December 31, 2020

BY ELECTRONIC FILING
The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ISO New England Inc., Docket No. ER21-_____-000;
Updates to CONE, Net CONE, and Capacity Performance Payment Rate

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. ("ISO") hereby submits to the Federal Energy Regulatory Commission ("Commission") this transmittal letter and revisions to the ISO New England Transmission, Markets and Services Tariff ("Tariff") to update three values used in the administration of the Forward Capacity Market ("FCM").[2] These values are being updated in advance of the sixteenth Forward Capacity Auction ("FCA 16"), to be conducted in February of 2022 for the Capacity Commitment Period that begins on June 1, 2025. The ISO is requesting that the new values and associated Tariff revisions become effective on March 2, 2021, such that they will be in place for the FCA 16 qualification process, which begins in March 2021.

I. INTRODUCTION

The Tariff requires that various parameters used in the administration of the Forward Capacity Market be updated periodically. This filing addresses three of those parameters: the Cost of New Entry ("CONE"), the net cost of new entry ("Net CONE"), and the Capacity Performance Payment Rate. (CONE is sometimes informally referred to as "gross CONE," to

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1 16 U.S.C. § 824d (2019).

2 Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff, the Restated New England Power Pool Agreement, and the Participants Agreement.

more clearly distinguish it from Net CONE.) At a very high level, the CONE and Net CONE values are, respectively, estimates of the total and net costs of developing the most economic type of new capacity resource in New England, while the Capacity Performance Payment Rate is the Tariff-prescribed settlement rate for resource performance (during Capacity Scarcity Conditions) in New England's two-settlement capacity market design (also called "Pay for Performance" or "PFP"). Each of these values is being updated in advance of FCA 16.

The ISO retained the energy consultancy firm Concentric Energy Advisors ("CEA") to perform the detailed analysis underlying the updated CONE and Net CONE values (as well as the Offer Review Trigger Prices ("ORTPs"), which as noted below will be filed separately). CEA partnered with the engineering firm Mott MacDonald for purposes of developing the detailed, bottom-up engineering estimates of entry costs for each of the resource types that were evaluated. CEA and Mott MacDonald prepared a draft report detailing the methodology they used to estimate entry costs and that report was reviewed by the ISO and stakeholders in the stakeholder process. Based on feedback from the ISO and stakeholders, the entry cost calculations detailed in the report were refined and revised throughout the stakeholder review process. The final version of the report, the *ISO-NE CONE and ORTP Analysis; An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction; FCA 16 and Forward* ("CEA Report") is included as an attachment to this filing and establishes the substantive basis for the updated CONE and Net CONE values filed here.[3]

Two other Forward Capacity Market parameters are also being updated for FCA 16, and were reviewed with stakeholders concurrently, but are being filed with the Commission separately. Those two other parameters are used in the mitigation processes of the Forward Capacity Market, and do not directly impact the CONE, Net CONE, and Capacity Performance Payment Rate values in the instant filing. First, updates to the Dynamic De-List Bid Threshold were voted separately and will be filed separately with the Commission. Second, updated Offer Review Trigger Prices were voted alongside the three parameters filed here, but as a result of stakeholder-proposed amendments, NEPOOL supported a set of Offer Review Trigger Prices different from those advanced by the ISO. Both sets of Offer Review Trigger Prices will be filed in January 2021 as a "jump ball" pursuant to Section 11.1.5 of the Participants Agreement. These process-related issues are explained in more detail in Part VI below.

[3] As indicated in its title, the CEA Report also includes detailed information (notably in Sections 7 and 8) regarding the calculation of updated Offer Review Trigger Prices, which, as discussed in Part VI below, will be filed separately in January 2021.

II. REQUESTED EFFECTIVE DATE

The ISO requests an effective date of March 2, 2021 for the Tariff revisions filed here. The qualification process for FCA 16 (to be conducted in February 2022) begins in March 2021. Specifically, the Existing Capacity Qualification Deadline for FCA 16 is March 12, 2021. This is the date by which Retirement De-List Bids must be submitted to the ISO. (The window for submitting those bids opens on March 5, 2021.) The calculations relevant to filing and assessing Retirement De-List Bids depend in part on the Forward Capacity Auction Starting Price, which is a function of the CONE and Net CONE values. Furthermore, pursuant to the revised Dynamic De-List Bid Threshold methodology also being filed (separately) with the Commission for use in FCA 16, the updated Dynamic De-List Bid Threshold – which uses Net CONE as an input – must be posted to the ISO's website no later than five business days before the Existing Capacity Retirement Deadline. Five business days before that deadline is March 5, 2021, but an effective date slightly before that deadline will ensure that the ISO has the time to calculate and post the numbers as required. For these reasons, it is very important for the smooth conduct of the FCA 16 qualification process that the updated values filed here become effective by March 2, 2021.

III. DESCRIPTION OF THE ISO; COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO plans and operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council and the North American Electric Reliability Corporation.

All correspondence, communications, and service in this proceeding should be addressed to the undersigned for the ISO as follows:

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IV. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[4] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[5] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[6] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[7] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[8] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[9]

V. EXPLANATION OF THE CONE, NET CONE, AND CAPACITY PERFORMANCE PAYMENT RATE UPDATES

Below, the ISO describes each of the three values that it proposes to update, along with details of their development and information about their role in the administration of the FCM. In addition, in Part V.F, the ISO describes clarifications it proposes to make to the definition of Net CONE. In explaining these clarifications, the ISO also responds to the substantive portions of a recent complaint filed by the New England Power Generators Association ("NEPGA"). NEPGA argues that the calculation of Net CONE must be based on a system modeled assuming currently-expected surplus conditions (or, "as expected"). As the ISO explains, the capacity market's design requires, and has always required, Net CONE to be calculated based on a system modeled under long-term equilibrium conditions (or "at criterion").

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[4] *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

[5] *Id.* at 10 (*quoting City of Winnfield v. FERC,* 744 F.2d 871, 876 (D.C. Cir. 1984)).

[6] *Id.* at 9.

[7] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) ("*Bethany"*).

[8] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[9] *Cf. Southern California Edison Co., et al,* 73 FERC ¶ 61,219 at p. 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (citing *Bethany*)).

A. Overview of CONE and Net CONE

As part of the design of the Forward Capacity Market, the ISO estimates the cost of developing new resources that may enter the market. These estimated entry costs, which are used for several inter-related purposes, come in two forms. The first is (gross) CONE, which is intended to reflect the total cost of developing a new resource, without any adjustment for the revenues that the resource might earn in supplying energy and ancillary services. The second is Net CONE, which is intended to reflect the total cost of developing a new resource (gross CONE) minus the variable profit the resource is expected to earn from supplying energy and ancillary services in the ISO-administered markets. As discussed in more detail below, the CONE and Net CONE values are based on the resource type that is expected to be the most cost-effective technology for new entry over the long term.

The primary use of Net CONE is to help define how demand is represented in the annual auction process. Demand is represented by system and zonal demand curves that are calculated to reflect the Marginal Reliability Impact (or "MRI") of adding capacity in different locations. The market rules specify that the system demand curve must be scaled so that the capacity quantity associated with the Net CONE value satisfies the New England region's resource adequacy reliability standard (which is a Loss of Load Expectation of 0.1 days per year).[10]

The CONE and Net CONE values also are used to set the Forward Capacity Auction Starting Price. The market rules specify that the Forward Capacity Auction Starting Price is the higher of: (1) CONE, and; (2) 1.6 multiplied by Net CONE.[11] The practical effect of the Forward Capacity Auction Starting Price is to serve as a price cap in the capacity market.

While the CONE and Net CONE values are integral parts of the Forward Capacity Auction, the values also are used during the qualification process that precedes each auction. The CONE and Net CONE values are first used in an auction cycle when capacity suppliers with existing resources submit any retirement de-list bids. The market rules specify that the remaining economic life of any resource subject to a retirement de-list bid will be calculated by the Internal Market Monitor pursuant to a formula that includes the Forward Capacity Auction Starting Price (which, as noted above, is a function of the CONE and Net CONE values). Importantly, for FCA 16, retirement de-list bids must be submitted to the ISO no later than March 12, 2021.

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[10] *See* Tariff Section III.13.2.2.4 ("Capacity Demand Curve Scaling Factor") and Section III.13.2.2.1 ("System-Wide Capacity Demand Curve"). Note that the MRI Transition Period addressed in Section III.13.2.2.1 will expire prior to the sixteenth Capacity Commitment Period, when the CONE and Net CONE values in the instant filing will apply, and therefore only the final paragraph of Section III.13.2.2.1 is germane to present matters.

[11] *See* Tariff Section III.13.2.4.

The CONE and Net CONE values continue to be used throughout the qualification process in various ways. For example, Project Sponsors with new capacity resources likely will consider the updated values, and their impact on the system and zonal demand curves, as they prepare for the submission of New Capacity Show of Interest Forms.

The Tariff requires that CONE and Net CONE be fully recalculated no less often than once every three years, and that in between such updates, they be adjusted annually using indices that are specified in the market rules.[12] The last full recalculation was filed with the Commission in early 2017 to be effective for the twelfth Forward Capacity Auction.[13] The full recalculation that would have occurred for the fifteenth Forward Capacity Auction was delayed until FCA 16 pursuant to a filing made jointly by the ISO and NEPOOL in 2018 to consolidate the review of the various FCM parameters.[14] When these values are fully recalculated, the ISO is required by the Tariff to review the results of the recalculation with stakeholders and file them with the Commission prior to the Forward Capacity Auction in which the new values are to apply.[15]

These requirements have been fully satisfied here. The CONE and Net CONE values filed here, representing the results of the latest full recalculation using updated data for estimated construction costs and expected net revenues of new resource types likely to participate in the market, were extensively discussed with stakeholders in eight separate meetings of the Markets Committee between May and November 2020, many of which spread across two or even three days. The updated values are filed here pursuant to Section 205 of the Federal Power Act, in full compliance with that section's notice requirement.

B. Resource Screening

The Tariff does not specify a technology to be used to perform the periodic full recalculations of CONE and Net CONE in New England. Instead, the ISO's consultants followed a broad, three-step process to select a specific resource technology to establish the values of CONE and Net CONE. The first step involved developing a set of screening criteria to identify which resource types to consider further. The second step was to identify specific generation technologies within each resource type that satisfied the screening criteria, for further evaluation

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[12] *See* Tariff Sections III.13.2.4 and III.A.21.1.2(e).

[13] *See* ISO New England Inc. Filing of CONE and ORTP Updates, FERC Docket No. ER17-795-000 (filed January 13, 2017). The "ISO-NE CONE and ORTP Analysis" included as Attachment 1 to that filing is referred to herein as the "2017 Net CONE Study."

[14] *See* ISO New England Inc. and New England Power Pool Participants Committee Filing re Consolidation of FCM Parameter Review, FERC Docket No. ER19-335-000 (filed November 14, 2018) (accepted by letter order issued December 19, 2018).

[15] *See* Tariff Section III.13.2.4.

as possible candidates for the CONE and Net CONE estimates. These specific generation technologies are known as "candidate reference technologies" for the CONE and Net CONE calculations. The final, and most involved, step was to develop financial calculations and engineering-economic cost estimates necessary to estimate the value of CONE and Net CONE for the candidate reference technologies. We discuss the first two steps presently, and the third step in Part V.C below.

For the first step, CEA developed and reviewed with stakeholders three screening criteria to identify candidate resource types for the CONE and Net CONE reference technology. As CEA explains in its report, these three screening criteria summarize factors that the ISO has employed, and that the Commission has previously considered, in prior filings for the full recalculation of CONE and Net CONE.[16] Specifically, CEA identified that the important considerations in screening resource types for estimating CONE and Net CONE should include the following:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions;

2. Must have reliable cost information available to calculate a CONE value using a full "bottom-up" analytical approach; and

3. Must reliably be able to meet load when resource adequacy is at risk.

The rationale for, and application of, each of these three screening criteria are discussed in detail in Section 3.A.i of the CEA Report.[17] The resource types that passed these screening criteria were then subject to a more detailed evaluation of their costs and revenues.[18]

CEA explains that various resource types were considered for evaluation against the screening criteria outlined above, including gas-fired resources, coal-fired resources, nuclear resources, various renewable-energy resources, and battery-storage resources. Gas-fired resources passed the screening criteria, as they have been proven to be economic for new entry in the recent past and have operating data with which to calculate a CONE value using a full "bottom up" analytical approach. No new coal or nuclear resources have been developed in New England in thirty years, and therefore, these resources do not meet all of the screening criteria. Renewable resources have been developed in recent years and additional renewable and battery storage resources have been proposed. However, these resources did not pass (one or more of)

[16] *See* CEA Report at 14-15 (including footnotes 8 and 9 therein).

[17] *See* CEA Report at 14-16.

[18] *See* CEA Report at 8.

the screening criteria, as shown in Table 5 in the CEA Report.[19] As a result, CEA's analysis focused on gas-fired resources in both simple cycle and combined cycle configurations as the appropriate technologies to consider for the next steps of the CONE and Net CONE analysis.[20]

For its second step, CEA then considered a broad range of gas-fired generation technologies, spanning combined cycle, simple cycle, and aero-derivative type machines, for further evaluation as possible candidates for the CONE and Net CONE estimates.[21] As described in the CEA Report, and based in part on the generation technologies developed within the ISO's footprint in recent years, CEA selected three candidate reference technologies to undergo a full-scale cost estimation for purposes of determining CONE and Net CONE. Those technologies are:

- the General Electric 7HA.02 simple cycle combustion turbine ("CT");
- the General Electric 7HA.02 combined cycle combustion turbine ("CC"); and
- the General Electric LM6000 aero-derivative gas turbine ("Aero").[22]

The technical specifications for each of these candidate reference technologies are set forth in Section 3.D of the CEA Report.[23]

C. (Gross) Cost of New Entry

1. Overview

Updating gross CONE begins with estimating the total (or gross) cost of constructing, in New England, each of the three candidate reference technologies enumerated above. CEA explains that for each of the candidate reference technologies, it developed technical specifications, installed capital costs, and operating costs over the modeled project life of each facility. Based on reasonable financial assumptions regarding the cost of debt, return on equity, and capital structure (*i.e.,* debt to equity ratio), CEA developed a discounted cash flow model to calculate a levelized annual cost for each candidate reference technology. Absent any net operating revenue, that calculation determines each candidate reference technology's levelized

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[19] *See* CEA Report at 17.

[20] *See* CEA Report at 16- 17.

[21] *See* CEA Report at 17-21.

[22] *See* CEA report at 16-21.

[23] *See* CEA Report at 33-35.

revenue requirement – *i.e.,* the gross CONE – necessary to ensure the recovery on and of its investment costs, consistent with the project's assumed return on equity.[24]

2. Capital Costs

The CEA report sets forth in considerable detail the physical assumptions applied to all three candidate reference technology facilities modeled for CONE and Net CONE, including:[25]

- The location of the reference technology facility is assumed to be New London County, CT, an area served by both existing high-voltage (345 kV) electric transmission and natural gas transmission infrastructure.[26]
- The reference technology facility is assumed to be located on a greenfield site, consistent with the 2017 Net CONE Study; this avoids the highly variable and potentially site-specific cost uncertainties associated with developing new entry cost estimates for brownfield sites.[27]
- The reference technology facility is assumed to have a project life of twenty years, consistent with the assumption used for all gas-fired generators in the 2017 Net CONE Study (as well as in the prior CONE re-calculation performed for the ISO, by a different consultancy, in 2014).[28]
- The reference technology facility is assumed to be dual-fuel capable with on-site backup fuel, in the form of No. 2 fuel oil, to address any potential issues with the availability of natural gas supply in the general region.[29]
- The reference technology facility is assumed to be in compliance with federal and regional environmental requirements, including both emissions and cooling system requirements.
- Interconnection costs include the facilities required to interconnect to the New England transmission system and to the region's natural gas infrastructure. The electrical interconnection costs assume the facility will interconnect, as a capacity

[24] *See* CEA Report at 8.

[25] *See* CEA Report at 21-26.

[26] *See* CEA Report at 22. As noted in the CEA Report, while the CONE reference unit is a hypothetical unit of a given resource and technology type, a general location is required for purposed of estimating certain costs such as property taxes, labor rates, interconnection costs, and such.

[27] *See* CEA Report at 23.

[28] *See* footnote 86 below.

[29] *See* CEA Report at 25.

> resource, to the region's 345kV transmission system. The natural gas interconnection costs assume the facility will interconnect on, or in very near proximity to, a main natural gas transmission line. CEA's siting approach to each modeled reference technology facility assumes that a two-mile interconnection to both the gas and electric grids would be required.[30]

The CEA Report next explains that Mott MacDonald, in partnership with CEA, prepared capital cost estimates for the three candidate reference technologies based on modern construction techniques and materials for electricity generating stations and related facilities. Capital costs fall into two general categories: Engineering, Procurement, and Construction ("EPC") (costs related to the construction of the plant itself) and non-EPC (owner's costs, interconnection costs, etc.). These costs and their many components are enumerated and explained in the CEA Report.[31]

Mott MacDonald developed the major equipment cost components, such as field construction labor hours and quantities, to develop "bottom-up" engineering-based cost estimates for each candidate reference technology facility. A bottom-up estimate utilizes a project's technical scope as the cost basis. The technical scope identifies what is required for the facility to be engineered, procured, constructed, tested, and delivered to commence initial operation. Once the technical scope is determined, it is used as the basis to calculate the cost to complete the proposed project. In addition to the technical scope, many additional cost considerations are addressed in a bottom-up estimate, such as labor rates, shipping costs, and scheduling requirements. The bottom-up cost analysis is based, in part, on information from Mott MacDonald's comprehensive power plant cost estimating database and the Thermoflow PEACE cost system, as applicable to power plants of the size and configuration selected for the candidate reference technologies.[32]

The CEA Report details the final EPC and non-EPC costs (together, the "overnight capital costs") for each candidate reference technology facility.[33] The resulting overnight capital costs, as set forth in Tables 14 through 16 of the CEA report,[34] are as follows.

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[30] *See* CEA Report at 25-26.

[31] *See* CEA Report at 26-32.

[32] *See* CEA Report at 26-27.

[33] *See* CEA Report at 27-32, 36-38. "Overnight capital costs" is industry shorthand for a project's total capital costs, exclusive of certain financing costs.

[34] *See* CEA Report at 36-38.

Candidate Reference Technology	Capital Cost (2019 $, in millions)	Capital Cost (2019 $/kW)
CC	535.3	985.0
CT	288.0	776.9
Aero	187.0	1,961.4

3. Financial Assumptions and (Gross) CONE

Section 4 of the CEA Report sets forth the financial assumptions used to develop the CONE and Net CONE estimate for each candidate reference technology. These financial assumptions were incorporated into a discounted cash flow model developed by CEA to calculate the CONE values summarized presently, and the Net CONE values summarized in the following section, for each of the three candidate reference technologies.[35]

At a high level, the (gross) CONE value represents the (levelized) revenue required to recover the modeled facility's investment costs over the assumed twenty-year project life. The Net CONE value represents the (levelized) revenue required to cover the modeled facility's capital costs and its operating costs, net of cash flows from supplying energy and ancillary services in the New England markets, over the same twenty-year horizon. In both cases, these estimates include the cost of providing a return to equity investors and to debt providers, and are based on the reasonable assumption that significant amounts of capital will only be invested if investors anticipate that their investment will generate returns that meet or exceed the market's cost of capital (that is, of debt and equity). Consistent with previous studies, CONE and Net CONE values are expressed on a real, levelized basis (*i.e.,* in constant 2025 dollars per kW-month). That is, the discounted cash flow model calculations produce a payment such that if the capacity payment increases at the assumed rate of inflation every year, the net present value ("NPV") of a facility's total costs are equal to the NPV of its total revenues over the twenty-year period.[36]

The CEA Report discusses the discounted cash flow model's financial inputs in detail, including inflation, depreciation, return on equity, cost of debt, income taxes, property taxes, and so forth.[37] Overall, the values of these financial inputs are comparable to the values used in the previous full recalculations of CONE and Net CONE, as well as recent recalculations (performed

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[35] The discounted cash flow spreadsheet model developed for this purpose is available on the ISO's website at https://www.iso-ne.com/static-assets/documents/2020/11/a4_a_i_net_cone_ortp_model_dcf_master_final.xlsm.

[36] *See* CEA Report at 44.

[37] *See* CEA Report at 40-41 and 45-57.

by different consultancies) for the NYISO and for PJM.[38] The final weighted average cost of capital of 8.3% is comparable to, but slightly less than, the CONE and Net CONE analyses performed in these three regions in 2014 and 2016.[39] This reflects, in significant part, a lower interest rate environment in which the cost of generic corporate debt has decreased from a peak in 2016, when the ISO's last full recalculation was performed.[40]

With these financial inputs and the discounted cash flow model, CEA then converted the investment costs for each candidate reference technology into levelized (gross) CONE values. Section 6 of the CEA report summarizes the final levelized CONE values, in 2025 dollars,[41] for each of the three candidate reference technologies. They are as follows:[42]

Candidate Reference Technology	CONE – Qualified[43] ($/kW-month)
CC	17.600
CT	11.874
Aero	28.144

D. Net Cost of New Entry

1. Overview

The Net CONE values for the three candidate reference technologies are calculated by subtracting from the CONE value the net revenue that each candidate reference technology can be expected to earn, in a system at criterion.[44] As explained in detail in Section 5 of the CEA Report, the candidate reference units have several potential revenue streams that must be considered in the Net CONE calculation: sales of energy and ancillary services ("E&AS") and Capacity Performance Payments. Estimates of these revenue streams, which partially offset the

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[38] *See* CEA Report at 56-57 (Table 26).

[39] *See* CEA Report at 56-57 (Table 26).

[40] *See* CEA Report at 53 ("A longer-term view of generic corporate debt reveals these averages have been steadily decreasing in recent years, with levels peaking in 2016, the time this analysis was completed in the previous Net CONE recalculation.")

[41] *See* CEA Report at 41-42 regarding escalation of costs to 2025 dollars.

[42] *See* CEA Report at 73 (Table 37).

[43] While the CEA Report includes (gross) CONE and Net CONE values based on both installed capacity MW and qualified capacity MW for each technology, the latter value is the one pertinent for this study, as it represents the MW value the technology can participate with and receive payments from the Forward Capacity Market.

[44] *See* Part V.F below.

new resource's levelized annual costs, are used to calculate Net CONE values for each candidate reference technology.[45]

CEA estimated a unique E&AS "revenue offset" for each of the three candidate reference technologies corresponding to energy and ancillary service revenue net of production costs. The ISO operates both day-ahead and real-time energy markets, and the three candidate reference technologies are eligible (and assumed) to offer energy into these markets based on their marginal costs, including fuel, emissions, and variable operations and maintenance costs.

In addition, resources in New England can receive market-based compensation for providing one or more of the following ancillary services: regulation, ten-minute spinning reserves ("TMSR"), ten-minute non-spinning reserve ("TMNSR"), and thirty-minute operating reserves ("TMOR"). In addition to real-time reserves the ISO also procures TMNSR and TMOR on a forward basis in the Forward Reserve Market ("FRM"). CEA's revenue offset methodology assumes that each candidate reference technology supplies reserves, to the extent supported by the physical capabilities of the candidate reference technology (which depends on its ramp rate, fast-start capability, and other technical specifications). None of the three candidate reference technologies is assumed to also provide regulation service.[46]

A summary of each of the energy and ancillary services products that each candidate reference technology is assumed to offer, based on the technical capabilities of each technology, is provided in Table 31 of the CEA Report and reproduced below.

Candidate Reference Unit	Day-Ahead Energy	Real-Time Energy	Forward Reserve Market		Real-Time Reserve Market		
			TMNSR	TMOR	TMSR	TMNSR	TMOR
Simple cycle	●	●	●	●		●	●
Aeroderivative	●	●	●	●		●	●
Combined cycle	●	●			●		

2. Energy and Ancillary Services Revenue Offset Modeling

At a high-level, CEA estimated E&AS revenue offsets for each of the candidate reference technologies using a three-step process. The first step was to develop energy and reserve market price estimates. This step, which involved multiple sub-components (and which used a revised approach from the 2017 Net CONE Study), is described presently. The second step was to use a

[45] *See* CEA Report at 58.

[46] *See* CEA Report at 63.

technology-specific dispatch model to estimate the quantity of energy and reserves each candidate reference technology would supply, and with that information to tabulate each candidate reference technology's energy and ancillary service net revenue during normal operating conditions. The third step involved supplementing these net revenues to account for each technology's estimated energy and ancillary service revenues during scarcity conditions (*i.e.,* the annual hours when the New England system is expected to experience real-time reserve shortages at criterion, which are periods when administrative reserve pricing applies).

CEA performed a separate calculation to estimate each candidate reference technology's expected Capacity Performance Payments, an additional form of revenue that may be earned during Capacity Scarcity Conditions under the ISO's Pay for Performance capacity market rules. Capacity Performance Payments, which are a component of the overall revenue offsets but not (strictly speaking) a form of E&AS markets revenue, are discussed further below in Part V.D.3.

a. Step 1: Energy and Ancillary Service Prices

To estimate energy and ancillary service prices for use in calculating the candidate reference technologies' revenue offsets, CEA employed a revised approach from that used in the 2017 Net CONE Study. As the CEA Report explains, in the previous study it forecasted New England energy market prices using a twenty-year run of a production cost model; however, experience with that process highlighted that using a production cost model involved complex calculations for energy revenues that were not transparent to stakeholders given the significant number of inputs, outputs, and assumptions involved, and the need for a blunt historical add-on for ancillary services revenues since the multi-year production cost model was not capable of modeling co-optimized energy and ancillary revenues.[47]

After considering alternatives and methodologies used for this purpose in other regions, CEA performed this full recalculation using a simplified price estimation method. Specifically, CEA determined that an E&AS price estimation methodology based on adjusted historical prices would produce reasonable E&AS offsets and would afford greater transparency to stakeholders. CEA notes that similar approaches have been employed in the Net CONE studies performed (by different consultancies) for the NYISO and for PJM, and approved by the Commission.[48]

Specifically, to estimate E&AS revenues for each of the candidate reference technologies, CEA began with New England's (hourly and sub-hourly) historical prices for day-ahead energy and real-time energy and reserves for a three-year period, from January 2017

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[47] *See* CEA Report at 58.

[48] *See* CEA Report at 58.

through December 2019.[49] As the CEA Report explains, using historical prices to estimate future energy and ancillary services prices cannot perfectly capture the expected impacts of future changes to the New England system.[50] However, starting from historical market prices during the past three years can produce a reasonable estimate, and CEA performed certain price adjustments to those historical data to better account for differences between recent years' market conditions and the market's long-term, or "at criterion," expected conditions.

In particular, CEA performed two adjustments to the historical prices: 1) an energy and reserve scarcity condition adjustment ("Energy/Reserve Scarcity Adjustment") to account for the impact of real-time operating reserve shortages when administrative reserve pricing is applied under existing market rules; and 2) an excess capacity supply adjustment ("Level of Excess Adjustment") to account for expected changes in overall energy and reserve price levels in a system at criterion, which may differ from the price levels observed during the excess supply conditions that have prevailed in New England during the three-year period of the historical data. We summarize each of these price adjustments, in turn, below.

i. ***Energy/Reserve Scarcity Adjustment***

Under existing market rules, if the ISO's co-optimized real-time energy and reserve dispatch has insufficient resource capabilities to meet the corresponding real-time energy and reserve requirements, administrative pricing is applied to set the real-time reserve price. The administratively-set reserve price is known as a Reserve Constraint Penalty Factor ("RCPF"), and periods when an RCPF applies are generally referred to as *scarcity conditions.* Note that, because energy and reserve prices are inter-dependent in the co-optimized real-time market, application of administrative pricing to the real-time reserve price will also impact (or "cascade into") the real-time energy price.

Because scarcity conditions are complex to model and their expected frequency differs between market conditions with excess supply (as in recent historical data) and market conditions expected in long-run equilibrium (*i.e.,* "at criterion"), CEA employed a separate calculation methodology to estimate each candidate reference technology's expected energy and ancillary services revenue during scarcity condition hours. This separate calculation methodology is discussed further below, in Part V.D.2.c.

As part of that separate calculation methodology, it is necessary to adjust the historical energy and reserve price data to account for the (limited) scarcity conditions that have occurred

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[49] The ISO does not operate a day-ahead reserve market.

[50] *See* CEA Report at 58.

during that three-year period. This is necessary to avoid double-counting. Because energy and reserve market revenues corresponding to scarcity hours are accounted for in a separate calculation methodology, they cannot be also included in the revenue derived from the historical price data as well. In simple terms, CEA 'removed' the pricing impact of administrative scarcity pricing from the (six) hours in which it occurred in the historical three-year data period.[51] By doing so, the estimated energy and reserve revenue based on those resulting 'scarcity adjusted prices' have a simple and natural interpretation: they correspond to the estimated E&AS revenue for each candidate reference technology under normal (that is, non-scarcity) operating conditions each year. The energy and ancillary services revenue under scarcity conditions are incorporated into the revenue offsets separately, as noted above.

Given that administrative scarcity pricing is only performed by the ISO in the real-time market, a comparable adjustment had to be made to remove the expected impacts of real-time energy and reserve scarcity prices from the day-ahead LMPs. In an efficient market, CEA explains, the day-ahead and real-time prices converge in expectation, and in equilibrium the expected impact of real-time energy and reserve scarcity pricing would be reflected in day-ahead LMPs.[52] The details of CEA's Energy/Reserve Scarcity Adjustment to the historical prices are explained in Section 5.A.i of the CEA Report.[53]

ii. *Level of Excess Adjustment*

The second adjustment to the historical energy and real-time reserve prices accounts for the overall impact of excess supply conditions during the 2017-2019 period. In general, when the system has excess capacity, E&AS prices (in this context, day-ahead and real-time energy and real-time reserve prices) can be expected to be lower than they would be in a system without excess capacity. Accordingly, since the New England system had excess capacity during the 2017-2019 historical data period, a "level of excess" adjustment was applied to the historical prices to better reflect values that would be expected in a system at criterion (that is, without any excess capacity). Through this level of excess adjustment, the resulting prices are intended to better reflect the revenues the candidate reference units would earn if the system was without excess supply, in long-run equilibrium conditions.[54]

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[51] *See* CEA Report at 59-60.

[52] *See* CEA Report at 60.

[53] *See* CEA Report at 59-61.

[54] A conceptually similar level of excess adjustment was recently used in the Net CONE update performed for the New York Independent System Operator. *See* New York Independent System Operator, Inc., ICAP Demand Curve Reset Proposal, FERC Docket No. ER21-502-000 (filed November 30, 2020), Transmittal Letter at 44-46; *id.* at Exhibit IV (Analysis Group, Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report) at footnote 5.

As explained in the CEA Report, a set of level-of-excess (or "LOE") adjustment factors was calculated based on market outcomes for the existing supply conditions during the historical data period, and then under a 'counterfactual' supply condition in which resources pending retirement were removed.[55] Specifically, this involved first constructing a "base case" day-ahead energy market supply curve, specific to each hour during the three-year historical period. The day-ahead energy market supply curves were intersected with the applicable day-ahead load forecast to establish the base case locational marginal prices. Second, the hourly day-ahead energy market supply curves were reconstructed by removing energy supply offers in amounts equal to the level of excess MW during each year. The day-ahead energy market supply offers removed were those associated with resources pending retirement.[56] The revised day-ahead energy market supply curves were then intersected with the (same) day-ahead load forecast to determine the "LOE-adjusted" locational marginal prices.

These base-case and LOE-adjusted day-ahead LMPs were calculated and aggregated by month, and by period of the day, as described in the CEA Report.[57] For each period of the day, a monthly level of excess adjustment factor ("LOE AF") was calculated as:

$$LOE\ AF = \frac{Monthly\ Average\ LMP_{Base\ Case}}{Monthly\ Average\ LMP_{LOE\ Adjusted}}$$

An LOE AF value of 1.0 indicates the same price levels are estimated to apply in a system without excess capacity as prevailed in the historical price data during that evaluation period. An LOE AF value less than 1.0 indicates that that the historical prices are less than those expected to prevail in a system without excess capacity.

The historical hourly energy and real-time reserve prices (adjusted to remove the impact of scarcity pricing, as discussed previously) in each hour of the evaluation period were divided by the applicable LOE adjustment factor to arrive at an LOE-adjusted price. The final level-of-excess adjustment factor values, and a detailed numerical example of the LOE-adjustment method, are provided in Tables 29 and 30 of the CEA Report.[58] Overall, most LOE adjustment factor values are close to, but slightly less than, 1.0. As a result, the LOE-adjusted prices are generally a few percentage points higher than the historical prices observed during the 2017-2019 period.

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[55] *See* CEA Report at 61-63.

[56] Resources pending retirement are documented in the ISO's Retirement Tracker, available at https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx.

[57] *See* CEA Report at 62.

[58] *See* CEA Report at 62-63.

b. Step 2: Technology-Specific Dispatch Models and E&AS Revenue

The energy and ancillary service revenues for each candidate reference technology encompass revenue from providing one or more of the following services: day-ahead energy, real-time energy, real-time reserves, and Forward Reserves. These revenues were estimated using simplified economic dispatch models for each candidate reference technology, the historical energy and real-time reserve prices (as adjusted) summarized above, and the historical Forward Reserve Market clearing prices.

More specifically, simplified (*i.e.,* spreadsheet-based) economic dispatch models were developed for each of the candidate reference technologies.[59] These models estimate both the quantity of energy and reserves each candidate reference technology would supply, and (with that information) tabulate each candidate reference technology's energy and ancillary service net revenue (that is, net of production costs) during normal operating conditions. The dispatch models, which are constructed at an hourly granularity, assume each generating technology is offered (hourly) into the energy markets at its marginal cost, based on its fuel cost, emissions and other production costs, and given the heat rate and various technical characteristics of each candidate reference technology.[60] For each of the candidate reference technologies, the CEA Report sets out the assumed fuel costs,[61] and the variable and fixed operations and maintenance costs (including the individual components thereof).[62]

Unlike previous Net CONE reviews, the dispatch model included (a simplified) unit commitment in the day-ahead energy market as well as dispatch in the real-time energy market.[63] A detailed flowchart describing the inputs into the economic dispatch model for each candidate reference technology is provided in Sections 5.A.iv and 5.A.v of the CEA Report.[64]

Both the combustion turbine (CT) and aero technology were assumed to participate in the Forward Reserve Market, which requires energy supply offers above a specific price (known as the Forward Reserve Threshold Price) in specified hours. This market rule was accordingly

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[59] These dispatch models are available at https://www.iso-ne.com/static-assets/documents/2020/11/a4_a_i_cone_ortp_dispatch_models.zip; and https://www.iso-ne.com/static-assets/documents/2020/11/a4_a_i_simple_cycle_cone_dispatch_with_frm_posted_nov_24.xlsx.

[60] *See* CEA Report at 63-70.

[61] *See* CEA Report at 66-67.

[62] *See* CEA Report at 38-40.

[63] *See* CEA Report at 67-68.

[64] *See* CEA Report at 65-66 (Figure 4) and 69 (Figure 5).

incorporated in the dispatch models for those two candidate reference technologies. In the dispatch models, a resource not providing energy in real-time is designated for reserves if and to the extent the resource is technically capable of providing the reserves.[65]

Final hourly revenues were calculated using the adjusted historical energy and real-time reserve prices, the historical Forward Reserve Market clearing prices, and the estimated energy and reserve dispatch from the economic dispatch models.[66] An estimated total annual E&AS revenue under normal operating conditions was produced for each candidate reference technology, based on the average of the (inflation-adjusted) E&AS revenue estimates for the three-year period of the economic dispatch model. This annual E&AS revenue offset is held constant (in real terms) throughout each candidate reference technology's twenty-year project life.

c. Step 3: E&AS Scarcity Revenue

As noted previously, the third and final step in estimating E&AS revenue offsets is to supplement the estimated net revenue during normal operating conditions with each technology's estimated energy and ancillary service revenues during real-time scarcity conditions (*i.e.,* the annual hours when the system is expected to experience real-time reserve shortages, when administrative reserve pricing applies). This scarcity revenue is calculated as a separate source of energy and ancillary service revenue, distinct from the LMPs and reserve prices used in the energy market dispatch models.

The specific hours of any given year when a real-time reserve shortage may trigger scarcity pricing are not known with certainty. Therefore, rather than make an assumption about the specific hours when scarcity pricing would be incorporated into the real-time energy and reserve prices, the total amount of energy and reserve scarcity revenue for each candidate reference technology was calculated and separately added into the net revenue streams in the Net CONE discounted cash flow model. Estimating the annual energy and reserve scarcity revenue requires two main inputs. First, an estimate of the expected number of scarcity hours annually applicable to the system in long-term equilibrium (*i.e.,* at criterion), which is discussed below. Second, the administrative scarcity price 'adder' (*i.e.,* the RCPF value) to apply during scarcity conditions, which is not being revised here.

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[65] *See* CEA Report at 68.

[66] It should be noted that the adjustments for scarcity and the level of excess were not applied to the historical Forward Reserve Market clearing prices. The Forward Reserve Market is a wholly voluntary market, and it is not possible with existing data to ascertain the direct impact, if any, that excess system-wide capacity conditions may have on Forward Reserve Auction prices.

In previous full recalculations of Net CONE, the estimated annual scarcity hours for the system at criterion were based upon the most recent published estimate of the system's operating reserve deficiency hours during peak-load conditions, as calculated by the ISO's reliability planning model. This is the same model, run using the same inputs, that is used to set the Installed Capacity Requirement and to calculate the system's Loss of Load Expectation in accordance with the region's resource adequacy planning standards.

For the present full recalculation of Net CONE, the ISO has enhanced the calculation of the estimated annual scarcity hours in two ways. First, instead of employing a single year's estimate of the system's operating reserve deficiency hours during peak-load conditions at criterion (as calculated by the ISO's reliability planning model), the ISO used the average of the last four years of the published estimates from the ISO's reliability planning model. Using the average of the ISO's published annual estimates reduces the year-to-year changes in the estimated annual scarcity hours applicable to peak-load conditions, thereby producing a more stable estimate for a system at criterion.[67]

The second enhancement is to account for additional, non-peak load situations when scarcity conditions may arise in real-time in the New England system. Specifically, the full recalculation of Net CONE now accounts for two additional categories of scarcity hours: *transient* scarcity hours and *winter* (*i.e.,* cold-weather related) scarcity hours. Transient scarcity hours capture the operational risks that arise from under-commitment and load forecast error, as well the unanticipated sudden loss of critical transmission elements. The estimated number of transient scarcity hours annually is calculated from the observed intervals of transient (*i.e.,* not peak-load) real-time operating reserve deficiencies in recent years. Winter scarcity hours capture the risks of real-time operating reserve deficiencies due to fuel-related supply constraints during periods of cold weather in New England. These estimated winter scarcity hours were derived from a probabilistic simulation model, combining forced outages with temperature-based limitations on New England's natural gas supply.[68]

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[67] *See Expected Capacity Scarcity Condition (CSC) Hours and Capacity Balancing Ratios (BR)*, Revision 2, at slides 5-6 (October 26, 2020), presentation to NEPOOL Markets Committee by Kevin Coopey on behalf of the ISO, available at https://www.iso-ne.com/static-assets/documents/2020/10/a00_iso_presentation_scarcity_hours_and_balancing_ratios.pptx.

[68] *See FCA16 Net CONE Parameters - Expected Capacity Scarcity Hours and Balancing Ratio* (July 8, 2020), memorandum to NEPOOL Markets Committee by Kevin Coopey on behalf of the ISO, available at https://www.iso-ne.com/static-assets/documents/2020/07/a5_a_iso_memo_scarcity_hours_balancing_ratio.pdf, and subsequent revisions thereto in *Expected Capacity Scarcity Condition (CSC) Hours and Capacity Balancing Ratios (BR)*, Revision 2 (October 26, 2020), presentation to NEPOOL Markets Committee by Kevin Coopey on behalf of the ISO, available at https://www.iso-ne.com/static-assets/documents/2020/10/a00_iso_presentation_scarcity_hours_and_balancing_ratios.pptx.

The detailed assumptions and methods for evaluating the transient and winter types of scarcity hours were reviewed with stakeholders in detail over multiple meetings. Overall, the estimated peak-load annual scarcity hours at criterion is 10.1 hours; the estimated transient and winter annual scarcity hours are 0.8 hours and 0.4 hours, respectively. Taken together, the total estimated annual scarcity hours used in the Net CONE revenue offset calculation is therefore 11.3 hours (10.1 + 0.8 + 0.4 = 11.3 hours).

