	5	8,760
F	Capital	581	53	203	0	361	59	5,922	0	29	3	1,549	0	8,760
G	Hudson Valley (Dutchess)	618	13	192	0	237	90	7,584	0	0	0	26	0	8,760

Run Hours: September 2018 - August 2019														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	539	11	159	0	267	35	7,097	0	13	0	639	0	8,760
F	Capital	161	0	138	0	187	140	6,147	0	25	4	1,958	0	8,760
G	Hudson Valley (Dutchess)	204	0	136	0	139	155	8,116	0	0	0	10	0	8,760

Run Hours: September 2019 - August 2020														
Day-Ahead Commitment		Energy				Reserve				None				Total
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited	
C	Central	220	0	84	0	146	35	8,261	0	0	0	38	0	8,784
F	Capital	169	0	28	0	127	69	7,767	0	15	1	608	0	8,784
G	Hudson Valley (Dutchess)	104	0	28	0	65	59	8,279	0	2	0	247	0	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Runtime limits were applied based on New Source Performance Standards: a limit of 200,000 lbs of NOx emissions in each modeled year.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 1x0 GE 7HA.02 15ppm without SCR

Net EAS Revenues: September 2017 - August 2018															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$33.56	$0.00	$3.05	$2.34	$6.17	$0.03	$10.55	$0.38	$0.18	$0.00	$0.00	$0.00	$56.27	$58.31
F	Capital	$8.42	$1.57	$2.43	$0.00	$7.63	$0.16	$9.90	$0.00	$1.91	$0.82	$0.00	$0.00	$32.84	$34.88
G	Hudson Valley (Dutchess)	$8.05	$0.18	$2.22	$0.00	$6.28	$0.45	$17.92	$0.00	$0.00	$0.00	$0.00	$0.00	$35.11	$37.15

Net EAS Revenues: September 2018 - August 2019															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$8.23	$0.04	$1.86	$0.00	$4.87	$0.11	$11.54	$0.00	$0.32	$0.00	$0.00	$0.00	$26.96	$29.00
F	Capital	$1.82	$0.00	$2.01	$0.00	$3.72	$0.53	$10.04	$0.00	$0.42	$0.18	$0.00	$0.00	$18.70	$20.74
G	Hudson Valley (Dutchess)	$1.80	$0.00	$1.90	$0.00	$3.34	$0.69	$16.41	$0.00	$0.00	$0.00	$0.00	$0.00	$24.14	$26.18

Net EAS Revenues: September 2019 - August 2020															
Day-Ahead Commitment		Energy				Reserve				None				Total	Total with VSS Adder
Real-Time Dispatch		Energy	Reserve	Buyout	Limited	Energy	Reserve	Buyout	Limited	Energy	Reserve	None	Limited		
C	Central	$1.48	$0.00	$0.59	$0.00	$1.64	$0.11	$14.30	$0.00	$0.00	$0.00	$0.00	$0.00	$18.13	$20.17
F	Capital	$0.84	$0.00	$0.23	$0.00	$1.66	$0.20	$11.09	$0.00	$0.30	$0.01	$0.00	$0.00	$14.34	$16.38
G	Hudson Valley (Dutchess)	$0.45	$0.00	$0.19	$0.00	$0.91	$0.15	$10.84	$0.00	$0.01	$0.00	$0.00	$0.00	$12.54	$14.58

Notes:

[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] Runtime limits were applied based on New Source Performance Standards: a limit of 3,066 hours of runtime in each modeled year.
[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Dual Fuel: 1x1 GE 7HA.02 with SCR

Run Hours: September 2017 - August 2018						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	5,160	681	1,123	1,796	8,760
F	Capital	4,730	931	795	2,304	8,760
G	Hudson Valley (Dutchess)	4,848	886	986	2,040	8,760
G	Hudson Valley (Rockland)	6,848	554	774	584	8,760
J	NYC	6,098	364	1,220	1,078	8,760
K	Long Island	7,181	290	882	407	8,760

Run Hours: September 2018 - August 2019						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	4,055	575	910	3,220	8,760
F	Capital	4,606	936	699	2,519	8,760
G	Hudson Valley (Dutchess)	4,198	830	742	2,990	8,760
G	Hudson Valley (Rockland)	6,246	542	549	1,423	8,760
J	NYC	6,255	473	868	1,164	8,760
K	Long Island	7,280	170	847	463	8,760

Run Hours: September 2019 - August 2020						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	2,447	388	673	5,276	8,784
F	Capital	2,641	548	508	5,087	8,784
G	Hudson Valley (Dutchess)	2,185	439	549	5,611	8,784
G	Hudson Valley (Rockland)	4,490	513	631	3,150	8,784
J	NYC	4,717	309	864	2,894	8,784
K	Long Island	6,325	375	1,205	879	8,784

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.

[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Dual Fuel: 1x1 GE 7HA.02 with SCR

Net EAS Revenues: September 2017 - August 2018								
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$80.27	$5.63	$2.56	$0.00	$88.46	$93.99
F	Capital	$62.45	$7.08	$3.13	$0.00	$72.65	$78.18
G	Hudson Valley (Dutchess)	$59.66	$7.77	$2.20	$0.00	$69.63	$75.16
G	Hudson Valley (Rockland)	$93.67	$4.36	$2.26	$0.00	$100.29	$105.82
J	NYC	$87.14	$2.60	-$0.39	$0.00	$89.35	$94.88
K	Long Island	$137.63	$3.30	-$0.07	$0.00	$140.87	$146.40

Net EAS Revenues: September 2018 - August 2019							
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$40.60	$4.59	$2.90	$0.00	$48.09	$53.62
F	Capital	$33.32	$8.95	$3.20	$0.00	$45.46	$50.99
G	Hudson Valley (Dutchess)	$32.26	$7.73	$3.57	$0.00	$43.56	$49.09
G	Hudson Valley (Rockland)	$61.25	$3.46	$1.91	$0.00	$66.61	$72.14
J	NYC	$61.74	$3.47	$0.10	$0.00	$65.31	$70.84
K	Long Island	$103.21	$1.58	-$0.92	$0.00	$103.86	$109.39

Net EAS Revenues: September 2019 - August 2020							
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$14.51	$1.88	$2.03	$0.00	$18.42	$23.95
F	Capital	$14.07	$2.45	$2.29	$0.00	$18.80	$24.33
G	Hudson Valley (Dutchess)	$11.49	$1.98	$1.45	$0.00	$14.92	$20.45
G	Hudson Valley (Rockland)	$24.93	$1.62	$1.51	$0.00	$28.06	$33.59
J	NYC	$30.64	$0.92	$0.15	$0.00	$31.71	$37.24
K	Long Island	$60.84	$2.41	$0.81	$0.00	$64.06	$69.59

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.

[3] Assumes a $5.53/kW-year ancillary service (AS) adder revenues for all units from provision of voltage support services ($1.63/kW-year) and other ancillary services ($3.90/kW-year), based on settlement data provided by NYISO.

[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Gas-Only: 1x1 GE 7HA.02 with SCR

Run Hours: September 2017 - August 2018						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	5,160	681	1,123	1,796	8,760
F	Capital	4,576	931	780	2,473	8,760
G	Hudson Valley (Dutchess)	4,674	886	995	2,205	8,760
G	Hudson Valley (Rockland)	6,709	554	760	737	8,760

Run Hours: September 2018 - August 2019						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	4,055	575	910	3,220	8,760
F	Capital	4,585	926	689	2,560	8,760
G	Hudson Valley (Dutchess)	4,178	830	731	3,021	8,760
G	Hudson Valley (Rockland)	6,246	542	549	1,423	8,760

Run Hours: September 2019 - August 2020						
Day-Ahead Commitment		Energy		None		Total
Real-Time Dispatch		Energy	Buyout	Energy	None	
C	Central	2,447	388	673	5,276	8,784
F	Capital	2,641	548	508	5,087	8,784
G	Hudson Valley (Dutchess)	2,185	439	549	5,611	8,784
G	Hudson Valley (Rockland)	4,490	513	631	3,150	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Net EAS Revenues
Gas-Only: 1x1 GE 7HA.02 with SCR