The detailed calculation of the E&AS revenue offsets associated with these 11.3 hours of expected scarcity conditions at criterion, for each candidate reference technology, are summarized in Table 28 of the CEA Report.[69]

3. Capacity Performance Payment Revenue Offsets

Finally, CEA details the assumptions and sources of data (generally, the ISO's most recently published information) it used in calculating estimated Capacity Performance Payments for each technology type.[70] Consistent with the existing settlement rules for Capacity Performance Payments under the Tariff, CEA calculated a unique estimate of annual Capacity Performance Payments for each candidate reference technology using the following formula:

$$\textit{Capacity Performance Payment} = PPR \times H \times (A - BR)$$

In this formula, there are four parameters on the right hand side, and CEA estimated each as follows:

- *PPR* is the Capacity Performance Payment Rate. The updated Capacity Performance Payment Rate of $8,782/MWh that will be in effect for the Capacity Commitment Period beginning June 1, 2025 (discussed in more detail in Part V.G below) was used for the first three years of the resource's twenty-year modeled life, and then adjusted for inflation every three years thereafter to reflect expected future updates of the Capacity Performance Payment Rate concurrent with future Net CONE recalculations.[71]

- *H* is the estimated annual scarcity hours for the system at criterion. For this parameter, CEA used the same number of scarcity hours employed in the E&AS scarcity adjustment

[69] *See* CEA Report at 61.

[70] *See* CEA Report at 71-72.

[71] While there is no Tariff provision requiring periodic updates to the Capacity Performance Payment Rate, that parameter uses many of the same inputs as those used to update Net CONE as described below in Part V.G, and the ISO anticipates that the Capacity Performance Payment Rate will be updated concurrently to reflect revisions to those same inputs.

described in Part V.D.2.c above.

- *A* is the average annual expected performance of each candidate reference technology (per MW) during Capacity Scarcity Conditions. This value differed between each candidate reference technology, and was provided by CEA's engineering partner, Mott McDonald, based on manufacturers' expectations or expected forced outage rates.[72] For example, the second numerical row in Table 35 of the CEA Report shows that the estimated average actual performance is 98% for the Simple Cycle technology (in this case, a GE 7HA.02 combustion turbine).

- *BR is* the system's estimated average annual Capacity Balancing Ratio during Capacity Scarcity Conditions.[73] This ratio is the sum of the system's real-time load and reserve requirement, as a share of the system's total Capacity Supply Obligations during a Capacity Scarcity Condition. Similar to the calculation of expected annual scarcity hours at criterion, the balancing ratio parameter was estimated using data for each of the three categories of scarcity condition hours (*i.e.,* peak load, transient, and winter scarcity conditions). A scarcity hour-weighted average balancing ratio, based on the corresponding number of scarcity hours in each category, was used in the Capacity Performance Payment calculation.[74]

These calculations, and resulting estimated Capacity Performance Payments for each candidate reference technology, are set forth in Table 36 of the CEA Report.[75]

4. Resulting Net CONE Values

These energy and ancillary service revenues and Capacity Performance Payments comprise the total revenue offsets for each candidate reference technology. Applying these calculated revenue offsets against the CONE values previously calculated for each technology type yields the following Net CONE values, as set forth in Section 6 of the CEA Report:[76]

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[72] *See* CEA Report at 71.

[73] *See* Tariff Section III.13.7.2.3(a).

[74] These values were reviewed in detail with stakeholders. *See* footnote 67 above.

[75] *See* CEA Report at 72.

[76] *See* CEA Report at 73 (Table 37).

Candidate Reference Technology	Net CONE – Qualified ($/kW-month)
CC	12.724
CT	7.024
Aero	23.455

E. Selecting the Final CONE and Net CONE Values

The final step in updating the CONE and Net CONE values is to select from the three candidates the single reference technology to be used to set these values. As noted earlier in Part V.B of this filing letter, the candidate reference technologies were selected because it is likely that they could be economic for merchant entry under long-term equilibrium conditions; there is reliable cost information available to estimate entry costs for each technology; and they can reliably meet load when resource adequacy is at risk.

From a market design perspective, the final CONE and Net CONE values generally should be based on the technology that is expected to be the most economically efficient and that is commercially available to new capacity suppliers.[77] Setting the CONE and Net CONE values in accordance with this design principle ensures that the demand curves used in the auction are consistent with the region's reliability planning objectives and will procure capacity cost-effectively in the Forward Capacity Market.[78]

Based on the results of the cost estimates for the three commercially-available candidate reference technologies, as discussed in Section 6 of the CEA Report and reviewed above,[79] the most economically efficient resource type is the CT with a (gross) CONE value of $11.874/kW-month and a Net CONE value of $7.024/kW-month. Accordingly, consistent with the recommendation in the CEA Report, the ISO has selected the CT value to set the new, updated CONE and Net CONE values. From a market design perspective, the selection of the CT reference technology to establish the updated CONE and Net CONE values is straightforward. As noted earlier, in order for the demand curves that are used in the auction to function efficiently, the CONE and Net CONE values generally should be based on the most efficient resource type that is commercially available. The CT satisfies this condition. This CT is the same generation technology that was selected by the ISO as the Net CONE reference technology in the

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[77] *See, e.g.*, Order Accepting Tariff Revisions, 147 FERC ¶ 61,173 (issued May 30, 2014) at P 32.

[78] This principle, as applied to the sloped system and zonal demand curves, has been previously explained by the ISO. *See* Demand Curve Design Improvements, Testimony of Dr. Christopher Geissler and Dr. Matthew White, FERC Docket No. ER16-1434-000 (filed April 15, 2016) at 46-47.

[79] *See* CEA Report at 73.

2017 Net CONE Study. These updated values are reflected in revisions to Tariff Section III.13.2.4.[80]

F. Response to NEPGA Complaint Regarding the Calculation of Net CONE Based on the System Modeled "As Expected" Versus "At Criterion" and Revisions to Net CONE Definition

Early in the 2020 stakeholder process to recalculate the parameters filed here, representatives of the New England Power Generators Association ("NEPGA") took issue with the ISO calculating Net CONE based on a system modeled under long-term equilibrium conditions, or "at criterion." NEPGA argues that the system should instead be modeled "as expected" – that is, reflecting expectations of continued excess supply conditions for FCA 16.[81] Although the specifics of NEPGA's position evolved over the course of the stakeholder process,[82] its core objection remained, and has now been codified in a separate complaint to the Commission.[83] The significant legal and procedural infirmities of that complaint are being addressed in the ISO's Motion to Dismiss and Answer, being filed with the Commission in the complaint docket on the same day as the instant filing. Those arguments need not be reiterated here. The ISO will, however, fully address here the substantive issue raised in NEPGA's complaint.

The substantive issue presented by NEPGA in its complaint boils down to one argument: that the "plain meaning" of the existing definition of Net CONE *requires* the ISO to model the system "as expected" (and not at criterion).[84] As discussed in detail below, not only is NEPGA incorrect about that "plain meaning," but the record demonstrates that NEPGA itself understood and supported the ISO's intended implementation of the Net CONE parameter. Furthermore,

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[80] Also in revised Section III.13.2.4, the ISO has simplified language regarding the timing for full recalculations of CONE and Net CONE. This is not a substantive change – those values must still be fully recalculated no less often than once every three years. But redundant language that would otherwise needlessly have to be revised each time is being deleted.

[81] Importantly, if the ISO were required to calculate Net CONE based on a system "as expected," considerable analysis and market design work may be required to determine how best to estimate the likely conditions in the future.

[82] When NEPGA raised this issue early in the 2020 stakeholder process, its position was *not* that the Tariff requires Net CONE to be calculated "as expected." Rather, NEPGA at that point seemed to acknowledge the history of Net CONE being calculated at criterion and argued merely that such precedent was not binding. *See Resource Balance for Net CONE Calculation*, at slide 9 (July 15, 2020), presentation to NEPOOL Markets Committee by Robert Stoddard of Berkeley Research Group on behalf of NEPGA, available at https://www.iso-ne.com/static-assets/documents/2020/07/a5_b_iii_nepga_resource_balance_for_net_cone_calculation.pdf.

[83] *See* Complaint and Request for Fast-Track Processing of the New England Power Generators Association, Inc., FERC Docket No. EL21-26-000 (filed December 11, 2020) ("NEPGA Net CONE Complaint").

[84] *See* NEPGA Net CONE Complaint at 13-16.

NEPGA all but ignores the ISO's repeated explanations of the market design principles that require an at criterion calculation. NEPGA's preferred approach would instead inefficiently incent unneeded new capacity, which is neither cost effective nor consistent with the Forward Capacity Market's overall 1-in-10 resource adequacy objective.

Furthermore, if NEPGA's arguments delay the appropriate application of the fully updated Net CONE value filed here, *even if those arguments subsequently fail on their merits*, it may result in excessive consumer capacity payments in FCA 16 – a direct consequence of NEPGA's requested relief to continue to apply the (larger) FCA 15 Net CONE value, with further adjustments, in lieu of the updated Net CONE value for FCA 16 filed herein.

1. The Net CONE Calculation Has Always Been Based on the System Under Long-Term Equilibrium Conditions ("At Criterion")

In its complaint, NEPGA considers it significant that the existing definition of Net CONE does not "refer at all to 'equilibrium' or 'long-term'…"[85] A review of the history of the Net CONE definition demonstrates that those concepts were well understood as part and parcel of the definition. Net CONE was first introduced into the Tariff in 2014, as a parameter needed to implement the first system-wide sloped demand curve in the Forward Capacity Market.[86] In that filing, supported and joined by the NEPOOL Participants Committee, and accepted by the Commission,[87] the ISO explained that "[t]he capacity market demand curve is designed to procure sufficient capacity to maintain resource adequacy. *Premised on the assumption that new entrants will set prices at true Net CONE in a long-term equilibrium state*, the curve's prices are indexed to an estimated Net CONE value . . ."[88] The ISO's expert witnesses further explained that:

> [t]he prices and quantities of the proposed curve are premised on the assumption that, in a long-term economic equilibrium, new entrants will set average capacity market prices at Net CONE – *where Net CONE is the first-year capacity revenue a new generation resource would need (in combination with expected energy and ancillary services margins) to recover its capital and fixed costs, given*

[85] NEPGA Net CONE Complaint at 13.

[86] *See* Demand Curve Changes, FERC Docket No. ER14-1639-000 (filed April 1, 2014) ("2014 Demand Curve Filing"). The Testimony of Dr. Samuel A. Newell and Mr. Christopher D. Ungate prepared on behalf of the ISO regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, submitted as part of that filing, is referred to herein as the "2014 Net CONE Study."

[87] *See* Order Accepting Tariff Revisions, 147 FERC ¶ 61,173 (issued May 30, 2014).

[88] 2014 Demand Curve Filing at 8 (emphasis added).

> *reasonable expectations about future cost recovery under continued equilibrium conditions*.[89]

The 2014 Demand Curve Filing also plainly stated that:

> [w]e also assume economically rational new entry, with new supply added infra-marginally until the long-term average price equals Net CONE, neither more nor less. As such, our simulations reflect long-term conditions at economic equilibrium on average, *and do not reflect a forecast of outcomes over the next several years or any other particular year.* [90]

These explanations – contemporaneous with the implementation of Net CONE – drive a stake through NEPGA's core contention that references in the Net CONE definition to "reasonable expectations of the first-year energy and ancillary services revenues" can only mean a system modeled "as expected." In fact, the 2014 explanations above make it perfectly clear that even the first-year capacity revenue is intended to be calculated "given reasonable expectations about future cost recovery under continued equilibrium conditions." The changes to the definition of Net CONE filed here merely bring that definition, which the ISO concedes is not as well worded as it could be, into harmony with the original, and unchanged, market design intent.

In 2016, the ISO – again joined by NEPOOL – filed improvements to the demand curve design.[91] In that proceeding, the ISO's expert witnesses were asked whether one component of the revised design, a scaling factor, is "consistent with expected offer behavior and the ISO's calculation of Net CONE more generally." Their response explained that:

> [c]alculating the scaling factor in this manner assumes that, on average, new resources can expect to earn Net CONE from the capacity market over the projected service life of the resource (though not necessarily in every year). *This is consistent with the capacity market's intended equilibrium property that the marginal resource is offered at Net CONE*.[92]

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[89] 2014 Net CONE Study at 5 (emphasis added).

[90] *See, e.g.*, 2014 Demand Curve Filing, Testimony of Dr. Samuel A. Newell and Dr. Kathleen Spees, at 14 (emphasis added).

[91] *See* Demand Curve Design Improvements, FERC Docket No. ER16-1434-000 (filed April 15, 2016) ("2016 Demand Curve Improvements Filing").

[92] 2016 Demand Curve Improvements Filing, Testimony of Dr. Christopher Geissler and Dr. Matthew White, at 46 (emphasis added).

The 2016 Demand Curve Improvements Filing was also accepted by the Commission.[93]

And in early 2017, the ISO filed the most recent full recalculation of Net CONE.[94] In its order accepting that filing, the Commission stated (in describing the ISO's proposal that was being accepted) that "Net CONE is intended to approximate the compensation a new entrant would need from the capacity market in the first year of operation to recover its capital and fixed costs *under long-term equilibrium conditions*."[95]

In short, there can be no doubt that the ISO, NEPOOL, and the Commission understood that, since its inception, the intention has always been to calculate Net CONE based on long-term equilibrium conditions. And importantly, despite these many clear statements across these various stakeholder processes and Commission proceedings, not once did NEPGA assert or argue that Net CONE must be calculated based on the system "as expected," as it now contends.

2. NEPGA Is on Record Acknowledging and Supporting the Net CONE Calculation Based on the System Under Long-Term Equilibrium Conditions ("At Criterion")

In fact, NEPGA is on record expressly *supporting* the ISO's intended implementation of Net CONE. In responding to the 2014 Demand Curve Filing, NEPGA stated that:

> [t]he Filing Parties' proposed curve . . . will reduce price volatility and provide Market Participants with greater confidence in the *FCA's likelihood of producing clearing prices that,* ***on average over time****, equal Net CONE*. The curve is likewise calibrated to procure capacity, on average and over time, in an amount equal to the 1-in-10 year loss of load expectancy, an appropriate resource adequacy goal.[96]

Later in that filing, in discussing the minimum price cap included in the demand curve design, NEPGA stated that "[t]he price cap in any downward sloping demand curve needs to be robust

[93] *See* Order Accepting Filing, 155 FERC ¶ 61,319 (issued June 28, 2016).

[94] *See* ISO New England Inc. Filing of CONE and ORTP Updates, FERC Docket No. ER17-795-000 (filed January 13, 2017).

[95] Order Accepting Filing, 161 FERC ¶ 61,035 at P 15 (issued October 6, 2017).

[96] Motion to Intervene and Protest of the New England Power Generators Association and Electric Power Supply Association, FERC Docket No. ER14-1639-000 (filed April 22, 2014) at 8 ("NEPGA 2014 Demand Curve Filing").

enough to incent new entrants that are looking to invest over the long-term, *with a demand curve designed to ensure that long-run average prices equal Net CONE*."[97]

NEPGA's 2014 filing was styled as a protest, and NEPGA was careful to say that even the portions of the demand curve filing it supported were "not in every detail without fault,"[98] but NEPGA specifically described the Net CONE as one of the core design components that, in total:

> represent a reasonable application of sound economic principles that should, together with the relief NEPGA and EPSA seek elsewhere in this Protest, create an FCM that strikes an appropriate balance between allowing for price signals sufficient to incent new entry when needed, and to retain appropriate existing resources or incent retirements when economic. These elements constitute the 'bones' of the demand curve and provide a reasonable framework to deliver clear, consistent and fair competitive market outcomes that the Commission has strived for in capacity markets.[99]

None of the issues that NEPGA protested in the 2014 Demand Curve Filing proceeding had anything to do with, let alone object to, the calculation of Net CONE based on long-term equilibrium conditions – a method amply explained in the joint filing and echoed by NEPGA in response. Given this record, NEPGA's observation that the existing definition of Net CONE "fails to refer at all to 'equilibrium' or 'long term'" may be factual, but it is disingenuous.[100] The ISO and NEPOOL expressly used those terms repeatedly in explaining the function and role of Net CONE over many years, the Commission has used them in accepting Net CONE, and NEPGA itself has used them in supporting it.

Importantly, the definition of Net CONE has never (yet) changed since it was initially filed in 2014. That is, the exact same definition that NEPGA supported in 2014 – and that was expressly based on the system modeled at criterion – NEPGA now argues requires the system to be modeled "as expected" (that is, assuming continued excess supply conditions).

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[97] NEPGA 2014 Demand Curve Filing at 31.

[98] NEPGA 2014 Demand Curve Filing at 8.

[99] NEPGA 2014 Demand Curve Filing at 8-9.

[100] NEPGA Net CONE Complaint at 13.

3. The Market Design Requires the Net CONE Calculation to Be Based on the System "At Criterion"

There is an excellent reason that the history of the Net CONE definition, described above, so clearly reflects an "at criterion" calculation – it is an essential feature of the market design that avoids procuring unnecessary capacity at excessive cost to consumers. In New England's Forward Capacity Market, the Forward Capacity Auction is intended to clear at the net Installed Capacity Requirement when the system is at equilibrium. The Installed Capacity Requirement is determined based on the "1-day-in-10" Loss of Load Expectation resource adequacy objective. By design, the Forward Capacity Auction should induce new entry (at a price of Net CONE) if capacity is less than the net Installed Capacity Requirement, and should not induce new entry otherwise. This design objective ensures that the Forward Capacity Market will induce competitive new entry only when it is needed to meet the system's resource adequacy goal.

This design objective is further expressly incorporated into the Forward Capacity Market's MRI-based capacity demand curves, which are structured to pass through the point of Net CONE at the net Installed Capacity Requirement. The capacity demand curves are scaled in a manner "such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year."[101]

NEPGA's re-interpretation of the Net CONE definition would expressly upset this central design objective of the Forward Capacity Market, institutionalizing the procurement of excess capacity. Worse yet, and contrary to sound market design, it would do so for a system that, by NEPGA's own characterization, is presently expected to face excess supply conditions.[102] If Net CONE were to be based on market conditions consistent with a capacity level that exceeds the Installed Capacity Requirement (such as under the current excess supply conditions), then the E&AS revenue offsets would be smaller (in dollar terms) than if calculated for a system at criterion. The smaller revenue offsets would increase the value of Net CONE and, in doing so, produce an excessive value of Net CONE that would incent new entry even when the system does not need additional capacity. This would be neither cost effective, nor consistent with the Forward Capacity Market's stated 1-in-10 resource adequacy objective.

These concepts were explained and discussed in the 2014 proceeding that introduced Net CONE to the Tariff,[103] and in the 2016 proceeding that improved the demand curve

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[101] Tariff Section III.13.2.2.4.

[102] *See* NEPGA Net CONE Complaint at 14.

[103] *See, e.g.*, 2014 Demand Curve Filing at 7 ("A demand curve should be compatible with system planning criteria, such as the NPCC's '1 day in 10' design criterion regarding the probability of disconnecting firm load due to a

mechanism.[104] For example, in its 2016 filing supporting the (present) MRI-based capacity demand curve design, the ISO's expert witnesses explained that New England's demand curves are intrinsically based on the region's "at criterion" approach to modeling Net CONE:

> [T]he [demand curve] assumption that the equilibrium capacity price reflects Net CONE is also consistent with the cash-flow and pricing calculations actually employed in the ISO's discounted cash-flow models used to estimate Net CONE for the New England system.[105]

Furthermore, in response to NEPGA's assertions, in the 2020 stakeholder process to update the parameters filed here, the ISO provided numerical examples to stakeholders demonstrating the adverse consequences of NEPGA's interpretation of the definition of Net CONE. Specifically, those examples explained that NEPGA's proposed "as expected" Net CONE calculation would incent new entry when no entry is needed to satisfy the Installed Capacity Requirement.[106]

Indeed, these principles are well-established enough that, in the many pages of its complaint, NEPGA barely suggests that basing the Net CONE calculation on a system modeled "as expected" would be appropriate, let alone preferable, from a market design standpoint. Again, NEPGA rests its entire argument on its assertions about what the Net CONE definition must mean, thoroughly debunked above.

4. Contrary to NEPGA's Claims, Previous Net CONE Calculations Were Based on the System "At Criterion"

As should be abundantly clear at this point, NEPGA is incorrect that the revisions here to the Net CONE definition "starkly diverge[] from the ISO-NE's prior approaches to Net

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resource deficiency. The sloped demand curve submitted by the Filing Parties is targeted at achieving the 0.1 days/year LOLE target over the long term…").

[104] *See, e.g.*, 2016 Demand Curve Improvements Filing at 7-8; 2016 Demand Curve Improvements Filing, Testimony of Dr. Christopher Geissler and Dr. Matthew White, at 18-22, 43 (the latter explaining that capacity demand curves should "be set at the level (just) high enough to produce outcomes consistent with the resource adequacy planning objective and to induce new entry when needed."), and at 44 ("the system demand curve will specify a price of Net CONE when the level of capacity procured is (just) enough to meet the region's "1-day-in-10" Loss of Load Expectation resource adequacy objective."). NEPGA's interpretation would violate this latter design property of the Forward Capacity Market's capacity demand curves.

[105] *Id.* at 47.

[106] *See Cost of New Entry and Offer Review Trigger Prices (Modeling the system at equilibrium for the Net Cost of New Entry)* at slides 4-18 (August 11-13, 2020), presentation to NEPOOL Markets Committee by Deborah Cooke on behalf of the ISO, available at https://www.iso-ne.com/static-assets/documents/2020/08/a4_a_i_modeling_system_at_equilibrium_and_estimated_revenue_offsets.pptx.

CONE."[107] As discussed above, the ISO has consistently explained – and the Commission has expressly interpreted – that Net CONE is intended to estimate the compensation a new entrant would require from the capacity market under long-term equilibrium conditions (*i.e.,* at criterion).[108] Nevertheless, in its complaint, NEPGA points to certain detailed elements of past Net CONE studies that, it asserts, are not consistent with that interpretation. NEPGA mischaracterizes those past studies. And, more generally, differences between the previous and present modeling techniques do not in any way render the present methods unreasonable, as NEPGA avers.[109]

As discussed in Part V.D.2.a above, in the 2017 Net CONE Study, the ISO's consultant used a multi-year production cost model of the New England system to estimate future energy prices. Those prices were then input into a unit-specific dispatch model to calculate the E&AS revenue offsets. Importantly, the production cost model was run to maintain a target 15% capacity planning margin in the system, a simplified means to reflect a system at the 1-in-10 resource adequacy criterion.[110] In that way, the resulting 2017 E&AS revenue offset calculations approximated a system in capacity balance (*i.e.,* at criterion) over the twenty-year lifetime of the Net CONE facility. Properly understood, then, NEPGA's witness's assertion that the production cost model in the 2017 study started with "a capacity surplus and gradually converg[ed] to a capacity balance" is substantively misleading.[111] Because of pending retirements, the production cost model assumed new generation would be developed beginning in the very first year of its simulations (for 2021) and in various subsequent years in order to approximate (within the limits of that modeling tool) an "at criterion" system with a 15% capacity reserve margin over the modeling horizon.[112]

Importantly, that observation highlights a broader point: While the 2017 Net CONE Study's modeling approach for energy prices differs from the present study (as noted previously in Part V.D.2.a), neither is unreasonable, nor implies fault in the other. Rather, they reflect the reality that there are multiple different modeling techniques that can be applied to estimate E&AS revenue offsets consistent with a system in long-run equilibrium.

NEPGA's misplaced assertions concerning "at criterion" modeling continue in its discussion of the estimate of annual scarcity hours used to estimate the Net CONE facility's

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[107] NEPGA Net CONE Complaint at 17.

[108] *See, e.g.,* Order Accepting Filing, 161 FERC ¶ 61,035 at P 15 (issued October 6, 2017).

[109] *See* NEPGA Net CONE Complaint at 20-22.

[110] *See* 2017 Net CONE Study at 56.

[111] NEPGA Net CONE Complaint, Affidavit of Robert B. Stoddard, at Paragraph 19.

[112] *See* 2017 Net CONE Study at 54-56.

Capacity Performance Payment revenue offsets.[113] As NEPGA correctly describes, for years 4 through 20 of that revenue component's calculation in the 2017 Net CONE Study, the ISO's consultant assumed 11.3 hours of scarcity conditions annually.[114] That value was the "at criterion" estimate of annual scarcity hours from the most recent ISO study available at the time, performed using the ISO's (stakeholder-vetted) reliability planning model.[115]

Yet, in discussing this very parameter estimate from that 2017 study, NEPGA now asserts that "[c]ompletely absent [from] ISO-NE's discussion of its methodology, benchmarking and results for the 2017 Net CONE recalculation is any mention of equilibrium or a system at criterion."[116] At best, that assertion is plainly mistaken; at worst, it is an effort to further mischaracterize prior Net CONE studies as not reflecting a system in long-run equilibrium. In fact, the 2017 Net CONE Study expressly summarized the rationale for its 11.3 annual scarcity hours estimate as "consistent with our stated assumption of calculating CONE/Net CONE under long-term equilibrium conditions."[117] In sum, it is evident that these detailed modeling elements – which NEPGA alleges show the ISO's present and past Net CONE methodologies "starkly diverge" – are both expressly and firmly grounded on a long-run equilibrium approach to Net CONE.[118]

NEPGA's complaint harkens even further back, flagging certain elements of the 2014 Net CONE Study that it finds inconsistent with a long-run equilibrium approach to Net CONE. In particular, while the 2014 Net CONE Study (performed by a different consultancy) estimated E&AS revenue offsets starting from a three-year historical data period for energy prices – a similar methodological starting point to the present Net CONE study – the 2014 study did not make similar adjustments to account for the excess supply conditions at the time. Those differences reflect the modeling technique variations of different expert consultancies, and do not, as NEPGA inaccurately claims, "reflect a thorough-going revision … to the underlying

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[113] NEPGA Net CONE Complaint at 19-20.

[114] *See* NEPGA Net CONE Complaint at 19-20.

[115] *See* 2017 Net CONE Study at 56, note 51, referencing *Estimated Hours of System Operating Reserve Deficiency – Final Results* (October 13, 2016), presentation to NEPOOL Power Supply Planning Committee by Fei Zeng of the ISO, available at https://www.iso-ne.com/static-assets/documents/2016/10/PSPC10132016_A2_2020-21_Reserve_Deficiencies_Hours_Final.pdf.

[116] NEPGA Net CONE Complaint at 20.

[117] 2017 Net CONE Study at 64.

[118] The 2017 Net CONE Study also notes that, for the first three years of the 2017 study, they assumed a lower estimate of annual scarcity hours (at 6 hours annually) than the criterion value. This transitory difference (from the value of 11.3 hours at criterion) does not imperil the reasonableness of modeling the system at long-term equilibrium generally, or – as NEPGA presently purports – give rise to "entirely different methodologies" for modeling expected scarcity hours. NEPGA Net CONE Complaint at 22.

philosophy ISO used to compute Net CONE."[119] Indeed, much like the present Net CONE analysis, the 2014 Net CONE Study sought to model a reference technology "economic for merchant entry under long-term equilibrium market conditions" and to calculate Net CONE based on the capacity revenue that resource would need "under continued equilibrium conditions."[120] The 2014 Net CONE Study expressly stated as its underlying philosophy for its estimate of Net CONE, "we assume the entrant has a generic cost structure and a fairly well-behaved, *long-term equilibrium view of the capital recovery trajectory* it can expect."[121]

Most importantly to the instant filing, the difference in methodological techniques between the ISO's past and present Net CONE studies do not undermine the reasonableness of the present methodology. The ISO has established beyond doubt that Net CONE is intended to reflect a system in long-run equilibrium and has been implemented in that manner. Even if NEPGA could establish – which it has not – that discrete sub-elements of past Net CONE studies were not optimally in keeping with that goal, it would not invalidate the goal. In fact, it would be all the more reason to support the continued refinement of the methodology to achieve it. Instead, NEPGA is trying to use any apparent inconsistency in past practices to completely overturn a well-established and thoroughly-vetted market design.

It bears emphasis, again, that the substantive issue is no academic matter for the capacity rates that consumers will pay. To model Net CONE "considering the system as it actually sits today," as NEPGA advocates[122] – that is, in conditions of excess supply – would institutionalize the procurement of excess capacity in the Forward Capacity Market. As explained in Part V.F.3 above, basing the Net CONE calculation on market conditions featuring supply in excess of the Installed Capacity Requirement would produce an excessive value of Net CONE that, when inserted into the region's capacity demand curves, would incent new entry even when the system does not need additional capacity to satisfy the Installed Capacity Requirement. That perverse outcome is indefensible under the ISO's overarching Tariff-based obligation to create and sustain markets that are economically efficient.[123]

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[119] NEPGA Net CONE Complaint, Affidavit of Robert B. Stoddard, at Paragraph 37.

[120] 2014 Net CONE Study at 5.

[121] 2014 Net CONE Study at 40 (emphasis added).

[122] NEPGA Net CONE Complaint, Affidavit of Robert B. Stoddard, at Paragraph 38.

[123] *See* Tariff Section I.1.3(b).

5. Nonetheless, It Is Now Clear that the Net CONE Definition Should Be Clarified

The ISO acknowledges (and did during discussions with NEPGA in the stakeholder process) that the existing Tariff definition of Net CONE is not as well worded as it could be. And in the instant filing, the ISO is including changes to the definition to more clearly reflect the intent, design, and practice as described in detail above. In its complaint, NEPGA alleges that these changes to the Net CONE definition can only be interpreted as evidence of a significant change to the underlying Net CONE methodology – "a fact ISO implicitly acknowledged by its proposal late in the stakeholder processes to rewrite the definition."[124] NEPGA overlooks a far simpler explanation.

The reason that the changes to the Net CONE definition came "late in the stakeholder process" is that at the outset of the stakeholder process – which itself occurs well after the ISO began its internal assessment, analysis, and planning – the ISO had no intention of revising the Net CONE definition. It was not considered a necessary element of the changes being filed here. The ISO was entirely comfortable that the Net CONE calculation being performed for the instant update was consistent with the definition, the design intent, and past practice, for the many reasons discussed throughout this Part V.F. *It was primarily in response to NEPGA's new assertion, in the stakeholder process, that the current definition requires a Net CONE calculated "as expected" that the ISO decided that the definition should be clarified.*

But as the explanations provided throughout this Part V.F amply demonstrate, the changes to the definition being filed here do not represent a substantive change from "as expected" to "at criterion." The existing definition, worded exactly as it is today, has always existed in support of the ISO's long-standing (and well-documented) design intent to calculate Net CONE based on a system at criterion. It is *NEPGA* that now seeks a radical departure from that long-standing design intent and practice. As the ISO has consistently maintained, and repeatedly explained, calculating Net CONE based on the system "as expected," as NEPGA desires, would inefficiently incent unneeded new entry when the system's resources exceed the Installed Capacity Requirement, which is neither cost effective nor consistent with the stated 1-in-10 resource adequacy objective.

The specific relief that NEPGA seeks in its complaint is also problematic. NEPGA is aware of the tight timing considerations at issue here, and that a recalculation based on its new

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[124] *See* NEPGA Net CONE Complaint, Affidavit of Robert B. Stoddard, at Paragraph 6.

interpretation of Net CONE would be impossible to accomplish in time for use in FCA 16.[125] In that case, NEPGA suggests "that the Commission direct ISO-NE to apply the Tariff-defined annual adjustment factors to the FCA 15 Net CONE value to be used for the FCA 16 Net CONE value."[126] The upshot of that action would be that instead of running FCA 16 with the fully updated Net CONE value (filed here) of $7.024/kW-month, it would be run using the then-stale FCA 15 value of $8.707/kW-month,[127] escalated still further pursuant to the Tariff's annual adjustment provisions. This outcome would result in an inappropriate increase in consumer payments on the order of tens of millions, and possibly over a hundred million, dollars in FCA 16.[128]

If clarifying the definition of Net CONE, in a manner fully consistent with the long-established design intent, will prevent that perverse outcome, the ISO is (now) eager to do so. The revisions to the definition filed here will remove all doubt that Net CONE must be calculated based on a system modeled under long-term equilibrium conditions. This is accomplished by simplifying the definition so that it no longer refers separately to "first year"

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[125] *See* NEPGA Net CONE Complaint at 29 ("NEPGA recognizes that this relief may not allow time for ISO-NE to review its recalculated Net CONE value with NEPOOL stakeholders prior to the beginning of the FCA 16 calendar.").

[126] NEPGA Net CONE Complaint at 29.

[127] As to staleness, this FCA 15 Net CONE value is not merely one auction old; it was last fully recalculated for FCA 12 four years ago, with only annual index-based adjustments since.

[128] The precise number is impossible to quantify, as it depends on the slope of the future supply curve (at the margin) for FCA 16, the Net CONE value, and the specific clearing conditions of upcoming FCA 16. As context, however, rough measures are informative. NEPGA's requested relief, which is to use the FCA 15 Net CONE value of $8.707/kW-month plus an (undetermined) additional annual adjustment for FCA 16, would increase the FCA 16 Net CONE value by at least 24% over the fully recalculated $7.024/kW-month Net CONE value filed herein (i.e., ($8.707 – $7.024) / $7.024 = 24%). Under the MRI-based capacity demand curve design, if NEPGA's requested relief is granted, it would automatically 'scale up' the FCA 16 system-wide demand curve by at least 24% (at all quantities below the FCA Starting Price), relative to the FCA 16 system-wide demand curve using the recalculated $7.024/kw-month Net CONE value filed herein. In general, every $1.000/kw-month increase in the FCA's clearing price increases consumers' annual capacity payments by approximately $400 million. Therefore, as a rough measure of the impact of NEPGA's requested relief, *if* a 24% higher Net CONE value increases the FCA 16 clearing price by even ½ that much (recognizing that the FCA's supply curve slope will attenuate, to some degree, how much of the full 24% increase in Net CONE would flow through to the auction clearing price) from the FCA 15 clearing price (which was $2.000/kw-month), then NEPGA's requested relief would increase the FCA 16 clearing price by (½ × 24%) of $2.000/kw-month = $0.24/kw-month. In turn, that price increase would raise consumers' annual capacity payments by approximately 0.24 × $400 million = $96 million. These impacts are illustrative, but by no means implausible; the actual impact of NEPGA's requested relief (*i.e.*, a 24% increase in the Net CONE value for FCA 16, relative to the fully recalculated Net CONE value in the instant filing) could be more or less than the $0.24/kw-month change in the FCA 16 auction clearing price assumed here (due to, *e.g.,* the elasticity of supply). Nevertheless, these illustrative calculations reveal that the impact of NEPGA's requested relief for FCA 16 may well increase consumers' capacity payments by many tens of millions, and possibly over a hundred million, dollars for FCA 16.

and "subsequent years" revenues, and instead expressly refers to "reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions."[129]

G. Capacity Performance Payment Rate

The Capacity Performance Payment Rate is the Tariff-prescribed settlement rate for resource performance (during Capacity Scarcity Conditions) under Pay for Performance, the common name for New England's two-settlement capacity market design. As noted earlier, with this filing, the Capacity Performance Payment Rate is being updated for the Capacity Commitment Period that begins on June 1, 2025 and in advance of the corresponding Forward Capacity Auction, to be conducted in February of 2022 (FCA 16).

The Tariff does not specify a schedule for reviewing and updating the Capacity Performance Payment Rate, stating that "[t]he ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate."[130] In the 2018 proceeding to consolidate the review process for the various FCM parameters, however, the ISO indicated its intention "to review and update, if appropriate, the Capacity Payment Performance Rate for FCA 16 in conjunction with the review of the other FCM parameters."[131]

Updating the Capacity Performance Payment Rate was not within the scope of work assigned to CEA, and hence is not addressed in the CEA Report. Thus, we provide a brief overview of the role and derivation of this rate, and then turn to the instant update and the associated Tariff revisions. Importantly, the Capacity Performance Payment Rate is based on a formula set forth in the ISO's original two-settlement capacity market design filing in 2014,[132] and that formula is not at issue in the instant proceeding. That formula, including its derivation and rationale, was fully vetted and approved by the Commission in the implementation of the two-settlement capacity market design,[133] and is not being modified here. The revised rate being filed here simply reflects updated inputs to the formula (which is dependent on several of the same inputs to Net CONE that have been recalculated for this proceeding).

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[129] *See* revised Tariff Section I.2.2 (definition of "Net CONE").

[130] Tariff Section III.13.7.2.5.

[131] ISO New England Inc. and New England Power Pool Participants Committee Filing re Consolidation of FCM Parameter Review, Docket No. ER19-335-000 (filed November 14, 2018) at 6.

[132] *See* Filings of Performance Incentives Market Rule Changes, FERC Docket Nos. ER14-1050-000 and ER14-1050-001 (filed January 17, 2014), attachment I-1a (Transmittal Letter on Behalf of the ISO) at 5, 23-25, 41-43 and attachment I-1c (Testimony of Matthew White on behalf of the ISO) at 86-116.

[133] *See* Order on Compliance Filing, 149 FERC ¶ 61,009 at P 24 (issued October 2, 2014).

1. Overview of the Role and Derivation of the Capacity Performance Payment Rate

The two-settlement capacity market design employed in New England incorporates two key elements, the first of which is a forward position in which a quantity of capacity is obligated, or sold. Each MW is paid at the auction clearing price. This sale in the forward capacity auction creates both a resource-specific physical obligation (*e.g.,* to submit daily offers in the energy markets) and a forward financial position.[134] The resource's forward financial position is a pro-rata share of the system's real-time energy and reserve requirements during any Capacity Scarcity Conditions that may occur during the Capacity Commitment Period. Second, there is a settlement for deviations. If a resource delivers more than its share of the system's requirements during a Capacity Scarcity Condition, it will be paid for that incremental production; if it delivers less than its share, it will "buy out" of its position by paying other resources that did deliver.

In two-settlement forward markets having a liquid spot market, the second-settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. (For example, the Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions.) But because there is no spot market for capacity, deviations are settled at an administratively-determined rate specified in the Tariff – the Capacity Performance Payment Rate.

The Capacity Performance Payment Rate formula was derived from two specific economic principles. First, the rate must be set at a level such that a (cost-effective) new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement; that is, the sum of the base payment plus expected performance credits are at least as large as Net CONE when the system is at criterion (and thus may require new entry). Second, a resource that expects to have zero performance (that is, it expects to supply zero energy and reserves) during all expected scarcity conditions over the course of the commitment period should expect zero net capacity revenue. These principles were translated into formulas that, when combined, yield a simple result for the Capacity Performance Payment Rate:[135]

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[134] These forward positions may be changed (acquired or shed) subsequent to the Forward Capacity Auction by various means, such as reconfiguration auctions, that are not material to the present explanations or the instant filing.

[135] The formula presented here for the Capacity Performance Payment Rate differs, non-substantively, from the version presented in the ISO's initial filing in 2014 of the two-settlement capacity market design (*see* references in footnote 133 above) in three ways. First, the numerator was previously described as "Net CONE," as opposed to "(Gross CONE – E&AS)" here. Conceptually, these are the same values, but the Net CONE value used in 2014 did not account for Capacity Performance Payments, as those payments did not yet exist. Using "(Gross CONE – E&AS)" here allows for the proper accounting of those potential revenues. Second, the 2014 version of the formula included a "risk factor" term in the numerator representing the amount of expected profit, if any, a new entrant would be willing to forego by not acquiring a Capacity Supply Obligation and deploying its capital

Capacity Performance Payment Rate = (*Gross CONE – E&AS*) / ($Hours_{new}$ x $Actual_{new}$)

where:

- (*Gross CONE – E&AS*) is the estimated cost of new entry, net of energy and ancillary services revenue offsets (but excluding Capacity Performance Payments), expressed in dollars per MW-year;

- $Hours_{new}$ is the expected number of hours of Capacity Scarcity Conditions annually when the system is at criterion, in hours per year; and

- $Actual_{new}$ is the new resource's actual expected annual performance, over the life of the unit (per MW of capacity).

This formula spreads the total capacity revenue that a new entrant, using a cost-effective technology, requires over its expected production (of energy and reserves) during scarcity conditions. The value in the numerator of the formula is the new entrant's total cost that it must expect to recover from the capacity market in order to be willing to enter. The amount in the denominator is the new entrant's expected total annual performance during scarcity conditions. Their ratio is therefore a settlement rate in dollars per MWh, applicable to energy and reserves provided during scarcity conditions.

The Capacity Performance Payment Rate, the economic principles on which it rests, and the derivation of the formula described above are explained in considerable additional detail in the ISO's 2014 filing of the two-settlement capacity market design.[136]

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in its next best alternative use. However, as the ISO explained then, for purpose of this calculation it is appropriate to assume this value to be zero, and so for simplicity the term is omitted here. *See* Filings of Performance Incentives Market Rule Changes, FERC Docket Nos. ER14-1050-000 and ER14-1050-001 (filed January 17, 2014), attachment I-1c (Testimony of Matthew White on behalf of the ISO) at 106-107. Third, the 2014 version of the Capacity Performance Payment Rate formula specified that the rate must be equal to *or greater than* the calculated number, but that the lowest value that satisfied the requirement would be used. *See id*. at 111. Consistent with this approach and for simplicity, a plain "equal" sign is used here.