Net EAS Revenues: September 2017 - August 2018							
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$80.27	$5.63	$2.56	$0.00	$88.46	$93.99
F	Capital	$50.59	$7.08	$4.22	$0.00	$61.88	$67.41
G	Hudson Valley (Dutchess)	$49.12	$7.77	$3.99	$0.00	$60.88	$66.41
G	Hudson Valley (Rockland)	$85.49	$4.36	$2.15	$0.00	$92.01	$97.54

Net EAS Revenues: September 2018 - August 2019							
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$40.60	$4.59	$2.90	$0.00	$48.09	$53.62
F	Capital	$33.01	$8.46	$2.60	$0.00	$44.07	$49.60
G	Hudson Valley (Dutchess)	$31.93	$7.73	$3.02	$0.00	$42.69	$48.22
G	Hudson Valley (Rockland)	$61.25	$3.46	$1.91	$0.00	$66.61	$72.14

Net EAS Revenues: September 2019 - August 2020							
Day-Ahead Commitment		Energy		None		Total	Total with AS Adder
Real-Time Dispatch		Energy	Buyout	Energy	None		
C	Central	$14.51	$1.88	$2.03	$0.00	$18.42	$23.95
F	Capital	$14.07	$2.45	$2.29	$0.00	$18.80	$24.33
G	Hudson Valley (Dutchess)	$11.49	$1.98	$1.45	$0.00	$14.92	$20.45
G	Hudson Valley (Rockland)	$24.93	$1.62	$1.51	$0.00	$28.06	$33.59

Notes:

[1] Results reflect data for the period September 2017 through August 2020.

[2] Combined cycle units are provided for informational purposes only and were determined to be unaffected by enviromental runtime limits.

[3] Assumes a $5.53/kW-year ancillary service (AS) adder revenues for all units from provision of voltage support services ($1.63/kW-year) and other ancillary services ($3.90/kW-year), based on settlement data provided by NYISO.

[4] For each hour, a unit is committed via day-ahead then dispatched in real time.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 4-Hour

Run Hours: September 2017 - August 2018																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	373	375	1	5	335	26	0	52	49	36	7,415	0	1	0	1	0	91	8,760
F	Capital	182	184	1	4	328	33	0	71	68	37	7,821	0	1	1	1	4	24	8,760
G	Hudson Valley (Dutchess)	465	467	1	4	345	18	0	34	31	26	7,279	0	0	0	0	0	90	8,760
G	Hudson Valley (Rockland)	315	317	1	5	341	21	0	38	34	30	7,597	0	0	0	0	0	61	8,760
J	NYC	335	337	2	5	332	26	0	46	43	33	7,479	0	0	0	0	0	122	8,760
K	Long Island	669	671	2	3	311	48	1	99	96	56	6,467	0	2	4	2	9	320	8,760

Run Hours: September 2018 - August 2019																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	189	189	0	3	329	34	0	67	63	37	7,817	0	0	1	0	0	31	8,760
F	Capital	60	60	3	6	315	41	0	94	91	48	8,028	0	0	0	1	0	13	8,760
G	Hudson Valley (Dutchess)	199	199	0	6	321	38	0	78	71	43	7,769	0	0	1	2	2	31	8,760
G	Hudson Valley (Rockland)	107	107	0	4	322	39	0	79	74	42	7,968	0	0	1	2	2	13	8,760
J	NYC	123	123	0	5	317	43	0	81	75	47	7,905	0	0	1	1	2	37	8,760
K	Long Island	515	515	4	3	319	40	0	75	74	47	6,944	2	1	3	1	1	216	8,760

Run Hours: September 2019 - August 2020																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	46	44	0	0	356	10	0	14	14	10	8,288	0	0	0	0	0	2	8,784
F	Capital	25	23	0	2	354	10	0	21	19	12	8,309	0	0	0	0	0	9	8,784
G	Hudson Valley (Dutchess)	88	86	0	1	361	4	0	9	8	4	8,218	0	0	0	0	0	5	8,784
G	Hudson Valley (Rockland)	49	47	0	1	361	4	0	9	8	4	8,298	0	0	0	0	0	3	8,784
J	NYC	48	46	0	1	348	17	0	37	36	17	8,226	0	0	0	0	0	8	8,784
K	Long Island	316	314	1	4	323	38	0	90	88	38	7,388	2	1	0	3	0	178	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] Extra Charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[4] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 4-Hour

Net EAS Revenues: September 2017 - August 2018

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$24.27	-$10.22	$0.13	-$0.15	-$0.79	$0.09	$0.00	$3.41	-$1.23	$0.12	$36.73	$0.00	$0.03	$0.00	-$0.02	$0.00	$0.00	$52.37	$54.41
F	Capital	$15.41	-$7.25	$0.12	-$0.48	$0.05	$0.15	$0.00	$5.53	-$2.71	$0.35	$44.80	$0.00	$0.02	-$0.13	-$0.02	$0.03	$0.00	$55.88	$57.92
G	Hudson Valley (Dutchess)	$28.77	-$13.32	$0.09	-$0.24	-$1.17	$0.08	$0.00	$2.69	-$1.17	$0.42	$41.76	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$57.91	$59.95
G	Hudson Valley (Rockland)	$22.58	-$10.80	$0.09	-$0.19	-$0.62	$0.09	$0.00	$2.97	-$1.32	$0.02	$43.57	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$56.38	$58.42
J	NYC	$26.94	-$12.63	$0.38	-$0.23	-$1.12	$0.10	$0.00	$4.57	-$2.16	-$0.09	$42.97	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$58.73	$60.77
K	Long Island	$52.49	-$21.14	$0.29	-$0.08	-$2.73	$0.28	$0.00	$9.65	-$4.09	$1.00	$38.47	$0.00	$0.15	-$0.18	-$0.02	$0.04	$0.00	$74.14	$76.18

Net EAS Revenues: September 2018 - August 2019

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$9.33	-$4.36	$0.00	$0.03	$0.23	$0.11	$0.00	$3.51	-$0.10	$0.16	$37.22	$0.00	$0.00	-$0.03	$0.00	$0.00	$0.00	$46.11	$48.15
F	Capital	$3.42	-$1.60	$0.20	-$0.17	$0.79	$0.18	$0.00	$5.24	-$1.61	$0.88	$40.60	$0.00	$0.00	$0.00	-$0.04	$0.00	$0.00	$47.90	$49.94
G	Hudson Valley (Dutchess)	$9.42	-$4.22	$0.00	$0.27	$0.29	$0.14	$0.00	$3.12	$0.92	$1.08	$39.14	$0.00	$0.00	-$0.05	-$0.06	$0.01	$0.00	$50.07	$52.11
G	Hudson Valley (Rockland)	$5.78	-$2.82	$0.00	$0.31	$0.52	$0.15	$0.00	$3.95	$0.81	$1.00	$40.44	$0.00	$0.00	-$0.05	-$0.06	$0.01	$0.00	$50.05	$52.09
J	NYC	$7.64	-$3.43	$0.00	-$0.05	$0.31	$0.15	$0.00	$6.00	-$0.85	$0.32	$40.85	$0.00	$0.00	-$0.05	-$0.02	$0.01	$0.00	$50.87	$52.91
K	Long Island	$34.23	-$14.75	$0.36	$0.06	-$1.67	$0.15	$0.00	$6.98	-$2.06	$0.16	$35.44	$0.00	$0.03	-$0.18	-$0.02	$0.00	$0.00	$58.73	$60.77