[136] *See* Filings of Performance Incentives Market Rule Changes, FERC Docket Nos. ER14-1050-000 and ER14-1050-001 (filed January 17, 2014), attachment I-1a (Transmittal Letter on Behalf of the ISO) at 5, 23-25, 41-43 and attachment I-1c (Testimony of Matthew White on behalf of the ISO) at 86-116.

2. Updated Inputs, New Capacity Performance Payment Rate, and Associated Tariff Revisions

All of the parameters that enter into this Capacity Performance Payment Rate formula have been updated for purposes of calculating Net CONE for the reference technology. Thus, the revision to the Capacity Performance Payment Rate amounts simply to inputting the corresponding recalculated parameter values into the Capacity Performance Payment Rate formula. For completeness, we summarize these inputs and the resulting rate.

As explained earlier in this filing and in the CEA Report, the gross CONE value for FCA 16 is \$11.874/kW-month, and the total E&AS revenue offset (excluding Capacity Performance Payments) is \$3.770/kW-month.[137] Subtracting the latter from the former yields \$8.104/kW-month as the (*Gross CONE – E&AS*) value. Converting measurement units, this value is equivalent to \$8.104/kW-month × 12 months per year × 1000 kW/MW = \$97,248 per MW-year. That is the numerator for the updated Capacity Performance Payment Rate.

As explained in Part V.D.2.c above and noted in the CEA Report, the expected annual hours of scarcity conditions when the system is at criterion ($Hours_{new}$) is 11.3 hours per year.[138] And as explained in Part V.D.3 above and in the CEA Report, the reference technology's actual expected annual performance ($Actual_{new}$), over the life of the unit (in this case, the average performance for a GE 7HA.02 combustion turbine), is 98%.[139] Multiplying these two values yields 11.3 × 0.98 = 11.074 hours per year as the denominator for the updated Capacity Performance Payment Rate.

Dividing \$97,248 per MW-year by 11.074 hours per year (and rounding to the nearest whole dollar) results in a Capacity Performance Payment Rate for FCA 16 of \$8,782 per MWh. This updated value is shown in revisions to Section III.13.7.2.5 of the Tariff, which also indicate that the new value will apply to the Capacity Commitment Period associated with FCA 16 (beginning on June 1, 2025) and thereafter.

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[137] This \$3.770 value is the sum of E&AS revenue (net of production cost), based on qualified capacity MW, during normal operating conditions of \$2.971/kW-month and E&AS scarcity revenue of \$0.799/kW-month. *See* CEA Report at 72 (Table 36).

[138] *See* CEA Report at 61, 71.

[139] *See* CEA Report at 71 (Table 35).

H. Correcting Typographical Errors

The revisions filed here also correct two minor typographical errors in the currently-effective Tariff, unrelated to the substantive issues addressed in this filing. First, in Section I.2.2, in the definition of the term "Senior Officer," a single letter that was inadvertently omitted is being added, such that the last word in the definition is being changed from "office" to "officer." Second, in Section III.13.2.3.2(a)(v), the capitalization of the defined term "Dynamic De-List Bid" is being corrected.

VI. STAKEHOLDER PROCESS

The CONE, Net CONE, and Capacity Performance Payment Rate updates filed here were considered through the complete NEPOOL Participant Processes. The ISO, its consultants, and stakeholders discussed the various Forward Capacity Market parameter updates in eight separate meetings of the Markets Committee between May and November 2020, many of which spread across two or even three days.

As mentioned above, two other Forward Capacity Market parameters were also addressed during this time period and within the Participant Processes: the Dynamic De-List Bid Threshold and the Offer Review Trigger Prices. The updated Dynamic De-List Bid Threshold was bifurcated from the other parameters prior to voting. Unlike the other parameters, it is being changed to a Tariff-based methodology, as opposed to a specific number set forth in the Tariff, and it is not mathematically interrelated in the same manner as the remaining parameters. Hence it was voted separately and will be jointly filed by the ISO and NEPOOL in a separate submission to the Commission.

The Offer Review Trigger Prices, however, were voted upon by NEPOOL as part of the same "package" of updates that included the new CONE, Net CONE, and Capacity Performance Payment Rate values. This package was voted by the NEPOOL Markets Committee at its November 10, 2020 meeting, and by the NEPOOL Participants Committee at its December 3, 2020 meeting. Numerous amendments to the ISO's package were presented by stakeholders, but the only ones that received the requisite level of stakeholder support for NEPOOL approval all concerned the Offer Review Trigger Prices.

Ultimately, the NEPOOL Participants Committee voted to support, with 71.84 percent in favor, a set of parameters (CONE, Net CONE, Capacity Performance Payment Rate, and Offer Review Trigger Prices) that included the stakeholder-supported amendments to the Offer Review

Trigger Prices. NEPOOL was then asked to vote on the ISO's unamended version of that set of parameters, which failed with 18.33 percent in favor.

In such circumstances, the "jump ball" provision of the Participants Agreement is invoked. That section states:

> If the Participants Committee vote relating to an ISO Market Rule proposal results in the approval by the Participants Committee by a Participants Vote equal to or greater than 60% of a Market Rule proposal that is different from the one proposed by ISO, including, but not limited to, a Governance Participant proposal, ISO shall, as part of any required Section 205 filing, describe the alternate Market Rule proposal in detail sufficient to permit reasonable review by the Commission, explain ISO's reasons for not adopting the proposal, and provide an explanation as to why ISO believes its own proposal is superior to the proposal approved by the Participants Committee.

In this case, as a result of the final vote on the various stakeholder-proposed amendments, the ISO's unamended package of parameters and the NEPOOL-supported package include exactly the same gross CONE, Net CONE, and Capacity Performance Payment Rate values. The two resulting packages of parameters differ only with respect to the Offer Review Trigger Prices.

Faced with this outcome, and after consulting with NEPOOL Counsel, the ISO determined that the appropriate course of action would be to file the updated CONE, Net CONE, and Capacity Performance Payment Rate values common to both packages in the instant filing, and confine the "jump ball" to the area in which the ISO and NEPOOL approaches actually differ – the Offer Review Trigger Prices. As indicated above, it is critical that the CONE and Net CONE values become effective no later than early March, prior to the first FCA 16 qualification process deadlines that rely on those values. The Offer Review Trigger Prices, however, do not need to be effective until slightly later in the FCA 16 qualification process. The ISO will work with NEPOOL Counsel to submit to the Commission both versions of the Offer Review Trigger Prices in a "jump ball" filing as soon as practicable in January 2021.

Because of these complexities, the ISO is making the instant filing independently, and cannot represent that NEPOOL supports the CONE, Net CONE, and Capacity Performance Payment Rate parameters filed here, even though they are the same values as those in the NEPOOL-approved package. NEPOOL has indicated that it plans to submit comments in this proceeding to provide the Commission with an explanation of its position(s) and with additional information regarding NEPOOL's consideration of the Tariff changes filed herein, including information on several Participant-sponsored amendments that were sought in the stakeholder process.

VII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the Tariff revisions filed here do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations.[140] Notwithstanding this request for waiver, the ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

35.13(b)(1) – Materials included herewith are as follows:

- This transmittal letter;
- The *ISO-NE CONE and ORTP Analysis; An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction; FCA 16 and Forward* (referred to herein as the "CEA Report");
- Affidavit of Danielle S. Powers, Concentric Energy Advisors, Inc.;
- Affidavit of Keith Paul, Mott MacDonald, Inc.;
- Blacklined Tariff sections reflecting the revisions discussed in this filing;
- Clean Tariff sections reflecting the revisions discussed in this filing; and
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – As set forth in Part II above, the ISO requests that the Tariff revisions filed here become effective on March 2, 2021.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-

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[140] 18 C.F.R. § 35.13 (2016).

ne.com/participate/participant-asset-listings. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in Part VII of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Parts I and V of this transmittal letter.

35.13(b)(6) – The ISO's approval of these changes is evidenced by this filing.

35.13(b)(7) – The ISO has no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(c)(1) – The Tariff changes herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the wholesale, resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions filed herein.

VIII. CONCLUSION

For the reasons discussed in this transmittal letter, the ISO requests that the Commission accept the updated CONE, Net CONE, and Capacity Performance Payment Rate values, and the associated Tariff revisions filed here, without modification, to become effective on March 2, 2021.

Respectfully submitted,

ISO NEW ENGLAND INC.

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ISO-NE NET CONE AND ORTP ANALYSIS

AN EVALUATION OF THE NET COST OF NEW ENTRY AND OFFER REVIEW TRIGGER PRICE PARAMETERS TO BE USED IN THE FORWARD CAPACITY AUCTION

FCA-16 AND FORWARD

CONCENTRIC ENERGY ADVISORS, INC.
Danielle Powers
Meredith Stone

MOTT MACDONALD
Keith Paul
Joe Farrell

December 2020

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Section 1: Executive Summary

A. Overview

The design of the Forward Capacity Market (FCM) involves estimating the cost of developing new resources that could enter the market, known as the Cost of New Entry (CONE). At a high level, the CONE and Net CONE values are, respectively, estimates of the total and net costs of developing the most economically efficient type of new capacity resource in New England. The Offer Review Trigger Price (ORTP) values are estimates of the entry costs for all resource types that would reasonably be expected to participate in the FCM and are used to screen offers from new resources that may require further review per ISO New England's (ISO-NE) buyer-side market power mitigation provisions.

The ISO-NE Open Access Transmission Tariff (Tariff) requires that the CONE, Net CONE and ORTP values used in the FCM be re-evaluated and updated at least once every three years pursuant to Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). In the years between such recalculations, the CONE, Net CONE and ORTP values are updated annually using indices specified in Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(e).

For the calculation of CONE and Net CONE, ISO-NE's Tariff requires the following:

> *"CONE and Net CONE shall be recalculated using updated data coincident with the recalculation of Offer Review Trigger Prices pursuant to Section III.A.21.1.2. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply."*
>
> *"Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e)…."*[1]

For the calculation of ORTP values, ISO-NE's Tariff requires the following:

> *"The Offer Review Trigger Price for each of the technology types… shall be recalculated using updated data no less often than once every three years. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply".*[2]

As more fully explained in this report, the CONE and Net CONE values are parameters that are intended to reflect the compensation a cost effective new entrant would need from the capacity market (net of expected revenues) to recover its capital and fixed costs under long-term equilibrium conditions, given reasonable expectations about future market conditions and cost recovery assumptions. Along with other values, the Net CONE value is used to scale the demand curves, and

1 Market Rule 1 Section III.13.2.4.
2 Market Rule 1 Section III.A.21.1.2.

the CONE and Net CONE values are used to set the Forward Capacity Auction (FCA) starting price (the maximum of CONE or 1.6 times Net CONE).

This report contains the results of the estimates of both: i) the CONE and the Net CONE values, and ii) the technology specific ORTP values for use in ISO-New England's FCA-16 for the 2025/2026 Capacity Commitment Period (CCP) (June 1, 2025 through May 31, 2026).[3] Net CONE estimates are made from the perspective of a hypothetical unit of a given resource and technology type in a generic location in New England, which is referred to as the "reference" unit.

B. Study Scope and Process

ISO-NE engaged Concentric Energy Advisors, Inc. (Concentric) to conduct an independent analysis of the CONE/Net CONE and ORTP values for FCA-16. Concentric and its subcontractor, Mott MacDonald, worked together to develop the recommendations presented in this report. To arrive at these results, we considered relevant market and technology issues, screened several technologies, and closely evaluated those that met the pre-specified CONE and ORTP screening criteria as described in Section 3 of this report. This evaluation included a detailed analysis of resource technical specifications, capital, and operating costs, and expected market conditions to calculate expected revenues and arrive at recommended CONE/Net CONE and ORTP values.

The study process consisted of the four basic tasks outlined below and further described in this report:

1. **Resource Screening and Selection.** The first step in the process was to develop screening criteria to identify the resource types for which Concentric and Mott MacDonald would calculate CONE/Net CONE values and ORTP benchmark values. The resource types that passed the screens were subject to a full bottoms-up evaluation of costs and revenues over the resource's expected life.
2. **Calculation of CONE.** For each of the selected resource types, we developed technical specifications, installed capital costs, and operating costs over the expected life of each facility. The study included an expected life of 20 years for technology types other than Energy Efficiency. Energy Efficiency was assumed to have a useful life of 11 years. Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, we used a levelized annual cost calculation to determine a revenue requirement that ensured the recovery on and of investment costs.
3. **Calculation of Expected Revenues.** We estimated the revenues that each resource type is expected to earn during its expected lifetime, including energy revenues net of variable production costs, ancillary service revenues, renewable energy credit (REC) revenues, and

[3] While CONE, Net CONE, and ORTP values are normally recalculated every three years according to Market Rule 1, ISO-NE requested and received from FERC a one-year deferral to allow potential impacts of proposed market changes to be reflected in the resulting values.

Pay for Performance (PFP) revenues. Expected energy revenues were based on the estimated revenues each resource would have earned in ISO-NE's energy and ancillary services markets during the most recent three calendar years using adjusted historical prices.[4]

4. **Calculation of Net CONE and ORTP.** Based on the calculation of CONE and expected revenues, we calculated the compensation needed from the capacity market, net of non-capacity market revenues, that the resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues to determine Net CONE and ORTP values for each resource type.
   - For generation resources, capital costs, operating costs, expected energy and ancillary services revenues, and assumptions regarding depreciation, taxes and discount rate were inputted into a capital budgeting model to calculate the break-even contribution required from the FCM to yield a levelized revenue requirement with a net present value (NPV) of zero. To calculate the ORTP benchmarks, we adjusted select operating costs and financial assumptions to reflect the expected costs of a new resource with a portion of its generation output under contract. These adjustments were made pursuant to Tariff requirements to calculate ORTP benchmarks that achieve the "low end of the competitive range" objective. The Net CONE value and ORTP benchmarks are equal to the net present value of the levelized costs of each resource, net of expected revenues.
   - For Energy Efficiency, the methodology used to calculate the ORTP value was the same as that used for generation resources, except that the cash flows were discounted over an 11-year project life and took into account the costs incurred by the utility and end-use customer to deploy the efficiency measure.
   - For Demand Response Resources, the methodology used to calculate the ORTP benchmarks was the same as that used for new generation resources with a 20-year project life.

Each of these tasks involved a detailed review of historical data, modeling techniques and analytical methods, and the application of professional judgement to calculate estimated values for each resource type. Concentric and Mott MacDonald conducted both studies simultaneously in an open and transparent process with stakeholders and ISO-NE staff. Key assumptions and issues were presented to stakeholders for input and feedback in eight separate meetings with the New England Power Pool ("NEPOOL") Markets Committee. These meetings provided important feedback and direction on concepts and metrics relevant to the study process, and provided guidance for consideration of, and recommendations on, key study issues, assumptions, and outcomes.

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[4] As discussed further in Section 6 below, the historical energy prices used in the Net CONE dispatch models were adjusted to both remove the impact of energy and reserve shortage conditions and to estimate energy prices that would occur if the system were at criterion. The historical energy prices for the ORTP dispatch models were adjusted to remove the impact of energy and reserve shortage conditions.

C. Summary of Recommendations

Based on our analysis, we recommend that the simple cycle gas turbine technology be used as the reference technology for FCA-16, which is the auction scheduled for the 2025/2026 Capacity Commitment Period, ensuring that the capacity market will cost effectively procure capacity sufficient to meet the region's resource adequacy requirement.

To arrive at these results, Concentric and Mott MacDonald considered the active development of gas-fired resources in New England and the participation of these resources in recent FCAs. The results of our CONE analysis are shown below.

Table 1: Net CONE Values for Candidate Reference Units

	1x1 7HA.02 (CC)	1x0 7HA.02 (CT)	2x0 LM6000 PF+ (AERO)
NOMINAL INSTALLED CAPACITY (MW)	543	371	95
QUALIFIED CAPACITY	489	361	91
INSTALLED COST (2019$/KW)	985	777	1,961
REAL ATWACC	6.1%	6.1%	6.1%
GROSS CONE (2025$/KW-MONTH) INSTALLED	$15.840	$11.399	$27.018
GROSS CONE (2025$/KW-MONTH) QUALIFIED	$17.600	$11.874	$28.144
REVENUE OFFSETS (2025$/KW-MONTH)	$4.388	$4.656	$4.502
NET CONE (2025$/KW-MONTH) INSTALLED	$11.452	$6.743	$22.517
NET CONE (2025$/KW-MONTH) QUALIFIED	**$12.724**	**$7.024**	**$23.455**

Similarly, we have conducted an evaluation of resources that have or are reasonably expected to participate in the FCM and have an ORTP below the expected auction starting price. Based on the CONE/Net CONE analysis for the simple cycle frame combustion turbine and combined cycle combustion turbine with appropriate modifications to assumptions to reflect the low end of the competitive range consistent with Tariff requirements, and a detailed analysis of other resources meeting stated screening criteria, we recommend the resource specific ORTPs shown in Table 2 below.

Table 2: ORTP Summary for Specific Resources (2025$)

Reference Technology	Combined Cycle	Combustion Turbine	Onshore Wind	Battery	Energy Efficiency	DR - On-Peak Solar	Load Mgmt C&I/ Prev Installed DG	DR - Combined PV/ Storage
Nominal Installed Capacity (MW)	557	376	82.5	150	--	--	--	--
Qualified Capacity (MW)	501	361	32.4	129	--	1	2	0.5
Installed Cost (2019$/kW)	956	758	2,097	938	--	--	--	--
Real ATWACC	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%	4.30%
Gross CONE (2025$/kW-mo)	$12.72	$9.18	$18.64	$8.92	$36.95	$20.07	$15.41	$22.11
Revenue Offsets (2025$/kW-mo)	$3.88	$4.02	$23.27	$6.00	$45.52	$14.65	$14.65	$14.73
Net CONE (2025$/kW-mo) Installed	$8.84	$5.15	-$4.63	2.92	-$8.57	$5.43	$0.76	$7.38
ORTP (2025$/kW-mo) Qualified	$9.819	$5.366	$0.00	$2.923	$0.00	$5.425	$0.761	$7.376

Section 2: FCM Overview

A. FCM Background

The FCM is a long-term market that ensures resource adequacy, both zonally and for the ISO-NE system as a whole. The market is designed to promote economic investment in capacity resources when and where they are needed. Resources that may participate in the FCM include new and existing resources, comprised of generating resources, imports, demand response resources and energy efficiency resources.

To purchase sufficient capacity to satisfy the region's future resource adequacy needs and allow enough time to construct new capacity resources, FCAs are held each year approximately three years in advance of the 12-month Capacity Commitment Period during which time the resources that clear in an FCA must meet their assumed obligation. The commitment that capacity resources undertake when they clear in an FCA is called a capacity supply obligation (CSO). Capacity resources with the lowest-priced offers clear the FCA and receive capacity payments based on the FCA clearing price, which is determined through a descending clock auction. The payments capacity resources receive for accepting a CSO are in addition to the revenues those resources are eligible to receive in the ISO-NE energy and ancillary services markets and other markets (e.g., REC markets). In exchange for capacity payments, the resources have an obligation to be ready to provide capacity when called upon.

B. Role of CONE and ORTP Values

The CONE, Net CONE and ORTP values are used during the annual FCA auction process. A primary use of Net CONE is as a parameter that helps to define how demand for resource adequacy in ISO-NE is represented in the FCA. Demand is represented by system and zonal demand curves that are calculated to reflect the Marginal Reliability Impact (or "MRI") of adding incremental capacity in different locations. The FCA market rules specify that the system demand curve must be scaled so that the quantity of capacity associated with the Net CONE value satisfies the ISO-NE system's resource adequacy reliability standard (which is a Loss of Load Expectation of 0.1 days per year). The CONE and Net CONE values also are used to set the FCA Starting Price. The market rules specify that the FCA Starting Price is the higher of: (1) CONE, and (2) 1.6 multiplied by Net CONE.[5]

The primary use of the ORTP values is to "screen" for resource offers in the FCA that are potentially below the competitive level. The ORTP values are designed to address the exercise of buyer-side market power that could inappropriately suppress capacity prices below the competitive level. A new capacity supply resource can submit an offer above the ORTP value without justification to the ISO-NE Internal Market Monitor (IMM). New capacity resource offers below the ORTP require IMM

[5] Market Rule 1, Section III.13.2.2.4 (Capacity Demand Curve Scaling Factor).

review. Consistent with guidance from ISO-NE and the FERC, the recommended ORTP values are set at the low end of the competitive range of expected values so as to strike a reasonable balance by only subjecting resources to review which appear commercially implausible absent out-of-market revenues.[6]

Establishing the ORTP benchmarks at the low end of the range of estimated competitive costs is intended to strike a reasonable balance by not subjecting offers that are "clearly competitive" to evaluation. For resource types where it is not possible to establish a reliable ORTP value, a default ORTP is set equal to the FCA starting price.[7] Importantly, having offers subject to review by ISO-NE does not prevent any individual resource or resource type from participating in the FCM. Rather, a resource that wishes to submit an offer below the ORTP benchmark for its resource type must substantiate its costs and show that its offer will not inappropriately suppress capacity prices below the competitive level.

6 *ISO New England Inc.*, 161 FERC ¶ 61,035, at P 21 (October 6, 2017).

7 Market Rule 1, Section III.A.21.1.1.

Section 3:
CONE Study

This section describes the CONE study performed on the three candidate resource types identified through the screening process: the simple cycle frame machine; the aeroderivative machine; and the combined cycle frame machine. The CONE value for a given resource type and technology is intended to reflect the annual levelized capital and fixed costs a new entrant would incur to enter the ISO-NE capacity market over its estimated project life. CONE values are used to estimate Net CONE values for each candidate reference unit. Net CONE values are calculated by subtracting a reasonable expectation of the energy, ancillary services, PFP, and other revenues the resource could earn under long-term equilibrium conditions. Section 3.B describes the key assumptions used to develop CONE estimates for the three candidate reference units.

A. Screening Process

i. General Criteria

The resource screening process used to establish the candidate technologies for a CONE calculation began with the recognition of the variety of resource types that currently participate in the FCM, and the application of the technology screening criteria that have been approved by the FERC in previous Net CONE calculation processes. Specifically, the FERC has found that important considerations in assessing the candidate reference technologies for determining Net CONE should include the following:

1. Must be likely to be economic for merchant entry under long-term equilibrium conditions;
2. Must have reliable cost information available to calculate a CONE value using a full "bottom-up" analytical approach; and
3. Must reliably be able to meet load when resource adequacy is at risk.[8]

In including each of these criteria, it is important to outline the manner in which we interpreted and applied each of these criteria. The application of this criteria is shown below.

[8] FERC Order Docket ER14-1639-000 147 FERC ¶ 61,173, May 30, 2014.
FERC Order Docket ER17-795-000 161 FERC ¶ 61,035, October 6, 2017.

Table 3: Application of CONE Analysis Criteria

SCREENING CRITERIA	APPLICATION
Must be likely to be economic for merchant entry under long-term equilibrium conditions	Net CONE value is high enough to incent new entry into the market, but not so high as to introduce unnecessary costs
Must have reliable cost information available to calculate a CONE value using a full "bottom-up" analytical approach	Demonstrated interest by developers such that capital costs and E&AS revenues can be estimated with a high level of certainty
Must reliably be able to meet load when resource adequacy is at risk	Technology is able to be dispatched whenever resource adequacy is at risk

The first principle, that the resource must be economic for merchant entry under long-term equilibrium conditions, has been expressed in past CONE filings and approved in related FERC orders as a requirement that the reference technology must result in a demand curve that "should produce prices high enough to meet the reliability standard but not so high as to add unnecessary costs".[9] This recognizes that uneconomic technologies would set Net CONE higher than required to meet ISO-NE's established reliability objectives.

The second principle is that the reference technology must have reliable cost information available to calculate a CONE and Net CONE value with confidence utilizing a "bottom-up" analytical approach. Estimating CONE and Net CONE values requires the development of assumptions about the resource's technical specifications, the analysis of potential costs and revenues, the estimation of various financial parameters and risks. Therefore, it is critical that a sufficient amount of data is available to determine a robust estimate of each resource type's CONE and Net CONE. As is shown in Table 4, there has been substantial development of the various gas-fired technologies that were included in the list of candidate resources to be evaluated. As can be seen below, both the simple cycle and combined cycle General Electric (GE) machines have participated and cleared in the most recent FCAs.

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9 *ISO New England Inc.*, 170 FERC 61,052 (January 24, 2020) at P 18 (citing *ISO New England Inc.*, 161 FERC ¶ 61,035 (2017) at 38 & n.67).

Table 4: Proposed Simple Cycle and Combined Cycle Projects in New England

Name	Unit Type	Year In Service Expected In Service	Turbine Manufacturer	Turbine Model	Location	Size (MW)	Status	Cleared Auction
Killingly Energy Center	Combined Cycle	2022	Mitsubishi	M501JAC	CT	650	Early Development	FCA11
Waters River	Gas Turbine	2021	GE Energy	LM9000	MA	60	Announced	N/A
Thomas A. Watson Generating Station	Gas Turbine	2020	Not Announced	Not Announced	MA	64	Late Stage Development	N/A
West Medway II	Gas Turbine	2019	GE Energy	LMS100PA+	MA	200	Operating	FCA9
Canal 3	Gas Turbine	2019	GE Energy	7HA.02	MA	350	Operating	FCA10
Bridgeport Harbor Station	Combined Cycle	2019	GE Energy	7HA.02	CT	496	Operating	FCA9
Wallingford Energy	Gas Turbine	2018	GE Energy	LM6000	CT	100	Operating	FCA9
Towantic Energy Center	Combined Cycle	2018	GE Energy	7HA.01	CT	785	Operating	FCA9
Salem Harbor Station	Combined Cycle	2017	GE Energy	7F 5-Series	MA	674	Operating	FCA7

The third principle is that the reference technology must be able to reliably meet load when resource adequacy is at risk. In assessing the ability of different resource types to contribute to resource adequacy, it is important to ensure that the reference technology is able to contribute to the reliability standard of 1 day in 10 years. Consistent with the development of ICR and the demand curves, the proxy unit used to meet the 1 day in 10 years reliability criteria is a dispatchable unit. Therefore, we have chosen to assess resource types that are dispatchable both up and down by ISO-NE to meet loss of load expectations consistent with ICR requirements.

ii. Resources Considered

Several different resources were considered for an evaluation against the screening criteria outlined above, including gas-fired resources, coal-fired resources, nuclear resources, various renewable resources, storage resources, and demand response and energy efficiency resources. Gas-fired resources passed the screening criteria, as they have been proven to be economic for new entry in the recent past and have numerous sources of historical operating data. No new coal or nuclear resources have been developed in ISO-NE in thirty years, and therefore, these resources do not meet all of the screening criteria. Renewable resources have been developed in recent years and additional renewable and battery storage resources have been proposed. However, these resources did not pass our screening criteria, as shown in Table 5 below. As a result, our analysis focused on gas-fired resources in both simple cycle and combined cycle configurations as the appropriate technologies to consider the CONE/Net CONE analysis.

Table 5: Resource Screening Results

	Expected to Be Economic For Merchant Entry Under Long Run Equilibrium Conditions	Reliable Cost Information for a Full Bottoms-Up Approach (Including E&AS Revenues to Calculate a Net CONE Value)	Able to Reliably Meet Load When Resource Adequacy is at Risk
Onshore Wind	√	√	×
Offshore Wind	×	√	×
Coal/Nuclear	×	√	√
Solar	×	√	×
Large-Scale Battery	×	×	×

It is important to remember that the frequency with which this study is updated – every three years – is designed to capture how the Net CONE values of various resource types change in relation to each other as market conditions and resource development costs change over time. Future Net CONE/ORTP re-calculations are expected to use similar screening criteria, and the resources that meet this screening criteria may change as technology evolves, resulting in a change in the reference unit.

Regarding simple cycle gas technologies, we considered both frame and aeroderivative machines. For frame machines, we considered the following key factors:

- Can provide reliable generation to the grid for a low capital cost;
- Can be installed with fast-start capability;
- Technology being continuously improved by the manufacturers;
- Usually installed for peak power production;
- Industrial design intended for long-term operation at high efficiencies; and
- Currently being installed in New England.

The simple cycle frame technologies that were considered as candidate simple cycle units are shown in Table 6 below.

Table 6: Simple Cycle Frame Machines

FRAME TECHNOLOGY	CONSIDERATIONS
GE7HA.02	• GE's largest and most efficient machine already installed in New England in simple cycle configuration • Highest output for a currently installed Frame Gas Turbine
GE7HA.03	• Newest large frame gas turbine from GE • Most efficient and highest capacity gas turbine offered by GE • Not yet run in GE test stand • Not yet installed anywhere in the world
Siemens 8000H	• Largest installed experience base for large H-Class gas turbines • Previous generation frame machine technology • Expected to be replaced by the 9000HL • None installed in New England
Siemens 9000HL	• Newest large frame machine from Siemens • Most efficient and highest capacity gas turbine offered by Siemens • Slightly lower capacity and efficiency than frame machines offered by GE and Mitsubishi Hitachi Power Systems (MHPS) Not yet operated in a test stand or a plant
MHPS M501GAC	• Air cooled large frame gas turbine evolved from previous generation technology • Installed and operating globally
MHPS M501JAC Classic	• Frame machine validated at MHPS T-Point Power Plant and 4 simple cycle units operated in Asian 60 Hz power plant • One unit in engineering for New England, but unit operated in combined cycle configuration • Most efficient Frame GT currently operating globally
MHPS 501JAC	• Largest frame machine offered by MHPS • Newest update of the M501JAC. Not considered a new frame design, but rather an "update" of the existing machines • Best heat rate available for an installed frame machine • Validated in MHPS T-Point Power Plant • Not yet installed in simple cycle configuration
Other Frame Machines	• MHPS H Series of smaller and less efficient frame machines • Siemens SGT family – Not a large installed base in New England, not being aggressively marketed by Siemens • Ansaldo GT-36 – Not yet being marketed for 60 Hz operations

As a result of the review of the above simple cycle frame combustion turbine options, and because there is a simple cycle 7HA.02 unit operating in New England, Concentric and Mott MacDonald chose the GE7HA.02 as the simple cycle frame machine as a reference unit candidate on which to conduct a full CONE/Net CONE evaluation. A project using this technology, the Canal 3 Project, achieved commercial operation in simple cycle configuration in 2019 and therefore represents the most current frame technology developed in the region.

For aeroderivative machines, we considered the following factors to be key when comparing aeroderivative technology against frame turbine technology:

- Speed to market and to engineer;
- Size makes them more expensive in $/kW (installed);
- Multiple LM6000 plants are operating in New England with the LM6000 PF+ being the latest version; and
- Can be converted to combined cycle if originally arranged properly.

The aeroderivative machines that were considered for the candidate simple cycle reference units are shown in Table 7 below.

Table 7: Simple Cycle Aeroderivative Machines

AERODERIVATIVE TECHNOLOGY	CONSIDERATIONS
GE LM6000	• One of the most widely installed machines in New England • LM6000PF+ is the latest dry-cooled version
LM2500	• High $/kW installed cost • Often utilized in combined heat and power or industrial process applications
Rolls Royce Trent	• Viable option to LM6000 family
MHI Pratt & Whitney FT8 Swiftpac	• Less efficient machine with small New England installed base
Siemens SGT 800	• Efficient competitor to LM6000 and Trent with small installed base in NE
Solar Titan 250	• Small machine with high heat rate and small installed base in NE
GE LMS100	• Hybrid aeroderivative gas turbine designed with some aeroderivative turbine sections and some frame machine sections • Only advanced aeroderivative machine available • Most efficient simple cycle machine available • Recently installed in New England after project delays but has not been proposed since

Following a review of the above aeroderivative machines, Mott MacDonald selected the GE LM6000 technology for the CONE/Net CONE evaluation. The GE LM6000 is currently installed in New England and represents a commercially acceptable and cost-effective technology.

Finally, for the combined cycle technologies, we considered the following factors:

- Can provide reliable generation to the grid;
- Can provide the best thermal efficiency available;
- Utilizes the largest and most efficient gas turbine technology available for combined cycle applications;

- Current frame designs are undergoing a step-change improvement in output and efficiency; and
- Currently operating in New England.

The combined cycle combustion turbine technologies considered for the candidate combined cycle unit are shown in Table 8 below.

Table 8: Combined Cycle Combustion Turbines

Frame Technology	Considerations
GE7HA.02	• GE's largest and most efficient machine already installed in New England in simple cycle configuration • Highest output for a currently installed Frame GT
GE 7HA.01	• Currently offered for sale but expected to be replaced by the 7HA.02 due to improvements in capacity and efficiency • Currently in operation in New England
GE 7FA - .04 thru.06	• Will continue to be offered for sale, but are smaller and less efficient than the 7HA technologies
GE7HA.03	• Newest large frame gas turbine from GE • Most efficient and highest capacity gas turbine offered by GE • Not yet run in GE test stand • Not yet installed anywhere in the world
Siemens 8000H	• Largest installed experience for large G, H, and J frame gas turbines • Smaller and less efficient than GE's or MHPS's latest technology machines
Siemens 9000HL	• Newest large frame machine from Siemens • Most efficient and highest capacity gas turbine offered by Siemens • Not yet operated in a test stand or a plant • Currently being installed in a test plant in the US • Slightly lower capacity and efficiency than frame machines offered by GE and MHPS
MHPS M501GAC	• Air cooled large frame gas turbine evolved from previous generation technology • Installed and operating globally
MHPS M501JAC Classic	• Frame Machine validated at MHPS T-Point Power Plant and 4 Simple Cycle units operated in Asian 60 Hz power plant • One unit in engineering for New England • Most efficient frame GT currently operating globally
MHPS M501JAC	• Largest frame machine offered by MHPS • Newest update of the M501JAC. Not considered a new frame design, but rather an "update" of the existing machines. • Best heat rate available for an installed frame machine • Validated in MHPS T-Point Power Plant
MHPS M501J	• M501J is a steam cooled large frame gas turbine • Slightly lower capacity than the M501JAC Classic, but with equal heat rate

FRAME TECHNOLOGY	CONSIDERATIONS
Other frame machines	• MHPS H Series of smaller and less efficient frame machines • Siemens SGT Family – Not a large installed base in New England, not being aggressively marketed by Siemens • Ansaldo GT-36 – Not yet being marketed for 60 Hz operations

Given a review of the above combined cycle combustion turbine options and the fact that there are 7HA.02 machines in both combined cycle and simple cycle operation in New England, Mott MacDonald advised the use of the GE 7HA.02 machine as the combined cycle turbine model candidate reference unit on which to conduct a full CONE/Net CONE evaluation. The Bridgeport Harbor Station 5 became operational in 2019 with 7HA.02 technology in combined cycle configuration, which supports the finding that the 7HA.02 is a commercially acceptable and cost-effective technology.

We note that all of the gas candidate reference units that underwent the full CONE/Net CONE evaluation utilize turbines developed by GE. This is because GE clearly continues to have the largest market share of new gas turbines being developed in New England at this time. Other gas-fired resources that use turbines from other manufacturers were also considered but were not fully evaluated since they did not reflect the level of activity in New England that has been demonstrated by GE.

B. Key Assumptions

General assumptions used in the CONE study that are applicable to all technologies include assumptions regarding location, plant configuration, interconnections to the natural gas pipeline and electric transmission/distribution systems, dual fuel capability, and environmental control capabilities. A summary of these assumptions is provided in Table 9 and each assumption is described in further detail below.

Table 9: Key Assumptions for Gas Candidate Reference Units

KEY ASSUMPTIONS	
Turbine model	7HA.02
Location	New London County, Connecticut
Cooling system	Fin fan coolers
Power augmentation	Evaporative coolers
Duel-fuel capability	Natural gas w/ No. 2 oil backup
Black start?	No
On-site gas compression?	No
Gas interconnection	Onsite connection
Electrical interconnection	Onsite connection

i. Location

While the CONE reference unit is a hypothetical unit of a given resource and technology type, it was necessary to identify a general location for this unit for the purposes of estimating property taxes, interconnection costs, labor rates, etc. Concentric and Mott MacDonald screened locations based on two primary criteria: i) locations where energy infrastructure already exists to allow ready access to the high voltage electric transmission system and natural gas pipeline and distribution network; and ii) locations in which retirements were likely to occur. Preference was given to locations meeting the first and second criteria that were located in close proximity to areas with a high demand for electricity.

Based on these criteria, we identified New London County Connecticut, Bristol County Massachusetts, and Rockingham County New Hampshire as potential sites. All three locations are in close proximity to the 345 kV network and natural gas infrastructure. Connecticut, however, has been far more active in terms of power plant development in recent years, with additional generating resources at risk of retirement, as shown in Figure 1. Rockingham County New Hampshire has no expected retirements near term, and Bristol County Massachusetts retirements have already occurred and were not immediately followed by development or repowering. For these reasons, New London County, CT was identified as an appropriate location for modeling the three gas candidate reference units.

Figure 1: Power Plant Development and Retirement Risk[10]

ii. Brownfield vs. Greenfield

Both greenfield and brownfield sites are currently being developed in New England and therefore both were considered for the CONE study. However, brownfield sites are highly variable in terms of characteristics and the extent of the re-use of existing equipment, making the ability to reasonably estimate development costs for brownfield sites challenging and uncertain. Because of their potentially unique re-development costs, brownfield sites tend to be an unreliable predictor of future entry costs under long-run equilibrium conditions, as the screening criteria require. In a January 2020 filing, FERC affirmed the use of a greenfield site, stating the following in calculating CONE values in ISO-NE:

> *"We continue to find it reasonable to use a greenfield site to calculate reference unit costs because cost information is more reliable and less varied at greenfield sites, in contrast to brownfield sites."*[11]

Therefore, Concentric assumed that a new entrant would be located on a greenfield site.

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10 https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements.

11 *ISO New England Inc.*, 170 FERC 61,052 (January 24, 2020), pg. 31, 55.

iii. Project Life

The levelization of costs and revenues is calculated over the estimated life of the generating resource. For the calculation of the levelized revenues required from the FCM, all candidate reference units were assumed to have a project life of twenty years, consistent with assumption used in the previous Net CONE/ORTP re-calculation performed in 2016.

iv. Plant Configuration

A survey of recently developed projects in New England provides important data points on viable plant configurations. Table 10, below, contains a sample of recent gas-fired projects developed in New England with operating capacities greater than 100 MW.[12] Note that these projects represent a mix of combined cycle and simple cycle frame technologies, and all use turbines manufactured by GE. All projects are located in Southern New England.

Table 10: Recent Gas Projects Developed in New England[13]

Plant Name	Type	Year in Service	Current Operating Capacity (MW)	Primary/ Secondary Fuel	Turbine Manufacturer	Turbine Type
West Medway II	GT	2019	200	Gas/ Distillate Fuel Oil	GE Energy	LMS100 PA+
Bridgeport Harbor Station CC Project	CC	2019	496	Gas	GE Energy	7HA.02
Canal 3 (CT)	GT	2019	333	Gas/Distillate Fuel oil	GE Energy	7HA.02
Wallingford	GT	2018	100	Gas	GE Energy	LM6000
Towantic Energy Center	CC	2018	805	Gas/ Distillate Fuel oil	GE Energy	7HA.01
Footprint Power Salem Harbor	CC	2018	674	Gas	GE Energy	7F.05

12 The projects contained in this sample are the same projects that were reviewed for the 2017 CONE Study with the exception of Clear River Energy Center which was terminated.

13 SNL Financial.

v. Dual Fuel

The candidate gas reference units were assumed to have backup fuel in the form of No. 2 oil to address any potential issues with the availability of gas supply in the general region. No. 2 oil is the most commonly installed backup fuel in New England, and publicly available data on the cost to install dual fuel capability and to operate the plant on oil are available. Given the high value the ISO-NE region places on fuel security, dual fuel capability is a reasonable assumption for the candidate gas resources.

vi. Dry and Wet Cooling Systems

The candidate gas reference units were assumed to be designed with dry cooling for primary heat sinks. This was done to maximize potential installation sites and to ease permitting. The simple cycle plants utilize dry fin fan coolers. The combined cycle plant was assumed to have an air-cooled condenser. While there are more thermally efficient designs available, air cooled condensers are the easiest to permit, do not require significant makeup water, and can be used on most sites where reasonable space is available.

vii. Evaporative Cooling

Evaporative coolers were included to provide improved performance on warm low humidity days. Evaporative cooler effectiveness was set at 85%, which is considered reasonable for standard evaporative cooler technology.

viii. Supplemental Firing

The design assumed for the combined cycle reference includes supplementary firing. The duct burners can be fired to a 1250° F burner exit gas temperature. This firing rate provides additional peaking capacity while not increasing the cost of the heat recovery steam generator and the steam turbine, or negatively impacting the base combined cycle heat rate significantly.

ix. Environmental Assumptions

All of the candidate gas plants are designed to be in compliance with federal requirements and regional requirements. This includes Carbon Monoxide (CO) Catalysts for the combined cycle design and Selective Catalytic Reduction (SCR) equipment for all simple cycle and combined cycle designs. Dry cooling is also utilized for ease of environmental permitting. Natural gas units in Connecticut must purchase SO_2 allowance permits to comply with the Federal Acid Rain Program and CO_2 allowance permits to comply with the Regional Greenhouse Gas Initiative. New gas plants in Connecticut are not required to purchase NO_x allowance permits.

x. Interconnection Assumptions

Interconnection costs include the interconnection facilities required to meet minimum interconnection standards, as well as required network upgrades beyond the point of interconnection to meet the capacity interconnection standard. Based on a review of interconnection costs for recently completed generating plants as well as generating plants currently in development, as well as the availability of gas and electric infrastructure in the Southeastern CT area, it is assumed that a two mile interconnection to both the gas and electric grids would be required.