Net EAS Revenues: September 2019 - August 2020

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$1.54	-$0.70	$0.00	$0.00	$0.85	$0.03	$0.00	$0.62	$0.23	$0.06	$30.64	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.27	$35.31
F	Capital	$1.35	-$0.78	$0.00	-$0.05	$0.91	$0.03	$0.00	$1.84	-$0.75	-$0.02	$30.35	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.88	$34.92
G	Hudson Valley (Dutchess)	$3.20	-$1.53	$0.00	-$0.01	$0.71	$0.01	$0.00	$0.63	-$0.12	-$0.02	$30.12	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.98	$35.02
G	Hudson Valley (Rockland)	$1.98	-$1.01	$0.00	-$0.02	$0.81	$0.01	$0.00	$0.66	-$0.15	-$0.02	$30.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.74	$34.78
J	NYC	$2.38	-$1.21	$0.00	-$0.02	$0.70	$0.05	$0.00	$3.43	-$1.25	-$0.12	$30.54	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$34.51	$36.55
K	Long Island	$18.19	-$6.92	$0.13	-$0.10	-$0.44	$0.12	$0.00	$9.21	-$3.43	-$0.10	$27.43	$0.00	$0.17	$0.00	-$0.12	$0.00	$0.00	$44.12	$46.16

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.
[4] Extra charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[5] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 6-Hour

Run Hours: September 2017 - August 2018																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	400	403	1	10	341	33	0	80	70	44	7,284	0	0	1	3	0	90	8,760
F	Capital	205	208	2	8	325	34	0	81	75	42	7,720	0	1	1	3	4	51	8,760
G	Hudson Valley (Dutchess)	534	537	3	5	352	26	0	51	49	36	7,079	0	1	1	0	0	86	8,760
G	Hudson Valley (Rockland)	333	336	0	5	338	27	0	52	48	33	7,526	0	1	0	1	0	60	8,760
J	NYC	406	409	0	5	339	37	0	62	57	42	7,265	0	0	0	4	0	134	8,760
K	Long Island	827	830	0	3	338	69	2	139	133	74	6,033	0	2	5	8	8	289	8,760
Run Hours: September 2018 - August 2019																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	170	170	1	4	318	46	0	89	87	51	7,788	0	1	0	1	0	34	8,760
F	Capital	63	63	2	9	319	35	0	104	98	45	7,998	0	1	0	2	0	21	8,760
G	Hudson Valley (Dutchess)	190	190	0	9	314	43	0	105	93	51	7,720	0	0	3	3	3	36	8,760
G	Hudson Valley (Rockland)	99	99	0	8	316	41	0	92	83	47	7,945	0	0	1	3	2	24	8,760
J	NYC	114	114	0	5	316	46	0	95	90	49	7,885	0	0	0	3	0	43	8,760
K	Long Island	569	569	3	4	295	78	0	167	163	91	6,598	0	4	7	4	8	200	8,760
Run Hours: September 2019 - August 2020																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	33	30	0	1	351	14	0	21	20	15	8,294	0	0	0	0	0	5	8,784
F	Capital	18	15	0	3	353	10	0	28	26	12	8,311	0	1	0	0	1	6	8,784
G	Hudson Valley (Dutchess)	79	76	0	1	360	6	0	13	12	6	8,227	0	0	0	0	0	4	8,784
G	Hudson Valley (Rockland)	45	42	0	1	360	6	0	11	10	6	8,298	0	0	0	0	0	5	8,784
J	NYC	46	43	0	1	344	22	0	41	40	22	8,213	0	0	0	0	0	12	8,784
K	Long Island	356	353	0	4	337	51	0	111	107	49	7,259	0	0	0	2	0	155	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] Extra Charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[4] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 6-Hour

Net EAS Revenues: September 2017 - August 2018

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$28.92	-$12.68	$0.07	-$0.45	-$1.13	$0.12	$0.00	$5.46	-$1.78	-$0.06	$35.43	$0.00	$0.00	-$0.05	-$0.11	$0.00	$0.00	$53.74	$55.78
F	Capital	$20.48	-$10.02	$0.15	-$0.26	-$0.06	$0.23	$0.00	$7.19	-$4.02	-$0.49	$43.25	$0.00	$0.02	-$0.13	-$0.25	$0.03	$0.00	$56.10	$58.14
G	Hudson Valley (Dutchess)	$34.70	-$16.01	$0.42	-$0.32	-$1.40	$0.11	$0.00	$4.21	-$1.94	$1.16	$39.82	$0.00	$0.08	-$0.13	$0.00	$0.00	$0.00	$60.71	$62.75
G	Hudson Valley (Rockland)	$25.52	-$12.11	$0.00	-$0.13	-$0.83	$0.13	$0.00	$4.63	-$2.23	-$0.15	$42.63	$0.00	$0.08	$0.00	-$0.13	$0.00	$0.00	$57.40	$59.44
J	NYC	$34.72	-$16.70	$0.00	-$0.10	-$1.74	$0.18	$0.00	$5.96	-$2.34	-$0.20	$41.15	$0.00	$0.00	$0.00	-$0.13	$0.00	$0.00	$60.80	$62.84
K	Long Island	$68.67	-$29.09	$0.00	-$0.07	-$3.81	$0.28	$0.00	$12.60	-$3.89	-$0.23	$34.98	$0.00	$0.07	-$0.22	-$0.20	$0.04	$0.00	$79.14	$81.18

Net EAS Revenues: September 2018 - August 2019

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$9.33	-$4.47	$0.00	-$0.04	$0.29	$0.14	$0.00	$4.48	-$0.26	$0.25	$37.14	$0.00	$0.04	$0.00	-$0.03	$0.00	$0.00	$46.89	$48.93
F	Capital	$4.18	-$2.09	$0.04	$0.00	$0.64	$0.15	$0.00	$5.74	-$1.60	$0.90	$40.36	$0.00	$0.03	$0.00	-$0.07	$0.00	$0.00	$48.29	$50.33
G	Hudson Valley (Dutchess)	$9.65	-$4.33	$0.00	$0.27	$0.27	$0.14	$0.00	$5.21	$0.93	$0.79	$38.87	$0.00	$0.00	-$0.22	-$0.09	$0.01	$0.00	$51.50	$53.54
G	Hudson Valley (Rockland)	$5.77	-$2.73	$0.00	$0.27	$0.56	$0.13	$0.00	$4.83	$0.81	$0.75	$40.27	$0.00	$0.00	-$0.05	-$0.10	$0.01	$0.00	$50.52	$52.56
J	NYC	$8.09	-$3.69	$0.00	$0.13	$0.22	$0.14	$0.00	$6.93	-$1.33	$0.47	$40.75	$0.00	$0.00	$0.00	-$0.08	$0.00	$0.00	$51.62	$53.66
K	Long Island	$39.31	-$17.34	$0.09	$0.09	-$1.82	$0.29	$0.00	$16.37	-$6.03	-$0.43	$33.31	$0.00	$0.28	-$0.38	-$0.13	$0.03	$0.00	$63.65	$65.69

Net EAS Revenues: September 2019 - August 2020

Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$1.25	-$0.54	$0.00	$0.02	$0.91	$0.04	$0.00	$1.02	$0.03	$0.02	$30.63	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.37	$35.41
F	Capital	$1.04	-$0.50	$0.00	-$0.15	$0.92	$0.03	$0.00	$2.40	-$1.09	-$0.03	$30.35	$0.00	$0.03	$0.00	$0.00	$0.01	$0.00	$32.99	$35.03
G	Hudson Valley (Dutchess)	$3.18	-$1.54	$0.00	-$0.02	$0.71	$0.02	$0.00	$0.91	-$0.25	-$0.02	$30.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.17	$35.21
G	Hudson Valley (Rockland)	$2.07	-$1.10	$0.00	-$0.02	$0.81	$0.02	$0.00	$0.77	-$0.23	-$0.02	$30.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.77	$34.81
J	NYC	$2.45	-$1.18	$0.00	-$0.02	$0.74	$0.06	$0.00	$3.68	-$1.41	-$0.17	$30.51	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$34.64	$36.68
K	Long Island	$21.73	-$8.40	$0.00	-$0.11	-$0.69	$0.15	$0.00	$10.93	-$4.24	-$0.18	$26.95	$0.00	$0.00	$0.00	-$0.05	$0.00	$0.00	$46.09	$48.13

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.
[4] Extra charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[5] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.