The electrical interconnection costs are based on an assumption that the generating plants will interconnect to the 345 kV system. The costs include a three breaker ring bus, line intercept, remote end relay communications network, two miles of overhead line transmission, revenue grade current transformers and potential transformers on the high side of the generator step-up transformer, and a revenue grade power meter all in accordance with utility requirements. Network upgrade costs required to meet the Capacity Network Resource Capability (CNRC) requirements are assumed to be zero, based on consultation with ISO New England.

Gas interconnection costs are based on an assumption that the generating plants are sited on or in very near proximity to a main natural gas transmission line, with gas available at 750 psi. The gas interconnection is comprised of a 16-inch pipeline. Fuel gas metering is assumed to be onsite at a small, dedicated fuel gas metering station with a gas chromatograph for contract gas measurement. It is assumed that gas compression is not required for a generating plant that is connected to the main gas transmission line, as is assumed in this study. The need for gas compression is highly site specific. The generic site assumption used in this study, as well as Mott MacDonald's development experience in Connecticut, supports the reasonableness of this assumption.

C. Approach to Capital Cost Estimation

Mott MacDonald, in partnership with Concentric, prepared capital cost estimates for the three candidate reference technologies based on modern construction techniques and materials for electricity generating stations and related facilities. Capital costs fall into two general categories: Engineering, Procurement, and Construction (EPC) (i.e., costs related to the construction of the plant itself) and non-EPC (i.e., owner's costs, interconnection costs, etc.).

Mott MacDonald developed the major equipment cost components, such as field construction labor hours and quantities, to develop the bottoms-up cost estimates in accordance with the screening criteria. A bottoms-up estimate utilizes a technical scope as the cost basis. This technical scope identifies what is required for a system to be engineered, procured, constructed, tested, and turned over to operations. Once the technical scope is determined, it is used as the basis of estimation where the cost to complete the project is determined. In addition to the technical scope, location, labor, available craft, shipping, and scheduling are addressed in a bottoms-up estimate. The bottoms up analysis included data from Mott MacDonald's comprehensive power plant cost estimating database[14] and information contained in the Thermoflow PEACE cost system for power plants of the size and configuration selected for this project.

[14] The Mott MacDonald cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle frame, combined cycle, and aeroderivative projects.

The Mott MacDonald cost estimating database consists of actual cost estimates for several hundred power projects including simple cycle frame, combined cycle, and aeroderivative projects. The database is maintained and updated on a regular basis as new project cost estimates are prepared, and information and data are received from clients indicating the results of Mott MacDonald's work. Mott MacDonald used "at-risk" quotes submitted by contractors, to produce estimates of the major equipment costs of each gas reference unit candidate. Many of the projects in the Mott MacDonald database also include as-built cost details. The database also includes project-specific information about the civil work associated with a particular new gas generation project, such as the crew and construction equipment required for concrete work.

Given that Connecticut was selected as the general location for the candidate gas reference units, which invites possible competition for labor, the cost estimates include scheduled overtime in order to attract the most productive craft labor staff. Cost estimates for the three candidate gas reference units were based on a 50-hour work week for the journeymen. This estimate is also based on past experience throughout the country, where many projects start at a forty-hour work week but eventually become sixty-hour work weeks. It is common practice to include overtime costs on major projects in order to avoid issues during construction. In addition to the 50-hour work week, additional overtime was included in each of the project estimates to account for miscellaneous extra work tasks.

i. Direct Costs

a) Major Equipment

Major equipment was priced based on the Mott MacDonald cost database and information obtained from Mott MacDonald clients that have constructed a large number of electric generating plants. The Mott MacDonald database is kept current and is checked against market conditions for the time frame basis of the cost estimates. For any specialized major equipment that was not contained in the cost estimate database, Mott MacDonald consulted directly with clients and/or the specialty manufacturers involved in that type of major equipment supply. The Mott MacDonald cost estimates contain detailed information where each piece of major equipment is identified and priced separately.

Freight costs for the major equipment are generally included within the unit major equipment costs in the direct cost section of the cost estimates. When freight costs were not available in the Mott MacDonald cost database, which was the case for a limited number of major equipment and bulk materials expenses, Mott MacDonald estimated those costs based on its judgment and experience.

b) Balance of Plant Materials

Mott MacDonald developed balance of plant bulk material quantities from a proprietary cost estimate model that was adapted for each candidate gas reference unit and updated with relevant information from other Mott MacDonald power projects. Bulk quantities and sizes were adjusted to suit the assumed major equipment location of Connecticut. If necessary, the size of various plant components was adjusted to reflect the size of each candidate gas unit. Mott MacDonald priced the balance of plant materials based on market conditions and prices in effect in the U.S., with adjustments to suit any special conditions that might apply in the New London County, Connecticut area. Concrete supply is the one item that is particularly influenced by local costs. Mott MacDonald estimated freight costs for certain plant material price estimates, which initially did not include freight.

c) Construction Labor

Construction labor rates were based on union labor rates for the New London County, Connecticut area. The construction labor rates used were composite craft labor rates for approximately 35 various crafts and included fringe benefits, worker's compensation costs, and all applicable insurance and taxes.

Mott MacDonald calculated field labor productivity based on field construction labor conditions for the New London County, Connecticut area. These productivity values are supported by previously completed projects in the general area and consistent with Mott MacDonald's past experience and construction site surveys the company prepared for projects in the Northeast.

ii. EPC Cost Estimate Details by Major Category[15]

a) Direct Costs (Major Equipment, Installation, Labor)

Field construction installation labor hours for major equipment installation were developed based on Mott MacDonald's experience in estimating such costs for similar projects. Mott MacDonald also considered its cost estimate model and had discussions with major equipment manufacturers about installation conditions and components associated with their equipment. All labor hours were adjusted to reflect the anticipated productivity levels associated with labor in the New London County, Connecticut area. As noted above, productivity values used in the study are consistent with Mott MacDonald's experience with similar types of construction projects in the general area.

b) Site Work

The New London County location is anticipated to require a minimal amount of additional fill given that a specific site location within the county was not identified, so site-specific cut and fill measurements were not available. Pilings for foundations were not considered given the lack of a specific site. The cost estimates include site drainage, a firewater loop system, the installation of new underground piping, new electrical duct banks and manholes, sanitary sewer piping, miscellaneous light site demolition, erosion control, excavation and backfill for the new foundations, site fencing, roadwork, site restoration and landscaping. The cost estimates include utility tie-ins at the fence. The final paving of roads was assumed to be accomplished at the conclusion of construction activities.

c) Concrete

Mott MacDonald derived concrete quantities from information contained in the Mott MacDonald cost estimate model adjusted to expected conditions considering the major equipment required for each project. Construction labor hours for concrete installation were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other

15 Further detail on the categorization of permitting, legal, and siting costs is provided in Appendix B.

construction projects in the general area. Major concrete work includes the gas turbine foundation, the SCR foundation, a firewall for the main transformers, a stack foundation, building foundations, pump foundations, and the switchyard area.

d) Masonry

Mott MacDonald developed masonry quantities from information available in the Mott MacDonald cost estimate model and assumed building sizes. The major work elements contained in this cost item include both interior and exterior concrete masonry unit walls where needed, scaffolding, and all grouting costs for major equipment, and structural steel base plates.

Field construction labor hours for masonry work were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other construction projects in the general area.

e) Structural Steel/Metals

Structural steel quantities were developed from information available from other Mott MacDonald projects of similar size, as well as the Mott MacDonald cost estimate model used for this project. Field construction labor hours for steel installation were calculated and adjusted based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

Major structural steel work in this section of the cost estimate includes structural and supplementary steel. Platforms, grating, handrails, ladders, anchor bolts, and prime coat painting of the steel are also included unless any of these items are supplied by the manufacturer of the major equipment.

f) Buildings

To determine material quantities for administration, control, machine shop, warehouse, and guard house buildings, Mott MacDonald relied on typical plant building information and the Mott MacDonald cost estimate model. Building costs include the costs of the siding, roofing, doors, carpentry, wallboard, acoustical treatment, resilient flooring, fire protection, plumbing and HVAC requirements for the buildings on the project.

Field construction labor hours for the building work were calculated and adjusted based on anticipated construction labor productivity based on Mott MacDonald's experience with other construction projects in the general area.

g) Piping/Mechanical

Piping and mechanical quantities contained in the Mott MacDonald cost estimate model were adjusted from the assumed locations of buildings and major equipment components. Piping systems included in the piping/mechanical cost estimate include auxiliary cooling water, feedwater, fuel gas, lube oil, fuel oil, wastewater, service water, raw water, demineralized water, sampling, process and instrument air and mixed chemicals. Other materials included in this estimate include various types of valves, piping insulation, equipment insulation, and fire protection systems. Insulation and electrical heat trace required for a cold climate condition were also included based on outputs from the cost estimate model for the project. Field construction labor hours for the piping systems were calculated and adjusted based on anticipated construction labor productivity derived from Mott MacDonald's experience with other construction projects in the general area.

h) Electrical

Mott MacDonald determined electrical quantities based on the assumed locations of buildings and major equipment components. In addition, the Mott MacDonald cost estimate model was used to determine cable, conduit and cable tray sizes and lengths of a number of required electrical services. The categories included in the electrical cost estimate include site electrical work, power/control and instrumentation for cable and conduit requirements, controls needed for interconnection to the system, area lighting and service requirements, building area lighting and services, public address system, building fire alarms, and a grounding system.

The site electrical cost estimate also includes site lighting, surveillance equipment, lightning protection, cathodic protection, heat tracing and aviation lighting for the stack. Mott MacDonald calculated and adjusted field construction labor hours for the electrical systems based on anticipated construction labor productivity derived from its experience with other construction projects in the general area.

i) Instrumentation

Instrumentation quantities were developed from Mott MacDonald's experience with similar projects and the Mott MacDonald cost estimate model for the applicable candidate gas unit. Instrumentation costs include the installation and supply of contractor furnished instruments, loop checks and functional check out, instrument stands and material handling and calibration. All instrumentation and control cable, conduit and cable tray associated with the instruments are included in the electrical section of the cost estimate. Mott MacDonald calculated and adjusted field construction labor hours for the instrumentation systems based on anticipated construction labor productivity derived from MM's experience with other construction projects in the general area.

j) Painting

Painting costs include the painting, sealer, and epoxy requirements for the project. This estimate includes the costs of painting of the masonry walls, painting of wallboard, floor sealer, epoxy coating, finish painting of all steel with two coats over shop-applied primer coat, touch up painting of major equipment, and painting of all uninsulated steel piping.

iii. Indirect EPC Costs

a) Construction Management

Construction management costs include the planned construction management team for the EPC Contractor. All owner construction management costs as well as other categories of owner's costs were included in this cost estimate.

Specific construction management costs include the following: construction manager; an assistant construction manager; civil, mechanical, structural, electrical and instrument and controls (I&C)

superintendents; a field office manager; engineering support; cost engineering; planning and scheduling; safety; quality assurance and control; field purchasing and general foremen. The costs are calculated based on an estimated project schedule. The construction manager's duration on the project includes one month in advance of beginning field operations and one month to close out the project, for a total of two additional months beyond the normal construction duration.

b) Temporary Facilities and Utilities

Temporary facilities and utilities costs include the elements needed in order to support the construction management staff and construction of the project. These costs normally exclude site trailers, clean-up of trailer area, water, sanitary facilities, field office supplies, site security, fire protection, medical supplies, temporary electrical power distribution system, telephones, copy machines and computer hardware and software.

c) Construction Equipment and Operators

These costs reflect the construction equipment and operating engineers required to construct the mechanical and electrical portion of the project. Civil construction equipment and operating engineer costs are included in this section. In addition to the construction equipment and operating engineer cost, this portion of the cost estimate includes a master mechanic, teamsters, maintenance engineers, fuel, oil and grease, small tools, consumables, and scaffolding.

d) Indirect Construction Services and Support

This portion of the cost estimate includes a detailed listing of the services needed in order to support the construction management staff and field forces. Items contained in this section of the cost estimate include continuous and final site clean-up, rubbish removal, safety equipment and supplies, various testing including soils and concrete, survey costs, weather protection, dust control, snow removal, piping radiography and other testing, testing of the grounding system and mechanical, electrical and I&C journeymen support during start-up.

e) Other Project Costs

Other project costs include a detailed listing of a variety of components required in the cost estimate that are not appropriate for inclusion in other sections of the estimate. These costs consist of freight costs for major equipment and bulk materials that are not included in the cost of the major equipment as supplied by the manufacturer or in the bulk material unit cost, travel costs, off-loading of major equipment and materials, heavy hauling of major equipment components not delivered directly to the site, general liability and umbrella insurance costs, start-up spare parts, permits, and payment and performance bonds. Mott MacDonald also included architecture/engineering costs which were calculated based on current information in the EPC cost estimate model and modified as required. Start-up and testing costs were also included in this section. Payment and performance bonds for the EPC Contractor as well as any subcontractors are part of the EPC cost estimate.

f) EPC Contractor Contingency

Mott MacDonald's EPC cost estimates include the anticipated contingency that will be applied by the EPC contractor based on the conceptual level of information that is typically available at the time a request for proposal is issued for an EPC contractor's proposal. Based on Mott Macdonald's experience developing proposals for firm lump sum projects at the conceptual stage, a contingency percentage of 5% of EPC costs was selected for the candidate gas units.

g) EPC Contractor Profit

Mott MacDonald evaluated current profit margins of constructors of a suitable size that could adequately perform on a project of this size. Mott MacDonald used 15% overhead and profit for the civil, mechanical, and electrical and I&C subcontractors to cover these costs. Mott MacDonald also used a 5% mark-up on the total value of the project for the EPC contractor. It was assumed that, as is typically the case today, the EPC contractor would subcontract all civil, mechanical, and electrical and I&C work and function as the general contractor. Therefore, in addition to the 15% mark-up for all the subcontractors, the EPC contractor includes a 5% mark-up on top of the all the subcontractors as his fee for monitoring their work under the total EPC contract.

iv. Non-EPC Cost Estimates

a) Owner's Contingency

The owner's contingency covers unanticipated project development costs which are owner obligations and is separate from the EPC project contingency. Owner's contingency of $6.957M was included in the cost estimate for the gas-fired simple cycle resource, $13.97M for the gas-fired combined cycle resource, and $4.1 for the gas-fired aeroderivative resource.[16]

b) Other Contingencies

The cost estimates assume that the project would involve a subcontract structure, meaning specifically that the prime EPC Contractor would be expected to outsource major portions of the project to local specialized subcontractors who are able to better control labor costs. Therefore, the total scope of the project is assumed be contracted out by major disciplines, including a Mechanical Contractor, an Electrical and Controls Contractor, a Civil Structural and Architectural Contractor, and a Construction/Erection contractor. Each of these contractors were assumed to add their own contingency equal to 5% of their respective costs. These contingencies represent the subcontractors' portion of the EPC bid and total $10.2M for the simple cycle candidate resource.

v. Escalation of Capital Costs to Start of Construction

Mott MacDonald produced capital cost estimates in 2019 dollars and Concentric escalated these amounts to the dollar value at the start of construction. EPC costs were escalated at a rate of 0.7%; Non-EPC costs were escalated at 1.9%. Both of these escalation rates are based on the Bureau of Labor Statistics Producer Price Index (PPI) escalation rates.

[16] Additional detail on the various contingency costs incorporated in the analysis can be found in Appendix A.

D. Cone Candidate Reference Unit Technical Specifications

i. 7HA.02 Simple Cycle Frame Combustion Turbine

The GE 7HA.02 is a large frame machine representing the current state-of-the-art regarding materials and combustion technology, giving it the highest efficiency available in the simple cycle technology market. In addition to a low minimum load point and high ramp rates that provide for flexible operation, the plant has relatively low capital costs. The 7HA.02 has entered commercial operation in a variety of locations throughout the country and is currently operating in New England at the Canal generating facility in simple cycle configuration and at the Bridgeport generating facility in combined cycle configuration.

The assumed nominal capacity of the 7HA.02 in the simple cycle configuration is 376 MW based on the site elevation, average ambient temperature, and coincident relative humidity over a ten-year period.[17] Based on current market trends, the unit is assumed to be equipped with evaporative coolers for power augmentation and a fin fan cooling system. The plant utilizes SCR to control emissions. A summary of the technical specifications is shown in Table 11 below.

Table 11: GE 7HA.02 Simple Cycle Technical Specifications

TURBINE MODEL	7HA.02
Configuration	Simple cycle frame machine
Net Plant Capacity (MW)	Nominal: 371[18] Summer: 359 Winter: 389
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Net Heat Rate (Btu/kWh) HHV	Shoulder: 9,132 Summer: 9,225 Winter: 9,060
Environmental Controls	Selective Catalytic Reduction
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-site Gas Compression?	No
Gas Interconnection	2 mile onsite connection
Electrical Interconnection	2 mile onsite connection
Plot Size (acres)	8
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and March; and Shoulder months are all other months.	

[17] Average site conditions are 57 degrees Fahrenheit, 80% relative humidity, and 250 feet above sea level.
[18] Includes degradation factor.

ii. LM6000PF+ Aeroderivative Gas Turbine

The LM6000PF+ is one of the most widely installed plants in New England and is in widespread commercial use around the world. The unit, which is based on GE jet engine technology, is highly modular and can be engineered, procured, constructed, and entered into operation more quickly than any alternative technology operating above 20 MW. While the LM6000PF+ can be utilized in a combined cycle configuration, the simple cycle configuration is more common and was thus selected for review and analysis.

The assumed capacity of the LM6000PF+ is 98 MW nominal.[19] Based on current market trends, this unit was assumed to be equipped with evaporative coolers for power augmentation as well as a fin fan cooling system. In addition, it was assumed that the plant would utilize SCR to control emissions. A summary of the technical specifications is shown in Table 12 below.

Table 12: LM6000PF+ Technical Specifications

TURBINE MODEL	LM6000PF+
Configuration	Two SC Aeroderivative GTs
Net Plant Capacity (MW)	Nominal: 95[20] Summer: 87 Winter: 108
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Net Heat Rate (Btu/kWh) HHV	Shoulder: 9,656 Summer: 9,964 Winter: 9,498
Environmental Controls	Selective Catalytic Reduction
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-site Gas Compression?	No
Gas Interconnection	2-mile onsite connection
Electrical Interconnection	2-mile onsite connection
Plot Size (acres)	4.5
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and March; and Shoulder months are all other months.	

iii. 7HA.02 Combined Cycle Combustion Turbine

The combined cycle combustion turbine uses the same machine as the simple cycle machine. However, with the combined cycle combustion turbine, a heat recovery steam generator (HRSG) and

[19] Average site conditions are 57 degrees Fahrenheit and 80% relative humidity.
[20] Includes degradation factor.

steam turbine generator are added to allow for additional generation using exhaust gas energy from the simple cycle machine. Adding the HRSG steam tail increases capital costs significantly; however, doing so also increases plant's capacity and efficiency.

The combined cycle combustion turbine was assumed to have duct firing capability. Duct firing is an option many plant developers choose to provide a highly flexible source of quick start capacity that can be used to capture revenues during high price periods.

The assumed nominal baseload capacity of the combined cycle combustion turbine is 535 MW with 22 MW of duct firing capability for a total nominal capacity of 557 MW when duct firing is engaged. This performance is based on the site elevation, average ambient temperature, and coincident relative humidity over a ten-year period.[21] It is also equipped with both fin fan cooling and evaporative coolers for power augmentation. To control emissions, the plant has both SCR and a CO catalyst. A summary of the combined cycle's technical specifications is provided in Table 13 below.

Table 13: GE7HA.02 Combined Cycle Technical Specifications

TURBINE MODEL	7HA.02 COMBINED CYCLE
Configuration	Combined Cycle w/ Frame GT
Net Baseload Capacity (MW)	Nominal: 522[22] Summer: 497 Winter: 542
Net Capacity w/ Duct Firing (MW)	Nominal: 544 Summer: 526 Winter: 570
Location	New London County, Connecticut
Cooling System	Fin fan coolers
Power Augmentation	Evaporative coolers
Baseload Net Heat Rate (Btu/kWh) HHV	Shoulder: 6,394 Summer: 6,573 Winter: 6,429
Duct Firing Net Heat Rate (Btu/kWh) HHV	Shoulder: 6,480 Summer: 6,732 Winter: 6,521
Environmental Controls	Selective Catalytic Reduction and CO catalyst
Dual-Fuel Capability	Natural gas w/ No. 2 oil backup
Black Start?	No
On-Site Gas Compression?	No
Gas Interconnection	2-mile Onsite connection
Electrical Interconnection	2-mile Onsite connection
Plot Size (acres)	15
Notes: For purposes of the ambient rate assumptions, Summer months are June, July, and August; Winter months are December, January, February, and March; and Shoulder months are all other months.	

[21] Average site conditions are 57 degrees Fahrenheit and 80% relative humidity.

[22] Includes degradation factor.

E. CONE Candidate Reference Unit Capital Costs

The capital costs for the candidate reference units were developed by Mott MacDonald through discussions with the manufacturer and reliance on the manufacturer's proprietary database. These capital cost estimates are shown in Tables 14-16, below.

i. 7HA.02 Simple Cycle Frame Combustion Turbine

Table 14: GE 7HA.02 Simple Cycle Capital Costs (2019$, in millions)[23]

COST COMPONENT	7HA.02 SIMPLE CYCLE (CONE)
EPC Costs	
Civil/Structural/Architectural	18.9
Mechanical Costs	137.7
Electrical/Instrumentation Costs	27.9
Construction Management	7.6
Other Project Costs	12.4
Project Contingency	12.3
EPC Contractor Fee	10.4
Total EPC	**227.2**
Non-EPC Costs	
Owner's Contingency	7.0
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	9.1
Working Capital (1% of EPC costs)	2.3
Total Non-EPC	**60.8**
Total Overnight Capital Costs	**288.0**
$/KW (Installed Capacity)	**776.9**

23 Numbers may reflect rounding.

ii. LM6000PF+ Aeroderivative Gas Turbine

Table 15: LM6000PF+ Capital Costs (2019$, in millions)[24]

Cost Component	LM6000 PF+
EPC Costs	
Civil/Structural/Architectural	14.0
Mechanical Costs	73.8
Electrical/Instrumentation Costs	19.5
Construction Management	5.1
Other Project Costs	8.1
Project Contingency	7.2
EPC Contractor Fee	6.1
Total EPC	**133.8**
Non-EPC Costs	
Owner's Contingency	4.1
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	5.4
Working Capital (1% of EPC costs)	1.3
Total Non-EPC	**53.2**
Total Overnight Capital Costs	**187.0**
$/KW (Installed Capacity)	**1,961.4**

24 Ibid.

iii. 7HA.02 Combined Cycle Combustion Turbine

Table 16: 7HA.02 Combined Cycle Capital Costs (2019$, in millions)[25]

COST COMPONENT	7HA.02 COMBINED CYCLE (CONE)
EPC Costs	
Civil/Structural/Architectural	49.0
Mechanical Costs	267.0
Electrical/Instrumentation Costs	54.0
Construction Management	11.4
Other Project Costs	29.0
Project Contingency	24.6
EPC Contractor Fee	20.9
Total EPC	**456.1**
Non-EPC Costs	
Owner's Contingency	14.0
Electrical Interconnection	27.0
Gas Interconnection	11.0
Fuel Inventories	4.5
Financing Fees (4% of costs financed through debt)	18.2
Working Capital (1% of EPC costs)	4.6
Total Non-EPC	**79.3**
Total Overnight Capital Costs	**535.3**
$/KW (Installed Capacity)	**985.0**

F. Variable Operations and Maintenance Costs

Variable O&M (VOM) is assumed at the following rates for each of the CONE candidate resources. Mott MacDonald developed VOM estimates based on information contained in their cost database and industry experience. VOM costs, as shown in Table 17 below, are directly related to plant electrical generation, and generally include routine equipment maintenance, long-term major maintenance events, variable long-term service agreement (LTSA) annual fees, makeup water, water treatment, water disposal, ammonia, SCR and CO catalyst replacements (as applicable), and other consumables not including fuel.

25 Ibid.

Table 17: Variable O&M (2025$/MWh)

RESOURCE	VOM
7HA.02 Simple Cycle	$1.75
LM6000 Aeroderivative	$1.16
7HA.02 Combined Cycle	$3.60

G. Fixed O&M Costs

Fixed O&M costs for each of the candidate reference units consist of operating expenses including management and administration costs, labor, materials, contract services, and associated costs (including the fixed price portion of an LTSA). While major maintenance costs are allowed to be included in the VOM costs that are submitted as part of a generating unit's offer in the day-ahead and real-time market, generating units are not required to do so. A review of historical offer data revealed a wide range of approaches to pricing major maintenance costs in an energy offer, with some not including these costs, and others including nominal amounts. Fixed O&M costs also include leasing of the land on which the plant is located, property taxes, and insurance. These costs are summarized in Table 18 below and discussed in more detail in the following sections.

Table 18: Total Fixed O&M Components

	SIMPLE CYCLE	AERODERIVATIVE	COMBINED CYCLE
LTSA & Ongoing Maintenance (2025$/kW-yr)	$39.81	$80.68	$61.25
Property Taxes	2.89%	2.89%	2.89%
Site Leasing (2025$/acre/yr)	$25,000	$25,000	$25,000

i. Ongoing Maintenance / LTSA

a) GE 7HA.02 Simple Cycle

The simple cycle will have an LTSA for parts, labor, and materials for all work done up to and including the first major outage. This LTSA is assumed to have a fixed price payment structure with monthly payments. Outage frequency and durations would be agreed to, but degradation is not generally guaranteed. Planned outages would be included under the agreement, but unplanned outages would not be covered. The LTSA amount was estimated by Mott MacDonald, and Concentric verified the assumed LTSA cost by consulting several publicly available studies. The LTSA was estimated at $35/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $2,500/MW-year in addition to the LTSA to account for ongoing maintenance expenses associated with required network upgrades, as allowed under the ISO-NE Tariff, resulting in a total of $39.81/kW-year (2025$).

b) LM6000PF+ Aeroderivative Gas Turbine

Like the simple cycle LTSA, the aeroderivative LTSA includes parts, labor, and materials as well as a turbine sharing program that would utilize a shared rotor for quick return to service. The removed rotor would then be serviced and used in the shared rotor program with other plant owners. This minimizes down time for the aeroderivative plants. The duration of the LTSA would be up to and including the first major outage. Planned outages would be included in the LTSA, but unplanned outages would not. The LTSA amount was provided by Mott MacDonald, and Concentric verified this number by consulting several publicly available studies. The LTSA is estimated at $75/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $1,000/MW-year in addition to the LTSA, consistent with the other reference units, resulting in a total of $80.68/kW-year (2025$).

c) 7HA.02 Combined Cycle

Like the other units, the combined cycle unit's LTSA includes labor, materials, contract services, and associated costs. The LTSA amount was provided by Mott MacDonald, and Concentric verified this number by consulting several publicly available studies containing estimates of O&M costs. The LTSA is estimated at $55.20/kW-year (2019$). Concentric also included an ongoing maintenance assumption of $2,500/MW-year in addition to the LTSA to account for ongoing maintenance expenses associated with required network upgrades, as allowed under the ISO-NE Tariff, resulting in a total of $61.25/kW-year (2025$).

ii. Property Taxes

Property taxes are based on municipal tax rates, which are often differentiated by business type. The assumed property tax rate for the candidate reference units is based on a review of commercial and industrial (C&I) rates in the reference county's 21 municipalities over the 2018-2020 period. Based on the rates shown in Table 19, we assumed a property tax rate of 2.89% for all new gas units in New London County, Connecticut.

Table 19: Municipal Tax Rates for Towns in New London County[26]

Town / City	2020	2019	2018
Bozrah	2.75%	2.75%	2.85%
Colchester	3.28%	3.23%	3.24%
East Lyme	2.82%	2.74%	2.62%
Franklin	2.37%	2.57%	Not Available
Griswold	2.86%	2.80%	2.76%
Groton	2.42%	2.42%	2.36%
Lebanon	2.94%	2.94%	2.94%

26 State of Connecticut Office of Policy and Management, 2020, https://portal.ct.gov/OPM/IGPP-MAIN/Publications/Mill-Rates.

TOWN / CITY	2020	2019	2018
Ledyard	3.51%	3.43%	3.25%
Lisbon	2.32%	2.25%	2.25%
Lyme	2.00%	1.86%	1.83%
Montville	3.25%	3.17%	3.17%
New London	3.99%	4.32%	4.32%
North Stonington	2.90%	2.82%	2.80%
Norwich	4.03%	4.10%	4.05%
Old Lyme	2.24%	2.19%	2.18%
Preston	2.64%	2.60%	2.40%
Salem	3.22%	3.22%	3.22%
Sprague	3.48%	3.33%	3.20%
Stonington	2.34%	2.27%	2.30%
Voluntown	2.92%	2.89%	2.95%
Waterford	2.80%	2.74%	2.70%
AVERAGE	**2.91%**	**2.89%**	**2.87%**

iii. Site Leasing Costs

Site leasing costs were assumed to be recorded as a Fixed O&M expense. Based on a review of industrial leasing costs, we assumed $25,000/acre based on the need to be close to gas and transmission interconnection infrastructure and consistent with the 2017 study and with other ISO CONE studies. This lease rate was multiplied by the estimated plot acreage to determine a total site leasing cost.

iv. Insurance

Insurance costs were assumed to be 0.6% of the overnight capital costs per year, consistent with the assumption in the 2013 and 2017 ISO- CONE studies, as well as the NYISO and PJM CONE studies. We continue to consider this assumption to be within a range of reasonableness.

H. Escalation to 2025$ Costs

Capital costs were escalated from 2019 dollars to the beginning of each candidate reference unit's construction period using estimates from the BLS PPI. A 10-year average annual percent change was used from two BLS PPI indices for different capital cost components.[27]

Fuel costs were escalated for the gas turbines using NY Harbor ultra-low-sulfur-diesel (ULSD) futures settlements. This estimate was based on the average percent change of ULSD futures prices at NY

[27] BLS PPI WPUID612: not seasonally adjusted, annual average percent change 2009-2018.
BLS PPI WPU1197: not seasonally adjusted, eight-year annual average percent change 2009-2018. For WPU1197, 2016 and 2017 data are missing from the BLS series. We calculated the three-year compound annual growth rate from 2015 to 2018 and applied this annual percent change (-1.62%) to the final three years in the ten-year span.

Harbor for 12-month periods beginning March 2020 and ending January 2022, when liquidity dropped off.[28]

[28] ULSD Forward Curve as of February 26, 2020; CME Group.

Section 4:
Financial Assumptions

A. Approach

The CONE/Net CONE estimate for each candidate reference unit is based on the revenue required, net of cash flows from ISO-NE energy, ancillary services and other market revenues, and (if applicable) REC market revenues, by a new entrant to recover its capital and operating costs over the unit's assumed 20-year project life. This estimate includes the cost of providing a return to equity investors and debt holders and is based on the reasonable assumption that significant amounts of capital will only be invested if investors anticipate that their investment will generate returns that meet or exceed their cost of capital. Consistent with previous studies, the CONE and Net CONE values are expressed on a real, levelized annual basis. That is, the calculation produces a payment such that if the capacity payment increases at the assumed rate of inflation every year over the twenty-year period, the NPV of a unit's costs are equal to the NPV of its revenues over the 20-year period.

It is customary to discount uncertain future cash flows at an after-tax weighted average cost of capital. The appropriate discount rate should reflect systemic financial market risks, project-specific risks of a merchant developer participating in the ISO-NE markets, and the return required by investors to compensate for those risks. We recognize that generation projects can be financed under a project financing or balance sheet financing approach. Project financing uses project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a generation asset. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual asset. Balance sheet financing employs debt backed by the project owner itself, which may have significant, diverse resources and assets beyond the individual asset. While some plants in ISO-NE are financed on a "stand-alone" or project-specific basis, the specifics of these financing structures are not publicly available and are diverse and difficult to estimate. Because data about project-specific financing is not publicly available, we chose a peer group of publicly traded independent power producers (IPPs) and used their financial parameters to inform our calculation of the recommended cost of capital. We then made reasonable adjustments to this proxy group data to calculate an after-tax weighted average cost of capital to reflect how a generic new entrant would likely view the risk of merchant development in New England.

Our financing paradigm assumes a reasonable balance between project-specific financing and large corporate balance sheet financing. The cost of capital is calculated as the weighted average of the required return for equity holders and cost of debt. In addition to the cost of capital, the key financial inputs to the calculation of CONE/Net CONE include inflation, depreciation, and property taxes. The derivation of each input is described below.

B. Financial Model Inputs

i. Inflation

CONE/Net CONE, and the inputs to calculate CONE/Net CONE are expressed in real (constant) dollars. Inflation is a key factor used to translate projected nominal cost and revenue streams to constant, or real, terms. It is also used in the calculation of a real discount rate, the levelization factor for CONE/Net CONE.

Three estimates of inflation were reviewed to develop the annual inflation outlook of 2.0%. The Blue Chip Financial Forecast, Long Term Consensus Forecast provides a forward looking forecast of inflation.[29] The CPI consensus estimate for 2022-2026 is 2.1%, while the 2027-2031 estimate is 2.2%.

Second, we reviewed inflation expectations from the Federal Reserve Bank of Cleveland. The Cleveland Fed reports estimates that use Treasury yields, inflation data, inflation swaps, and survey-based measures of inflation expectations.[30] The current 20 and 25-year expected inflation for the average of previous 6 months as of the time of our analysis is 1.62 and 1.74%, respectively.[31]

Finally, we review inflation expectations as included in EIA's 2020 Annual Energy Outlook. The GDP Chain-type Price Index – CPI Energy Commodities and Services 2025 estimate is 2.3%.[32]

Based on these inputs, we assumed an average long-term annual inflation rate of 2.0% to be a reasonable estimate for all CONE and ORTP calculations.

ii. Amortization Period

The amortization period is the term over which the project is expected to operate such that all upfront capital costs are returned in a manner that yields both a return of capital (i.e., depreciation) and a return on that invested capital. The CONE, Net CONE, and ORTP values are estimated over the amortization period based on an estimate of the annual levelized capital cost and ongoing costs and revenues. Consistent with the last CONE and ORTP update and the ISO-NE tariff requirements for the calculation of CONE and ORTP values,[33] this study assumes a 20-year amortization period. Finally, a 20-year amortization period and project life is consistent with a recent FERC directive to PJM regarding the calculation of default Minimum Offer Price Rule offer floors, which serve a similar role to the ORTP, based on an assumed 20-year project life for various resource types.[34]

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29 Blue Chip Financial Forecasts®, Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them, Vol. 39, No. 6, June 1, 2020.

30 https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx.

31 Cleveland Federal Reserve, September 2017-September 2019, 20-year expected inflation.

32 EIA AEO 2020. Table 20, Macroeconomic Indicators. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2020&cases=ref2020&sourcekey=0

33 Market Rule 1 Section III.A.21.1.2.

34 Calpine Corporation v. PJM Interconnection, L.L.C., 169 FERC ¶ 61,239 (2019) at 153.

iii. Depreciation

The tax life of each resource is based on IRS guidelines under the Modified Accelerated Cost Recovery System (MACRS) to depreciate the eligible portion of total installed costs over the amortization period.[35] The MACRs allows for recovery of depreciation over 15 years for a new combustion turbine and over 20 years for a new combined cycle turbine.

To calculate the annual value of depreciation, the "depreciable costs" for a new resource are the sum of the depreciable capital costs and the accumulated interest during construction (IDC). Several capital cost line items are considered non-depreciable, including fuel inventories, and working capital, and are not included in total depreciable costs. IDC is calculated based on the assumption that capital structure during the construction period is the same as the overall project, i.e., 55% debt and 6.0% cost of debt (COD).

iv. Income Taxes

The income tax rates applicable to each new project are based on current federal and state tax rates. The marginal federal income tax rate is 21%.[36] The state income tax rate for Connecticut, where the candidate reference units are located, is 7.5%.[37] The effective income tax rate is calculated to be 26.9%.

v. Cost of Capital

The Weighted Average Cost of Capital (WACC) for an investment represents the blend of rates paid on equity and debt specific to that investment's capital structure and can be expressed by the following equation:

WACC = ROE * Weight of Equity + COD * Weight of Debt

Where:

ROE = Return on Equity
COD = Cost of Debt

Derivation of each input to the WACC calculation is described below and is based on a peer group of merchant generation companies who may be likely to develop projects in New England. Our peer group consists of the following public traded companies:

- AES Corporation
- Clearway Energy Group
- NRG Energy, Inc.

35 Table B-2, IRS Publication 946. Half-Year Convention.

36 Internal Revenue Service, 2019 Instructions for Form 1120, U.S. Corporation Income Tax Return. January 22, 2020. Available at https://www.irs.gov/pub/irs-dft/i1120--dft.pdf.

37 Connecticut Department of Revenue Services, 2020. Available at: https://portal.ct.gov/DRS/Corporation-Tax/Tax- Information.

- Vistra
- Atlantic Power Corp.

We note that the current peer group differs from the 2016 CONE recalculation due to the fact that several IPPs are no longer publicly traded or have merged to become new entities.[38] We received feedback from stakeholders that the full group of peers does not appropriately represent merchant entry in New England because many hold diverse portfolios with some portion of regulated assets. We considered these comments in evaluating the components of cost of capital, as well as the overall cost of capital chosen for the evaluation of CONE and Net CONE; each component is discussed in more detail below.

vi. Return on Equity

Return on equity (ROE) is the amount of return that would be required by investors to compensate for the risk of making an equity investment in a merchant generation plant. The risk environment determines the hurdle rates for investment. Equity raised for uncontracted, merchant projects requires a higher return to investors than equity raised for contracted projects. For energy and capacity that is fully contracted, the cost of equity reflects a lower level of risk, assuming a significant degree of leverage. For uncontracted merchant capacity, developers target a higher after-tax return on equity based on the perceived high risks of cost recovery in the market. A return on equity of 13.0% represents an appropriate return under equilibrium market risk conditions based on a peer group review of merchant generating companies.

To calculate the appropriate return on equity for this analysis, the Capital Asset Pricing Model (CAPM) was used. CAPM is a common analytical approach in financial modeling and assumes that equity investors base their required returns on a risk-free rate of return, the rate at which they would be compensated for an available investment that carried no risk, plus compensation for the relative risk of a specific security in relation to the broader market. CAPM is expressed by the following equation:

$$Re = Rf + \beta\ (Rm - Rf)$$

Where:

Re= Required return on equity

Rf = The risk-free rate

β = Beta, a measure of the covariance between the returns (dividends plus capital gains) of the market average and those of a specific security, and

Rm = The return required of the market as a whole

[38] The 2016 peer group included AES, Calpine, Dynegy, NRG, and Talen.

Concentric reviewed several estimates of a risk-free rate, including the 30-day average of the 30-year Treasury yield curve, as well as estimates from Blue Chip. We also reviewed beta estimates from several sources including Bloomberg and Value Line. Based on our assumed capital structure of 55/45 debt to equity, we re-levered our estimates of beta for inclusion in our CAPM calculation.

Table 20 shows beta estimates that reflect each individual IPP's historical capital structure (levered beta). Using the historical average capital structure, or debt to equity ratio (D/E Ratio), we calculate an unlevered beta which reflects the beta of each IPP without any debt. We then re-lever the beta (Re-levered Beta) using our assumed capital structure of 55/45 (D/E).

Table 20: Peer Group Beta Estimates

Bloomberg [1]	**(2-year Beta)**	**[3]**		
	Levered Beta	**D/E Ratio**	**Unlevered Beta**	**Re-levered Beta**
AES	1.14	2.34	0.42	0.79
CWEN	0.67	1.04	0.38	0.72
NRG	1.20	1.39	0.59	1.12
VST	1.07	0.72	0.70	1.32
AT	0.76	1.44	0.37	0.71
Value Line [2]	**(5-year Beta)**			
	Levered Beta	**D/E Ratio**	**Unlevered Beta**	**Re-levered Beta**
AES	1.05	2.34	0.39	0.73
CWEN	NA	1.04	NA	NA
NRG	1.25	1.39	0.62	1.17
VST	1.15	0.72	0.75	1.43
AT	NA	1.44	NA	NA
Sources:				
[1] Bloomberg as of June 30, 2020				
[2] Value Line as of June 2020				
[3] Bloomberg data as of June 30, 2020; D/E ratio is calculated from 2018Q2-2020Q1 average quarter-end debt %				

We reviewed two estimates of the overall market return: a historical estimate from Duff & Phelps; and a forward-looking estimate of the S&P 500 Index. shows the calculations for a number of historic and forward-looking estimates of peer company returns on equity.