Dispatch Co-Optimization By Year: Run Hours
Battery Energy Storage System (BESS) 8-Hour

Run Hours: September 2017 - August 2018																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	432	436	4	10	331	38	1	108	99	55	7,124	0	0	3	2	0	117	8,760
F	Capital	218	222	3	7	318	42	0	105	102	49	7,621	0	1	0	5	2	65	8,760
G	Hudson Valley (Dutchess)	546	550	3	8	349	30	0	76	71	45	6,991	0	1	1	0	0	89	8,760
G	Hudson Valley (Rockland)	366	370	1	7	343	26	0	70	64	36	7,404	0	1	1	1	0	70	8,760
J	NYC	428	432	1	11	334	40	0	86	74	52	7,155	0	0	2	5	1	139	8,760
K	Long Island	963	964	2	6	326	82	1	179	171	88	5,665	0	2	6	15	9	281	8,760

Run Hours: September 2018 - August 2019																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	152	152	1	5	317	46	0	107	104	52	7,779	0	1	0	2	0	42	8,760
F	Capital	72	72	2	11	313	40	0	108	100	51	7,956	0	1	0	4	0	30	8,760
G	Hudson Valley (Dutchess)	189	189	1	7	320	40	0	116	107	50	7,689	0	0	3	4	4	41	8,760
G	Hudson Valley (Rockland)	97	97	1	5	320	40	0	97	92	47	7,927	0	0	1	2	2	32	8,760
J	NYC	124	124	1	4	308	53	1	110	103	58	7,810	0	0	4	5	7	48	8,760
K	Long Island	615	618	4	10	287	81	0	208	201	109	6,410	0	6	7	5	7	192	8,760

Run Hours: September 2019 - August 2020																			
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	
C	Central	27	23	0	0	352	14	0	23	23	14	8,301	0	0	0	0	0	7	8,784
F	Capital	16	12	2	3	351	10	0	30	30	13	8,309	0	1	0	0	1	6	8,784
G	Hudson Valley (Dutchess)	77	73	0	1	359	7	0	14	13	7	8,227	0	0	0	0	0	6	8,784
G	Hudson Valley (Rockland)	32	28	0	1	359	7	0	11	10	7	8,325	0	0	0	0	0	4	8,784
J	NYC	43	39	0	1	343	23	0	41	40	23	8,218	0	0	0	0	0	13	8,784
K	Long Island	413	409	2	5	333	52	0	119	116	56	7,130	0	0	0	3	0	146	8,784

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] For each hour, a unit is committed via day-ahead then dispatched in real time.
[3] Extra Charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[4] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.

Dispatch Co-Optimization By Year: Net EAS Revenues
Battery Energy Storage System (BESS) 8-Hour

Net EAS Revenues: September 2017 - August 2018																				
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$30.08	-$13.52	$0.20	-$0.47	-$1.22	$0.16	$0.00	$7.85	-$3.38	-$0.14	$34.65	$0.00	$0.00	-$0.14	-$0.04	$0.00	$0.00	$54.02	$56.06
F	Capital	$22.07	-$11.10	$0.31	-$0.45	-$0.27	$0.27	$0.00	$10.49	-$6.40	$0.49	$42.27	$0.00	$0.02	$0.00	-$0.45	$0.02	$0.00	$57.25	$59.29
G	Hudson Valley (Dutchess)	$36.62	-$17.15	$0.43	-$0.73	-$1.53	$0.14	$0.00	$7.46	-$3.77	$0.87	$38.80	$0.00	$0.08	-$0.13	$0.00	$0.00	$0.00	$61.09	$63.13
G	Hudson Valley (Rockland)	$28.26	-$13.85	$0.08	-$0.47	-$1.15	$0.13	$0.00	$7.54	-$3.85	$0.10	$41.41	$0.00	$0.08	-$0.13	-$0.07	$0.00	$0.00	$58.07	$60.11
J	NYC	$38.11	-$18.89	$0.08	-$0.53	-$1.76	$0.18	$0.00	$8.67	-$3.28	-$0.80	$39.66	$0.00	$0.00	-$0.12	-$0.15	$0.00	$0.00	$61.17	$63.21
K	Long Island	$75.75	-$33.27	$0.71	$0.03	-$4.36	$0.35	$0.00	$18.11	-$7.23	-$0.61	$32.71	$0.00	$0.07	-$0.30	-$0.54	$0.04	$0.00	$81.44	$83.48