Table 21 shows the calculations for a number of historic and forward-looking estimates of peer company returns on equity.

Table 21: CAPM Results

CAPM										
		[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
	Risk Free Rate						Market Risk Premium		ROE Based On	
			Beta- Relevered		Historical	S&P 500			Historical	Projected
		Value Line	Bloomberg	Average	Return	Projected	Historical	Projected	MRP	
	30-year [1a]									
AES	1.47%	0.73	0.79	0.76	8.50%	13.16%	7.03%	11.69%	6.84%	10.40%
CWEN	1.47%	NA	0.72	0.72	8.50%	13.16%	7.03%	11.69%	6.52%	9.86%
NRG	1.47%	1.17	1.12	1.15	8.50%	13.16%	7.03%	11.69%	9.53%	14.88%
VST	1.47%	1.43	1.32	1.38	8.50%	13.16%	7.03%	11.69%	11.14%	17.55%
AT	1.47%	NA	0.71	0.71	8.50%	13.16%	7.03%	11.69%	6.43%	9.71%
									8.09%	**12.48%**
	30-year [1b]									
AES	3.00%	0.73	0.79	0.76	8.50%	13.16%	5.50%	10.16%	7.20%	10.76%
CWEN	3.00%	NA	0.72	0.72	8.50%	13.16%	5.50%	10.16%	6.95%	10.29%
NRG	3.00%	1.17	1.12	1.15	8.50%	13.16%	5.50%	10.16%	9.31%	14.65%
VST	3.00%	1.43	1.32	1.38	8.50%	13.16%	5.50%	10.16%	10.56%	16.97%
AT	3.00%	NA	0.71	0.71	8.50%	13.16%	5.50%	10.16%	6.88%	10.16%
									8.18%	**12.57%**
	30-year [1c]									
AES	3.80%	0.73	0.79	0.76	8.50%	13.16%	4.70%	9.36%	7.39%	10.95%
CWEN	3.80%	NA	0.72	0.72	8.50%	13.16%	4.70%	9.36%	7.17%	10.52%
NRG	3.80%	1.17	1.12	1.15	8.50%	13.16%	4.70%	9.36%	9.19%	14.53%
VST	3.80%	1.43	1.32	1.38	8.50%	13.16%	4.70%	9.36%	10.26%	16.67%
AT	3.80%	NA	0.71	0.71	8.50%	13.16%	4.70%	9.36%	7.11%	10.40%
									8.23%	**12.62%**
								Average	**8.17%**	**12.55%**
								Average	**10.36%**	

CAPM
Notes:
[1]
a) 30-day average 30-Yr T Note Bloomberg
b) 10-year forecast of 30-year Treasury Bonds; Blue Chip Financial Forecast, Vol. 39, No. 6, June 1, 2020.
c) Average 30-year treasury yield for 2026-2030; Blue Chip Financial Forecast, Vol. 39, No. 6, June 1, 2020.
[2] Source: Value Line accessed on 7/24/20
[3] Source: Bloomberg Professional as of 6/30/20
[4] Equals average ([2], [3])
[5] https://vasdc8grscoc.blob.core.windows.net/files/ReleaseLogs/TEMPLATE_NavigatorReleaseUpdate_Master.pdf
[6] Source: Bloomberg Professional
[7] Equals [5] – [1]
[8] Equals [6] – [1]
[10] Equals [1] + ([4] x [7])
[10] Equals [1] + ([4] x [8])

We also reviewed these results in light of stakeholder feedback regarding the appropriate peer group. We performed several sensitivities on the peer group, as detailed below.

Table 22: CAPM Results – Sensitivity #1

	RISK FREE RATE	ROE BASED ON	
		Historical	Projected
		MRP	
	30-year		
AES	1.47%	6.84%	10.40%
NRG	1.47%	9.53%	14.88%
VST	1.47%	11.14%	17.55%
		9.17%	**14.28%**
	30-year		
AES	3.00%	7.20%	10.76%
NRG	3.00%	9.31%	14.65%
VST	3.00%	10.56%	16.97%
		9.03%	**14.13%**
	30-year		
AES	3.80%	7.39%	10.95%
NRG	3.80%	9.19%	14.53%
VST	3.80%	10.26%	16.67%
		8.95%	**14.05%**
		9.05%	**14.15%**
		11.60%	

Table 23: CAPM Results – Sensitivity #2

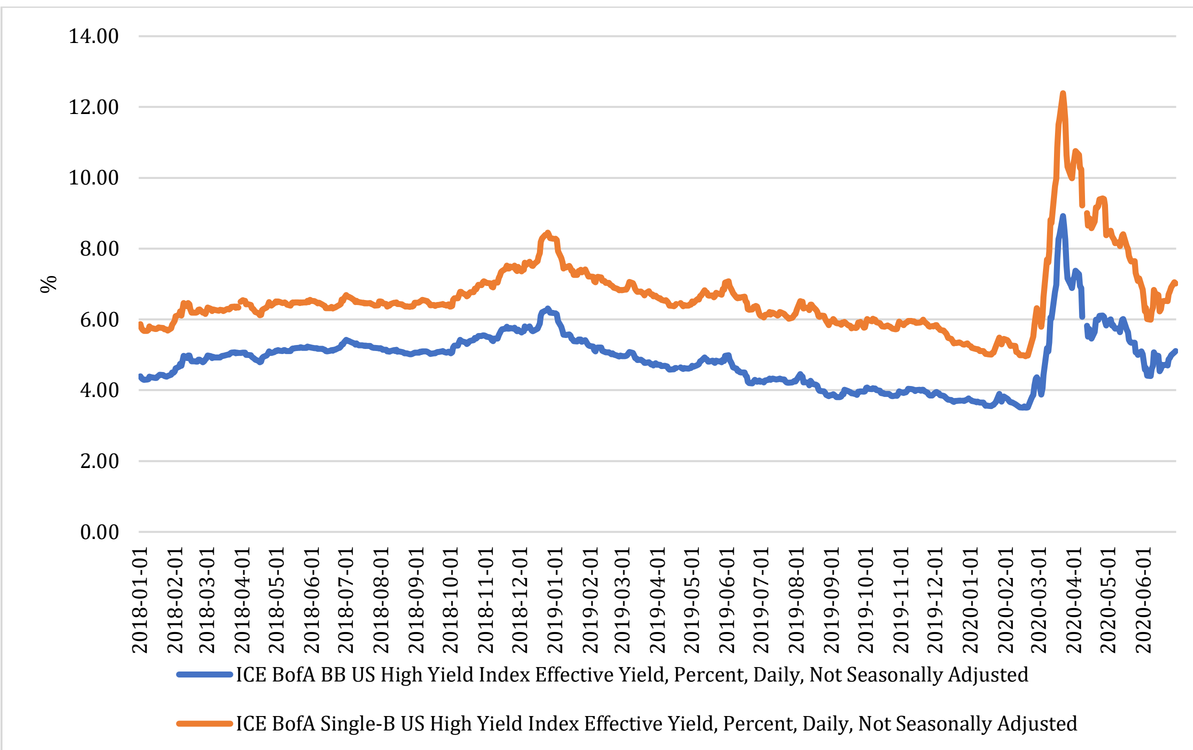
	RISK FREE RATE	ROE BASED ON	
		Historical	Projected
		MRP	
	30-year		
NRG	1.47%	9.53%	14.88%
VST	1.47%	11.14%	17.55%
		10.33%	**16.21%**
	30-year		
NRG	3.00%	9.31%	14.65%
VST	3.00%	10.56%	16.97%
		9.94%	**15.81%**
	30-year		
NRG	3.80%	9.19%	14.53%
VST	3.80%	10.26%	16.67%
		9.73%	**15.60%**
		10.00%	**15.87%**
		12.94%	

As seen in the two peer group sensitivity results above, the average CAPM result increases to 11.6% and 12.9% when subsets of the full peer group are considered. We recommend a 13% cost of equity, which is in line with the adjustments made to the peer group to better approximate merchant generation risk. We believe this appropriately reflects an upward adjustment to the full peer group of results and is aligned with the NRG and VST-only sensitivities – the peers whose portfolio most closely reflects pure play merchant generation.

vii. Cost of Debt

To estimate the Cost of Debt (COD), Concentric reviewed credit ratings of companies active in the development and commercialization of merchant generation. Of the five comparators, each has below investment-grade senior unsecured debt ratings in the BB range (BB- to BB+).[39] We then reviewed historical generic corporate bond yields for B and BB rated companies. In calendar year 2019, bond yields for companies with a B rating averaged 6.38%, while yields for companies with a BB rating averaged 4.45%.

Figure 2: Generic Corporate Bond Yields[40]



39 SNL Financial. Ratings are estimated by Standard & Poor's and Moody's reported by SNL, as of July 2020.

40 BofA Merrill Lynch, BofA Merrill Lynch US High Yield B and BB Effective Yield©, retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/BAMLH0A2HYB[B]EY.

A longer-term view of generic corporate debt reveals these averages have been steadily decreasing in recent years, with levels peaking in 2016, the time this analysis was completed in the previous Net CONE recalculation. Given these trends and considering that our peer group credit ratings are primarily BB rated, we have assumed a cost of debt of 6.0%. This assessment is at the upper end of the range of BB rated bond yields and is consistent with the increased risk associated with a merchant generating plant investing in a new capacity resource without a long-term contract.[41]

Concentric also reviewed recent bond issuances for peer companies. These showed coupon rates ranging from 3%-6%, with an unweighted average of approximately 4.5%, as shown below.

[41] The COVID19 pandemic had a significant impact on capital markets as seen in Figure 2. However, we expect lending rates to return to pre-COVID levels (as is indicated in the figure) and our recommended cost of debt takes this into consideration.

Table 24 : Recent IPP Debt Issuances[42]

NAME	TICKER	MATURITY TYPE	CURRENCY	BLOOMBERG COMPOSITE RATING	COUPON	ANNOUNCE
AES Corp/The	AES	CALLABLE	USD	BBB-	3.95	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.3	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.95	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BBB-	3.3	5/15/2020
AES Corp/The	AES	CALLABLE	USD	BB+	4.5	3/1/2018
Atlantic Power Corp	ATPCN	CONV/CALL	CAD	#N/A N/A	6	1/22/2018
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	#N/A N/A	4.75	5/19/2020
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	4.75	12/4/2019
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	4.75	12/4/2019
Clearway Energy Operating LLC	CWENA	CALLABLE	USD	BB	5.75	9/5/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	4.45	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	3.75	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	4.45	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BBB-	3.75	5/20/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.25	5/7/2019
NRG Energy Inc	NRG	CALLABLE	USD	BB	5.75	10/2/2018
NRG Energy Inc	NRG	CONV/PUT/CALL	USD	#N/A N/A	2.75	5/21/2018
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.7	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.7	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	11/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5	6/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5	6/6/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	4.3	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	4.3	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BBB-	3.55	6/4/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.625	1/22/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.625	1/22/2019
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.5	8/7/2018
Vistra Operations Co LLC	VST	CALLABLE	USD	BB	5.5	8/7/2018

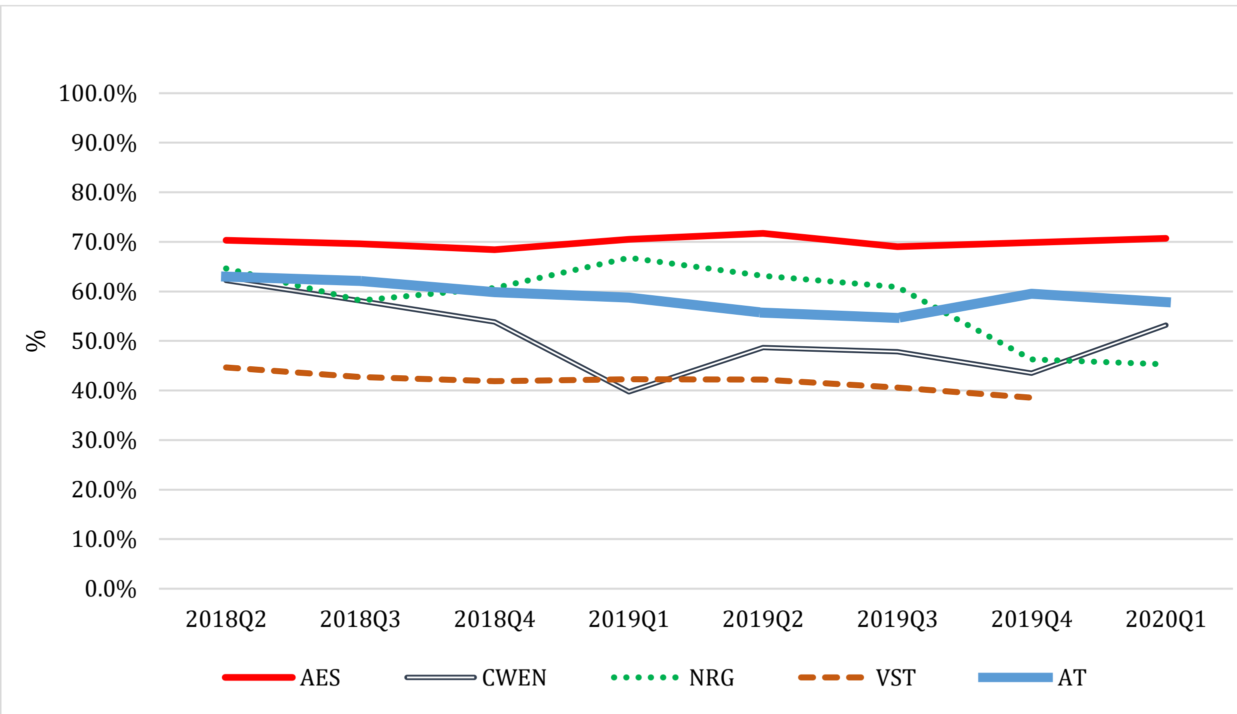
42 As reported by Bloomberg. Debt issuances as of 8/10/2020, for years 2018-August 2020.

viii. Capital Structure

Capital structure is the ratio of debt to equity used to finance an investment. The appropriate capital structure for a merchant development project can take many forms depending on its financing.

To derive an appropriate capital structure for the CONE calculation, we reviewed the capital structures of the aforementioned peer group of companies who would be likely to make such an investment. Since each company in the peer group is public, their debt weight, the total market value of the debt outstanding as a percentage of the market value of their total capital (debt plus equity) is available in their filings with the Securities Exchange Commission (SEC). We reviewed this data as reported by Bloomberg. Debt weights for each member of the peer group are shown in Figure 3 below.

Figure 3: Peer Group Debt Weights[43]



Over the previous eight quarters, the average capital structure contained a mix of 56% debt and 44% equity. This average was also confirmed through Bloomberg as a secondary source, as shown below.

43 SNL Financial.

Table 25: Total Debt/Total Capitalization[44]

COMPANY	2018Q2	2018Q3	2018Q4	2019Q1	2019Q2	2019Q3	2019Q4	2020Q1	AVERAGE
AES	70.3%	69.6%	68.4%	70.5%	71.7%	69.0%	69.9%	70.7%	70.0%
CWEN	62.2%	58.1%	53.9%	39.7%	48.7%	47.9%	43.5%	53.2%	50.9%
NRG	64.7%	58.2%	60.7%	66.8%	63.2%	60.9%	46.3%	45.3%	58.2%
VST	44.7%	42.7%	41.9%	42.3%	42.2%	40.6%	38.6%		41.8%
AT	63.0%	62.1%	59.9%	58.8%	55.7%	54.7%	59.5%	57.9%	58.9%
								Average	**56.0%**

While the debt weight of the peer group has, on average, been lower in the most recent quarters, the range of capitalization ratios is quite broad. As such, a capital structure more consistent with the longer historical period, on average, was assumed. We recommend a 55% debt, 45% equity capital structure.

ix. WACC Calculation and ATWACC

Inputting the assumptions for ROE, COD, and capital structure described above into the WACC calculation yields a WACC of 9.2%, as shown below:

WACC = 13.0% * 45% + 6.0% * 55% = 9.2%

We translated these components to a discount rate by reflecting the effect of taxes on the cost of debt to derive an after-tax WACC of 8.3%. This rate was then adjusted for inflation to derive a "real ATWACC" of 6.1%.

x. Cost of Capital Comparison

The estimate of WACC described above, as well as each of the key inputs, is consistent with findings utilized in the 2017 Net CONE estimate, as well as recent calculations of Net CONE conducted by PJM and NYISO. Those values are shown in Table 26.

44 Bloomberg Professional.

Table 26: Cost of Capital Comparison

	ISO-NE[45] (2014)	PJM[46] (2014)	NYISO[47] (2016)	ISO-NE[48] (2016)	PJM[49] (2018)	ISO-NE (2020)
ROE	13.8%	13.8%	13.4%	13.4%	12.8%	13.0%
COD	7.0%	7.0%	7.75%	7.8%	6.5%	6.0%
Debt Weight	60.0%	60.0%	55.0%	60.0%	65.0%	55.0%
WACC	9.7%	9.7%	10.3%	10.0%	8.2%	8.3%

45 FERC Docket ER14-1639-000, Testimony of Dr. Samuel A. Newell and Mr. Christopher Ungate of behalf of ISO-NE Regarding the Net Cost of New Entry for the Forward Capacity Market Demand Curve, April 1, 2014.

46 PJM Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, The Brattle Group and Sargent & Lundy, May 15, 2014.

47 NY-ISO Study to Establish New York Electricity Market ICAP Demand Curve Parameters, Analysis Group & Lummus Consultants International. September 13, 2016.

48 ISO-NE CONE and ORTP Analysis, An evaluation of the entry cost parameters to be used in the Forward Capacity Auction to be held in February 2018 ("FCA-12") and forward. Concentric Energy Advisors & Mott MacDonald. January 17, 2017.

49 PJM Cost of New Entry, Combustion Turbines and Combined-Cycle Plants with June 1, 2022 Online Date, The Brattle Group & Sargent & Lundy. April 19, 2018.

Section 5: Revenue Offsets

The candidate reference units have several potential revenue streams that must be considered in the Net CONE calculation: sales of energy and ancillary services (E&AS) and PFP revenues associated with shortage events. These revenue streams, which partially offset the new resource's levelized annual carrying costs, are used to estimate Net CONE values for each candidate reference unit. Specifically, all revenue offsets are levelized and subtracted from the gross CONE estimates to produce a Net CONE value for each candidate resource unit. Each type of revenue offset is discussed in turn below with a summary of the revenue offset estimates for each candidate resource unit.

A. Energy and Ancillary Services

In the 2016 CONE/ORTP study, Concentric estimated market-based E&AS offsets for each candidate resource based on a 20-year Locational Marginal Price (LMP) forecast produced with a production cost model and a simplified dispatch model. Based on experience gained during the 2016 CONE/ORTP re-calculation, Concentric determined that using a production cost model involved complex calculations for energy revenues that were not transparent to stakeholders given the significant number of inputs, outputs, and assumptions involved, and a blunt historical add-on for ancillary services revenues since production cost models are not capable of modeling co-optimized energy and ancillary revenues. Concentric considered a simplified price forecast and the use of historical prices and ultimately determined that an E&AS estimation methodology based on adjusted historical prices would produce reasonable E&AS offsets and would afford greater transparency to ISO-NE stakeholders. Similar approaches have been approved by FERC to approve CONE values in NYISO and PJM[50].

The dispatch models used to estimate E&AS revenues for each of the candidate CONE reference units used historical prices from the January 2017- December 2019 period with two adjustments: 1) an energy and reserve scarcity adjustment ("Energy/Reserve Scarcity adjustment") to account for the impacts of energy and reserve scarcity under the excess supply conditions that have prevailed in New England; and 2) a Level of Excess adjustment ("LOE adjustment") to estimate E&AS revenues the candidate CONE reference units would earn if the system were at criteria. As discussed further below, the LOE adjustment is not applied to the prices used in the ORTP dispatch models.

Using historical prices to estimate future energy and ancillary services prices cannot perfectly capture the expected impacts of future changes to the ISO-NE system. However, market prices during the past three years produce a reasonable estimate of near-term market conditions, and to the extent that system conditions change over time, the next CONE and ORTP re-calculation, which will be based on then prevailing market conditions, will reflect such changes. The Energy/Reserve Scarcity and LOE adjustments are discussed in turn below.

50 See e.g., PJM Tariff, Attachment DD, sections 5.10(v)(A) & (B).

i. Energy/Reserve Scarcity Adjustment

The historical LMPs used in the dispatch models for the CONE units were first adjusted for energy and reserves shortages with an Energy/Reserve Scarcity Adjustment. Specifically, the Energy/Reserve Scarcity Adjustment sought to remove the impacts of administrative shortage pricing set by the Reserve Constraint Penalty Factor (RCPF), which is reflected in the historical prices during periods of scarcity. Scarcity pricing was then included as a separate adjustment based upon the expected number of scarcity hours being modeled, as described further below. Given that the RCPF only affects prices in the real-time market, a comparable adjustment had to be made to remove the expected impacts of energy and reserve revenue scarcity from the day-ahead LMPs. In an efficient market, the day-ahead and real-time prices converge in expectation, and in equilibrium the expected impact of real-time energy and reserve scarcity would be reflected in day-ahead LMPs.

The Energy/Reserve Scarcity adjustment was only applied in hours over the 2017-2019 period when the RCPF impacted real-time clearing prices (i.e., hours when the RCPF was non-zero). These hours are shown in Table 27 below. The top panel of Table 27 shows the actual real-time market clearing prices for energy and reserves for the Connecticut Load Zone in the hours when the RCFP was non-zero. The last two columns of the top panel show the RCPF for TMNSR and TMOR. The bottom panel of Table 27 reflects prices in the same hours with the impact of the non-zero RCPF values removed, through subtraction, from the actual real-time prices. For example, the $357.69/MWh Energy/Reserve Scarcity adjusted LMP on October 18, 2017 hour ending 19 is the actual integrated hourly real-time LMP of $691.02/MWh minus the integrated hourly RCPF impact of $333.33/MWh. Note that the values in Table 27 are presented on an integrated hourly basis. For example, an integrated hourly TMOR RCPF value of $333.33/MWh reflects the hourly integrated value of an TMOR RCPF of $1,000/MWh for 20 minutes and an TMOR RCPF value of zero in 40 minutes.

Table 27: Energy/Reserve Scarcity Adjustments (Nominal $/MWh)

Actual Prices (.Z.CONNECTICUT)							
Date	Hour End	Real-time LMP	Real-time TMSR price	Real-time TMNSR price	Real-time TMOR price	TMNSR RCPF	TMOR RCPF
10/18/2017	19	691.02	648.6	644.44	507.14	333.33	333.33
10/22/2017	19	422.60	396.08	395.49	390.82	250.00	250.00
9/3/2018	16	562.86	480.55	480.55	477.51	333.33	333.33
9/3/2018	17	1,092.46	1,061.57	1,061.57	1,000.00	1,000.00	1,000.00
9/3/2018	18	2,375.72	2,313.30	2,313.30	1,000.00	2,000.00	1,000.00
9/3/2018	19	763.05	720.16	720.16	595.16	458.33	333.33
		Energy/Reserve Scarcity Adjusted Prices					
Date	Hour End	Adj. Real-time LMP	Adj. Real-time TMSR price	Adj. Real-time TMNSR price	Adj. Real-time TMOR price		
10/18/2017	19	357.69	315.27	311.11	173.81		
10/22/2017	19	172.60	146.08	145.49	140.82		
9/3/2018	16	229.53	147.22	147.22	144.18		
9/3/2018	17	92.46	61.57	61.57	0.00		
9/3/2018	18	375.72	313.30	313.30	0.00		
9/3/2018	19	304.72	261.83	261.83	261.83		

The total market impact of the RCPF during the 2017-2019 period (the hours shown in Table 27) was $4,374.99 of energy and reserve scarcity revenue. In an efficient market, the expected real-time impact of the RCPF would be included in day-ahead LMPs. However, this impact is not observable in practice. Therefore, to maintain the historical convergence between day-ahead and real-time prices in expectation, the same amount of real-time energy and reserve scarcity revenue is reflected in the day-ahead market in all on-peak hours. Assuming the expected price impact of the RCPF is applied equally across all on-peak hours yields in the day-ahead market, a downward adjustment to day-ahead LMPs of $0.36/MWh is applied in on-peak hours ($4,375/12,224 hours = $0.36/MWh).

After the observed scarcity pricing was removed from the historical day ahead and real time LMPs and reserve prices, the scarcity pricing that is expected to occur needs to be reconstituted with the expected amount of scarcity revenues in an at-criterion system. These scarcity revenues earned from the RCPF are calculated as a separate source of energy and ancillary service revenue distinct from the LMPs and reserve prices used in the energy market dispatch models described below. A separate scarcity revenue calculation is required, as the specific hours of any given year when a reserve deficiency triggers the RCPF is not known. Therefore, rather than make an assumption about the specific hours that would have RCPF scarcity pricing included in the LMPs and reserve prices, the total amount of energy market scarcity revenue to be reconstituted was calculated directly in the financial model.

The expected amount of energy market scarcity revenue depends on two variables: the first variable is the RCPF, which is $1,000 /MWh for TMOR and $1,500 /MWh for TMNSR; the second variable is the expected number of scarcity hours, which ISO-NE forecasts to be 11.3 hours annually in an at-criterion system. ISO-NE's scarcity hour forecast does not delineate a distinction between a TMOR reserve deficiency and a TMNSR reserve deficiency, therefore the RCPF used when establishing the energy market scarcity revenue was assumed to be the TMOR RCPF of $1000/MWh. Finally, the technology-specific forced outage rate was applied to the expected energy market scarcity revenues. The per-kW-month calculations for each modeled Net CONE technology are shown in Table 28 below.

Table 28: Energy Market Scarcity Revenue

TECHNOLOGY	SCARCITY HOURS	RESERVE CONSTRAINT PENALTY FACTOR ($/MWH)	AVERAGE ACTUAL PERFORMANCE (%)	ENERGY MARKET SCARCITY REVENUE ($/KW-MO)
Combined Cycle	11.3	1000	92.77%	0.874
Simple Cycle	11.3	1000	98.00%	0.923
Aero	11.3	1000	98.00%	0.923

ii. Level of Excess Adjustment

Next, historical energy and real-time reserve prices during the 2017-2019 period were adjusted by the LOE adjustments to account for long-run equilibrium conditions. The LOE adjustment was calculated by successively removing resources from the supply stack until the system was at criteria and estimating what prices would have been if the installed capacity was at criteria.[51] This involved constructing a 'base case" energy market curve and an "LOE-adjusted" supply curve for each hour of the day that represented what the clearing price would have been if that price were determined by the intersection of the demand curve and the LOE-adjusted supply curve. The average LMPs for the base case and the LOE-adjusted case were derived for three periods in each month and year:

- On-peak hours: HE 08 through HE 23, non-holiday weekdays
- High on-peak hours: a subset of on-peak hours, coincident with summer and winter intermittent reliability hours and all summer hours with a system-wide capacity scarcity condition
- Off-peak hours: all non-on-peak hours

Next, an LOE adjustment factor ("LOE AF") was calculated specific to each hourly period in every month (36 LOE AFs per year and 108 for the 2017-2019 period) as follows:

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51 Offers removed from the supply stack were associated with resources pending retirement. See ISO New England, Cost of New Entry and Offer Review Trigger Prices, Energy and Ancillary Service Revenue Adjustments for Level of Excess Supply and Energy Security Improvements, July 14-15, 2020.

$LOE\ AF=〖Monthly\ Average\ LMP〗\_(Base\ Case)/〖Monthly\ Average\ LMP〗\_(LOE\ Adj\ Case)$

A summary of the LOE adjustment factors is provided in Table 29. These LOE adjustments were applied by dividing the historical LMPs in the Connecticut zone (where the candidate CONE units are assumed to be located) by the applicable LOE adjustment factor based on the month, year, and period (i.e., high on-peak, on-peak, and off-peak).

Table 29: Level of Excess Adjustment Factors[52]

2017	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEPT	OCT	NOV	DEC
High On-Peak	0.99	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00
On-Peak	0.99	0.99	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Off Peak	0.98	0.99	0.99	0.99	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99
2018												
High On-Peak	0.98	1.00	1.00	1.00	1.00	0.94	0.87	0.82	0.88	0.94	0.93	0.92
On-Peak	0.98	1.00	1.00	1.00	1.00	0.95	0.90	0.88	0.95	0.96	0.95	0.95
Off Peak	0.98	1.00	1.00	1.00	1.00	0.98	0.97	0.97	0.99	0.99	0.96	0.97
2019												
High On-Peak	0.94	0.93	0.94	0.96	1.00	0.97	0.93	0.96	0.99	0.99	0.97	0.96
On-Peak	0.94	0.96	0.96	0.97	1.00	0.98	0.96	0.98	0.99	0.99	0.98	0.96
Off Peak	0.95	0.97	0.97	0.99	1.00	0.99	0.96	1.00	1.00	1.00	0.98	0.98

Table 30 illustrates the mechanics of the LOE adjustment factor in a sample hour - September 3, 2018 in hour ending 16. The Energy/Reserve Shortage adjustment for this hour is shown in Table 27. The applicable LOE AF for High On-peak in September 2018 is 0.88 (see Table 29 above). The LOE and Energy/Reserve Scarcity adjusted prices are calculated by dividing the Energy/Reserve Scarcity price by the applicable LOE AF (i.e., 0.88). The Energy/Reserve Scarcity and LOE adjusted prices reflecting this calculation are shown in the bottom panel of Table 30.

52 ISO New England, Cost of New Entry and Offer Review Trigger Prices, Energy and Ancillary Service Revenue Adjustments for Level of Excess Supply and Energy Security Improvements, July 14-15, 2020, at 9.

Table 30: Level of Excess Adjustment Example

ENERGY/RESERVE SCARCITY ADJUSTED PRICES ($/MWH)	
Adj. day-ahead LMP	57.31
Adj. real-time LMP	229.53
Adj. TMSR price	147.22
Adj. TMNSR price	147.22
Adj. TMOR price	144.18
LEVEL OF EXCESS ADJUSTMENT	
Hour type	High On-Peak
LOE AF	0.88
LEVEL OF EXCESS ADJUSTED PRICES ($/MWH)	
LOE Adj. day-ahead LMP	65.13
LOE Adj. real-time LMP	260.83
LOE Adj. TMSR	167.30
LOE Adj. TMNSR	167.30
LOE Adj. TMOR	163.84
Note: the actual day-ahead LMP in this hour was $57.31/MWh and there was no Energy/Reserve Scarcity adjustment in this hour because this hour occurred on Labor Day, an off-peak day.	

iii. E&AS Methodology Overview

Concentric estimated E&AS revenue offsets estimates for each candidate reference unit resource type based on adjusted historical prices from the three-year period starting on January 1, 2017 and ending on December 31, 2019. A unique EA&S estimate, which is defined as energy and ancillary service revenues net of production costs, was produced for each candidate resource type based on a simple average of the three (inflation-adjusted) E&AS estimates from each calendar year and applied as an E&AS offset to each candidate reference unit. This annual E&AS offset is held constant (in real terms) throughout each resource's assumed 20-year life. Before discussing the specifics of the EAS methodology for each candidate reference unit, it is helpful to review ISO-NE's energy and ancillary services markets.

Resources in ISO-NE can currently receive market-based compensation for generating electricity or providing one or more of the following ancillary services: regulation, ten-minute synchronized reserves (TMSR), ten-minute non-synchronized reserve (TMNSR); and thirty-minute operating reserves (TMOR). ISO-NE operates both day-ahead and real-time energy markets and the three candidate reference units are eligible to offer energy into these markets. Provided they meet the technical specifications, the candidate reference units may also be eligible to provide ancillary services. Based on their technical specifications, none of the candidate reference units also provide regulation.

ISO-NE currently procures reserves on a forward basis in the Forward Reserve Market (FRM) or in real time by designating eligible resources for Real-Time reserves. Table 31 below summarizes the energy and ancillary services products that each candidate reference unit is assumed to offer in the E&AS dispatch models based on the technical capabilities of each resource and the products that each resource can economically offer.

Table 31 : Energy and Ancillary Service Products Offered in E&AS Estimates

Candidate Reference Unit	Day-Ahead Energy	Real-Time Energy	Forward Reserve Market		Real-Time Reserve Market		
			TMNSR	TMOR	TMSR	TMNSR	TMOR
Simple cycle	●	●	●	●		●	●
Aeroderivative	●	●	●	●		●	●
Combined cycle	●	●			●		

The dispatch models for the CONE units also reflect estimated lifecycle non-recoverable degradation to each unit's capacity factor and heat rate. The lifecycle non-recoverable degradation factors in Table 32 were applied in the dispatch models for the candidate CONE units (see Table 12, Table 13, and Table 14 for the ambient adjusted capacity factor and heat rate of each CONE unit). The lifecycle capacity degradation factors were applied to the ambient adjusted capacity of each unit resulting in a decrease in unit capacity by the amounts shown in Table 32.[53] The lifecycle heat rate degradation factors were used increase each unit's ambient-adjusted heat rate upward by the amounts shown in in Table 32.[54]

Table 32: Lifecycle Degradation for CONE Units

	Lifecycle Non-Recoverable Capacity Degradation	Lifecycle Non-Recoverable Heat Rate Degradation
Combined Cycle	2.43%	1.63%
Simple Cycle	1.41%	1.00%
Aeroderivative	2.70%	0.50%

The remainder of this section discusses the methods used to estimate the E&AS revenues each candidate reference unit is expected to earn over its project life. Given their technical similarities, the same method was used to estimate E&AS revenues for the simple cycle and aeroderivative units. An alternate method was used for the combined cycle unit. While the candidate reference units included

53 For example, the simple cycle's ambient-adjusted capacity was multiplied by (1-0.0141).

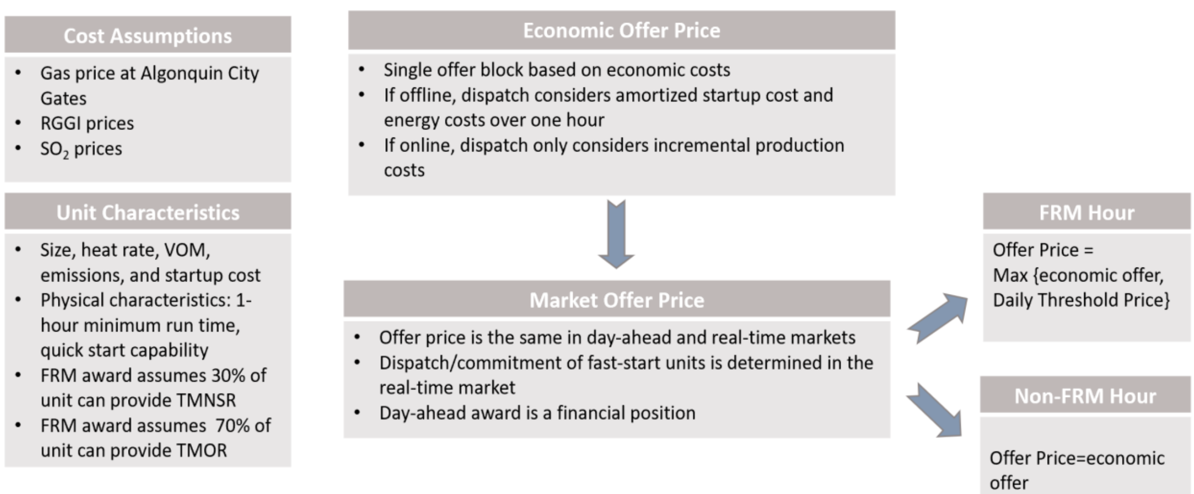
54 For example, the simple cycle's ambient-adjusted heat rate was multiplied by (1+0.01).

dual fuel capability, the unit are not dispatched on oil under normal operating conditions, and therefore were not dispatched on oil in the Net CONE dispatch models. As a final step for each candidate reference unit, net E&AS revenues (i.e., E&AS revenues net of production costs) were calculated for each candidate reference unit to produce the E&AS offset.

iv. Simple Cycle and Aeroderivative E&AS methodology

As indicated in Table 31, the simple cycle and aeroderivative candidate reference units are expected to participate in the day-ahead and real-time energy markets and are designated to provide TMNSR and TMOR in the FRM and RTM.[55] Concentric developed a simplified economic dispatch model to estimate the net E&AS revenues these units can be reasonably expected to receive in ISO-NE day-ahead and real-time markets. The simple cycle and aeroderivative dispatch model committed and dispatched the units economically based on the adjusted historical day-ahead and real-time energy and reserve prices and each unit's production costs. An overview of the dispatch methodology for the simple cycle and aeroderivative units is shown in Figure 4 below.

Figure 4 : Overview of Dispatch Methodology for Simple Cycle and Aeroderivative Units



55 These assumptions are consistent with the approach employed in the 2016 CONE/ORTP Study. See 2016 CONE/ORTP Study at 65.

	Day-Ahead Market	Real-time Market

Energy, FRM, and Real-time Reserve Market Compensation	• Clear for energy if DA Offer ≤ Day-ahead LMP adjusted for LOE and scarcity. Financial position where revenues = MW x (DA LMP – RT LMP)
	• Startup costs amortized if the unit is offline and ignored if the unit is online
	• Offer adjusted for Daily Threshold Price as appropriate
	• 30% of capacity assigned TMNSR
	• 70% of capacity assigned TMOR
		• If RT Offer ≤ Real-time LMP:
		   • Clear for energy (no reserves)
		   • Compensation based on real-time LMP and unit capacity (single offer block)
		• If RT Offer > Real-time LMP:
		   • Do not clear for energy
		   • Clear for reserves
		• 30% of capacity designated TMNSR
		• 70% of capacity designated TMOR
		• Compensation for reserves depends on whether it is an FRM hour
		   • FRM hour: FRM price
		   • Non-FRM hour: real-time reserves price

Unit production costs include start-up costs,[56] fuel costs, VOM, and CO_2 and SO_2 emission allowance costs. Fuel costs are based on the unit's nominal heat rate (in non-summer and non-winter months) multiplied by the gas price at Algonquin City Gates.[57] The gas price is also adjusted for a 5% state gross earnings tax which is applicable in Connecticut.[58]

The simple cycle and aeroderivative units rarely clear the day-ahead market in the dispatch model. This is also generally true for these unit types in ISO-NE's day-ahead market. Without a day-ahead award, the simple cycle and aeroderivative units are unlikely to purchase gas in the next-day gas market, and instead purchase gas in the intraday gas market if they are dispatched in real-time. Analysis of historical natural gas price data for next-day and intraday (or "same day") indicated that an intraday gas premium existed on the days the simple cycle and aeroderivative were dispatched in real-time. Accordingly, the dispatch models for the simple cycle and aeroderivative include the intraday fuel price seasonal premiums show in Table 33.

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56 Start -up costs consist mainly of consumables such as water and chemicals. The assumed startup costs are $11,000 per start for the simple cycle and $3,000 per start for the aeroderivative.

57 Algonquin City Gates is the most liquid natural gas hub in ISO-NE and is geographically close to all three gas candidate reference units, which the study assumes are located in Connecticut. The next day gas price is appropriate to use for the gas-fired resources because the natural gas resources in ISO-NE purchase the majority of their gas from the natural gas spot market rather than through long-term gas contracts.

58 Concentric reviewed a redacted natural gas invoice provided by a natural gas generator in Connecticut and confirmed that natural gas purchases include this 5% tax.

Table 33: Intraday Gas Premiums

SEASON	INTRADAY GAS PREMIUM
Summer (June-August)	4%
Winter (December-February)	20%
Shoulder (all other months)	11%

These intraday gas premiums are based on the average, by season, of actual intraday gas premiums (i.e., intraday price minus the next-day price for the same operating day) during the 2017-2019 period on the days when the simple cycle was dispatched in real time. The intraday gas premium is applied to the day-ahead and real-time energy offers of the simple cycle and aeroderivative units in the dispatch models.

The E&AS models assumed that reserves (TMNSR and TMOR for the simple cycle and aeroderivative) had a production cost of zero. The simple cycle and aeroderivative units were assumed to offer their full capacity into both the day-ahead and real-time markets in a single block with a one-hour minimum run time. The units also have fast-start capability, which is required of FRM resources. Thirty percent of each unit's capacity can be deployed from a cold start within 10 minutes and the remaining capability can be deployed within 30 minutes. The reserves products assumed to be provided are shown in Table 34 below:

Table 34 : Reserves Amounts Provided (Shoulder Months)

	TMNSR (MW)	TMOR (MW)
Simple Cycle Unit	111	260
Aeroderivative Unit	29	67

The first step in the E&AS dispatch model involves determining the unit commitment and dispatch schedule in the day-ahead market based on the unit's day-ahead energy offer and the day-ahead market clearing prices. For each hour, the model evaluates each unit's commitment (startup) and dispatch (fuel, VOM, and emissions) costs and commits the unit if the day-ahead LMP is high enough to recover the unit's startup and variable energy costs within the hour. If the unit is already online, the dispatch model will keep the unit online if its variable costs are less than or equal to the day-ahead LMP. The unit is de-committed (i.e., shut down) if its variable energy costs exceed the day-ahead LMP.

As noted above, the simple cycle and aeroderivative resources participate in the FRM (in the case with the continuation of the FRM market). An award in the FRM market affects the way a resource can offer into the day-ahead energy market during Forward Reserve Delivery Period hours.[59] Forward Reserve Delivery Period hours are specified as hours ending 8 through 23, Monday through Friday, excluding NERC holidays. Market Participants with FRM awards must assign resources to meet the obligation and those resource are required to submit a day-ahead energy offer that is at least as high as the Forward Reserve Threshold Price (FRTP) established by ISO-NE.[60] The FRTP is designed to be high enough to sufficiently reduce the likelihood that the FRM resource clears the day-ahead energy market for energy, which reduces (and in some cases eliminates) the resource's ability to provide reserves. Accordingly, the simple cycle and aeroderivative units offer energy into the day-ahead market at the higher of their production costs and the FRTP.[61] Any day-ahead energy award is treated as a financial position and creates a charge for the MW quantity of that award at the real-time energy price.

The second step in the E&AS model involves determining the unit's real-time unit commitments and dispatch. The unit commitment and dispatch algorithm for the real-time market is identical to the day-ahead algorithm described above. However, the unit's energy offers, which remain unchanged from the day-ahead market, are evaluated against real-time LMPs rather than day-ahead LMPs. If the unit is offline, it will be designated to provide TMNSR and TMOR reserves and compensated at prices determined by the real-time reserves market.[62] Given that all commitments and dispatches are economic, the units do not require any Net Commitment Period Compensation payments.

The simple cycle and aeroderivative units are subject to potential penalties for non-performance in the FRM.[63] Based on a review of actual FRM penalties assessed to FRM suppliers with gas-fired resources with commercial online dates of June 2016 or later that participated in the LFRM, the average penalties assessed were just below 1% of the total LFRM obligation in MWh. To account for the LFRM penalty rate, the simple cycle and aeroderivative unit capacity was de-rated by 1% in all hours.

v. Combined Cycle E&AS methodology

A similar unit commitment and dispatch model was used for the combined cycle as was used for the simple cycle and aeroderivative units. However, the model was adapted to reflect the fact that the

[59] Forward Reserve Auction awards are not resource-specific but rather a market participant with an FRM obligation is required to assign an asset to supply reserves for the delivery period and location of its award. The FRM offer cap is $9,000/MW-month. Note that FCA price-netting, a practice that reduced the payment a resource received for assuming a forward reserve obligation by the value of the applicable FCA clearing price, was eliminated in 2016. As such, the 2017-2019 historical FRM prices do not reflect the impact of FCA netting.

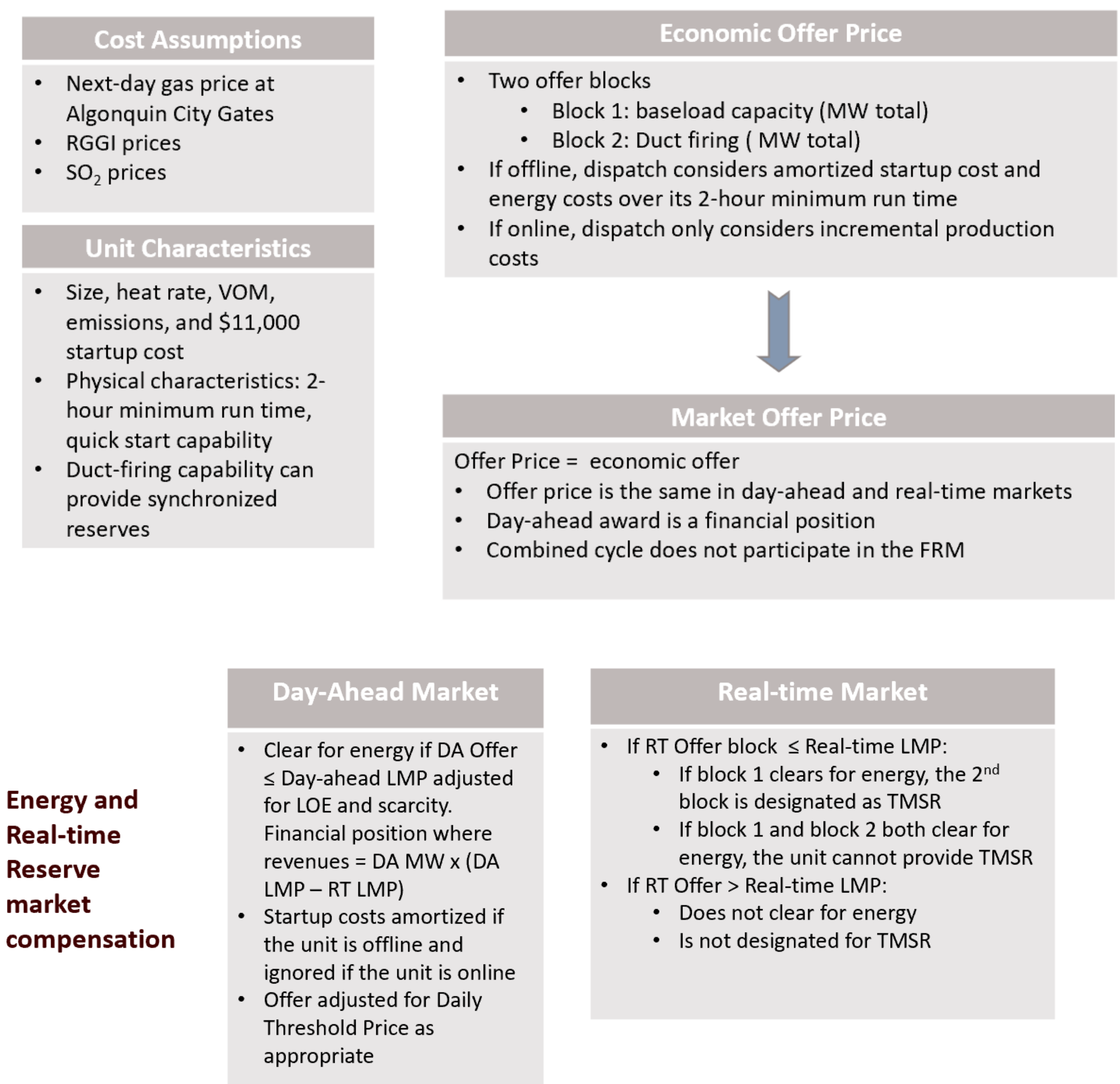
[60] See e.g., ISO-NE, *Forward Reserve Daily Threshold Price Report,* available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/fwd-cap-daily-threshold-price.

[61] Consistent with FRM requirements, if the unit is offline, its day-ahead offer is equal to the higher of the FRMDTP and the sum of its variable production costs and startup cost amortized over its total capacity. If the unit is online, its day-ahead offer is equal to the higher of the FRMDTP and its variable energy production costs.

[62] When providing forward reserves and designated for real-time reserves, the total reserve payment is reduced by the product of the Forward Reserve MW multiplied by the Real-time reserve price to ensure the unit is not doubly compensated for providing the same reserve MW.

combined cycle does not participate in the FRM, and thus was not required to submit offers at or above the FRTP during certain intervals. Instead, the combined cycle dispatch model assumes the unit offers competitively through a two-block energy offer. The first block is based on the production costs of its 535 MW baseload capacity and the second block is based on the production costs of its 34 MW duct firing capability. For any given operating day, the combined cycle's 2-block offer is the same in the day-ahead and real-time markets.[64] An overview of the dispatch methodology for the simple cycle and aeroderivative units is shown in Figure 5 below.

Figure 5: Overview of Dispatch Methodology for Combined Cycle Units



[64] Adjusted to reflect degradation.

Like the other candidate reference units, the combined cycle's production costs consist of fuel costs (ambient adjusted heat rate multiplied by the Algonquin next day gas price plus the 5% gross earnings tax), VOM and emissions allowance costs. The combined cycle unit has a six-hour minimum run-time and is limited to two starts per day and the unit commitment and dispatch model honors both of these operating constraints. If the combined cycle is online but only dispatched at its baseload capacity, the combined cycle is designated to provide TMSR in real-time, based on its available ambient adjusted duct firing capability, and compensated accordingly at the real-time TMSR price. No intraday gas price adjustment was applied to the combined cycle unit since this unit was expected to receive a financially binding day-ahead commitment and purchase natural gas at the next-day price.

B. Pay for Performance

ISO-NE's PFP mechanism is designed to encourage resource performance consistent with its assumed capacity obligation. Under PFP, a resource that underperforms will forfeit some or all capacity payments awarded in an FCA. Resources that perform beyond their CSO will receive PFP payments. Exposing resource owners to the risk of forfeiting capacity payments for underperformance, as well as providing them the opportunity to receive more compensation for over performance, is designed to incent resource owners to make investments that ensure their resource can perform.

The ISO-NE experienced its first capacity shortage conditions under the PFP market rules on September 3, 2018. The New England system experienced 2.4 hours of shortage resulting in $44.2 million in PFP credits to overperformers and $36.3 million in PFP charges to under-performers.[65]

In calculating expected compensation for CONE technologies, we consulted with ISO-NE and stakeholders, and reviewed and discussed ISO-NE's most recent study on expected system conditions and scarcity hours over the life of the generating facilities. A review of historical data shows relatively few scarcity hours since the PFP mechanism was implemented. For example, ISO-NE's November 2019 scarcity hour event analysis shows relatively few shortage hours in recent years, with ten shortage events between May 2015 and October 2019. However, it is important to note that the objective of the CONE/Net CONE analysis is to calculate what a merchant developer would need to enter the market with a future system condition that is at criterion.

Based on ISO-NE's most recently published analysis,[66] we have assumed 11.3 hours for the CONE analysis and 7.4 hours for the ORTP analysis. We have also assumed a Performance Payment Rate of

65 ISO-NE, *2018 Annual Markets Report*, at 20. The Internal Market Monitor notes that the $7.9 million difference between PFP credits and charges was due to energy efficiency exemption rules and were charged *pro rata* to resources holding a capacity supply obligation (see note 30).

66 https://www.iso-ne.com/static-assets/documents/2020/10/a00_iso_presentation_scarcity_hours_and_balancing_ratios.pptx.

$8,782/MWh. For the Balancing Ratio, we assumed a value of 0.847 for the CONE analysis and 0.816 for the ORTP analysis, consistent with ISO-NE's updated analysis.

The study assumes a performance score of 0.9277 for a combined-cycle machine based on manufacturer expectations.[67] For a simple cycle machine, we have assumed a performance score of 0.98 consistent with the expected forced outage rate for this technology based on consultation with Mott MacDonald and the assumption that a state-of-the-art fast-start unit would generally be expected to capture shortage hour revenues unless on a forced outage. Our shortage hour and performance payment rate assumptions are shown in Table 35 below.

Table 35: Pay for Performance Assumptions

Technology	Scarcity Hours (hrs)	Performance Payment Rate ($/MWh)	Average Actual Performance (%)	Average Balancing Ratio (%)	Net Performance Payments ($/kW-mo)
Combined Cycle	11.3	8,782	92.77	84.7	0.67
Simple Cycle	11.3	8,782	98.00	84.7	1.10
LM6000	11.3	8,782	98.00	84.7	1.10

C. Summary of Revenue Offsets

Table 36 presents a summary of the estimated revenue offsets of the three candidate reference units evaluated in the CONE study. These revenue offsets are subtracted from the CONE values presented in Section 7 below to calculate Net CONE values.

[67] Testimony of Dr. Matthew White, Docket No. ER14-1050-000, January 17, 2014, pg. 110.

Table 36: Summary of Revenue Offsets for Candidate Reference Units (2025$/kW-mo)

CANDIDATE REFERENCE UNIT	PAY FOR PERFORMANCE REVENUES	SCARCITY	E&AS REVENUES	TOTAL OFFSETS
INSTALLED CAPACITY				
Combined Cycle	0.590	0.681	3.117	4.388
Simple Cycle	1.037	0.767	2.852	4.656
Aeroderivative	1.037	0.767	2.698	4.502
QUALIFIED CAPACITY				
Combined Cycle	0.655	0.757	3.464	4.875
Simple Cycle	1.080	0.799	2.971	4.850
Aeroderivative	1.080	0.799	2.810	4.689

Section 6:
CONE Calculation and Results

The CONE/Net CONE is calculated as the minimum revenue required for entry, or CONE, less expected revenue offsets. A summary of the CONE/Net CONE values for the candidate reference units evaluated are shown in Table 37 below.

Table 37: Net CONE Summary for Candidate Reference Technologies

	1x1 7HA.02 (CC)	1x0 7HA.02 (CT)	2x0 LM6000 PF+ (AERO)
NOMINAL INSTALLED CAPACITY (MW)	543	371	95
QUALIFIED CAPACITY	489	361	91
INSTALLED COST (2019$/KW)	985	777	1,961
REAL ATWACC	6.1%	6.1%	6.1%
GROSS CONE (2025$/KW-MONTH) INSTALLED	$15.840	$11.399	$27.018
GROSS CONE (2025$/KW-MONTH) QUALIFIED	$17.600	$11.874	$28.144
REVENUE OFFSETS (2025$/KW-MONTH)	$4.388	$4.656	$4.502
NET CONE (2025$/KW-MONTH) INSTALLED	$11.452	$6.743	$22.517
NET CONE (2025$/KW-MONTH) QUALIFIED	**$12.724**	**$7.024**	**$23.455**

Based on our analysis, we recommend that the simple cycle frame combustion turbine be used as the reference unit for FCA-16. The simple cycle frame machine is substantially more economic under the parameters of the current study than the combined cycle machine and the aeroderivative machines and is an established technology in New England. This recommendation is consistent with the selection of the simple cycle combustion turbine in the last CONE/Net CONE update performed in 2016.

Section 7:
ORTP Study

A. Introduction

The FCM ensures that sufficient capacity is available to meet ISO-NE's current and expected future resource adequacy needs. Under the FCM design, capacity auctions (i.e., FCAs) are held annually, three years in advance of the Capacity Commitment Period. New and existing resources compete in the FCAs to obtain a CSO in exchange for a market-based capacity payment. Capacity payments support the development of new capacity resources and retain existing resources when and where they are needed.

The FCM design includes a mechanism to protect against the potentially price suppressing effects of new resource offers that are below the competitive level. This buyer-side market power mitigation mechanism requires IMM review of any new capacity resource offer at or below a benchmark known as the ORTP (Offer Review Trigger Price). The ORTP acts as a proxy for the price at which a given resource type would offer into the FCA were it not to receive out-of-market revenues as defined in Market Rule 1. It does so by setting benchmark prices intended to represent the low end of the range of competitive offers in order to prevent new resources from offering at prices significantly below their true net cost of entry. Offers submitted by new resources that are above the ORTP level are presumed to be competitive and not reviewed. ORTPs are calculated for specific resource types every three years and adjusted annually between calculation periods.

B. Approach

The objective of this ORTP study was to develop ORTP values for FCA-16 for the 2025/2026 Capacity Commitment Period. Consistent with guidance from ISO-NE and FERC, the recommended ORTPs presented in this report were set at the low end of the competitive range of expected values to strike a reasonable balance by only subjecting resource offers that appear commercially implausible absent out-of-market revenues to IMM review. In addition, consistent with Tariff requirements, all resources were assumed to have a contract for their output.[68]

The study process consisted of the four basic steps outlined below and further described in the balance of this report:

1. **Resource Screening and Selection**. The first step in the process was to develop screening criteria to select the resource types to calculate ORTP values for. The resource types that pass the screening criteria are subject to a full evaluation of costs and revenues over the facility's expected life.
2. **Calculation of CONE.** The second step was to develop technical specifications, installed capital costs and operating costs over the 20-year amortization period (11 years for

[68] Market Rule 1 Appendix A Section III.A.21.1.2

Energy Efficiency and 20 years for Demand Response) for each resource type selected in step 1 above. The CONE calculations for each ORTP resource type are intended to reflect the low end of the competitive range requirement for the ORTP values. Based on reasonable financial assumptions associated with merchant plant development in New England regarding the cost of debt, return on equity and debt to equity ratio, adjusted for contract-backed revenues, we calculated a first-year revenue requirement that ensured the recovery on and of investment costs.

3. **Calculation of Expected Revenues.** The third step is to estimate the expected revenues for each of the selected resource types, which include energy revenues and ancillary services revenues (net of production costs), REC revenues, and PFP revenues.
4. **Calculation of Net CONE/ORTP.** The final step is to calculate the break-even contribution required from the FCM, based on the calculation of CONE, and expected revenues above, to yield a discounted cash flow with a net present value of zero for each project. The ORTP is set equal to the project's revenue requirement such that the project's net present value from participating in the ISO-NE's wholesale energy and capacity markets is equal to zero.

Each of the steps above involved a detailed bottoms-up analysis that included a review of engineering and construction costs, historical data, forecast of future prices, and professional judgement. The ORTP values were informed through consultation with ISO-NE and stakeholders in eight separate meetings in order to ensure the effectiveness and appropriateness of the methods and data used.

C. Resource Screening Criteria, Process and Selection

We began our ORTP study by establishing the criteria to identify which resource types required ORTP values. The screening criteria used and reviewed with stakeholders are consistent with the criteria accepted by the FERC in previous ORTP studies. These criteria remain appropriate and are as follows:

- Must represent technologies that have been installed in the region and participated in recent FCAs;
- Must have reliable cost information available to calculate an ORTP using a full "bottom-up" analytical approach; and
- Must have a first-year revenue requirement below the FCA starting price.[69]

These criteria were applied consistently to potential resource types identified in consultation ISO-NE and stakeholders. The resources types that were considered in the screening process and the outcome of that process are shown in Table 38 below.

[69] Order Accepting Filing, 161 FERC ¶ 61,035 (October 6, 2017) PP 48.

Table 38: Resource Screening Results

Technology Type	Installed in New England and Participated in Recent FCAs *	Reliable "Bottom Up" Cost Data	Value < FCA Starting Price
Simple Cycle Gas Turbine	Yes	Yes	Yes
Combined Cycle Gas Turbine	Yes	Yes	Yes
Onshore Wind	Yes	Yes	Yes
Offshore Wind	Yes	Yes	No
Solar	Yes	Yes	No
Biomass	Yes	No	No
Battery Storage	Yes	Yes	Yes
Co-Located	Yes	Yes	No
Energy Efficiency	Yes	Yes	Yes
Demand Response	Yes	Yes	Yes

We were asked by the ISO to consider offshore wind for an ORTP value. While the 30MW Block Island Wind facility is the only offshore wind facility in operation in the U.S., offshore wind has seen significant increased attention from renewable developers and state regulators. Connecticut and Massachusetts both have specific offshore wind capacity targets in place at 2,000 MW and 3,200 MW, respectively, and several projects are in early development off the coast of New England. A few of these projects have been awarded contracts, increasing their likelihood of reaching commissioning.

An ORTP for an offshore wind unit ultimately was not recommended, although the industry has seen significant public policy interest in recent years. We consulted with Mott MacDonald to develop capital cost estimates for offshore wind projects based on available information in their proprietary database, as well as publicly available information on offshore wind projects currently in development. The offshore wind capital cost estimate was largely based on benchmarking against large scale projects in the North Sea in which Mott MacDonald has been directly involved. Reasonable adjustments were made to account for US-specific requirements such as permitting, idiosyncratic technical requirements for the onshore portion including cable landing, distance to shore, upland routing, grid connection and labor rates. Offshore wind construction costs were benchmarked against projects where European EPCs were used, as well as publicly available estimates of construction costs. It warrants mention that there is no completed large scale offshore wind project in the US, so the overnight capital cost estimates for this resource type involves more uncertainty than estimates for other resource types which have more publicly available cost and operational data. We reviewed several sources of publicly available information from the New York State Energy Research and Development Authority (NYSERDA), the Environmental Protection Agency (EPA), the Department of Energy (DOE), among others, but found them to not be comparable due to differences in distance from shore, water depth, interconnection requirements, and larger locational differences.

Based on bottoms-up analysis of installed costs, we estimated the cost to construct an offshore wind facility in New England at approximately $5,358/kW (in 2019$). According to the publicly available data published by Energy Information Administration (EIA), a principal agency of the U.S.

Department of Energy, they estimated the overnight capital cost for an offshore wind facility in New England to be approximately $5,446 (2019$ per kW).[70] The $/kW value stated above is within an acceptable range of this value. When also considering operating costs and expected revenues, we determined that costs remain too high to justify an ORTP below the expected auction starting price based on our recommended Net CONE technology and the associated value presented in this report.

The previous ORTP study conducted in the 2016 - 2017 timeframe did not include an ORTP value for solar resources since a high-level analysis indicated that the ORTP would be well above the FCA starting price. However, the installed cost of solar facilities has decreased dramatically since that time, so Concentric revisited the ORTP for a solar resource in this study. Ultimately, the calculated ORTP value for a 20MW fixed-tilt solar array located in Connecticut was above the auction starting price.

The study also involved an analysis of a co-located photovoltaic/battery resource for a potential ORTP value. For reasons similar to the offshore wind facility, co-located resources have become increasingly active in New England, warranting at least a high-level analysis of costs and revenues to determine if an indicative ORTP value would be above the implied auction starting price. Based on our analysis, we determined that an ORTP value for a co-located resource would not be warranted at this time.

It is important to note that FERC has opined on the absence of a resource-specific ORTP value. In its February 2013 Order, the FERC confirmed that the lack of a resource-specific ORTP value does not create undue uncertainty or impose an unduly discriminatory burden on a developer. The FERC went on to state:

> "To the extent that a resource owner, including a consumer-owned utility, believes that its costs are lower than the applicable trigger price, it can seek a lower offer floor by submitting its unit-specific costs to the IMM."[71]

Based on the screening process as described above, individual ORTPs were developed for the following resource types:

- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Onshore Wind
- Battery
- Energy Efficiency
- Demand Resources

70 EIA 2020 AEO, Table 8.2, Cost and Performance Characteristics of New Generation Technologies, Annual Energy Outlook 2020, January 2020. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

71 FERC Order Docket No. ER12-953-001, at 13.

D. Financial Assumptions

Similar to the calculation of CONE, the calculation of ORTP requires a real discount rate to translate uncertain future cash-flows to a levelized revenue requirement. The approach to determining the appropriate discount rate for ORTP values is identical to the approach taken for the calculation of Net CONE, except that the Tariff provisions for calculating ORTPs specifies a contract for non-capacity revenues. As such, the inputs for cost of capital have to be adjusted accordingly to reflect a lower risk than that of the CONE calculation. Ultimately, the ORTP values reflect the "low end of the competitive range," and therefore require lower returns to equity and debt holders.

We determined that 6.4% is an appropriate nominal after-tax weighted average cost of capital at which to evaluate ORTP values. To derive this ATWACC, we adjusted inputs to the cost of capital used in the CONE study above to reflect the low end of the competitive range and to account for the lower risk associated with contract-backed energy revenues.

First, we adjusted the cost of debt to more closely reflect the generic corporate debt of a higher rated company. Instead of a cost of debt of 6.0% assumed for the gas-fired candidate reference units, which assumes a premium on top of recent debt issuances for IPPs, and which assumes a premium on top of B and BB rated corporate bond yields, we assumed a lower cost of debt of 4.5%, which does not assume a premium and is more in line with the average costs of debt for a company with a BB rating and is in line with recent debt issuances for IPP peer companies.

Second, we adjusted the return on equity lower to reflect contracted revenues according to the Power Purchase Agreement (PPA) assumption specific in the Tariff. We estimated ROE using the CAPM, equal to a risk-free rate plus a risk premium given by the expected risk premium of the overall market times the company's "beta." As discussed in Section 5.B, we reviewed estimates from Blue Chip, Value Line, Ibbotson, and Bloomberg for the inputs to the CAPM. We maintained the same approach for the calculation of beta as that of CONE. Instead of basing our ROE on the high end of the competitive range using a forward-looking estimate, we relied on the average results from the historical and forward-looking estimates, with a resulting return on equity of 11.0%.

We adjusted the assumed capital structure to 60/40 (D/E) in favor or more leverage and lower returns to equity. A summary of the financial assumptions on which the ORTP calculations are based is shown in Table 39 below.[72]

[72] Brattle 2014, Concentric 2017.

Table 39: ORTP Financial Assumptions

ROE	11.0%
COD	4.5%
Capital structure:	
Debt weight	60%
Equity weight	40%
WACC	7.1%
Nominal ATWACC	6.4%
Real ATWACC	4.3%

The tax life of each resource is based on IRS guidelines under the Modified Accelerated Cost Recovery System (MACRS) to depreciate the eligible portion of total installed costs over the amortization period.[73] The MACRs allows for recovery of depreciation over 15 years for a new combustion turbine and over 20 years for a new combined cycle turbine, over 5 years for a new wind facility, and over 7 years for a battery facility.

Finally, in addition to the relevant MACRs depreciation schedule, the ORTP calculation assumes an allowance for bonus depreciation. The Tax Cuts and Jobs Act, enacted at the end of 2018, increases first-year bonus depreciation for generating facilities to 100%. After January 1, 2023, first-year bonus depreciation decreases to 40% for property placed in service after December 31, 2024 and before January 1, 2026 and will decrease further thereafter. While an election to take advantage of bonus depreciation may not be feasible for every new entrant, and the expected cash flows do not justify including it in the CONE analysis, we believe it is reasonable to assume that some new entrants could seek to maximize the economic benefit available to them, including those available through tax credits or effective tax shields. Therefore, including bonus depreciation in the ORTP values conservatively represents a low end of the range of possible tax efficient parameters. We note that FERC has previously opined on this issue in its acceptance of PJM's most recent cost of new entry reset. FERC noted:

> "[b]ecause corporate structures and tax planning strategies can vary, we find that PJM reasonably assumes that generation investment is taxed at the full corporate and state tax rate without considering tax planning strategies that companies can use to lower or eliminate their income tax liability. Moreover, we agree that it is reasonable to assume that entities will attempt to minimize their income tax liability through the use of tax benefits, such as increased bonus depreciation. Accordingly, we are not persuaded by LS Power's arguments that PJM has failed to meet its burden that its treatment of bonus depreciation is just and reasonable."[74]

[73] Table B-2, IRS Publication 946. Half-Year Convention.

[74] FERC Order Accepting Tariff Revisions, Docket No. ER19-105, April 15, 2019, at 34.

If bonus depreciation is applied in addition to the ITC, the unit's taxable basis is reduced by one half of the ITC benefit.

E. PTC/ITC for Qualifying Resources

Tax credits currently available to eligible renewable energy resources were considered in the calculation of ORTP values. Assumptions about possible further extensions of these tax credits in the future are considered speculative and were not included in calculations. The Production Tax Credit (PTC) or an Investment Tax Credit (ITC) are currently available for eligible renewable resources. However, the PTC is not available to facilities that begin construction after December 31, 2020. Accordingly, the PTC is not considered in this ORTP analysis. However, the ORTP study did consider the value of the ITC when screening the solar and co-located resources. The ITC is scheduled to step down from 2020 to 2024 and beyond. For eligible facilities that are constructed before 2022 and placed in service beginning in 2024 or constructed in or after 2022 and placed in service after that time, the ITC is stepped down to 10%.[75]

F. Project Life

ORTP resources were assumed to have a project life of 20 years. While it is possible for different resource technologies to have varying project life assumptions, it is important to have consistent financial assumptions across resource types in order to evaluate these ORTP values on a comparable basis. This assumption is consistent with FERC guidance in PJM in the Minimum Offer Price Rule (MOPR) proceeding, where the FERC found that "default MOPR values should maintain the same basic financial assumptions, such as the 20-year asset life, across resource types" in keeping with the Commission's previous determination "that standardized inputs are a simplifying tool appropriate for determining default offer price floors…. "it is reasonable to maintain these basic financial assumptions for default offer price floors in the capacity market to ensure resource offers are evaluated on a comparable basis."[76]

G. ORTP Technical Specifications

For the ORTP calculation, the technical specifications for the gas units are consistent with those assumed in the CONE study. The remaining ORTP resource technical specifications are described below.

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[75] Internal Revenue Service, Notice 2018-59. Available at: **https://www.irs.gov/pub/irs-drop/n-18-59.pdf**.
[76] Order Establishing Just and Reasonable Rate, Docket Nos. EL16-49-000, EL18-178-000, December 19, 2019, pg. 63.

i. Onshore Wind

General assumptions utilized in calculating the ORTP value for an onshore wind unit include location, number and size of turbines, interconnections to the electric distribution systems, and required electric system upgrades. Each assumption is described in further detail below.

Facility size is an important consideration in the calculation of a CONE value for the candidate onshore wind reference unit. These scale economies drive the per-kW installed cost of project down. Mott MacDonald's estimates found that economies of scale yield per-kW installed savings for onshore wind facilities when the number of installed turbines is approximately 15 or higher. Therefore, Mott MacDonald assumed a minimum of 15 turbines for the candidate onshore wind facility. The Vestas V150 5.5 MW machine was selected for this project due to its overall efficiency and economics. A facility with 15 5.5 MW Vestas turbines results in a total facility capacity of 82.5 MW.

In addition to size, location is another important consideration for a new wind facility. Mott MacDonald considered locations in ISO-NE with elevation differential (which typically results in high wind velocities) and reasonable access to the ISO-NE transmission system with minimal need for network upgrades. The location selected for the onshore wind resource is approximately 7 miles east of Berlin, New Hampshire.

Mott MacDonald considered publicly available data sources for wind speed information at the selected location for the wind facility, including the National Renewable Energy Laboratory (NREL) wind speed map and reanalysis data. Based on a review of this windspeed information and climate data from the nearby Mount Washington, the predicted gross yield is 380 GWh with a gross capacity factor of 51.6%. Mott MacDonald estimated a total efficiency factor of 0.834 based on project efficiency estimates including assumed indicative wake efficiency, electrical efficiency, availability, scheduled maintenance, BOP availability, possible curtailment by the ISO (i.e., congestion on the transmission system), power curve performance, suboptimal operation, performance degradation due to icing, blade degradation, and hysteresis. The net yield is estimated to be 317GWh with a net capacity factor of 43.1%.

ii. Battery

The previous ORTP study conducted in 2017 did not include an ORTP value for battery resources. However, these resources are becoming increasingly active in the FCM. Therefore, Concentric calculated an ORTP value for these facilities. The battery storage facility selected for the ORTP analysis is a Lithium Ion storage facility capable of delivering 150 MW, 300 MWh at the point of interconnection. This size is consistent with projects proposed in the ISO-NE queue, as well as data Mott MacDonald collected from New England developers. The two-hour duration is consistent with projects that are focused on E&AS revenues, which is how the unit is modeled to participate, as opposed to arbitrage opportunities. This facility utilizes 73 storage containers that contain 3,200 Lithium Ion racks. Lithium Ion technology was chosen because it is the most common battery type being installed in the United States, and there are multiple operating Lithium Ion batteries operating in the New England region. We assumed that the Lithium Ion battery storage facility provides ancillary services in support of the grid, consistent with the characteristics of the battery resources that have participated in recent FCAs. For this reason, the selected site is near a critical node where renewable energy is expected to be injected in the near future; adjacent to the Kent County Substation in Rhode Island, which has readily 345 kV transmission on site.

H. Capital/Operating Costs

The table below summarizes operating costs for the ORTP units, described in further detail in the following sections. The capital cost estimates for each ORTP resource are also described in detail below.

Table 40 : Summary of ORTP Operating Costs (2025$ Levelized)

	CC	SC	ONSHORE WIND	BATTERY
$/kW-year				
Property Taxes	4.65	2.72	1.97	1.27
Site Leasing	0.67	0.53	9.97	1.67
Insurance	3.10	2.45	6.63	2.93
Fixed O&M (LTSA plus ongoing O&M)	59.66	38.21	32.91	24.41
Total Fixed Expenses	**66.08**	**43.92**	**51.48**	**30.28**
$/kW-month				
Property Taxes	0.39	0.23	0.16	0.11
Site Leasing	0.06	0.04	0.83	0.14
Insurance	0.26	0.20	0.55	0.24
Fixed O&M (LTSA plus ongoing O&M)	4.97	3.18	2.74	2.03
Total Fixed Expenses	**5.67**	**3.66**	**4.29**	**2.52**

i. Gas-Fired Resources

The overnight capital costs for both simple cycle and combined cycle combustion turbines were based on the capital costs calculated as part of the CONE/Net CONE analysis. Costs for insurance, electrical interconnection, property taxes, and contingency were reduced consistent with calculating a "low-end of the competitive range" value. Specifically, insurance was adjusted from 0.6% of overnight costs used in the CONE study to 0.3% for the ORTP study; property taxes were reduced from 2.89% to 1% to represent the negotiation of a Payment In-Lieu-of Taxes (PILOT) agreement, and capital costs were reduced by 1% from the CONE values. The resulting overnight costs and fixed O&M costs are shown below.

Table 41: Summary of Overnight Capital Costs (2025$)

COST COMPONENT	7HA.02 COMBINED CYCLE	7HA.02 SIMPLE CYCLE	ONSHORE WIND	BATTERY
Total Overnight Capital Costs (2019$M)	532.3	285.0	173.0	140.7
Total Overnight Capital Costs $/KW	956	758	2,097	938

ii. Onshore Wind

The site for onshore wind was selected based on the Mott MacDonald "X marks the spot" methodology where a quality wind resource location crosses installed transmission and is able to sell the power into a competitive renewable energy market. Locations evaluated led Mott MacDonald to focus on northern New England where multiple good wind resources are located. Historically, onshore wind projects have had difficulty finding existing transmission capable of wheeling power to market without extremely high system upgrade or system construction requirements. This project is in an area where some upgrade costs are required to enable wheeling, but they are not significant enough to overwhelm the project. Upgrades are assumed to include new wires and towers and some upgrades to substations as well as the installation of fiber optic controls to bring the system up to current design standards.

Capital costs for onshore wind facilities vary significantly from project to project due to site specific conditions and development and installation costs. In calculating an appropriate capital cost for the reference wind facility, Concentric consulted Mott MacDonald and reviewed publicly available data about the wind facility capital costs. The assumed overnight costs for the reference onshore wind facility are shown in Table 42. The overnight costs represent a 45% decrease in the assumed cost for the reference onshore wind farm from the previous ORTP study of approximately $2,500/kW, reflecting the declining cost trajectory for wind farm installations.

Table 42: Onshore Wind Facility Overnight Costs (2019$, in millions)

COST COMPONENT	ONSHORE WIND (ORTP)
EPC Costs	
Civil/Structural/Architectural	84.1
Mechanical Costs	4.3
Electrical/Instrumentation Costs	11.3
Construction Management	2.4
Medium Voltage Collection System	5.7
Project Substation and O&M Building	5.4
Meteorological Towers	0.4

COST COMPONENT	ONSHORE WIND (ORTP)
Project Contingency	8.0
Owners Development Costs	0.3
Total EPC	**121.9**
Non-EPC Costs	
Owner's Contingency	0.0
Electrical Interconnection	7.0
Electrical System Upgrade Costs/Substation Upgrades	38.0
Financing Fees (4% of costs financed through debt)	4.9
Working Capital (1% of EPC costs)	1.2
Total Non-EPC	**51.1**
Total Overnight Capital Costs	**173.0**
$/KW	**2,097**

Concentric estimated Fixed O&M costs for the onshore wind unit based on an LTSA estimate provided by Mott MacDonald. The LTSA includes labor, materials, contract services, and associated costs with an estimated cost of $2.50/kW-month (2019$). To confirm the reasonableness of this assumption, Concentric also reviewed several publicly available studies which include estimates of onshore wind fixed O&M costs. Ongoing maintenance costs were assumed to be approximately $1,000/MW-year, reflecting a low end of the range.

We assumed that 4,700 acres of land would be leased at an annual cost of approximately $822,500 or $175/acre based a review of publicly available site leasing agreements, described below in section iii.

We determined that a property tax rate of 1% was representative of projects that have entered into PILOT agreements with local cities and towns. This rate was applied to an average of net plant values on an annual basis. Concentric also reviewed property taxes for Coos County, New Hampshire to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Coos County from 2017-2019 range from 1.2% to 4.0%, with an average of 2.26%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range and therefore conservative. Based on this assumed rate, the property taxes for the onshore wind farm were estimated at approximately $73,000 per year, or $0.88/kW-year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with the assumption contained in the 2017 ORTP study, which continues to be reasonable. Annual insurance costs were estimated to be approximately $409,000 in 2025 dollars.

Based on these assumptions, the levelized fixed O&M cost of the wind facility over its 20-year life is $51.48/kW-year. This all-in fixed O&M cost is less than the $63.60/kW-year assumed in the 2017 ORTP study.

iii. Battery

Through consultation with Mott MacDonald, we estimated capital costs for lithium-ion battery energy storage system projects based on available information in their database as well as any publicly available information on recently developed projects. Mott MacDonald's proprietary database of project costs was utilized to develop this estimate. This database is continuously developed using active Mott MacDonald Battery projects. The assumed battery unit's EPC costs fall into the following major categories: major equipment, foundations, plant electrical, site work, substation and tie line, general conditions, testing and energization, and indirect costs. Table 43 below contains our assumed overnight capital cost for the reference battery storage project.

Mott MacDonald assumed an electrical interconnection at the nearby Kent County 345 kV substation, as previously stated. Mott MacDonald analyzed the estimated costs associated with the necessary electrical infrastructure to complete this interconnect and reviewed a reference feasibility study within the interconnection queue. The estimated electrical interconnection cost is included below.

Table 43: Reference Battery Storage Overnight Costs (2019$, in millions)

COST COMPONENT	BATTERY
EPC Costs	
Civil/Structural/Architectural	0.4
Mechanical Costs	0.0
Electrical/Instrumentation Costs	1.3
Construction Management	1.5
Project Substation and O&M Building	6.8
Major Equipment - Wind Turbines, PV Modules, PV Inverters, PV Racks, Batteries	101.6
Testing & Energization	0.3
Other Indirect Costs	10.2
Project Contingency	5.8
Owners Development Costs	1.0
Total EPC	**128.8**
Non-EPC Costs	
Electrical Interconnection	5.4
Financing Fees (4% of costs financed through debt)	5.2
Working Capital (1% of EPC costs)	1.3
Total Non-EPC	**11.9**
Total Overnight Capital Costs	**140.7**
$/KW	**938**

Concentric estimated fixed O&M costs for the battery through consultation with Mott MacDonald and the use of assumptions consistent with the other ORTP units. Land lease costs are typically negotiated and are therefore difficult to calculate. Public documentation and data on leasing costs for battery systems are very limited, and although we considered using the same $10,000/MW leasing estimate from the solar ORTP calculation, through consultation with stakeholders it was determined that battery sites are more likely to resemble that of the gas units than the solar unit. Therefore, we assumed that 10 acres of land would be leased at a cost of $25,000/acre, consistent with the per-acre cost used for the gas units.

Similar to the ORTP assumptions for the other studies, the study assumes a property tax rate of 1% for the battery, which was applied to an average of net plant values on an annual basis and reflects actual PILOT agreement structures. Concentric also reviewed property taxes for Kent County, Rhode Island to ensure the reasonableness of the ORTP property tax assumption. Property taxes for Kent County from 2017-2019 range from 2.3% to 3.3%, with an average of 2.70%. A 1% tax rate based on a PILOT agreement is sufficiently lower than this range. Based on this assumed rate, the property taxes for the battery storage system were estimated at approximately $110,000 per year.

Insurance costs were assumed to be 0.3% of installed costs, consistent with other technologies evaluated in this study. Annual insurance costs were estimated to be approximately $422,000 in 2025 dollars, or $2.93/kW-year.

LTSA and ongoing maintenance costs, which do not include augmentation costs, were assumed to be approximately $25/kW-year in 2025$ based on consultation with Mott MacDonald. To assess the reasonableness of this assumption, Concentric also reviewed publicly available EIA data which include estimates of battery fixed O&M costs. The EIA data showed an expense of approximately $36/kW-year, which is in line with the all-in fixed O&M assumption made here. Based on these assumptions, we calculated a levelized fixed O&M cost for the reference battery storage system of $2.52/kw-month or approximately $30/kW-year.