Net EAS Revenues: September 2018 - August 2019																				
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$8.54	-$4.06	$0.07	-$0.09	$0.23	$0.15	$0.00	$5.29	-$0.35	$0.09	$37.04	$0.00	$0.04	$0.00	-$0.03	$0.00	$0.00	$46.93	$48.97
F	Capital	$4.81	-$2.46	$0.11	$0.19	$0.73	$0.17	$0.00	$5.97	-$1.81	$0.74	$40.06	$0.00	$0.03	$0.00	-$0.11	$0.00	$0.00	$48.42	$50.46
G	Hudson Valley (Dutchess)	$9.83	-$4.53	$0.27	$0.13	$0.33	$0.14	$0.00	$5.62	$0.77	$0.67	$38.72	$0.00	$0.00	-$0.16	-$0.10	$0.01	$0.00	$51.70	$53.74
G	Hudson Valley (Rockland)	$5.75	-$2.74	$0.27	$0.14	$0.65	$0.13	$0.00	$4.91	$0.89	$0.80	$40.15	$0.00	$0.00	-$0.05	-$0.08	$0.01	$0.00	$50.82	$52.86
J	NYC	$8.59	-$4.02	$0.27	-$0.02	$0.34	$0.16	$0.00	$8.08	-$1.80	$0.28	$40.28	$0.00	$0.00	-$0.11	-$0.16	$0.02	$0.00	$51.91	$53.95
K	Long Island	$41.50	-$18.95	$0.35	-$0.13	-$1.95	$0.31	$0.00	$20.20	-$7.55	-$0.80	$32.42	$0.00	$0.33	-$0.38	-$0.14	$0.03	$0.00	$65.23	$67.27

Net EAS Revenues: September 2019 - August 2020																				
Day-Ahead Commitment		Discharge	Charge	Extra Charge					Reserve					None					Total	Total with VSS Adder
Real-Time Dispatch		Discharge	Charge	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None	Discharge	Charge	Extra Charge	Reserve	None		
C	Central	$1.07	-$0.46	$0.00	$0.00	$0.92	$0.04	$0.00	$1.09	$0.03	$0.03	$30.64	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.37	$35.41
F	Capital	$0.90	-$0.39	$0.15	-$0.08	$0.90	$0.03	$0.00	$2.53	-$1.29	-$0.03	$30.36	$0.00	$0.03	$0.00	$0.00	$0.01	$0.00	$33.11	$35.15
G	Hudson Valley (Dutchess)	$3.10	-$1.54	$0.00	-$0.01	$0.72	$0.02	$0.00	$0.93	-$0.26	-$0.02	$30.16	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$33.11	$35.15
G	Hudson Valley (Rockland)	$1.54	-$0.81	$0.00	-$0.02	$0.86	$0.02	$0.00	$0.77	-$0.23	-$0.02	$30.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.71	$34.75
J	NYC	$2.36	-$1.14	$0.00	-$0.02	$0.74	$0.07	$0.00	$3.68	-$1.41	-$0.16	$30.55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$34.65	$36.69
K	Long Island	$24.53	-$9.89	$0.17	-$0.12	-$1.01	$0.15	$0.00	$11.57	-$4.77	-$0.23	$26.52	$0.00	$0.00	$0.00	-$0.05	$0.00	$0.00	$46.85	$48.89

Notes:
[1] Results reflect data for the period September 2017 through August 2020.
[2] Assumes $2.04/kW-year VSS Revenues for all units, based on settlement data provided by NYISO.
[3] For each hour, a unit is committed via day-ahead then dispatched in real time.
[4] Extra charge hours are additional charging hours that units undertake on each cycle day with charging and discharging activity in order to make up for efficiency losses in charging.
[5] Units also earn reserve revenues during Charge and Extra Charge hours reflecting their current stored energy and the amount of power they are scheduled to withdraw for charging purposes.