I. Revenue Offsets for ORTP Generating Resources

This section summarizes the estimated revenue offsets used for each ORTP resource. ORTP revenue offsets come from one or more of the following potential revenue streams: E&AS revenues, FRM revenues, PFP revenues, and REC revenues. All of the E&AS estimates for the ORTP resources, excluding regulation revenue for the battery technology, were developed with simplified dispatch models that used historical energy prices during the 2017-2019 period that were adjusted with Energy/Reserve Scarcity adjustment noted above. The prices used in the ORTP dispatch models do not include an LOE adjustment since the ISO-NE Tariff does not require that ORTP units be modeled at criterion.

i. Scarcity

Similar to the CONE units, estimated revenues from energy and reserve shortages were added back as a separate line item outside of the ORTP dispatch models. However, the Energy/Reserves Scarcity adder for the ORTP units assumed 7.4 scarcity hours, which is based on current excess supply conditions in New England. This scarcity hours estimate is lower than the 11.3 scarcity hours assumed in the CONE unit Energy/Reserve Scarcity adder, which assumed installed capacity equal to the system's installed capacity requirement. The Energy/Reserve Scarcity unit adders are shown in Table 44.

Table 44 : ORTP Energy/Reserve Scarcity Adjustment

UNIT	AVAILABILITY FACTOR	ADJUSTMENT $/KW-MO
Combined Cycle	92.77%	0.57
Simple Cycle	98.00%	0.60
Onshore Wind	26.46%	0.16
Battery	98.00%	0.60

ii. Pay for Performance

Pay for performance for ORTP resources was calculated in same way as the CONE units, with updated parameters for "H", "A", and "Br". As noted above, scarcity hours were reduced from 11.3 to 7.4. Balancing ratios were also adjusted downward.

Estimating the expected performance during scarcity hours for the onshore wind technology requires a different set of assumptions than using a forced-outage rate. To estimate the average performance during scarcity hours, or "A", we assumed that the unit's average performance during scarcity hours would, on average, be equal to the forecasted generation during Summer Intermittent Reliability Hours and Winter Intermittent Reliability Hours. These summer/winter performance values are then weighted by the expected amount of seasonal scarcity hours. Peak load scarcity hours are assumed to occur in the summer, transient scarcity hours are assumed to occur randomly through the year, and winter scarcity hours are assumed to occur in the winter. These values are shown in the table below.

Table 45 : Renewable Resource 'A' Values

TECHNOLOGY	NAMEPLATE (MW)	SUMMER PERFORMANCE MW	WINTER PERFORMANCE MW	SCARCITY TYPE WEIGHTED PERFORMANCE	SCARCITY WEIGHTED [A]
Onshore Wind	82.5	19.4	39.0	21.8	26.46%

In addition to calculating the expected performance value, the expected incremental PFP revenues earned by the intermittent units needs to account for the seasonal variation in the CSO MW that these units receive. Assuming that the unit receives a seasonal CSO MW equal to its QC MW, the percent of nameplate having CSO MW is applied on the same scarcity-hour specific dimension.

iii. E&AS: Gas-Fired Generating Resource

The dispatch models used to estimate the E&AS revenue offsets for the candidate two gas units ORTP (combined cycle and simple cycle) employed the same dispatch logic as the dispatch models used to estimate E&AS offset for the CONE/Net CONE value of each unit. However, as noted above, the historical prices used in the dispatch models to estimate E&AS offsets for the ORTP units include an Energy/Reserve Scarcity adjustment but do not include an LOE Adjustment. Accordingly, the estimated E&AS offsets for the gas units in the ORTP study are lower than the estimated E&AS offsets for the same units in the CONE study because the dispatch models use lower market clearing prices.

As noted above, the Energy/Reserve Scarcity adjustment was added back outside of the ORTP dispatch model assuming scarcity hours of 7.4. Similarly, expected PFP revenues for the natural gas resources are equal to those used in the CONE/Net CONE analysis, but are based on 7.4 scarcity hours. The ORTP estimates for the gas-fired units did not include an adjustment for lifecycle degradation given the nature of the ORTP estimates, which are designed to be at the lower end of the range.

iv. E&AS: Onshore Wind Resource

As noted above, this study assumes the onshore wind unit will be located in New Hampshire and have an annual capacity factor of 43.1%. The onshore wind unit's generation is based on hourly DNV-GL data modeled from onshore wind data for the 2017-2019 period.[77] The hourly offshore DNV-GL data, which had an average capacity factor of 32.2%, were adjusted upward to achieve the assumed onshore wind unit's annual capacity factor of 43.1%. The dispatch model to estimate E&AS revenues for the onshore wind unit assumed the wind unit offered 53% of its assumed generation into the day-ahead energy market at a price equal to negative one times its average annual average REC price (i.e., the unit's opportunity cost). This percentage is based on the average proportion of real-time generation that wind facilities in ISO-NE offered into the day-ahead market during the June 2019-July 2020 period.[78] The dispatch model also assumes the onshore wind facility offers all of its generation into the real-time market at the negative average annual REC price. The onshore wind facility's offer clears the day-ahead and real-time markets in hours when the applicable LMP exceeds the unit's energy offer. The wind facility does not provide ancillary services. The wind facility's VOM costs were assumed to be zero and dispatch model used historical energy prices in the New Hampshire zone adjusted with the Energy/Reserve Scarcity adjustment.

v. E&AS: Battery Resource

The battery resource has a maximum injection capacity of 150 MW, a 300 MWh of storage capability, and is located in Rhode Island. The battery's storage capability is rated at 300 MWh (i.e., the battery is capable of injecting 300 MWh into the grid from a full state of charge), however given the battery's 86% roundtrip efficiency, the battery's nominal storage capability is 349 MWh (300/0.86 = 348.8 MWh). The battery is assumed to follow a strategy to maximize its expected revenues and minimize cycling due to battery wear and tear and warranty concerns. Concentric considered two modes of operation for the battery: a "reserve mode" where the battery primarily provides reserves; and an "arbitrage mode" where the battery arbitrages intra-day price differences. In both cases, Rhode Island LMPs adjusted for energy and reserve shortages were used.

In the reserve mode of operation, the battery participates in the FRM (for the case where this market continues) and is designated to provide TMNSR. The battery also offers into both the day-ahead and real-time markets at the higher of the daily threshold price and the 95th percentile of the day-ahead and real-time markets, respectively. This offer behavior satisfies the battery's FRM offer obligations

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77 See e.g., https://www.iso-ne.com/static-assets/documents/2020/02/a7b_wind_power_time_series_dnvgl.pdf.

78 ISO-NE market rules changed rules related to supply offers for wind units in June 2019 after the Do Not Exceed reforms were implemented. Accordingly, day-ahead market offer behavior prior to June 2019 were not considered.

and only clears the day-ahead energy market 5 percent of the time given in order to be reserve capable.[79] Given its technical capability to deploy reserves almost instantaneously, the battery is eligible to provide 150 MW of TMNSR in the FRM. In real-time, the battery is designated to provide TMSR based on its available state of charge in each hour.

In the arbitrage mode, the battery cycles once per day, charging during the lowest priced hours of the day on average (hours ending 3-5) and discharging during the highest priced hours on average (hours ending 18-20). Concentric determined that the reserve mode of operation was more profitable for the battery.[80] This finding is consistent with research in the California ISO, which found that batteries in that market generally preferred to provide ancillary services (regulation and reserves) as opposed to engaging in energy arbitrage. The California ISO surmised that batteries generally preferred to provide ancillary services given concerns regarding wear and tear and the impact that excessive cycling would have on the battery's warranty.[81]

Accordingly, the battery's E&AS revenue estimate is based on the battery operating in the "reserve mode" based on the dispatch logic described above. Given the battery operates in a reserve mode, it is capable of providing both reserves and regulation at the same time in the hours it is neither charging nor discharging. Studies performed by ISO-NE indicates that storage resources that provide regulation make 11% of their capacity available, on average, to provide regulation. Therefore, with the exception of TMSR, the battery dispatch model uses 89% of the battery's storage and injection capability. The battery dispatch model assumes the battery can be designated 150 MW of TMSR because the battery can be designated to provide TMSR and regulation at the same time.

Regulation revenues for the battery were calculated outside of the dispatch model and included as a standalone adder. The battery's estimated annual regulation revenues are $3,041,936 per year in 2019 dollars.[82] ISO-NE prepared this estimate based on the assumption that the battery would provide 11% of its 150 MW capacity for regulation in the hours it is neither charging nor discharging energy. Based on a review of regulation payments, ISO-NE calculated an average regulation payment rate of $24.72/MWh, which includes payments for both regulation capacity and regulation movement.[83] Based on the battery's 86% roundtrip efficiency and assuming the incremental cost of charging is equal to price of providing regulation amounts to a net average payment rate of $21.26/MWh.

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79 The 95% percentile price was determined for each calendar year in the 2017-2019 period based on the adjusted LMPs used in the ORTP models. If the battery is dispatched for energy because it clears the real-time energy market, it charges during the lowest price hours of the day, on average, which are hours ending 3-5. The battery also recharges 5% of its energy during these hours on the first Sunday of every month to account for losses.

80 This was true even when assuming a zero VOM cost for the battery, which is conservative given the impact cycling has on battery warranties and wear and tear.

81 California ISO, Energy Storage and Distributed Energy Resources Phase 4, Final Proposal, , August 21, 2020, at 19. http://www.caiso.com/InitiativeDocuments/FinalProposal-EnergyStorage-DistributedEnergyResourcesPhase4.pdf.

82 The battery's estimated regulation revenues in 2025 dollars is $3,425,714.

83 This average regulation payment was calculated over the January 1, 2018-December 31, 2019 period. Regulation payments in 2017 were not used because ISO-NE market did not have 5-minute settlement in the real time market in 2017.

vi. Renewable Energy Credits

Revenue offsets for the onshore wind resource includes RECs. The REC revenue for this resource is the product of an estimated REC price and the unit's size and annual capacity factor. To estimate the REC price, Concentric relied on historical price data for MA Class I REC indices for the 2016 - 2020 vintages.[84] Concentric calculated the average price for each REC vintage based on all trades available at the time of the analysis. Concentric then averaged those five estimates (normalized to 2019$) to produce a single REC price and then escalated that average to 2025 dollars.[85] The resulting average REC price is $29.32/MWh. The annual REC prices were also used in the onshore wind dispatch model to establish the hourly offer prices of that unit.

J. Demand Resources

ISO-NE defines demand resources (DR) as installed measures (products, equipment, systems, services, practices, and strategies) that result in verifiable reductions in end-use consumption of electricity in the New England power system. ISO-NE separates DR into two categories – "passive" and "active". Passive DR are energy efficiency measures and non-dispatchable distributed generation). Energy efficiency can include any combination of products, equipment, systems, services, practices, and strategies an end-use customer can use to reduce the total amount of electrical energy needed at their facilities while delivering a comparable or improved level of end-use service. These measures can include the installation of more energy-efficient lighting; motors; refrigeration; heating, ventilation, and air conditioning (HVAC) equipment and control systems; envelope measures; operations and maintenance procedures; and industrial process equipment. Active DR are typically behind-the-meter generation resources and distributed generation that are activated when dispatched by the ISO. An example of what a customer might do to comply with a dispatch instruction would be the practice of powering down machines or using electricity from an on-site generator or a storage device rather than from the grid.

Various types of DR can participate in the capacity markets. Active Demand Capacity Resources (ADCR) can be made up of one or more Demand Response Resources and bid their demand reduction capability into the FCM. Demand Response Resources are dispatched economically in the energy market and may be eligible to provide ancillary services. In addition, non-dispatchable passive demand resources—the on-peak and seasonal peak resources - may only participate in the capacity market, as described below:

- On-peak resources offer on their reduced electricity consumption during summer peak hours (nonholiday weekdays, 1:00 p.m. to 5:00 p.m., during June, July, and August) and winter peak hours (nonholiday weekdays, 5:00 p.m. to 7:00 p.m., during December and January).

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84 REC price data sourced from SNL Financial.

85 Though RECs are traded beyond their vintage year, our average does not include those prices as they would have skewed the estimate downward.

- Seasonal-peak resources offer on their reduced electricity consumption during the summer months of June, July, and August, and during the winter months of December and January, in hours on nonholiday weekdays when the real-time system hourly load is equal to or greater than 90% of the most recent "50/50" system peak-load forecast for the applicable summer or winter season

A discussion of the types of DR reviewed follows, with Energy Efficiency measures discussed in the following section.

i. Technical Specifications

Demand resources take many forms and vary in size and type. A review of past submittals into the FCA shows that many of the submittal fall into the following categories:

- On-Peak Solar Generation – collection of distributed generation facilities with a 1 MW active load reduction capability.
- Combined Photovoltaic Solar and Energy Storage - collection of distributed generation facilities with a 2 MW active load reduction capability.
- Load Management - a measure by a small commercial customer or entity that is representative of small commercial customers that control specific end-use processes and can provide 0.5 MW of demand reduction.

Increasingly, aggregators are facilitating demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other.

ii. Capital and Operating Costs

To determine the appropriate level of capital costs for the types of DR resources identified above, Concentric reviewed data and analysis from new supply offers in the last five FCAs to determine an appropriate level of capital costs that is reflective of the resources that have been participating in the FCM. It is clear based on the data reviewed that determining a representative capital cost for each of the measures is challenging due to the variation in technology types and the variation in the data available.

Based on the information reviewed, we determined an average installation cost for each of the measures identified on a cost per KW as shown below. Similarly, the average operating costs represent an average of the operating costs submitted by participants for the DR measures reviewed.

Table 46: DR Capital Costs

COST COMPONENTS	COST (2025$/KW-MO)
On-Peak Solar	
Capital Costs+ Operating Costs	$20.07
Combined PV Solar and Energy Storage	
Capital Costs+ Operating Costs	$22.11
Load Management	
Capital Costs+ Operating Costs	$15.41

iii. Financial Assumptions

In terms of financial assumptions, the submitted information was similarly diverse in terms of debt to equity ratio and cost of equity. Based on the universe of data reviewed, we have assumed a 4.3% real ATWACC, a 20-year project life and a revenue stream consistent with the forecast of energy prices and REC prices used for the analysis of generating resources.

iv. DR ORTP Calculations

Based on the cost and revenue estimates detailed above as well as the financial assumptions, we recommend the ORTP values as shown in Table 47.

Table 47: DR ORTP Calculation

ASSUMPTIONS / VALUE			
	On-Peak Solar	***Combined PV Solar and Energy Storage***	**Load Management**
Demand Reduction	1 MW	2 MW	500kW
Contract Life (years)	20	20	20
Real ATWACC (%)	4.3%	4.3%	4.3%
Levelized Capital Cost (2025$/kW-mo)	$20.07	$22.11	$15.41
Revenue Offsets(2025$/kW-mo)	$14.65	$14.73	$14.65
ORTP Value ($/kW-mo)	$5.425	$7.376	$0.761

In addition to the categories above, distributed generation may participate as Demand Response. For new distributed generation, the ORTP is based upon the generation technology type. For existing distributed generation, the ORTP for Load Management is applied.

K. Energy Efficiency

Many of the existing EE programs in New England are established through state-sponsored mandates and implemented by each state's investor-owned utilities. These EE programs generally cover the residential, commercial, and industrial sectors. EE programs include a range of measures and incentives, such as rebates for purchasing new efficient equipment, process improvements, energy management systems, and energy audits. Some states also have established aggressive long-term energy-efficiency goals tied to reductions in greenhouse gas emissions and global-warming solutions. In New England, lighting and mixed-lighting measures constitute most of the savings in energy use and peak demand, and the commercial and industrial sectors provide a majority of the overall savings.

The savings in energy use resulting from EE programs result in demand reductions that can be bid into the FCM. The ISO-NE Tariff permits an energy efficiency resource program administrator to aggregate the reduction in capacity needs in New England resulting from energy efficiency and bid that capacity reduction into each FCA. As a result, providers of energy efficiency resources that are successful bidders into a FCA are compensated for the reduction in regional capacity needs that they provide in the same manner as generators are compensated for providing capacity. Like generating resources, EE resources must meet market rules for eligibility and availability. To be eligible for the auction, EE resources must demonstrate in advance their ability to perform during those hours.

i. Technical Specifications

In calculating an appropriate ORTP for EE programs, we reviewed all investor-owned utility energy efficiency programs in New England. There are currently forty-one EE programs, excluding programs targeted towards low-income customers. Low-income programs were excluded from the analysis since they are not subject to the same cost-effectiveness screening practices as standard EE programs. Cost effectiveness screening is employed to ensure that the use of ratepayer funds results in sufficient benefits. States have recognized various benefits provided by low-income EE programs that are not included in benefit/cost ratios, such as a reduction in hardship customers and a reduction in uncollectible bills. Without these benefits, many of the low-income EE programs are not cost-effective. Therefore, including these programs in the ORTP calculation, which represents the low-end estimate of the first-year revenues needed by the resource to be economically viable, is not recommended. Table 48 shows the EE programs that have been included in our ORTP calculations.

Table 48: Energy Efficiency Programs Included in ORTP Analysis[86]

CONNECTICUT	MASSACHUSETTS	MAINE	NEW HAMPSHIRE	RHODE ISLAND	VERMONT
Residential Retail Products	Residential Whole House	Commercial and Industrial Prescriptive Program - Electric	Home Performance w/ Energy Star	Residential New Construction	Business New Construction
Residential New Construction	Residential Products	Commercial and Industrial Custom Program - Electric	Energy Star Homes	Energy Star HVAC	Business Existing Facilities
Home Energy Solutions	C&I New Construction	Small Business Initiative	Energy Star Products	EnergyWise	Residential New Construction
HES - HVAC, Water Heaters	C&I Retrofit	Consumer Products Program	Home Energy Reports Energy Savings	EnergyWise Multifamily	Efficient Products
Residential Behavior		Home Energy Savings Program	Large Business Energy Solutions	Energy Star Lighting	Existing Homes
Energy Conscious Blueprint			Small Business Energy Solutions	Residential Consumer Products	
Energy Opportunities			Municipal EE Program	Home Energy Reports	
Business and Energy Sustainability			Energy Rewards RFP	Large Commercial New Construction	
Small Business Energy Program				Large Commercial Retrofit	
				Small Business Direct Install	

There are three tests that are most commonly used in determining the cost-effectiveness of EE programs – the Program Administrator Cost (PAC) test, the Total Resource Cost (TRC) test and the Societal Cost test. The PAC test includes all of the costs and benefits associated with the utility system. It includes all the costs incurred by the utility to implement efficiency programs, and all the benefits associated with avoided generation, transmission, and distribution costs. The TRC test includes all the costs and benefits to the program administrator and the program participants. It includes all of the costs and benefits of the PAC test, but also includes participant costs and participant benefits. The Societal Cost test includes all impacts to all members of society. It includes all the costs and benefits of the TRC test, but also includes societal impacts. These impacts typically fall within the following

86 Connecticut: Eversource Energy, et al., 2018.
Massachusetts: National Grid, et al., 2018.
Maine: Efficiency Maine, 2018.
New Hampshire: Granite State Electric Company, et al., 2017.
Rhode Island: Narragansett Electric Company, 2018.
Vermont: Efficiency Vermont, 2019.

categories: environmental impacts; reduced health care costs; economic development impacts; reduced tax burdens; and national security impacts.

Each test is designed to present the costs and benefits from different perspectives. While all of these different perspectives may be considered relevant and important, and warrant consideration, states typically use one of these tests as the primary test to determine whether to invest ratepayer funds in energy efficiency programs. Because most states screen for cost-effectiveness using the TRC as the primary test, it is recommended that the ORTP calculation be based on the TRC test.

To calculate the costs and benefits of EE programs based on the TRC approach, we reviewed the investor-owned utility filings to gather information on forecasted program costs and savings. These costs and benefits associated with EE programs under the TRC test generally include the following:

- **Costs:**
  - **Program Administrator costs –** the cost for the IOU to administer the EE program
  - **Program financial incentive** – incentive amounts paid to customers or other equipment purchasers
  - **Participant contribution** – costs recognized by the customer and any involved third parties to install the EE measure
- **Benefits:**
  - **Avoided energy costs** – the value of the energy avoided by EE measure. This includes environmental costs that require expenditures to reduce emissions to comply with carbon dioxide emissions regulations (RGGI) and state clean energy standards. This includes a risk premium attributable to the reduced risk for retail electricity suppliers in the costs of acquiring energy capacity and ancillary services to meet
  - **Avoided renewable energy credit** - Energy efficiency programs reduce the cost of compliance with RPS requirements by reducing total LSE load. Reduction in load due to energy efficiency or other demand-side resources will therefore reduce the RPS obligations of LSEs and the associated compliance costs recovered from consumers. This estimate of avoided costs includes the expected impact of avoiding each class of RPS or renewable energy standards within each of the six New England states.[87]
  - **Avoided environmental costs**[88] – the includes the cost of sulphur dioxide allowances for compliance with the Cross -State Air Pollution Rule (CASPR)
  - **Avoided transmission and distribution costs –** the value that load reductions contribute to deferring or avoiding the addition of load-related transmission and distribution facilities, due to reduced load growth and reduced loading of existing equipment.
  - **Value of reliability** - One important issue in determining the value of energy efficiency-induced reliability is whether any reliability improvements can be quantified in dollar values. The value of lost load (VoLL) describes the cost to consumers of being unable to take power from the system. VoLL is not a single value,

[87] The avoided cost is a function of REC price and load obligation percentage (i.e., the RPS target percentage).
[88] Nitrogen oxide prices were assumed to be zero since the New England states are exempt from the CSAPR rule.

since the cost of an outage varies with such factors as the type of customer and the length of the outage.

- **Energy demand reduction induced price effect (DRIPE)** - Demand Reduction Induced Price Effect (DRIPE) refers to the reduction in prices in the wholesale markets for capacity and energy—relative to the prices forecast in the Reference case—resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

A review of these filings showed a potential annualized savings of 2,633,192 MWh and approximately 383 MW of savings at the customer meter over an estimated measure life of approximately 10 years consistent with the average of existing programs. In order to present the information contained in the filings on a consistent basis, we adjusted the program size to 1 MW of capacity by the ratio of the annual energy savings to the peak load reduction. Based on this calculation, we assumed that a 1 MW EE measure would be expected to provide 6,361 MWh of annual energy savings.

ii. Capital/Operating Costs

We calculated the total operating costs of the EE programs using data from the investor-owned utility annual EE program annual reports.[89] The total costs of the programs are shown below in Table 49.

Table 49: Energy Efficiency Programs Costs

		2025 Operating Costs (2025 $)	2025 Operating Costs (2025 $/kW)
Peak Load Reduction			
At Meter	MW	383	383
At Generator Bus Bar		414	414
Total Operating Costs			
Labor & Services	$	236,815,607	572
Materials & Supplies	$	65,115	0
Incentives	$	680,956,427	1,645
Marketing, A&G, Other	$	72,604,407	175
Customer Costs	$	535,066,665	1,293
M&V	$	17,916,602	43
Total Utility Costs	$	1,543,424,822	3,729

89 Please note: some reports are provided as fiscal years and therefore time periods likely vary.

iii. Revenue Offsets

The calculation of revenue offsets for the energy efficiency resource includes these components: energy, reliability, RECs, and DRIPE. Concentric based these categories off of a review of Synapse's 2018 Avoided Energy Supply Costs study. Energy and REC values are consistent with those used throughout the study.

The calculation of benefits includes both the value of the energy saved, as well as environmental and reliability benefits. For the energy-related savings, we used an average historical locational marginal price for all hours for 2017-2019 as well as recently published avoided cost components specific to New England.[90]

Table 50: Energy Efficiency Programs Benefits

2018$		
Energy	($/kW-mo)	$22.42
Reliability	($/kW-mo)	$0.29
RECs	($/kW-mo)	$15.66
DRIPE	($/kW-mo)	$1.26
Levelized Avoided Cost of Energy ($2018/kW-mo)	($/kW-mo)	$39.63
Levelized Avoided Cost of Energy ($2025/kW-mo)	($/kW-mo)	$45.52

iv. EE ORTP Calculations

Based on the estimated program savings and costs as shown above, the Net CONE calculation is ($8.57)/kW-month. Therefore, we recommend an ORTP value for EE programs of $0.00/kW-month.

Table 51: Energy Efficiency Programs ORTP Calculation

Levelized Capital Costs ($2025)	($/kW-mo)	$36.95
Levelized Avoided Costs of Energy ($2025)	($/kW-mo)	$45.52
ORTP	**$/kW-mo**	**$ --**

90 Avoided Energy Supply Components in New England 2018 Report, Synapse Energy Economics, Inc. October 24, 2018

L. ORTP Summary

The CONE/Net CONE is calculated as the revenue required for entry, or CONE, less the expected revenue offsets. A summary of the CONE/Net CONE values for the evaluated technologies are shown in Table 52 below.

Table 52: Summary of ORTP Values

Reference Technology	Nominal Installed Capacity (MW)	Qualified Capacity (MW)	Installed Cost 2019$/kW	Real ATWACC	Gross CONE (2025$/kW-mo)	Revenue Offsets (2025$/kW-mo)	Net CONE (2025$/kW-mo Installed)	Net CONE (2025$/kW-mo Qualified)	ORTP (2025$/kW-mo)
Combined Cycle	557	501	956	4.3%	12.72	3.88	8.84	9.82	9.819
Combustion Turbine	376	361	758	4.3%	9.18	4.02	5.15	5.37	5.366
Onshore Wind	82.5	32.4	2,097	4.3%	18.64	23.27	-4.63	-11.78	0.000
Battery	150	129	938	4.3%	8.92	6.00	2.92	2.92	2.923
Energy Efficiency				4.3%	36.95	45.52	-8.57	-8.57	0.000
DR - On-Peak Solar		1		4.3%	20.07	14.65	5.43	5.43	5.425
Load Mgmt C&I		2		4.3%	15.41	14.65	0.76	0.76	0.761
DR - Combined PV/Storage		0.5		4.3%	22.11	14.73	7.38	7.38	7.376

Section 8: CONE and ORTP Annual Update Process

For years in which no full recalculation is performed pursuant to Market Rule 1, Section III.13.2.4, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2 (e) of Market Rule 1.

In past interim year updates, ISO-NE has followed a prescribed process for updating various components of each ORTP technology's gross CONE value, as well as certain components of its revenue offset. Ultimately, Concentric recommends a simplified annual update process whereby relevant values are updated to reflect high level changes in expectations of inflation and the profitability of merchant generators entering the market.

Four components of each resource's calculation (i.e., the Net CONE reference resource, and each resource with an ORTP value below the auction starting price) should be updated during years where a full recalculation does not take place. Technology types for whom an ORTP is not calculated in this current recalculation will remain at the auction starting price for all interim year auctions. The four components to be updated are as follows:

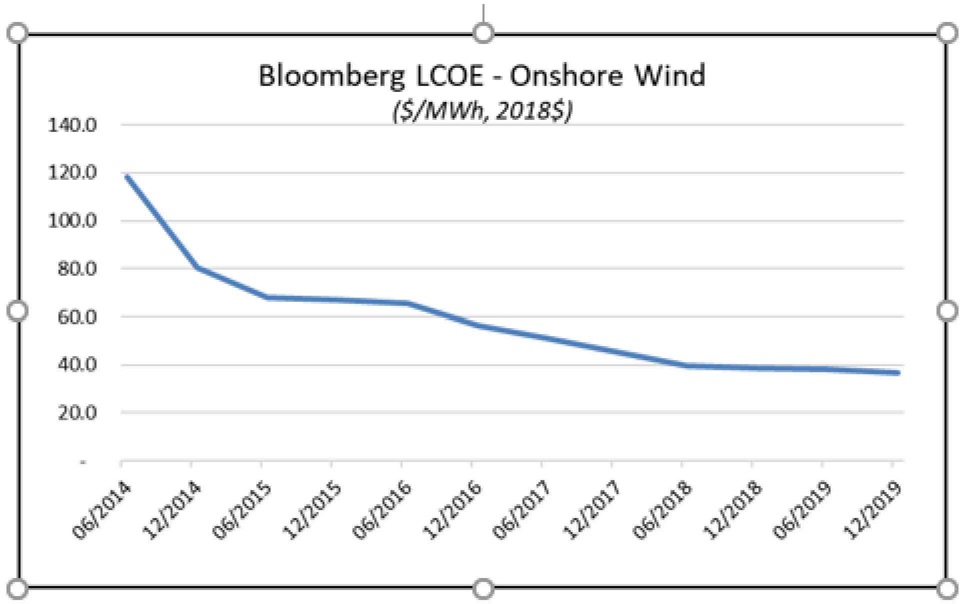
1. Capital Costs;
2. E&AS offsets;
3. REC prices;
4. Bonus depreciation.

A. Gross CONE

Concentric recommends that the capital cost component of gross CONE be updated by adjusting capital costs in the financial model using publicly available cost indices representing changes to generic major equipment.[91] Unlike traditional/fossil/gas generation, the cost of renewables has been declining. Therefore, for the capital cost components for the renewable resources, it is more appropriate to use the levelized cost of energy (LCOE), which is a commercially available value, to capture this declining trend. An example of this declining LCOE trend for onshore wind is shown in the figure below. All capital cost line items in the financial model for respective Net CONE and ORTP resources should be adjusted by a multiplier set according to the parameters agreed to between ISO-NE and stakeholders.

[91] For example, BLS PPU Commodity Data for Machinery and Equipment; General Purpose Machinery and Equipment. Series ID WPU114.

Figure 6: LCOE – Onshore Wind



B. E&AS Offsets

Concentric is proposing to maintain the current E&AS update procedure which relies on publicly available forward prices to quantify the change in profitability expectations. For the reference unit and gas ORTP units, profitability is a function of the spread between electric prices and delivered gas prices. Therefore, the E&AS update will be based on changes to the relationship between electric forwards and gas forwards, both of which are publicly available from ICE. Calculations should be based on settlements for the farthest date forward in time for which power settlements are available.

Calculations for the gas units (Net CONE reference unit and gas ORTPs) will be based on three contracts on ICE: an Algonquin Citygate basis swap, the Henry Hub futures price, and the MA Hub Day-Ahead On-Peak Future. The basis swap is added to the Henry Hub futures prices to create an index for a delivered Algonquin CG price. The ratio of the power price to the delivered gas price is then calculated for each month, after which the twelve-monthly ratios are averaged. As an example, Table 53 shows the calculation using settlements on ICE from August 31, 2020.

Table 53: Calculation of Power: Gas Ratio for E&AS Offset Update

	a	*b*	*a+b = c*	*d*	*e = d/c*
	Henry Hub (H)	**Algonquin CG Basis (ALQ)**	**Algonquin CG Delivered**	**MA Hub On-Peak (NEP)**	**Ratio**
	($/MMBtu)	*($/MMBtu)*	*($/MMBtu)*	*($/MWh)*	
Jan 2024	2.79	5.23	8.02	71.75	8.94
Feb 2024	2.76	5.24	8.00	69.30	8.67
Mar 2024	2.62	1.98	4.60	50.10	10.90
Apr 2024	2.32	0.48	2.80	32.20	11.50
May 2024	2.30	(0.10)	2.20	28.75	13.06
Jun 2024	2.34	(0.10)	2.24	30.50	13.62
Jul 2024	2.38	0.08	2.46	36.50	14.85
Aug 2024	2.39	0.02	2.40	34.45	14.34
Sep 2024	2.38	(0.34)	2.05	30.95	15.12
Oct 2024	2.41	(0.13)	2.28	31.10	13.62
Nov 2024	2.50	1.33	3.83	40.60	10.60
Dec 2024	2.69	4.21	6.90	60.60	8.78
				Average	**12.001**

Preceding an update, these calculations will be performed again. The average ratio that results will be compared to the ratio shown above. The percentage difference (positive or negative) in the ratios will be applied to the E&AS offsets.

For non-gas ORTP units, profitability is a function of the overall level of energy prices, not the spread between energy and gas prices. Therefore, the calculation supporting the adjustment of the E&AS portion of the revenue offset is based only on the power futures. For example, as of August 31, 2020, the average MA Hub on-peak settlement for all contracts in 2024 is $43.07/MWh. In the future, that average will be calculated again for contracts in the Capacity Commitment Period in question. The percentage difference (positive or negative) in the averages will be applied to the E&AS portion of the revenue offset for each non-gas ORTP resource.

C. REC Prices

REC prices are currently updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial. This has resulted in significant swings in ORTP values and in addition does not necessarily reflect the final average REC price for the vintage in question if that vintage has not finished trading. Therefore, Concentric recommends that ISO-NE update REC prices based on a rolling 5-year average MA Class 1 REC price for all trade dates for the 5 annual vintages closest to the Capacity Commitment Period. The updated REC price adjusted to the appropriate dollar year should be input into the financial model.

D. Bonus Depreciation

For the ORTP technologies, Concentric recommends that ISO-NE account for declining bonus depreciation in subsequent years. As of the writing of this report, available guidance suggests that 20% bonus depreciation will be available for units placed in service in calendar year 2026 and will expire thereafter.

APPENDIX A

Additional detail for EPC Contractor Fee and Contingency Costs.

COST CATEGORY	PREVIOUS MODEL	CURRENT MODEL
Project Contingency	$14,314,750	$12,269,786
EPC Contractor Fee	$15,316,783	$10,404,778
Owner's Contingency	$0	$6,957,000

CAPITAL COST CATEGORY	MILLION $
Owner's Contingency	$6.957
Project Contingency	$12.27
Mechanical Contract*	$6.89
Electrical and I&C Contract*	$1.39
Civil Struct Arch Contract*	$0.94
Construction Management*	$0.38
Other Project Costs*	$0.62
Total Contingency	**$29.45**

* Included within the category costs

APPENDIX B

Additional detail for Owner's Development Costs.

Permitting, legal, and siting costs are included in the Mechanical, Electrical & I&C, Civil Structural, Construction Management, and Other Project Costs line items. These costs total $5M, as shown below. Though these costs have not been differentiated in a single or separate capital cost line item, they are incorporated in the estimate.

COST CATEGORY	MILLION $
EPC - Mechanical	$3.4
EPC – Electrical and I&C	$0.7
EPC - Civil/Structural	$0.5
EPC - Construction Management	$0.1
EPC - Other Project Costs	$0.3
	$5.0
Permitting	$1.5
Legal	$2.5
Siting	$1.0

AFFIDAVIT OF DANIELLE S. POWERS

1. My name is Danielle S. Powers. I am a Senior Vice President at Concentric Energy Advisors, Inc. ("Concentric"). Concentric is an employee-owned management consulting and financial advisory firm focused on the North American energy industry specializing in utility regulation, finance and mergers and acquisitions , energy markets, management and operations support, as well as civil litigation and dispute resolution. Concentric is headquartered in Marlborough, Massachusetts. My office address is 293 Boston Post Road West, Marlborough, Massachusetts 01752.

2. I have over 30 years of experience in the wholesale electric market design and operations, power generation, and energy consulting fields. I have been with Concentric for over 15 years. I am also a former employee of ISO New England, Inc. ("ISO-NE"), where I was a Principal Analyst working on the design, implementation, and operation of the Forward Capacity Market. Prior to working at ISO-NE, I was a Senior Engagement Manager at Navigant Consulting from December 1999 to February 2003, where I managed asset sale transactions. From October 1997 to December 1999, I was employed at XEnergy, Inc. working on negotiating retail power supply contracts with large commercial and industrial customers.

3. I began my career in the energy industry in April of 1989, joining New England Power Company as a production engineer at Brayton Point Generating Station in Somerset, Massachusetts with responsibility for the design and operation of all environmental control equipment. I worked at New England Power Company until October 1997, over which time I worked in the transmission marketing, generation marketing and supply chain management departments.

4. I hold a B.S. in Mechanical Engineering from the University of Massachusetts, Amherst, and an M.B.A. from Bentley University.

5. I, in cooperation with Keith Paul of Mott MacDonald, was responsible for preparing the *ISO-NE CONE and ORTP Analysis; An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction; FCA 16 and Forward* (referred to as the "CEA Report") and the information contained in that report is true and correct to the best of my knowledge.

6. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on December 23, 2020

Danielle S. Powers

Danielle S. Powers

AFFIDAVIT OF KEITH PAUL

1. My name is Keith Paul. I am a Senior Consulting Engineer at Mott MacDonald, Inc. ("Mott MacDonald") at their Boston office. Mott MacDonald is an engineering, management and development consultancy operating in 150 countries, through over 16,000 local experts in 180 principal offices. Mott MacDonald operates in the following sectors: Buildings, Communications, Defense, Education, Environment, Health, International development, Industry, Mining, Oil and gas, Power, Transport, Urban development, Water and wastewater. Mott MacDonald provides services to customers to plan, design, procure and deliver projects on any scale; provide management consultancy built on technical know-how, shape and implement development policies and programs; and advance sustainability. Our portfolio ranges from small projects worth thousands of dollars to the world's largest multidisciplinary, multi-billion dollar programs.

2. I have over 20 years of consulting, design, and development experience of power generation systems and subsystems on plants located around the world. My experience includes power plant design, engineering, operations, and project development. My consulting experience includes the development of project power cycles, site arrangements and detailed design documentation, development of project financial capabilities, and documentation of plant performance criteria to ensure target performance and financial goals.

3. I have been with Mott MacDonald since December 2015 in support of projects across the globe. Prior to joining Mott MacDonald, I worked for InterGen from 2012 to 2015, from 2009 to 2012 at Stone & Webster Management Consultants, from 2006 to 2009 at Power Advocate, from 1997 to 2006 at the Shaw Group and Stone & Webster Engineering Corporation, from 1995 to 1997 at TODD Combustion, from 1992 to 1995 New England Power, and from 1990 to 1992 at Narragansett Electric.

4. I hold a B.S. in Mechanical Engineering from Northeastern University and an M.B.A. from F.W. Olin Graduate School of Business at Babson College.

5. I, in cooperation with Danielle S. Powers of Concentric Energy Advisors, Inc, was responsible for preparing the *ISO-NE CONE and ORTP Analysis; An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction; FCA 16 and Forward* (referred to as the "CEA Report") and the information contained in that report is true and correct to the best of my knowledge.

6. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on December 29, 2020

Keith Paul (by [illegible])

Keith Paul

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or

Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a

Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant’s share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant’s or Non-Market Participant Transmission Customer’s credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a “material adverse impact” on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD’s Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of ~~the first-year~~ non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require~~, in its first year of operation,~~ to be economically viable given reasonable expectations of the ~~first year~~ energy and ancillary services revenues under long-term equilibrium conditions~~, and projected revenue for subsequent years~~.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the

Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:

(a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \qquad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic De~~-l~~List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource’s capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

   (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

   (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

   (i) that interface's approved capacity transfer limit (net of tie benefits), or;

   (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, ~~2021~~ 2025 is $11.874~~11.35~~/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, ~~2021~~2025 is $7.024~~8.04~~/kW-month.

CONE and Net CONE shall be recalculated ~~for the Capacity Commitment Period beginning on June 1, 2025 and~~ no less often than once every three years~~ thereafter~~. ~~-~~Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23, 2023/24 and 2024/25 Capacity Commitment Period, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23, 2023/24 and 2024/25 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions. A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2025.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.2 Peak Energy Rents.

For Capacity Commitment Periods beginning prior to June 1, 2019, Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve FCM Commercial Operation, shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with one of the following formulas, which include scaling adjustments for system load and availability:

For hours within the period beginning September 30, 2016 through May 31, 2018:

Hourly PER($/kW) = [(LMP - Adjusted Hourly PER Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Adjusted Hourly PER Strike Price = Strike Price + Hourly PER Adjustment

Hourly PER Adjustment = average of Five-Minute PER Strike Price Adjustment values

Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserve clearing price - $500/MWh, 0)+ MAX (Ten-Minute Non-Spinning Reserve clearing price – Thirty-Minute Operating Reserve clearing price - $850/MWh, 0).

Strike Price = as defined below

Scaling Factor = as defined below

Availability Factor = as defined below

For all other hours:

Hourly PER($/kW) = [LMP - Strike Price] * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Capacity Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of the following, as determined on a daily basis: ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation; or day-ahead gas measured at the AGT-CG (Non-G) hub;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2. Monthly PER Application.

The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource’s Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource’s PER deduction for an Obligation Month be less than zero or greater than the product of the resource’s Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]

Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]

Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

> (i) For Energy Efficiency measures, if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource’s Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource’s Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero); provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval; provided however, that if the interval occurs outside of Demand Resource On-

Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a

Seasonal Peak Demand Resource, if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided and Capacity Supply Obligation associated with any applicable Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025~~ and thereafter~~, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $8782/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to the following charges and adjustments:

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

> Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.
>
> Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent

Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section

III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the Capacity Load Obligation in the Capacity Zone less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Zonal Capacity Obligation.

Where:

Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.
(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the most recent seasonal claimed capability of the ownership entitlements in such unit, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company ("MMWEC") and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located, and; (ii) the MW quantity of the specifically allocated CTRs.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or

Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a

Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant’s share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer’s failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO’s technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer’s Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.
Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.
The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.
The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \ldots & \ldots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic De-List Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

(i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

(ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

(i) that interface's approved capacity transfer limit (net of tie benefits), or;

(ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $11.874/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2025 is $7.024/kW-month.

CONE and Net CONE shall be recalculated no less often than once every three years. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23, 2023/24 and 2024/25 Capacity Commitment Period, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23, 2023/24 and 2024/25 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions. A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2025.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

> (a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

III.13.7. Performance, Payments and Charges in the FCM.

Revenue in the Forward Capacity Market for resources providing capacity shall be composed of Capacity Base Payments as described in Section III.13.7.1 and Capacity Performance Payments as described in Section III.13.7.2, adjusted as described in Section III.13.7.3 and Section III.13.7.4. Market Participants with a Capacity Load Obligation will be subject to charges as described in Section III.13.7.5.

In the event of a change in the Lead Market Participant for a resource that has a Capacity Supply Obligation, the Capacity Supply Obligation shall remain associated with the resource and the new Lead Market Participant for the resource shall be bound by all provisions of this Section III.13 arising from such Capacity Supply Obligation. The Lead Market Participant for the resource at the start of an Obligation Month shall be responsible for all payments and charges associated with that resource in that Obligation Month.

III.13.7.1. Capacity Base Payments.

Resources acquiring or shedding a Capacity Supply Obligation for the Obligation Month shall receive a Capacity Base Payment for the Obligation Month reflecting the payments and charges described in Section III.13.7.1.1, as adjusted to account for peak energy rents as described in Section III.13.7.1.2.

III.13.7.1.1. Monthly Payments and Charges Reflecting Capacity Supply Obligations.

Each resource that has: (i) cleared in a Forward Capacity Auction, except for the portion of resources designated as Self-Supplied FCA Resources; (ii) cleared in a reconfiguration auction; or (iii) entered into a Capacity Supply Obligation Bilateral shall be entitled to a monthly payment or charge during the Capacity Commitment Period based on the following amounts:

(a) **Forward Capacity Auction**. For a resource whose offer has cleared in a Forward Capacity Auction, the monthly capacity payment shall equal the product of its cleared capacity and the Capacity Clearing Price in the Capacity Zone in which the resource is located as adjusted by applicable indexing for resources with additional Capacity Commitment Period elections pursuant to Section III.13.1.1.2.2.4 in the manner described below. For a resource that has elected to have the Capacity Clearing Price and the Capacity Supply Obligation apply for more than one Capacity Commitment Period, payments associated with the Capacity Supply Obligation and Capacity Clearing Price (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only.

(b) **Reconfiguration Auctions**. For a resource whose offer or bid has cleared in an annual or monthly reconfiguration auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the appropriate reconfiguration auction clearing price in the Capacity Zone in which the resource cleared.

(c) **Capacity Supply Obligation Bilaterals**. For resources that have acquired or shed a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, the monthly capacity payment or charge shall be equal to the product of the Capacity Supply Obligation being assumed or shed and price associated with the Capacity Supply Obligation Bilateral.

(d) **Substitution Auctions.** For a resource whose offer or bid has cleared in a substitution auction, the monthly capacity payment or charge shall be equal to the product of its cleared capacity and the substitution auction clearing price. Notwithstanding the foregoing, the monthly capacity charge for a demand bid cleared at a substitution auction clearing price above its bid price shall be calculated using its bid price.

III.13.7.1.2 Peak Energy Rents.

For Capacity Commitment Periods beginning prior to June 1, 2019, Capacity Base Payments to resources with Capacity Supply Obligations, except for (1) On-Peak Demand Resources, (2) Seasonal Peak Demand Resources, and (3) New Generating Capacity Resources that have cleared in the Forward Capacity Auction and have completed construction but due to a planned transmission facility (e.g., a radial interconnection) not being in service are not able to achieve FCM Commercial Operation, shall be decreased by Peak Energy Rents ("PER") calculated in each Capacity Zone, as determined pursuant to Section III.13.2.3.4 in the Forward Capacity Auction, as provided below. The PER calculation shall utilize hourly integrated Real-Time LMPs. For each Capacity Zone in the Forward Capacity Auction, as determined pursuant to Section III.13.2.3.4, PER shall be computed based on the load-weighted Real-Time LMPs for each Capacity Zone, using the Real-Time Hub Price for the Rest-of-Pool Capacity Zone. Self-Supplied FCA Resources shall not be subject to a PER adjustment on the portion of the resource that is self-supplied.

III.13.7.1.2.1 Hourly PER Calculations.

(a) For hours with a positive difference between the hourly Real-Time energy price and a strike price, the ISO shall compute PER for each hour ("Hourly PER") equal to this positive difference in accordance with one of the following formulas, which include scaling adjustments for system load and availability:

For hours within the period beginning September 30, 2016 through May 31, 2018:

Hourly PER($/kW) = [(LMP - Adjusted Hourly PER Strike Price) * [Scaling Factor] * [Availability Factor]

Where:

Adjusted Hourly PER Strike Price = Strike Price + Hourly PER Adjustment

Hourly PER Adjustment = average of Five-Minute PER Strike Price Adjustment values

Five-Minute PER Strike Price Adjustment = MAX (Thirty-Minute Operating Reserve clearing price - $500/MWh, 0)+ MAX (Ten-Minute Non-Spinning Reserve clearing price – Thirty-Minute Operating Reserve clearing price - $850/MWh, 0).

Strike Price = as defined below

Scaling Factor = as defined below

Availability Factor = as defined below

For all other hours:

Hourly PER($/kW) = [LMP - Strike Price] * [Scaling Factor] * [Availability Factor]

Where:

Strike Price = the heat rate x fuel cost of the PER Proxy Unit described below.

Scaling Factor = the ratio of actual hourly integrated system load (calculated as the sum of Real-Time Load Obligations for the system as calculated in the settlement of the Real-Time Energy Market and adjusted for losses and including imports delivered in the Real-Time Energy Market) and the 50/50 predicted peak system load reduced appropriately for Demand Capacity Resources, used in the most recent calculation of the Installed Capacity Requirement for that Capacity Commitment Period, capped at an hourly ratio of 1.0.

Availability Factor = 0.95.

(b) PER Proxy Unit characteristics shall be as follows:

(i) The PER Proxy Unit shall be indexed to the marginal fuel, which shall be the higher of the following, as determined on a daily basis: ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation; or day-ahead gas measured at the AGT-CG (Non-G) hub;

(ii) The PER Proxy Unit shall be assumed to have no start-up, ramp rate or minimum run time constraints;

(iii) The PER Proxy Unit shall have a 22,000 Btu/kWh heat rate. This assumption shall be periodically reviewed after the first Capacity Commitment Period by the ISO to ensure that the heat rate continues to reflect a level slightly higher than the marginal generating unit in the region that would be dispatched as the system enters a scarcity condition. Any changes to the heat rate of the PER Proxy Unit shall be considered in the stakeholder process in consultation with the state utility regulatory agencies, shall be filed pursuant to Section 205 of the Federal Power Act, and shall be applied prospectively to the settlement of future Forward Capacity Auctions.

III.13.7.1.2.2. Monthly PER Application.

The Hourly PER shall be summed for each calendar month to determine the total PER for that month ("Monthly PER"). The ISO shall then calculate the Average Monthly PER earned by the proxy unit. The Average Monthly PER shall be equal to the average of the Monthly PER values for the 12 months prior to the Obligation Month. The PER deduction for each resource shall be calculated as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation for the Obligation Month (less any Capacity Supply Obligation MW from any portion of a Self-Supplied FCA Resource); provided, however, that in no case shall a resource's PER deduction for an Obligation Month be less than zero or greater than the product of the resource's Capacity Supply Obligation and the relevant Forward Capacity Auction Capacity Clearing Price.

III.13.7.1.3. Export Capacity.

If there are any Export Bids or Administrative Export De-List Bids from resources located in an export-constrained Capacity Zone or in the Rest-of-Pool Capacity Zone that have cleared in the Forward Capacity Auction and if the resource is exporting capacity at an export interface that is connected to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone that is different than the Capacity Zone in which the resource is located, then charges and credits are applied as follows (for the following calculation, the Capacity Clearing Price will be the value prior to PER adjustments).

> Charge Amount to Resource Exporting = [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-List Bid]
>
> Credit Amount to Capacity Load Obligations in the Capacity Zone where the export interface is located= [Capacity Clearing Price $_{\text{location of the interface}}$ - Capacity Clearing Price $_{\text{location of the resource}}$] x Cleared MWs of Export Bid or Administrative Export De-list Bid]
>
> Credits and charges to load in the applicable Capacity Zones, as set forth above, shall be allocated in proportion to each LSE's Capacity Load Obligation as calculated in Section III.13.7.5.2.

III.13.7.1.4. [Reserved.]

III.13.7.2 Capacity Performance Payments.

III.13.7.2.1 Definition of Capacity Scarcity Condition.

A Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the Minimum Total Reserve Requirement; (ii) the Ten-Minute Reserve Requirement; or (iii) the Zonal Reserve Requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

III.13.7.2.2 Calculation of Actual Capacity Provided During a Capacity Scarcity Condition.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. For resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision below applicable to the resource type. Notwithstanding the specific provisions of this Section III.13.7.2.2, no resource shall have an Actual Capacity Provided that is less than zero.

(a) A Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Reserve Quantity For Settlement during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the sum of the resource's Desired Dispatch Point during the interval, plus the resource's Reserve Quantity For Settlement during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

(b) An Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata.

(c) An On-Peak Demand Resource or Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided for each of its components, as determined below, where the MWhs of reduction, other than MWhs associated with Net Supply, are increased by average avoided peak transmission and distribution losses.

(i) For Energy Efficiency measures, if the Capacity Scarcity Condition occurs during Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be equal to the applicable reported monthly performance value; if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided shall be zero.

(ii) For Distributed Generation measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted meter data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iii) For Load Management measures submitting meter data for the full 24 hour calendar day during which the Capacity Scarcity Condition occurs, the Actual Capacity Provided shall be equal to the submitted demand reduction data, adjusted as necessary for the five-minute interval in which the Capacity Scarcity Condition occurs.

(iv) Notwithstanding any other provision of this Section III.13.7.2.2(c), for any On-Peak Demand Resource or Seasonal Peak Demand Resource that fails to provide the data necessary for the ISO to determine the Actual Capacity Provided as described in this Section III.13.7.2.2(c), the Actual Capacity Provided shall be zero.

(d) An Active Demand Capacity Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Actual Capacity Provided by its constituent Demand Response Resources during the Capacity Scarcity Condition.

(i) A Demand Response Resource’s Actual Capacity Provided during a Capacity Scarcity Condition shall be: (1) the sum of the Real-Time demand reduction of its constituent Demand Response Assets (provided, however, that if the Demand Response Resource was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the sum of the Real-Time demand reduction of its constituent Demand Response Assets may not be greater than its Desired Dispatch Point during the interval), plus (2) the Demand Response Resource’s Reserve Quantity For Settlement, where the MW quantity, other than the MW quantity associated with Net Supply, is increased by average avoided peak transmission and distribution losses; provided, however, that a Demand Response Resource’s Actual Capacity Provided shall not be less than zero.

(ii) The Real-Time demand reduction of a Demand Response Asset shall be calculated as described in Section III.8.4, except that: (1) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, a Real-Time demand reduction shall also be calculated for intervals in which the associated Demand Response Resource does not receive a non-zero Dispatch Instruction; (2) in the case of a Demand Response Asset that is on a forced or scheduled curtailment as described in Section III.8.3, the minuend in the calculation described in Section III.8.4 shall be the unadjusted Demand Response Baseline of the Demand Response Asset; and (3) the resulting MWhs of reduction, other than the MWhs associated with Net Supply, shall be increased by average avoided peak transmission and distribution losses.

III.13.7.2.3 Capacity Balancing Ratio.

For each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

(a) If the Capacity Scarcity Condition is a result of a violation of the Minimum Total Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Minimum Total Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(b) If the Capacity Scarcity Condition is a result of a violation of the Ten-Minute Reserve Requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall be zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Ten-Minute Reserve Requirement during the interval.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval; provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(c) If the Capacity Scarcity Condition is a result of a violation of the Zonal Reserve Requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

Load = the total amount of Actual Capacity Provided (excluding applicable Real-Time Reserve Designations) from all resources in the Capacity Zone during the interval plus the net amount of energy imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero); provided, however, that if the interval occurs outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, then the Actual Capacity Provided of any applicable Energy Efficiency measures shall zero, as specified in Section III.13.7.2.2(c)(i).

Reserve Requirement = the Zonal Reserve Requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface.

Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval; provided however, that if the interval occurs outside of Demand Resource On-

Peak Hours or Demand Resource Seasonal Peak Hours, then the Capacity Supply Obligations associated with any applicable Energy Efficiency measures shall be excluded from the total amount of Capacity Supply Obligations.

(d) The following provisions shall be used to determine the applicable Capacity Balancing Ratio where more than one of the conditions described in subsections (a), (b), and (c) apply in a Capacity Zone.

(i) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Minimum Total Reserve Requirement and the Ten-Minute Reserve Requirement, but not the Zonal Reserve Requirement, the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) for resources in that Capacity Zone.

(ii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with both the Ten-Minute Reserve Requirement and the Zonal Reserve Requirement, but not the Minimum Total Reserve Requirement, the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(b) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

(iii) In any Capacity Zone subject to Reserve Constraint Penalty Factor pricing associated with the Minimum Total Reserve Requirement and the Zonal Reserve Requirement (regardless of whether the Capacity Zone is also subject to Reserve Constraint Penalty Factor pricing associated with the Ten-Minute Reserve Requirement), the Capacity Balancing Ratio for resources in that Capacity Zone shall be the higher of the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(a) and the Capacity Balancing Ratio calculated as described in Section III.13.7.2.3(c).

III.13.7.2.4 Capacity Performance Score.

Each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource’s Capacity Performance Score for the interval shall equal the resource’s Actual Capacity Provided during the interval minus the product of the resource’s Capacity Supply Obligation (which for this purpose shall not be less than zero) and the applicable Capacity Balancing Ratio; provided, however, that for an On-Peak Demand Resource or a

Seasonal Peak Demand Resource, if the Capacity Scarcity Condition occurs in an interval outside of Demand Resource On-Peak Hours or Demand Resource Seasonal Peak Hours, as applicable, then the Actual Capacity Provided and Capacity Supply Obligation associated with any applicable Energy Efficiency measures shall be excluded from the calculation of the resource's Capacity Performance Score. The resulting Capacity Performance Score may be positive, zero, or negative.

III.13.7.2.5 Capacity Performance Payment Rate.

For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025, the Capacity Performance Payment Rate shall be $5455/MWh. For the Capacity Commitment Period beginning on June 1, 2025 and ending on May 31, 2026 and thereafter, the Capacity Performance Payment Rate shall be $8782/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

III.13.7.2.6 Calculation of Capacity Performance Payments.

For each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. The resulting Capacity Performance Payment for an interval may be positive or negative.

III.13.7.3 Monthly Capacity Payment and Capacity Stop-Loss Mechanism.

Each resource's Monthly Capacity Payment for an Obligation Month, which may be positive or negative, shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month, except as provided in Section III.13.7.3.1 and Section III.13.7.3.2 below.

III.13.7.3.1 Monthly Stop-Loss.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month (or, in the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month).

III.13.7.3.2 Annual Stop-Loss.

(a) For each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

MaxCSO x [3 months x (FCAcp – FCAsp) – (12 months x FCAcp)]

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

(b) For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited as described in Section III.13.7.3.1.

(c) If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the stop-loss amount calculated as described in Section III.13.7.3.2(a) and the resource's cumulative Capacity Performance Payments as described in Section III.13.7.3.2(b).

III.13.7.4 Allocation of Deficient or Excess Capacity Performance Payments.

For each type of Capacity Scarcity Condition as described in Section III.13.7.2.1 and for each Capacity Zone, the ISO shall allocate deficient or excess Capacity Performance Payments as described in subsections (a) and (b) below. Where more than one type of Capacity Scarcity Condition applies, then the provisions below shall be applied in proportion to the duration of each type of Capacity Scarcity Condition.

(a) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If the charge described in this Section III.13.7.4(a) causes a resource to reach the stop-loss limit described in Section III.13.7.3, then the stop-loss cap described in Section III.13.7.3 will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in this Section III.13.7.4(a).

(b) If the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism described in Section III.13.7.3, and the remaining excess will be further allocated to other resources in the same manner as described in this Section III.13.7.4(b)

III.13.7.5. Charges to Market Participants with Capacity Load Obligations.

III.13.7.5.1. Calculation of Capacity Charges Prior to June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning prior to June 1, 2022. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to a charge equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone; and (b) the applicable Net Regional Clearing Price. The Net Regional Clearing Price is defined as the sum of the total payments as defined in Section III.13.7 paid to resources with Capacity Supply Obligations in the Capacity Zone (excluding any capacity payments and charges made for Capacity Supply Obligation Bilaterals and excluding any Capacity Performance Payments), less PER adjustments for resources in the zone as defined in Section III.13.7.1.2, and including any applicable export charges or credits as determined pursuant to Section III.13.7.1.3 divided by the sum of all Capacity Supply Obligations (excluding (i) the quantity of capacity subject to Capacity Supply Obligation Bilaterals and (ii) the quantity of capacity clearing as Self-Supplied FCA Resources) assumed by resources in the zone. A load serving entity satisfying its Capacity Load Obligation by a Self-Supplied FCA Resource shall not receive a credit for any PER payment for its Capacity Load Obligation so satisfied. A load serving entity with a Capacity Load Obligation as of the end of the Obligation Month may also receive a failure to cover credit equal to the product of: (a) its Capacity Load Obligation in the Capacity Zone, and; (b) the sum of all failure to cover charges in the Capacity Zone calculated pursuant to Section III.13.3.4(b), divided by total Capacity Load Obligation in the Capacity Zone.

III.13.7.5.1.1. Calculation of Capacity Charges On and After June 1, 2022.

The provisions in this subsection apply to charges associated with Capacity Commitment Periods beginning on or after June 1, 2022. For purposes of this Section III.13.7.5.1.1, Capacity Zone costs calculated for a Capacity Zone that contains a nested Capacity Zone shall exclude the Capacity Zone costs of the nested Capacity Zone. A Market Participant with a Capacity Load Obligation as of the end of the Obligation Month shall be subject to the following charges and adjustments:

III.13.7.5.1.1.1 Forward Capacity Auction Charge.

The FCA charge, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone FCA Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone FCA Costs, for each Capacity Zone, are the Total FCA Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total FCA Costs are the sum of, for all Capacity Zones, (i) Capacity Supply Obligations in each zone (the total obligation awarded to or shed by resources in the Forward Capacity Auction process for the Obligation Month in the zone, excluding any obligations awarded to Intermittent

Power Resources that are the basis for the Intermittent Power Resource Capacity Adjustment specified in Section III.13.7.5.1.1.6 and excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) multiplied by the applicable clearing price from the auction in which the obligation was awarded to (or shed by) the resource, and (ii) the difference between the bid price and the substitution auction clearing price that was not included in the capacity charge pursuant to the second sentence of Section III.13.7.1.1(d). Capacity Supply Obligations awarded to Proxy De-List Bids in the primary auction, or shed by demand bids entered into the substitution auction on behalf of a Proxy De-List Bid, are excluded from Total FCA Costs.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.2 Annual Reconfiguration Auction Charge.

The total annual reconfiguration auction charge, for each Capacity Zone and each associated annual reconfiguration auction, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Capacity Zone Annual Reconfiguration Auction Costs divided by Zonal Capacity Obligation.

Where

Capacity Zone Annual Reconfiguration Auction Costs, for each Capacity Zone, are the Total Annual Reconfiguration Costs multiplied by the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.

Total Annual Reconfiguration Auction Costs are the sum, for all Capacity Zones and each associated annual reconfiguration auction, of the product of the Capacity Supply Obligations acquired through the annual reconfiguration auction in each zone (adjusted for any obligations procured in the annual reconfiguration auction that are subsequently terminated pursuant to Section III.13.3.4A) and the zonal annual reconfiguration auction clearing price, minus the sum, for all Capacity Zones, of the product of the amount of any Capacity Supply Obligation shed through the annual reconfiguration auction in each zone and the applicable annual reconfiguration auction clearing price.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.1.1.3. Monthly Reconfiguration Auction Charge.

The monthly reconfiguration auction charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total Monthly Reconfiguration Auction Costs divided by Total Zonal Capacity Obligation.

Where

Total Monthly Reconfiguration Auction Costs are the sum of, for all Capacity Zones, the product of Capacity Supply Obligations acquired through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price, minus the sum of, for all Capacity Zones, any Capacity Supply Obligations shed through the monthly reconfiguration auction in each zone and the applicable monthly reconfiguration auction clearing price.

Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.4. HQICC Capacity Charge.

The HQICC capacity charge is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) Total HQICC Credits divided by Total Capacity Load Obligation.

Where

Total HQICC credits are the product of HQICCs multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone in which the HQ Phase I/II external node is located.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.5. Self-Supply Adjustment.

The self-supply adjustment is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) the Self-Supply Variance divided by Total Capacity Load Obligation.

Where

Self-Supply Variance is the difference between foregone capacity payments and avoided capacity charges associated with designated self-supply quantities.

Foregone capacity payments to Self-Supplied FCA Resources are the sum, for all Capacity Zones, of the product of the zonal Capacity Supply Obligation (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A) designated as self-supply, multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Avoided capacity charges are the sum, for all Capacity Zones, of the product of any designated self-supply quantities multiplied by the sum of the values calculated in Sections IIII.13.7.5.1.1.1(b), IIII.13.7.5.1.1.2(b), IIII.13.7.5.1.1.3(b), IIII.13.7.5.1.1.6(b), IIII.13.7.5.1.1.7(b), III.13.7.5.1.1.8(b), and III.13.7.5.1.1.9(b) in the Capacity Zone associated with the designated self-supply quantity.

Total Capacity Load Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.6. Intermittent Power Resource Capacity Adjustment.

The Intermittent Power Resource capacity adjustment in a winter season for the Obligation Months from October through May is: (a) total Capacity Load Obligation for all Capacity Zones; multiplied by (b) the Intermittent Power Resource Seasonal Variance divided by Total Zonal Capacity Obligation.

Where

Intermittent Power Resource Seasonal Variance is the difference between the FCA payments for Intermittent Power Resource in the Obligation Month and the base FCA payments for Intermittent Power Resources.

FCA payments to Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the Capacity Supply Obligations awarded to or shed by Intermittent Power Resources in the Forward Capacity Auction process for the Obligation Month pursuant to Section

III.13.2.7.6 or Section III.13.2.8.1.1 (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Base FCA payments for Intermittent Power Resources are the sum, for all Capacity Zones, of the product of the FCA Qualified Capacity procured from or shed by Intermittent Power Resources in the Forward Capacity Auction process (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the applicable clearing price from the auction in which the obligation was awarded.

Total Zonal Capacity Obligation is the total Capacity Load Obligation in all Capacity Zones.

III.13.7.5.1.1.7. Multi-Year Rate Election Adjustment.
For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period, multiplied by the Zonal Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation and divided by the Total Peak Load Allocator for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation.

Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal Capacity Clearing Price.

Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

For multi-year rate elections made in the primary Forward Capacity Auction for Capacity Commitment Periods beginning prior to June 1, 2022, the multi-year rate election adjustment, for each Capacity Zone, is: (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Multi-Year Rate Election Costs divided by Zonal Capacity Obligation.

Where

Zonal Multi-Year Rate Election Costs is the sum in each Capacity Zone, for each resource with a multi-year rate election in the Obligation Month, of the amount of Capacity Supply Obligation designated to receive the multi-year rate (excluding any obligations procured in the Forward Capacity Auction that are terminated pursuant to Section III.13.3.4A), multiplied by the difference in the applicable zonal Capacity Clearing Price for the Forward Capacity Auction in which the resource originally was awarded a Capacity Supply Obligation (indexed using the Handy-Whitman Index of Public Utility Construction Costs in effect as of December 31 of the year preceding the Capacity Commitment Period) and the applicable zonal Capacity Clearing Price for the current Capacity Commitment Period.

III.13.7.5.1.1.8 CTR Transmission Upgrade Charge.

The CTR transmission upgrade charge is: (a) the Capacity Load Obligation in the Capacity Zones to which the applicable interface limits the transfer of capacity, multiplied by (b) Zonal CTR Transmission Upgrade Cost divided by Zonal Capacity Obligation.

Where

Zonal CTR Transmission Upgrade Cost for each Capacity Zone to which the interface limits the transfer of capacity is the amount calculated pursuant to Section III.13.7.5.4.4 (f), multiplied by the Zonal Capacity Obligation and divided by the sum of the Zonal Capacity Obligation for all Capacity Zones to which the interface limits the transfer of capacity.

III.13.7.5.1.1.9 CTR Pool-Planned Unit Charge.

The CTR Pool-Planned Unit charge is: (a) the Capacity Load Obligation in the Capacity Zone less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5, multiplied by (b) CTR Pool-Planned Unit Cost divided by Total Zonal Capacity Obligation less the amount of any CTRs specifically allocated pursuant to Section III.13.7.5.4.5.

Where

> The CTR Pool-Planned Unit Cost for each Capacity Zone is the sum of the amounts calculated pursuant to Section III.13.7.5.4.5 (b).
>
> Total Zonal Capacity Obligation is the total of the Zonal Capacity Obligation in all Capacity Zones.

III.13.7.5.1.1.10. Failure to Cover Charge Adjustment.

The failure to cover charge adjustment, for each Capacity Zone, is (a) Capacity Load Obligation in the Capacity Zone; multiplied by (b) Zonal Failure to Cover Charges divided by Zonal Capacity Obligation.

Where:

> Zonal Failure to Cover Charges are the product of: (1) the sum, for all Capacity Zones, of the failure to cover charges calculated pursuant to Section III.13.3.4(b), and; (2) the Zonal Peak Load Allocator and divided by the Total Peak Load Allocator.
>
> Zonal Peak Load Allocator is the Zonal Capacity Obligation multiplied by the zonal annual reconfiguration auction clearing price as determined pursuant to Section III.13.3.4.
>
> Total Peak Load Allocator is the sum of the Zonal Peak Load Allocators.

III.13.7.5.2. Calculation of Capacity Load Obligation and Zonal Capacity Obligation.

The ISO shall assign each Market Participant a share of the Zonal Capacity Obligation prior to the commencement of each Obligation Month for each Capacity Zone established in the Forward Capacity Auction pursuant to Section III.13.2.3.4. The Zonal Capacity Obligation of a Capacity Zone that contains a nested Capacity Zone shall exclude the Zonal Capacity Obligation of the nested Capacity Zone.

Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the total of the system-wide Capacity Supply Obligations (excluding the quantity of capacity subject to Capacity Supply Obligation Bilaterals for Capacity Commitment Periods beginning prior to June 1, 2022 and excluding any additional obligations awarded to Intermittent Power Resources pursuant to Section III.13.2.7.6 that exceed the FCA Qualified Capacity procured in the Forward Capacity Auction for Capacity Commitment Periods beginning on or after June 1, 2022) plus HQICCs; and (ii) the ratio of the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022) to the system-wide sum of all load serving entities' annual coincident contributions to the system-wide annual peak load from the calendar year two years prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning prior to June 1, 2022) and from the calendar year one year prior to the start of the Capacity Commitment Period (for Capacity Commitment Periods beginning on or after June 1, 2022).

The following loads are assigned a peak contribution of zero for the purposes of assigning obligations and tracking load shifts: load associated with the receipt of electricity from the grid by Storage DARDs for later injection of electricity back to the grid; Station service load that is modeled as a discrete Load Asset and the Resource is complying with the maintenance scheduling procedures of the ISO; load that is modeled as a discrete Load Asset and is exclusively related to an Alternative Technology Regulation Resource following AGC Dispatch Instructions; and transmission losses associated with delivery of energy over the Control Area tie lines.

A Market Participant's share of Zonal Capacity Obligation for each month and Capacity Zone shall equal the product of: (i) the Capacity Zone's Zonal Capacity Obligation as calculated above and (ii) the ratio of the sum of the load serving entity's annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period to the sum of all load serving entities' annual coincident contributions to the system-wide annual peak load in that Capacity Zone from the calendar year prior to the start of the Capacity Commitment Period.

A Market Participant's Capacity Load Obligation shall be its share of Zonal Capacity Obligation for each month and Capacity Zone, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations. A Capacity Load Obligation can be a positive or negative value.

A Market Participant's share of Zonal Capacity Obligation will not be reconstituted to include the demand reduction of a Demand Capacity Resource or Demand Response Resource.

III.13.7.5.2.1. Charges Associated with Dispatchable Asset Related Demands.

Dispatchable Asset Related Demand resources will not receive Forward Capacity Market payments, but instead each Dispatchable Asset Related Demand resource will receive an adjustment to its share of the associated Coincident Peak Contribution based on the ability of the Dispatchable Asset Related Demand resource to reduce consumption. The adjustment to a load serving entity's Coincident Peak Contribution resulting from Dispatchable Asset Related Demand resource reduction in consumption shall be based on the Nominated Consumption Limit submitted for the Dispatchable Asset Related Demand resource. The Nominated Consumption Limit value of each Dispatchable Asset Related Demand resource is subject to adjustment as further described in the ISO New England Manuals, including adjustments based on the results of Nominated Consumption Limit audits performed in accordance with the ISO New England Manuals.

III.13.7.5.3. Excess Revenues.

(a) For Capacity Commitment Periods beginning prior to June 1, 2022, revenues collected from load serving entities in excess of revenues paid by the ISO to resources shall be paid by the ISO to the holders of Capacity Transfer Rights, as detailed in Section III.13.7.5.3.

(b) Any payment associated with a Capacity Supply Obligation Bilateral that was to accrue to a Capacity Acquiring Resource for a Capacity Supply Obligation that is terminated pursuant to Section III.13.3.4A shall instead be allocated to Market Participants based on their pro rata share of all Capacity Load Obligations in the Capacity Zone in which the terminated resource is located.

III.13.7.5.4. Capacity Transfer Rights.

III.13.7.5.4.1. Definition and Payments to Holders of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

Capacity Transfer Rights are calculated for each internal interface associated with a Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4). Based upon results of the Forward Capacity Auction and reconfiguration auctions, the total CTR fund will be calculated as the difference between the charges to load serving entities with Capacity Load Obligations and the payments to Capacity Resources as follows: The system-wide sum of the product of each Capacity Zone's Net Regional Clearing Price and absolute value of each Capacity Zone's Capacity Load Obligations, as calculated in Section III.13.7.5.1, minus the sum of the monthly capacity payments to Capacity Resources within each zone, as adjusted for PER.

Each Capacity Zone established in the Forward Capacity Auction (as determined pursuant to Section III.13.2.3.4) will be assigned its portion of the CTR fund.

For CTRs resulting from an export constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between the absolute value of the total Capacity Supply Obligations obtained in the exporting Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources, and the absolute value of the total Capacity Load Obligations in the exporting Capacity Zone.

For CTRs resulting from an import constrained zone, the assignment will be calculated as the product of: (i) the Net Regional Clearing Price for the Capacity Zone to which the applicable interface limits the transfer of capacity minus the Net Regional Clearing Price for the absolute value of the Capacity Zone from which the applicable interface limits the transfer of capacity; and (ii) the difference between absolute value of the total Capacity Load Obligations in the importing Capacity Zone and the total Capacity Supply Obligations obtained in the importing Capacity Zone, adjusted for Capacity Supply Obligations associated with Self-Supplied FCA Resources.

III.13.7.5.4.2. Allocation of Capacity Transfer Rights.

This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

For Capacity Zones established in the Forward Capacity Auction as determined pursuant to Section III.13.2.3.4, the CTR fund shall be allocated among load serving entities using their Capacity Load Obligation (net of HQICCs) described in Section III.13.7.5.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from their Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Connecticut Import Interface**. The allocation of the CTR fund associated with the Connecticut Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the Connecticut Capacity Zone.

(b) **NEMA/Boston Import Interface**. Except as provided in Section III.13.7.5.3.6 of Market Rule 1, the allocation of the CTR fund associated with the NEMA/Boston Import Interface shall be made to load serving entities based on their Capacity Load Obligation in the NEMA/Boston Capacity Zone.

III.13.7.5.4.3. Allocations of CTRs Resulting From Revised Capacity Zones.
This subsection applies to Capacity Commitment Periods beginning prior to June 1, 2022.

The portion of the CTR fund associated with revised definitions of Capacity Zones shall be fully allocated to load serving entities after deducting the value of applicable CTRs that have been specifically allocated. Allocations of the CTR fund among load serving entities will be made using their Capacity Load Obligations (net of HQICCs) as described in Section III.13.7.5.3.1. Market Participants with CTRs specifically allocated under Section III.13.7.5.3.6 will have their specifically allocated CTR MWs netted from the Capacity Load Obligation used to establish their share of the CTR fund.

(a) **Import Constraints.** The allocation of the CTR fund associated with newly defined import-constrained Capacity Zones restricting the transfer of capacity into a single adjacent import-constrained Capacity Zone shall be allocated to load serving entities with Capacity Load Obligations in that import-constrained Capacity Zone.

(b) **Export Constraints.** The allocation of the CTR fund associated with newly defined export-constrained Capacity Zones shall be allocated to load serving entities with Capacity Load Obligations on the import-constrained side of the interface.

III.13.7.5.4.4. Specifically Allocated CTRs Associated with Transmission Upgrades.
(a) A Market Participant that pays for transmission upgrades not funded through the Pool PTF Rate and which increase transfer capability across existing or potential Capacity Zone interfaces may request a specifically allocated CTR in an amount equal to the number of CTRs supported by that increase in transfer capability.

(b) The allocation of additional CTRs created through generator interconnections completed after February 1, 2009 shall be made in accordance with the provisions of the ISO generator interconnection or planning standards. In the event the ISO interconnection or planning standards do not address this issue, the CTRs created shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(c) Specifically allocated CTRs shall expire when the Market Participant ceases to pay to support the transmission upgrades.

(d) CTRs resulting from transmission upgrades funded through the Pool PTF Rate shall not be specifically allocated but shall be allocated in the same manner as described in Section III.13.7.5.4.2.

(e) **Maine Export Interface**. Casco Bay shall receive specifically allocated CTRs of 325 MW across the Maine export interface for as long as Casco Bay continues to pay to support the transmission upgrades.

(f) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price to which the applicable interface limits the transfer of capacity minus the Capacity Clearing Price from which the applicable interface limits the transfer of capacity; and (ii) the MW quantity of the specifically allocated CTRs across the applicable interface.

III.13.7.5.4.5. Specifically Allocated CTRs for Pool-Planned Units.

(a) In import-constrained Capacity Zones, in recognition of longstanding life of unit contracts, the municipal utility entitlement holder of a resource constructed as Pool-Planned Units shall receive an initial allocation of CTRs equal to the most recent seasonal claimed capability of the ownership entitlements in such unit, adjusted for any designated self-supply quantities as described in Section III.13.1.6.2. Municipal utility entitlements are set as shown in the table below and are not transferrable.

	Millstone 3	Seabrook	Stonybrook GT 1A	Stonybrook GT 1B	Stonybrook GT 1C	Stonybrook 2A	Stonybrook 2B	Wyman 4	Summer (MW)	Winter (MW)
Nominal Summer (MW)	1155.001	1244.275	104.000	100.000	104.000	67.400	65.300	586.725		
Nominal Winter (MW)	1155.481	1244.275	119.000	116.000	119.000	87.400	85.300	608.575		
Danvers	0.2627%	1.1124%	8.4569%	8.4569%	8.4569%	11.5551%	11.5551%	0.0000%	58.26	63.73
Georgetown	0.0208%	0.0956%	0.7356%	0.7356%	0.7356%	1.0144%	1.0144%	0.0000%	5.04	5.55
Ipswich	0.0608%	0.1066%	0.2934%	0.2934%	0.2934%	0.0000%	0.0000%	0.0000%	2.93	2.37
Marblehead	0.1544%	0.1351%	2.6840%	2.6840%	2.6840%	1.5980%	1.5980%	0.2793%	15.49	15.64
Middleton	0.0440%	0.3282%	0.8776%	0.8776%	0.8776%	1.8916%	1.8916%	0.1012%	10.40	11.07
Peabody	0.2969%	1.1300%	13.0520%	13.0520%	13.0520%	0.0000%	0.0000%	0.0000%	57.69	60.26
Reading	0.4041%	0.6351%	14.4530%	14.4530%	14.4530%	19.5163%	19.5163%	0.0000%	82.98	92.77
Wakefield	0.2055%	0.3870%	3.9929%	3.9929%	3.9929%	6.3791%	6.3791%	0.4398%	30.53	32.64
Ashburnham	0.0307%	0.0652%	0.6922%	0.6922%	0.6922%	0.9285%	0.9285%	0.0000%	4.53	5.22
Boylston	0.0264%	0.0849%	0.5933%	0.5933%	0.5933%	0.9120%	0.9120%	0.0522%	4.71	5.35
Braintree	0.0000%	0.6134%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	7.63	7.63
Groton	0.0254%	0.1288%	0.8034%	0.8034%	0.8034%	1.0832%	1.0832%	0.0000%	5.81	6.61
Hingham	0.1007%	0.4740%	3.9815%	3.9815%	3.9815%	5.3307%	5.3307%	0.0000%	26.40	30.36
Holden	0.0726%	0.3971%	2.2670%	2.2670%	2.2670%	3.1984%	3.1984%	0.0000%	17.01	19.33
Holyoke	0.3194%	0.3096%	0.0000%	0.0000%	0.0000%	2.8342%	2.8342%	0.6882%	15.34	16.63

Hudson	0.1056%	1.6745%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.3395%	24.05	24.12
Hull	0.0380%	0.1650%	1.4848%	1.4848%	1.4848%	2.1793%	2.1793%	0.1262%	10.70	12.28
Littleton	0.0536%	0.1093%	1.5115%	1.5115%	1.5115%	3.0607%	3.0607%	0.1666%	11.67	13.63
Mansfield	0.1581%	0.7902%	5.0951%	5.0951%	5.0951%	7.2217%	7.2217%	0.0000%	36.93	42.17
Middleborough	0.1128%	0.5034%	2.0657%	2.0657%	2.0657%	4.9518%	4.9518%	0.1667%	21.48	24.45
North Attleborough	0.1744%	0.3781%	3.2277%	3.2277%	3.2277%	5.9838%	5.9838%	0.1666%	25.58	29.49
Pascoag	0.0000%	0.1068%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.33	1.33
Paxton	0.0326%	0.0808%	0.6860%	0.6860%	0.6860%	0.9979%	0.9979%	0.0000%	4.82	5.53
Shrewsbury	0.2323%	0.5756%	3.9105%	3.9105%	3.9105%	0.0000%	0.0000%	0.4168%	24.33	26.23
South Hadley	0.5755%	0.3412%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	10.89	10.90
Sterling	0.0294%	0.2044%	0.7336%	0.7336%	0.7336%	1.1014%	1.1014%	0.0000%	6.60	7.38
Taunton	0.0000%	0.1003%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	1.25	1.25
Templeton	0.0700%	0.1926%	1.3941%	1.3941%	1.3941%	2.3894%	2.3894%	0.0000%	10.67	12.27
Vermont Public Power Supply Authority	0.0000%	0.0000%	2.2008%	2.2008%	2.2008%	0.0000%	0.0000%	0.0330%	6.97	7.99
West Boylston	0.0792%	0.1814%	1.2829%	1.2829%	1.2829%	2.3041%	2.3041%	0.0000%	10.18	11.69
Westfield	1.1131%	0.3645%	9.0452%	9.0452%	9.0452%	13.5684%	13.5684%	0.7257%	67.51	77.27

This allocation of CTRs shall expire on December 31, 2040. If a resource listed in the table above retires prior to December 31, 2040, however, its allocation of CTRs shall expire upon retirement. In the event that the NEMA zone either becomes or is forecast to become a separate zone for Forward Capacity Auction purposes, National Grid agrees to discuss with Massachusetts Municipal Wholesale Electric Company (“MMWEC”) and Wellesley Municipal Light Plant, Reading Municipal Light Plant and Concord Municipal Light Plant ("WRC") any proposal by National Grid to develop cost effective transmission improvements that would mitigate or alleviate the import constraints and to work cooperatively and in good faith with MMWEC and WRC regarding any such proposal. MMWEC and WRC agree to support any proposals advanced by National Grid in the regional system planning process to construct any such transmission improvements, provided that MMWEC and WRC determine that the proposed improvements are cost effective (without regard to CTRs) and will mitigate or alleviate the import constraints.

(b) The value of CTRs specifically allocated pursuant to this Section shall be calculated as the product of: (i) the Capacity Clearing Price for the Capacity Zone where the load of the municipal utility entitlement holder is located minus the Capacity Clearing Price for the Capacity Zone in which the Pool-Planned Unit is located, and; (ii) the MW quantity of the specifically allocated CTRs.

III.13.7.5.5. Forward Capacity Market Net Charge Amount.

The Forward Capacity Market net charge amount for each Market Participant as of the end of the Obligation Month shall be equal to the sum of: (a) its Capacity Load Obligation charges; (b) its revenues from any applicable specifically allocated CTRs; (c) its share of the CTR fund (for Capacity Commitment Periods beginning prior to June 1, 2022); and (d) any applicable export charges.

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